BEFORE
THE DISTRICT OF COLUMBIA
PUBLIC SERVICE COMMISSION

In the Matter of	)	
	)	
The Application of the	)	**Formal Case No. 1053**
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 2 OF 2

KARL PAVLOVIC	**EXHIBIT OPC (E)**
CHARLES KING	**EXHIBIT OPC (F)**
KAJAL KAPUR	**EXHIBIT OPC (G)**
HUGH LARKIN	**EXHIBIT OPC (H)**
JEROME PAIGE	**EXHIBIT OPC (I)**
DONALD JONES	**EXHIBIT OPC (J)**
RICHARD LOCKLEY	**EXHIBIT OPC (K)**

MAY 31, 2007

DIRECT TESTIMONY OF
OPC WITNESS
KARL R. PAVLOVIC, Ph.D.

EXHIBIT OPC (E)

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DIRECT TESTIMONY OF KARL R. PAVLOVIC, Ph.D.

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

A. My name is Karl Richard Pavlovic. I am President of DOXA, Inc., with offices at 22 Brookes Avenue, Gaithersburg, MD 20877.

Q. PLEASE BRIEFLY DESCRIBE DOXA, INC.

A. DOXA, Inc. was formed in April of 1994. It provides clients with business strategic consulting services and economic and operations analyses for use in civil and regulatory proceedings.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

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

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

A. Yes.

Q. HAVE YOU ATTACHED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE TO THIS TESTIMONY?

A. Yes. Exhibit OPC (E)-1 is a brief summary of my qualifications and experience.

Q. HAVE YOU PREVIOUSLY APPEARED BEFORE THIS COMMISSION?

A. Yes. In Formal Case No. 917, I appeared on behalf of the Office of the People's Counsel and presented testimony to the Commission concerning the planning reserve margin of the Potomac Electric Company ("PEPCO"). In Formal Case No. 929, I addressed claims by the Company regarding "lost revenues" attributable to PEPCO's Demand-Side Management ("DSM") program. In Formal Case No. 936, I addressed the causes of and PEPCO's response to the January 1994 Energy Emergency. In Formal Case No. 945, I addressed issues regarding PEPCO's divestiture of its generating assets and the subsequent unbundling of retail rates. In Formal Case No. 991, I submitted Direct Testimony addressing the performance of PEPCO's transmission and distribution facilities. In Formal Case No. 1002, I submitted Direct Testimony regarding the cost and benefits of the PEPCO-Conectiv merger. In Formal Case No. 1017, I submitted testimony and numerous affidavits concerning procurement of Standard Offer Service ("SOS") electric supply and retail SOS rates. In Formal Case No. 1044, I submitted Direct Testimony addressing the need for new 69 kV and 230 kV transmission lines to serve load in the District of Columbia.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address Commission designated Issues 3, 5, 10, 11, 12, 16, 18, 19 and 20.

Q. WOULD YOU PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS ON THESE ISSUES?

A. Summarized by Commission Designated Issue, my findings and conclusions are as follows.

- **Issue 3**: While the plans and costs of the Northeast Substation System are both reasonable and prudent, the facility will serve load growth during the rate effective period and should be removed from the adjustments to the test-year.
- **Issue 5**: PEPCO has properly weather-normalized and annualized the test-year sales and revenues. However, PEPCO has provided no support for the Billing Day adjustment to revenues and it should removed from the adjustments to the test-year.
- **Issue 10**: As I detail in my testimony below, PEPCO has not performed a proper jurisdictional allocation study. I recommend that the Commission direct PEPCO perform the jurisdictional allocation study correcting the flaws I identify in my testimony.
- **Issue 11**: PEPCO's proposed distribution of its revenue requirement among the rate classes is not reasonable, because it is based on a flawed class cost study and uses the study in an arbitrary manner. I recommend that the Commission direct PEPCO to perform the class cost study correcting the flaws I identify in my testimony and to distribute the revenue requirement among the rate classes on the basis of class cost causation using a proper and accurate class cost study.
- **Issues 12, 13 and 16**: The class rates proposed by PEPCO are not just and reasonable because they do not properly reflect cost causation. I recommend that the

Commission direct PEPCO to construct Customer/Demand Charge rates based on cost causation as reflected in a proper and accurate class cost study. Such rates would (1) send the proper economic price signal to customers, (2) stabilize both customer bills and PEPCO's distribution revenue, and (3) decouple revenue from usage.

- **Issues 18 and 19**: RAD and RAD-AE rates (distribution, transmission and generation) should be revised to reflect a 28 percent discount from the residential rates (as was the case prior to the unbundling of PEPCO's rates) and the discounts should be funded by a non-bypassable surcharge on commercial and residential non-RAD customers.
- **Issue 20**: As detailed in my testimony below, PEPCO's Standard Offer Service and associated surcharges and administrative fees insulate PEPCO from business and regulatory risk.

Q. IN HIS DIRECT TESTIMONY, PAGES 8 TO 10 OF EXHIBIT PEPCO (A), PEPCO WITNESS RIGBY REFERENCES THE FACT THAT PEPCO'S LAST BASE RATE INCREASE WAS GRANTED IN FORMAL CASE NO. 939, DESCRIBES THE UNBUNDLING OF PEPCO'S RATES AND THE ATTENDANT RATE REDUCTIONS AND CAPPING OF THE UNBUNDLED DISTRIBUTION RATES IN 2000. PLEASE EXPLAIN THE UNBUNDLING THAT PRODUCED PEPCO'S CURRENT DISTRIBUTION RATES.

A. As part of the sale of PEPCO's generation assets and the implementation of retail competition in the District in Formal Case No. 945, PEPCO proposed to reduce and unbundled its rates into generation, transmission and distribution rates. In that proceeding OPC took the position that prior to unbundling the rates, the Commission should undertake a rate case analysis of PEPCO's costs and rates to determine, inter alia, the appropriate level of reduction and manner of unbundling. The Commission, however, rejected that suggestion. PEPCO then proposed an unbundling of the rates that was the subject of settlement negotiations, in which I participated on behalf of OPC, and produced the Formal Case No. 945 Phase II Settlement Agreement approved by the Commission. Regarding Mr. Rigby's assertions it is important to emphasize that PEPCO not only voluntarily agreed to reduce and cap the unbundled rates; the reductions and cap were proposed by it. It is highly unlikely that PEPCO would propose and agree to rates that in its best professional judgment it believed would be non-compensatory and inconsistent with its fiduciary obligations to stockholders.

Q. HOW WERE THE RATES UNBUNDLED IN THE PHASE II SETTLEMENT AGREEMENT?

A. The process is described in the May 2000 Testimony of Dr. Browning in Formal Case No. 945. A 1998 class cost study for the District, updated to 1999, was used to develop for each class, cost percentages for distribution, transmission and generation services. These percentages were then applied to each class' bundled rate elements (minimum charge, kilowatthour charge and kilowatt charge) to produce rate elements for distribution, transmission, and generation service that summed to the bundled rate elements. The point of this exercise was to preserve rate and revenue neutrality, i.e., the sum of a customer's monthly bill for the three unbundled services would equal that customer's bill under the bundled rates.

Q. IN THIS PROCESS WAS AN EXPLICIT DETERMINATION MADE AS TO WHETHER THE UNBUNDLED DISTRIBUTION RATES FOR THE CLASSES RECOVERED THE ACTUAL COSTS OF DISTRIBUTION SERVICE?

A. No. However, in the unbundling process PEPCO determined that its revenue requirement for distribution service in the District was at that time approximately $248 million and the distribution rates were unbundled to recover that amount.

Q. WHAT EVIDENCE IS THERE REGARDING COST INCREASES VERSUS THE UNBUNDLED DISTRIBUTION RATE INCREASES OR THE LACK THEREOF SINCE THAT TIME?

A. Mr. Rigby cites the CPI which is irrelevant to the question of PEPCO's costs, since it is a measure of consumer prices, not the prices PEPCO faces as a distribution company. Mr. Rigby also cites to wage increases in PEPCO's union workforce, but this is not relevant either. As OPC witness Smiley-Smith discusses, during this period PEPCO has aggressively cut its workforce, so while individual wages may have increased, PEPCO's overall compensation cost has declined. The relevant issue is not increases or decreases in PEPCO's unit costs and unit revenues, but rather whether PEPCO's revenues have kept pace with its costs.

Q. WHAT EVIDENCE IS THERE ON THAT QUESTION?

A. PEPCO conducted its first distribution-only jurisdictional study for the year 2002. According to that study, its District distribution operating expenses were $252 million and revenues were $319 million. According to the test-year jurisdictional study in this proceeding, PEPCO's District operating expenses were $288 million and revenues were $349 million. Thus, according to PEPCO, the expense increases about which Mr. Rigby shows great concern produced a $26 million increase in expenses, while revenues (the result of the capped rates about which Mr. Rigby shows equally great concern) increased $30 million. Clearly, PEPCO's revenue increases kept pace with PEPCO's expense increases. This merely illustrates the Economics 101 point that whether rates are compensatory is a question of the amount of revenue generated by the rates and the total costs incurred in generating that revenue.

I. Issue 3.b and c – Northeast Substation System

Q. WHY IS PEPCO CONSTRUCTING THE NORTHEAST SUBSTATION SYSTEM?

A. What PEPCO refers to as the Northeast Substation System, i.e., Substation 212 and associated supply and distribution feeders, is being constructed to accommodate future load growth on the portion of PEPCO's District of Columbia distribution system that is currently served by Substations 133, 52, 161, 7 and 117. The anticipated in-service date for the first phase of the Northeast Substation System is June 2007.

Q. PEPCO WITNESS GAUSMAN STATES THAT "[T]HIS PROJECT WILL NOT SERVE NEW LOAD NOR PRODUCE NEW SALES" (PEPCO (E), PAGE 25, LINES 18-19). IS THAT CORRECT?

A. No. Mr. Gausman distinguishes between the transfer of existing load to Substation 212 and load growth on the substation, but in this case this is a distinction without a difference. As

Mr. Gausman indicates in his testimony, "[i]f the Northeast Substation System is not in service by June 2007, [PEPCO's] planning shows that there will be two overloads at existing substations; one at Substation 133 and the second at Substation 52." PEPCO's confidential planning studies (provided in response to Formal Case No. 766, OPC Data Requests 13-6 and 13-7), indicate that the overloads to which Mr. Gausman refers will occur due to load growth beyond capacity on Substations 133 and 52 during 2007. Further, PEPCO anticipates that load on these substations, after the transfer of load to Substation 212, will grow from ** percent of capacity to ** percent by 2009. The transfer of load to Substation 212 will allow Substations 133 and 52 to accommodate new load that will produce new sales. In the same time period, PEPCO anticipates that load on Substation 212 will grow from ** percent of capacity to ** percent of capacity – this will be new load that will also produce new sales. In aggregate, by 2009, PEPCO projects that the new load producing new sales on all three Substations will be ** MVA – ** MVA of near term (i.e., rate effective period) load growth that PEPCO could not accommodate if the Northeast Substation System were not constructed.

Q. ARE YOU ABLE TO ESTIMATE THE NEW SALES REVENUE ASSOCIATED WITH THIS NEW LOAD?

A. A rough estimate can be made using PEPCO's District 2006 total load (2438.5 MVA) (see Exhibit OPC (E)-2) and PEPCO's unadjusted District test-year revenues ($349,088,000) (see Exhibit PEPCO (C)-1). At an average annual revenue per MVA of $143,000 ($349,088,000 divided by 2438.5 MVA), the new ** MVA of load would produce annual revenue of approximately $6.7 million. Using the revenue requirement PEPCO is seeking in this proceeding, the average annual revenue per MVA would be $161,000 ($392,810,000 divided by 2438.5 MVA) and the new load would produce approximately $7.6 million.

Q. PEPCO WITNESS VONSTEUBEN TESTIFIES THAT IF AN ADJUSTMENT TO THE TEST-YEAR EXPENSES FOR THE NORTHEAST SUBSTATION SYSTEM IS NOT MADE, "THE RATES AUTHORIZED BY THE COMMISSION WILL NOT FULLY REFLECT THE COSTS WHICH THE COMPANY WILL INCUR DURING THE RATE EFFECTIVE PERIOD." IS THIS CORRECT?

A. No. The rates proposed by PEPCO witness Bumgarner when applied to the new load during the rate effective period will generate additional revenue that I estimate to be approximately $1.0 million less than the revenue requirement Mr. VonSteuben calculates for the Northeast Substation System. However, just as individual cost items, such as those associated with the Northeast Substation System, can increase during the rate effective period, other individual cost items can decrease during the rate effective period. PEPCO witness Rigby lists in Exhibit PEPCO (A)-1 PEPCO's on-going cost containment efforts, many of which can be reasonably expected to produce further cost savings during the rate effective period. For example, Mr. Rigby expects changes in PEPCO's life insurance contract (effective in 2007) to produce annual savings of $1.3 million during the rate effective period. This projected decrease in a single cost item is not reflected in PEPCO's proposed rates and will clearly offset the Northeast Substation System net 'shortfall' of $1.0 million. Thus, the rates that PEPCO is asking the Commission to authorize can be reasonably expected to reflect and recover the Northeast Substation System costs.

Q. COMMISSION DESIGNATED ISSUES 3.B AND 3.C SPECIFICALLY ASK WHETHER THE NORTHEAST SUBSTATION SYSTEM'S COSTS ARE REASONABLE AND PROPERLY ALLOCATED TO THE DISTRICT AND WHETHER THE NORTHEAST SUBSTATION SYSTEM IS THE APPROPRIATE MEANS TO MAINTENANCE OF THE RELIABILITY OF PEPCO'S DISTRIBUTION SYSTEM IN THE DISTRICT. WHAT IS YOUR TESTIMONY ON THESE POINTS?

A. Given PEPCO's load growth forecasts for its District substations, there is no reasonable alternative to the Northeast Substation System for maintaining reliability and accommodating that load growth. The costs for the system are reasonable.

II. Issue 5.a. – Test-Year Revenue Adjustments

Q. ISSUE 5.A ASKS WHETHER PEPCO HAS PROPERLY WEATHER-NORMALIZED AND ANNUALIZED ITS SALES AND REVENUES. WHAT IS YOUR TESTIMONY ON THESE POINTS?

A. PEPCO has used appropriate heating and cooling seasons in its weather normalization and has properly weather normalized its sales and revenues. PEPCO has also properly annualized sales and revenues. PEPCO's billing days adjustment has not been shown to be appropriate, may understate test period revenues relative to costs, and should be rejected.

Q. WHAT IS PEPCO'S BILLING DAY ADJUSTMENT?

A. The billing day adjustment is shown on line 2 of page 4 of PEPCO witness VonSteuben's Exhibit PEPCO (C)-1. The workpapers showing the calculation of the adjustment are attached to this testimony as Exhibit OPC (E)-3. PEPCO cycle bills its customers and a billing cycle can contain more or fewer days than the number of days in the previous month. As a result, over a twelve month period these discrepancies can aggregate to more or fewer days in the twelve month period. PEPCO calculates that for the twelve months of the test-year in this case the billed revenues actually correspond to 365.72 days rather than the 365 days in the test-year. The billing day adjustment adjusts test-year revenues down by 0.72 days.

Q. IS THIS ADJUSTMENT APPROPRIATE?

A. In this case, no. In rate-making, the point of the test-year is reasonably accurately to model the revenue-cost structure of the company over the rate-effective period, which structure may or may not in fact be accurately represented by the mechanical aggregation of costs and revenues for any given specific period of operation of the company. To that end and in recognition of that fact, various adjustments may be made to the test-period cost study results where it has been demonstrated that such adjustments will result in a more accurate representation of the revenue-cost structure. This adjustment would be appropriate on a showing that it will produce a more accurate test year.

Q. HAS PEPCO MADE SUCH A SHOWING?

A. No. To consider allowing the adjustment that PEPCO proposes, the Commission would have to conclude that PEPCO's revenue-cost structure during the rate-effective period will match 365 days of revenue to 365 days of expenses. PEPCO has presented no evidence to support such a conclusion. PEPCO has not demonstrated that its cycle billing will not produce the same discrepancy during the rate-effective period as was found in the test year. PEPCO has not demonstrated that its cycle billing will not produce negative and positive discrepancies that will cancel out to 365 days over the rate-effective period. PEPCO has never proposed such an adjustment before – it may be that in previous test years the billing day discrepancy has been negative, which discrepancy would be wholly or partially offset by the positive discrepancy in this test year. The Commission should disallow the billing day adjustment.

III. Issue 10 – Jurisdictional Allocation

Q. COMMISSION DESIGNATED ISSUE 10 ASKS "[I]S PEPCO'S JURISDICTIONAL COST ALLOCATION STUDY REASONABLE." IS PEPCO'S JURISDICTIONAL STUDY REASONABLE?

A. No. PEPCO witness Browning describes the study at pages 4 -15 of his direct testimony, Exhibit PEPCO (F) and Exhibit PEPCO (F)-2. The results of the study are contained in Exhibit PEPCO (F)-1. PEPCO provided a copy of the study workpapers as Attachment B to its response to OPC Data Request No. 1-145. The study and its results are not reasonable because (1) PEPCO has not actually done a jurisdictional study of test-year rate base items and expenses as Dr. Browning describes in his testimony and (2) the allocation of subtransmission costs to jurisdictions (explained at pages 7 and 10 of Exhibit PEPCO (F)) is not consistent with cost causation.

Q. WHY DO YOU SAY THAT PEPCO HAS NOT DONE A JURISDICTIONAL STUDY OF THE TEST-YEAR RATE BASE ITEMS AND EXPENSES?

A. At pages 6 – 7 of his testimony, Dr. Browning correctly describes a jurisdictional cost study as involving the <u>direct assignment</u> to jurisdictions of the "majority of Pepco's distribution related plant costs." However, examination of the workpapers of the test-year study shows that the functionalized distribution-related plant in service and distribution-related other operation and maintenance expenses were not in fact directly assigned to the jurisdictions at all. Instead, PEPCO's system test-year costs and expenses were allocated to the jurisdictions using ratios from what in the workpapers is identified, but not provided, as a 2004 analysis which, according to the workpapers, is an update using what is identified, but not provided, as a 2003 inventory. It is not reasonable to assume that the ratios developed from data from an three or more years earlier would produce the same results as an actual direct assignment of current costs. Using such a procedure does not produce a proper cost study. The foundational principle of a cost study is the direct assignment of costs that can be directly assigned. If PEPCO employs such a procedure the analysis from which the ratios are taken should be part of the workpapers and should have been provided along with a demonstration that the use of the ratios can be expected to produce results as accurate as a direct assignment; no such analysis was provided.

Q. WHY IS PEPCO'S ALLOCATION OF SUBTRANSMISSION COSTS TO JURISDICTIONS UNREASONABLE?

A. For the allocation of subtransmission facilities, PEPCO has used the "Average and Excess Demand Non-Coincident Peak" (AED NCP) method. As Dr. Browning points out, this is the method PEPCO has used for years to allocate, *inter alia*, subtransmission facilities and costs. Nonetheless, use of this method is inappropriate for the allocation of subtransmission facilities and costs because the method reflects neither the cost-causative characteristics of subtransmission facilities nor the way in which PEPCO plans and constructs distribution subtransmission facilities.

The AED NCP method measures and allocates facilities and costs on two bases: average demand and excess demand. Average demand is a measure of quantity or amount of electricity transported over a period (in this case, a year). Excess demand is a measure of the peak demand on the facilities. The only driver of subtransmission facility costs is peak demand on the subtransmission facilities. The total amount of energy delivered and consumed has no cost impact on subtransmission facilities. Moreover, it is the maximum peak demand on the facilities that PEPCO uses to plan and construct subtransmission facilities. Thus, demand at peak demand is the appropriate method to allocate subtransmission facilities and costs. In contrast, the average demand component of the method interjects consumption into the allocation and, thus, is inconsistent with both cost causation and PEPCO facilities planning. The use of non-coincident peak demand as the measure of peak demand is also a departure from cost-causation – a perverse departure.

Q. WHY DO YOU CALL THE NON-COINCIDENT PEAK DEPARTURE PERVERSE?

A. The departure from cost-causation is perverse because it shifts costs to the demand that does not coincide with system peak demand, thus sending an economic signal to shift peak demand to coincide with system peak demand; this would result in an increase in total costs. It is also perverse because the magnitude of the cost shift is a direct function of the size of difference between peak and off-peak demand – the greater the difference, the more costs are shifted to the demand which does not peak at the system peak. Because peak demand is the driver of distribution system costs, a more efficient incentive mechanism to maximize peak demand and, thus increase total system costs, could not be devised.

Q. DOES THE DISTRICT OF COLUMBIA PEAK DEMAND COINCIDE WITH PEPCO'S SYSTEM PEAK DEMAND?

A. No. As a consequence, PEPCO's use of the AED NCP method over allocates subtransmission costs to the District of Columbia. The District of Columbia percentage of system peak demand has been for the last five years approximately 40 percent. The District's non-coincident demand percentage used in the jurisdictional study is approximately 41 percent. See Exhibit OPC (E)-4.

Q. WHY DOES PEPCO USE THE AED NCP METHOD?

A. On several occasions in the past PEPCO has proposed using a coincident peak method but the Commission directed that the AED NCP method be used.

Q. ON WHAT BASIS OF DID PEPCO PROPOSE A COINCIDENT PEAK METHOD?

A. In Formal Case No. 869, PEPCO argued that a coincident peak methodology (1) would align the jurisdictional allocation methods with marginal cost allocation methods, (2) would add an additional check on the accuracy of class and jurisdictional demands, and (3) would produce uniformity in cost allocation among its retail jurisdictions because Maryland used, and still uses, a coincident peak method. In Formal Case No. 905, PEPCO in rebuttal adopted WMATA's position that (A) the non-coincident peak method fails to (1) recognize cost causation factors, (2) produce proper revenue responsibility, (3) stimulate diversification and load conservation, and (4) comport with PEPCO's allocation criteria and (B) a coincident peak method (1) more accurately reflects cost causation factors, (2) provides more stable, reliable, and accurate cost causation factors, and (3) produces better price signals. In both cases, the Commission stated that a change to coincident peak method required a showing that new facts and changed circumstances warranted a change and found that such a showing had not been made by either PEPCO or WMATA.

Q. ARE THERE NEW FACTS AND/OR CHANGED CIRCUMSTANCES THAT WOULD WARRANT A CHANGE TO COINCIDENT PEAK METHODS TODAY?

A. Yes, there are two significant changes that have occurred since PEPCO's last rate case. First, PEPCO is now a wires-only company, having divested itself of its generation facilities. As a consequence, both its cost structure and the cost-causative factors acting on that cost structure have changed significantly. Second, the importance of sending the proper economic signals regarding the consumption of energy resources (both commodity energy and the facilities used to transport and deliver commodity energy) has greatly increased.

Q. WHAT IS THE SIGNIFICANCE OF PEPCO'S HAVING BECOME A WIRES-ONLY COMPANY?

A. When PEPCO was a vertically integrated electric company generating, transporting, and delivering electric energy, its costs were driven, often in complex interaction by three cost causative factors (1) the number of customers, (2) the quantity of energy generated, transported and delivered (KWH), and (3) the instantaneous electrical load on various facilities (KW). When PEPCO was vertically integrated, the AED NCP method was used to allocate both subtransmission and generation facilities and costs. Because average demand is a significant cost driver of generation facilities and costs and PEPCO's generation costs were much greater than its subtransmission costs, the distortion caused by using the average demand was relatively minor in the overall allocation of PEPCO's costs. There was even a certain amount of sense to this, because a case could be made that the subtransmission distortion offset a distortion on the generation side.

As a wires-only company, however, PEPCO's cost structure is simpler, being driven by only two cost-causative factors – customers and instantaneous load or demand. The distortion of the overall allocation of costs caused by using average demand in the allocation of subtransmission costs is both much greater and not justified by any offsetting distortion elsewhere in the allocation of costs.

Q. DOES THIS ANALYSIS APPLY TO THE USE OF NON-COINCIDENT VERSUS COINCIDENT PEAK FOR DEMAND ALLOCATION?

A. Yes. Use of non-coincident peak demand shifts subtransmission costs to the demand that does not peak at the system peak. A case can be made here as well that in the past this represented a distortion that offset a distortion in the allocation of generation costs.

Q. WHAT HAS CHANGED WITH REGARD TO ECONOMIC SIGNALS REGARDING CONSUMPTION OF ENERGY RESOURCES?

A. Energy use and the environmental impact of energy use have become major public policy issues in the years since Formal Cases Nos. 869 and 905. As a consequence, the need for the pricing of both energy and energy infrastructure to send the proper economic signals so as to maximize the efficient use of energy and energy infrastructure is greater today than at any time in the past.

Q. HAVE YOU ESTIMATED THE ALLOCATION OF THE TEST-YEAR JURISDICTIONAL COSTS USING COINCIDENT PEAK ONLY ALLOCATION?

A. Yes. I estimate that using coincident peak only allocation, subtransmission rate base and operating expenses allocated to the District are reduced by $1,217,000 and $106,000, respectively. Exhibit OPC (E)-5.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A. Because the proper rate design rests on the accurate assignment of costs to rate classes and because the accurate assignment of costs to rate classes in turn rests on accurate assignment of costs to the District jurisdiction, I recommend that the Commission direct PEPCO to recalculate the District jurisdictional costs using direct assignment of test-year distribution costs and expenses and coincident peak allocation of subtransmission costs.

VI. Issue 11 – Revenue Requirement Distribution

Q. COMMISSION DESIGNATED ISSUE 11 ASKS WHETHER PEPCO'S PROPOSED DISTRIBUTION OF ITS REVENUE REQUIREMENT AMONG RATE CLASSES IS REASONABLE. MORE SPECIFICALLY, ISSUE 11 ASKS WHETHER THE CLASS COST ALLOCATION STUDY, WHICH IS THE BASIS OF THE REVENUE REQUIREMENT DISTRIBUTION, REASONABLY AND ACCURATELY ALLOCATES RATE BASE ITEMS AND OPERATING EXPENSES TO CLASSES AND FUNCTIONS. PLEASE EXPLAIN THE RELATIONSHIP BETWEEN THE CLASS COST ALLOCATION STUDY AND THE PROPOSED REVENUE REQUIREMENT DISTRIBUTION.

A. The summary results of the Class Cost Allocation study are presented by Dr. Browning in Exhibit PEPCO (F)-3 to his testimony. Dr. Browning provides a brief description of the study at pages 15 to 18 of his direct testimony, Exhibit PEPCO (F). Copies of the cost study itself and supporting workpapers were provided by PEPCO in Attachment B of its response to OPC Data Request No. 1-146. The class cost study takes the results of the jurisdictional cost study and "determines the amount of rate base, revenues, expenses, depreciation, amortization, taxes and return for each of the major classes." It does this by (1) taking the jurisdictional study's functionalization of District rate base items and expenses (i.e., subtransmission, primary, secondary and customer), (2) further functionalizing these rate base items and expenses into subfunctions (e.g., secondary facilities into secondary lines, secondary transformers and secondary services), (3) then either directly assigning or allocating, as appropriate, the subfunctionalized rate base items and expenses to the various rate classes, and (4) finally using the class rate base, expenses and revenues to calculate class rates of return.

PEPCO witness Bumgarner then uses the class cost study results to distribute the revenue requirement among the classes. The calculations distributing the revenue requirement are shown on pages 1a and 1b of Exhibit PEPCO (H)-1. Mr. Bumgarner provides a brief explanation of the calculations on pages 5 to 7 of his direct testimony, Exhibit PEPCO (H). Page 2 of Exhibit PEPCO (H)-1 shows the percentage changes in the class revenue requirements that result from the calculations. Mr. Bumgarner starts with the class rates of return from Dr. Browning's class cost study and assumes that the ultimate goal is a unitary rate of return (the 8.42 percent proposed by PEPCO witness Morin in his direct testimony) for all classes. To distribute the revenue requirement he (1) increases the residential class rate of return by an arbitrary 25 percent toward the proposed 8.42 percent overall rate of return and decreases the commercial class rates of return by an equally arbitrary 50 percent and then (2) increases the commercial rates of return until the sum of all the class revenue distributions equals the total District revenue requirement at 8.42 percent.

Q. IS PEPCO'S PROPOSED REVENUE REQUIREMENT DISTRIBUTION REASONABLE?

A. No. The proposed distribution of revenue requirement is not reasonable because the class cost allocation study, upon which it is based, does not accurately assign and allocate rate base and expenses to classes and, as a consequence, does not accurately calculate class rates of return. Even if the class cost study accurately assigned and allocated rate base and expenses and accurately determine class rates of return, the proposed distribution would not be reasonable because it is based on a totally arbitrary revision of the class rates of return.

Q. Why does the class cost study not accurately assign and allocate rate base items and expenses classes and functions?

A. The study is not accurate because (1) the subfunctionalization of the test-year results is not based on a current analysis, but rather on ratios from earlier analyses, (2) secondary services are reclassified as customer services, (3) customer services rate base and expenses are demand allocated rather than directly assigned, (4) significant differences in the costs and class usage of network and underground facilities versus radial and overhead facilities are not recognized in the study, and (5) the demand allocators used in the study do not properly reflect class cost causative characteristics. Among other things, these errors would appear inevitably to result in an overallocation of costs to the residential class, although the failure to provide relevant data makes it impossible to calculate the magnitude of the overallocation.

Q. PLEASE DEFINE THE SUBTRANSMISSION, PRIMARY, SECONDARY AND CUSTOMER FUNCTIONS AND THEIR SUBFUNCTIONS.

A. PEPCO's so-called wires operation consists of electrical equipment (lines, substations, transformers, circuit breakers, capacitors, meters, etc.) operating at voltage levels ranging from 500 kilovolts ("KV") down to 120 volts ("V"). Transmission facilities operate at voltages ranging from 500 KV to 69 KV – the costs associated with transmission facilities are excluded at the outset from PEPCO's jurisdictional and class cost studies.

Facilities functionalized as Subtransmission operate at voltages ranging from 69 KV to 34.5 KV. In PEPCO's studies subtransmission facilities and their costs are not further subfunctionalized and are allocated using a demand allocator referenced in the cost study as "D6 Avg & Excess-Subtrans – NCAP."

Facilities functionalized as Primary carry power from subtransmission facilities to distribution substations. PEPCO subfunctionalizes primary facilities and their costs as "primary substations" and "primary lines" that are then separately allocated using demand allocators referenced as, respectively, "D10 NCAP (Primary Subs)" and "D12 NCAP (Primary Lines)."

Facilities functionalized as Secondary carry power from distribution substations to PEPCO's connection to customer premises. PEPCO subfunctionalizes secondary facilities as "secondary lines," "transformers," and "secondary services" that are allocated using demand allocators referenced as, respectively, "D13 Sum of Max (Secondary Lines)," "D18 Avg Max & NCAP (Transf)," and "D21 Sum of Max (Secondary-Serv)."

Facilities functionalized as Customer connect the customer premises to the secondary facilities and measure the customer's electric usage and/or load. Customer facilities and their costs are subfunctionalized as "services-customer," "meters," and "installations." In previous class cost studies PEPCO has allocated services using a customer allocator referenced as "C13 Avg No. Customers," but in this study PEPCO uses the secondary-services demand allocator, D21. Meter and installations facilities and costs are directly assigned, not allocated.

Q. HAS PEPCO REASONABLY AND ACCURATELY ASSIGNED RATE BASE ITEMS AND OPERATING EXPENSES TO FUNCTIONS?

A. No, for at least two reasons. First, in subfunctionalizing, PEPCO does not directly disaggregate, for example, the primary function costs from the jurisdictional study. Examination of the workpapers reveals that, as in the jurisdictional study, ratios from a 2004 analysis were applied to the test-year total primary costs. The workpapers also indicate that this 2004 analysis is apparently the result of ratio updating in 1998 and 2003 of an earlier analysis. Subfunctionalization of Secondary and Customer facilities and costs was also done using ratios. Rather than conduct an actual subfunctionalization, PEPCO, with explanation or justification, applied ratios determined years, if not decades, ago, to current costs. Second, in the 2003 ratio update secondary services facilities and costs were removed from the secondary function and combined with customer services subfunction. As is the case with the jurisdictional study, it is not reasonable to assume that the ratios developed from data from three or more years earlier would produce the same results as a direct analysis of current costs. This procedure does not produce a proper cost study and, if PEPCO employs such a procedure, the analysis from which the ratios are taken should have been part of the workpapers and should have been provided and along with a demonstration that the use of the ratios can be expected to produce results as accurate as a direct analysis; no such analysis or demonstration was provided.

Q. HAS PEPCO REASONABLY AND ACCURATELY ASSIGNED AND ALLOCATED RATE BASE ITEMS AND EXPENSES TO CLASSES?

A. No, for at least five reasons. First, the assignment and allocation to classes rests upon the flawed and unreliable subfunctionalization of rate base items and expenses. Second, customer installations costs, which should be directly assigned to classes, are assigned on the basis of the ratios of a presumably direct assignment of 1996 costs. Third, customer meter costs, which should be either directly assigned to classes or allocated on the basis of number of customers, are assigned on the basis of the ratios of a presumably direct assignment of 1998 costs. Again, as with the jurisdictional study and the subfunctionalization, it is not reasonable to assume that the ratios that would result from a direct assignment of test-year installations and meters costs and expenses would match those from, respectively, ten and eight years earlier; nor has PEPCO provided any evidence supporting such an assumption. Fourth, customer services costs, which should be either directly assigned to classes or, if it were demonstrated that there is no significant difference in the costs of services for different rate classes, allocated on the basis of number of customers, are assigned on the basis of a demand allocator. Fifth, subtransmission, primary and secondary costs are allocated on the basis of non-coincident peak allocators.

Q. WHAT IS THE PROBLEM WITH USE OF NON-COINCIDENT PEAK ALLOCATORS FOR SUBTRANSMISSION, PRIMARY AND SECONDARY COSTS?

A. Subtransmission, primary and secondary costs are driven by the demand in the facilities. The demand cost causative characteristic of each rate class is the class' coincident maximum demand on the facilities, not the sum of the non-coincident demands of the classes, which is the allocator PEPCO used for subtransmission and primary costs. The use of non-coincident demand allocators shifts costs to the classes whose maximum demand does not occur at the point of peak demand on the facilities and provides the perverse incentives that I earlier described regarding non-coincident demand allocation on the jurisdictional level. For secondary costs, the study uses non-coincident demand allocators based on the sum of customer maximum demands. The cost causative characteristic of the class is, as with subtransmission and primary facilities, the collective class demand at the point of peak demand on the facilities. Sum of customer maximum demand allocators add to the non-coincident cost shift a further shift of costs to classes with relatively large numbers of customers with relatively small individual demands, such as the residential and small commercial classes.

Q. ARE THERE ANY OTHER FLAWS IN THE PEPCO CLASS COST ALLOCATION STUDY?

A. Yes. The majority of residential customers are served by low cost overhead and radial design facilities, while the majority of commercial customers are served by high cost underground and network design facilities. While PEPCO accounts separately for the costs of overhead and underground facilities, in the cost study overhead and underground costs are combined before allocation to classes and, thus, this difference in cost is not reflected in the study. As a result, the study over allocates underground facilities costs to the residential classes and thus overstates the costs of serving residential customers and understates the cost of serving commercial customers.

Q. CAN THE IMPACT OF THESE FLAWS IN THE CLASS COST STUDY BE QUANTIFIED?

A. From the information and data contained in the study and workpapers it is not possible to quantify most of these flaws. Clearly only PEPCO can correct the direct assignment and direct disaggregation of costs.

As regards high cost versus low cost facilities, I have asked PEPCO in data requests for the average cost of serving network, radial, underground, and overhead customers, but PEPCO responded that it does not have those figures. I believe that PEPCO could readily calculate these numbers because in response to OPC Data Request No. 1-139 PEPCO was able to provide the numbers of residential and commercial customers served by the four types of facilities. That data indicates that 18 percent of residential customers are served by network facilities compared to 35 percent of commercial customers and 39 percent of residential customers are served by underground facilities versus 54 percent of commercial customers. In addition, the ratios used to subfunctionalize costs indicate that 90 percent of Primary and Secondary line costs are for underground lines and that 98 percent of Secondary services and Customer services costs are for underground services. Thus, while I am not able to quantify the impact, it is clear that PEPCO's class cost allocation study over-allocates to the residential classes the costs of lines and services.

As regards demand allocators, using coincident demand data provided in PEPCO's response to Section 211.15 of the Filing Requirements, an estimate of the impact can be made. Substituting coincident demand allocators reduces rate base and expenses allocated to the residential classes by, respectively, $51.0 million and $3.5 million. Exhibit OPC (E)-6.

Q. SHOULD ANY CLASS(ES) AND/OR CUSTOMER(S) RECEIVE A DIRECT ASSIGNMENT OF A PORTION OF THE NORTHEAST SUBSTATION COSTS BASED ON CAPACITY OR OTHER FACTORS?

A. No. There is no portion of the Northeast Substation project that can be properly attributed to a subset of customers or classes in the District. Direct assignment of all or a portion of the costs to any class or set of customers would be inappropriate.

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATION REGARDING THE DISTRIBUTION OF REVENUE REQUIREMENT AMONG THE RATE CLASSES?

A. The proper basis for distributing the revenue requirement among the rate classes is to distribute the revenue requirement according to the distribution of costs caused by the classes as determined by a class cost study. Only on the basis of the accurate assignment of costs to the classes can class rates be designed that will recover the costs caused by each class and will send the proper economic signal to customers. As I have explained the class cost study provided by PEPCO does not accurately and reasonably assign costs to the rate classes and can not be used as the basis for distribution of the revenue requirement to the classes or the design of rates. I recommend that the Commission direct PEPCO to provide a class cost that properly functionalizes test-year rate base items and expenses, that directly assigns to the classes those functionalized rate base items and expenses that can be directly assigned and that accurately allocates on the basis of cost causation the remaining rate base items and expenses.

V. Issues 12 and 16 – Rate Design

Q. COMMISSION DESIGNATED ISSUES 12 AND 16 ASK GENERALLY AND COLLECTIVELY WHETHER THE CLASS RATES PROPOSED BY PEPCO ARE JUST AND REASONABLE. AS A PRELIMINARY MATTER, ISSUE 12 SPECIFICALLY ASKS ABOUT THE APPROPRIATE BENCHMARKS AGAINST WHICH TO MEASURE BOTH THE DISTRIBUTION OF THE REVENUE REQUIREMENT TO INDIVIDUAL RATE CLASSES AND THE DISTRIBUTION OF CLASS REVENUE REQUIREMENT TO RATE ELEMENTS. WHAT ARE THE APPROPRIATE BENCHMARKS?

A. For ratemaking purposes, cost-causation is the appropriate benchmark against which to measure both the distribution of the revenue requirement to rate classes and the distribution of class revenue requirement to rate elements. As regards rate elements, the rate elements should reflect both the structure and the costs of distribution service to the individual class customer. Dr. Chamberlin correctly quotes Bonbright on this point – "optimal rates should provide clear, efficient, effective, informative, and cost effective market signals about the present and future costs of service to buyers and sellers, which requires that prices track costs." As regards revenue requirement distribution to classes, the distribution should reflect the total of the costs incurred by the company in providing distribution service to the class, i.e., represent the total costs caused by the class.

Q. ISSUE 12 ALSO SPECIFICALLY ASKS WHETHER THE PERCENTAGE CHANGES IN THE CLASS REVENUE REQUIREMENTS ARE JUST AND REASONABLE AND WHETHER THE PROPOSED RATES EMBODY INTER-CLASS SUBSIDIES. ARE THE CHANGES JUST AND REASONABLE AND DO THE PROPOSED RATES EMBODY INTER-CLASS SUBSIDIES.

A. The changes in the class revenue requirements are not just and reasonable because, as I explained above, the changes are based on an arbitrary revision of the questionable class rates of return under the current rates calculated by the flawed class cost study. An accurate class cost study will indicate the presence and magnitude of any inter-class subsidies in a set of rates. As I explained above, PEPCO's class cost study over allocates costs to the residential classes, creating the appearance of a subsidy of the residential classes by the commercial classes in the current rates. The revenue requirement distribution proposed by PEPCO and the proposed rates based on that revenue requirement distribution attempt explicitly to correct that putative subsidy. Thus, it is likely that the attempt to correct a subsidy that does not exist has created a subsidy of the commercial classes by the residential classes. But that is only a likelihood and yet another reason why I recommend that the Commission direct PEPCO to perform a proper and accurate class cost study of the test-year.

Q. PLEASE DESCRIBE PEPCO'S RATE DESIGN PROPOSAL.

A. As PEPCO witness Chamberlin explains at pages 10-11 of his direct testimony, Exhibit PEPCO (G), PEPCO's rate design proposal consists of (1) increases to customer charge rate elements, (2) decreases to volumetric charge rate elements, together with (3) the Bill Stabilization Adjustment ("BSA"). Mr. Bumgarner shows the proposed tariff rate element changes on pages R-3 to R-14 of the revised tariff pages in Exhibit PEPCO (H)-2 to his direct testimony. Mr. Bumgarner explains the changes to the rate elements (which he refers to as rate components) on pages 8 to 12 of his direct testimony, Exhibit PEPCO (H)-1. Pages 3a to 16 of Exhibit PEPCO (H)-1 show the development of the proposed rate components. Mr. Bumgarner shows the BSA on page R-44 of the revised tariff pages in Exhibit PEPCO (H)-2 and presents a sample calculation of the BSA in Exhibit PEPCO (H)-4. The calculation of the BSA is explained at pages 19 to 20 of his direct testimony, Exhibit PEPCO (H).

Q. WHAT ARE THE ACTIVITIES AND COST STRUCTURE OF DISTRIBUTION SERVICE?

A. The activities involved in providing electric distribution service can be divided into two groups:

1) customer-related activities: construction, operation and maintenance of the facilities connecting the customer to the distribution system (services and meters) and construction, operation and maintenance of billing facilities (meters, meter reading, bill preparation and payment processing), and

2) distribution system-related activities: construction, operation and maintenance of secondary, primary and subtransmission facilities.

Customer-related activities and the costs of those activities are driven by the number of customers. System-related activities and the costs of those activities are driven by the aggregate customer peak demand on the system. The quantity of electricity delivered to customers over a month or a year has no effect on the level and costs of customer-related and system-related activities, and thus has no effect on distribution costs. A rate structure that is aligned with the distribution cost structure consists of a customer element and a demand or capacity element.

Q. DO THE PROPOSED RATES REFLECT THIS COST STRUCTURE?

A. No. The current residential rate structure consists of a minimum charge element and a usage or volumetric element. The minimum charge is actually a volumetric charge as well, because it simply consists of 30 kilowatthours of the volumetric charge. The Company proposes to replace the minimum charge with a customer charge, but a customer charge set at only 22 percent of what it calculates the full customer cost to be, and maintain a volumetric charge element. The proposed rate elements clearly reflect neither the cost structure nor the costs of residential distribution service.

The current commercial rate structure consists of a customer charge element, a volumetric element, and in some cases a demand element. The Company proposes to increase the customer charge elements to half of what it calculates the full customer cost to be, increase the demand elements to half of what it calculates the full demand cost to be (in the case of one class the demand charge is increased to 100 percent of cost), and maintain the volumetric element. As is the case with the proposed residential rates, the proposed commercial rate elements clearly reflect neither the cost structure nor the costs of commercial distribution service.

Q. WHAT CONSIDERATIONS DOES PEPCO OFFER IN SUPPORT OF THESE PROPOSED CHANGES?

A. Both Mr. Bumgarner and Dr. Chamberlin support these changes as movement toward what they acknowledge is the proper rate structure – customer and demand charge elements, with no volumetric charge element. Dr. Chamberlin points out that retention of the volumetric element means that '[i]ncreases or decreases in electricity purchased will cause the utility to over-collect or under-collect its fixed costs" and thus "creates a basic mismatch between the underlying costs and the rates intended to recover the [] costs." He also points out that "this may create inappropriate incentives," which it clearly does for both the company and customers. He asserts, however, that elimination of the volumetric element would "significantly increase rates for small usage customers" and that the revenue mismatch and inappropriate incentives can be dealt with via the BSA.

Q. WHAT DOES COMBINING THE BSA WITH PEPCO'S PROPOSED CHANGES TO THE RATE STRUCTURE ACCOMPLISH?

A. In his testimony OPC witness Larkin describes in great detail how the BSA works and its impacts on both PEPCO and ratepayers. From a rate design standpoint, adding the BSA to the proposed rate structure accomplishes very little and all of what it accomplishes is negative. While Dr. Chamberlin presents the combination as a balancing compromise, the fact is that adding the BSA mechanism to the proposed rate structure (1) negates any putative improvement in the rate structure alignment of costs, (2) temporally misdirects what price signals there are in the proposed rate structure, (3) insulates the company from the proposed rate structure's incentive to maintain and improve the reliability and quality of service, and (4) neither stabilizes revenues nor decouples revenue from usage.

Q. WHY DO YOU SAY THE BSA WOULD MAKE PEPCO INDIFFERENT TO THE QUALITY OF DISTRIBUTION SERVICE IT PROVIDES?

A. Where a utility's revenue stream is related positively to sales volumes, a customer whose service is interrupted is not providing any revenue to the company. The utility therefore has an incentive to restore the customer's service as quickly as possible. This is particularly true where a large number of customers are interrupted at the same time, as occurred in the aftermath of major storms such as Hurricane Isabel in 2003. By contrast, with the BSA, PEPCO's revenues will be unaffected by a decrease in sales volumes, even if that decrease is the result of widespread and/or prolonged outages. PEPCO would therefore have significantly less incentive to restore service to its customers than is currently the case. Similarly, if a company is assured that it will receive its revenue requirement, which includes an element of profit, irrespective of the quality of service, it has no incentive to improve poor or spotty service. For example, a PEPCO with its revenue requirement tied to sales and performance ought to have an incentive to try to improve areas of its distribution system that experience frequent interruptions. But the BSA or any decoupling mechanism that does not incorporate performance metrics and penalties for poor performance will invite this indifference to reliable quality service. Unchecked, monopolies tend to inefficiency and the stifling of innovation, because the monopoly has no competition threatening its revenue flow. The BSA will only add to PEPCO monopoly tendency to inefficiency and lack of innovation. The BSA could actually harm the reliability of the PEPCO distribution system. If a company is guaranteed the recovery of its revenue requirement, one way to immediately improve its profitability is to cut costs. A BSA mechanism would create incentives for a company's management to defer otherwise necessary maintenance activities in order to improve the next quarter's financials through saved maintenance costs.

Q. ARE THERE REASONS TO BE CONCERNED ABOUT THE QUALITY OF DISTRIBUTION SERVICE PEPCO PROVIDES IN THE DISTRICT, EVEN IN THE ABSENCE OF THE BSA OR ANOTHER DECOUPLING MECHANISM?

A. Yes. For several years PEPCO's reliability performance (as measured by SAIFI, SAIDI and CAIDI reliability indices) relative to other utilities has been fair to poor. Moreover, in recent years PEPCO's normal (excluding major events) restoration performance has been deteriorating. More specifically, there is a group of feeders on PEPCO's District distribution system that for a number of years have performed extremely poorly, subjecting customers to frequent and lengthy outages. OPC has laid these problems out in detail in its Comments on PEPCO's 2007 Consolidated Report, filed May 15, 2007 in Formal Case No. 766. Overall, despite PEPCO's assurances at the time that divestiture of its generation assets would allow the company to laser-focus on its distribution operations, performance has deteriorated rather than improved.

Q. WOULD A CUSTOMER CHARGE/DEMAND CHARGE RATE STRUCTURE STABILIZE REVENUE AND DECOUPLE REVENUE FROM USAGE?

A. Yes.

Q. WOULD THE CUSTOMER CHARGE DEMAND/CHARGE RATE STRUCTURE REDUCE PEPCO'S INCENTIVE TO PREVENT SERVICE OUTAGES AND RESTORE POWER AS QUICKLY AS POSSIBLE WHEN OUTAGES DO HAPPEN?

A. Yes. That is why it is essential that, along with adopting my proposed rate design, the Commission must adopt an enforcement mechanism for reliability and quality of service standards that penalizes PEPCO financially if it fails to provide reliable service. A good starting point for developing such a mechanism would be the "Reliability Mechanism" that the New York Public Service Commission has adopted and applied to Consolidated Edison ("Con Ed") for several years. The Con Ed Reliability Mechanism lays out clear reliability and performance standards and levies significant financial penalties on Con Ed for failure to meet those standards.

Q. ARE YOU PROPOSING A CUSTOMER CHARGE/DEMAND CHARGE RATE DESIGN FOR RESIDENTIAL CUSTOMERS?

A. Yes. For all the reasons given above customer charge/demand charge rates constructed upon proper and accurate jurisdictional and class cost studies would be, in the words of Bonbright, "optimal rates … provid[ing] clear, efficient, effective, informative, and cost effective market signals about the present and future costs of service to buyers and sellers." In the absence of the results of an accurate class cost study from PEPCO, I have designed a set of illustrative residential rates, including Residential Aid Discount (RAD) rates consistent with my recommendations regarding Issues 18 and 19, below. The tables below compare the current rate residential rate structure with the revenue-requirement equivalent rate structure appropriate to distribution service. In this rate structure, there is no distinction between summer and winter period rates and no distinction between R-Standard and R-AE rate classes.

MONTHLY RATE – Residential R

	Current Rates		Proposed Rates
Distribution Service Charge	**Summer**	**Winter**	**Summer Winter**
Minimum/Customer Charge	$0.47	$0.47	$5.30
Kilowatthour Charge			
31-370 kwh	$0.00945 per kwh	$0.00945 per kwh	---------
More than 400 kwh	$0.02845 per kwh	$0.02845 per kwh	---------
Kilowatt Charge	--------	--------	$4.12 per kw

MONTHLY RATE – Residential RAD-Standard

	Current Rates		Proposed Rates
Distribution Service Charge	**Summer**	**Winter**	**Summer Winter**
Minimum/Customer Charge	$0.19	$0.19	$3.78
Kilowatthour Charge			
31-370 kwh	$0.00151 per kwh	$0.00578 per kwh	---------
More than 400 kwh	$0.02850 per kwh	$0.01947 per kwh	---------
Kilowatt Charge	--------	--------	$2.72 per kw

Q. PLEASE BRIEFLY DESCRIBE HOW YOU CONSTRUCTED THESE RATES.

A. I first used the customer/demand full cost ratio from the class cost study (the same study used by Mr. Bumgarner) and applied that ratio to the test-year residential revenue from Exhibit PEPCO (H)-1 to calculate full residential customer and demand costs under the current rates. To calculate the residential customer charge, I then divided the full residential customer cost by the number of residential bills for the test-year. To calculate the demand charge, I then divided the full residential demand cost by the 4-year average residential coincident kilowatt demand from Section 211.15 of the Compliance Filing. To calculate the RAD customer charge and demand charge, I reduced the residential customer charge and residential demand charge by 28 percent. I want to emphasize that these rates are illustrative. I believe that a proper and accurate class cost study (1) would decrease the residential classes' revenue requirement relative to the commercial classes and (2) would reduce the customer cost percentage of the residential classes' revenue requirements.

Q. HAVE YOU DONE AN ANALYSIS OF THE IMPACT OF THESE ILLUSTRATIVE RATES?

A. Yes. I have done a bill analysis comparison to the current rates. Exhibit OPC (E)-7. Under a usage or volumetric rate structure, low-consumption customers pay far less than the full cost of distribution service, while consumption customers pay far more. The change to a customer/demand charge rate structure increases the low-consumption customer's bill, bringing it up to the full cost of the service.

VI. Issues 18 – RAD Rate Mismatch

Q. ISSUE 18 ASKS WHETHER THE PORTIONS OF THE RAD RATES THAT ARE HIGHER THAN THE CORRESPONDING RESIDENTIAL RATES SHOULD BE CORRECTED AND, IF SO, HOW IT SHOULD BE FUNDED.

A. The mismatch should be corrected and is corrected in the residential rates I have designed. I address the question of funding in addressing Issue 19.

VII. Issue 19 – RAD Discounts and Funding

Q. ISSUE 19 ASKS ABOUT VARIOUS OPTIONS REGARDING THE LEVEL AND FUNDING OF THE RAD DISCOUNTS. PLEASE BRIEFLY DESCRIBE THE RAD DISCOUNTS AND THEIR FUNDING.

A. The situation with regard to the RAD discounts and their funding is extremely complicated and opaque. The funding of the RAD discounts is from two sources. The expanded RAD discounts are funded through the explicit RETF surcharge that is applied to all non-RAD rates. The original RAD discount, to which the expanded discount was added, was part of PEPCO’s rate structure and was funded by an implicit surcharge embedded in the rates of other classes. This funding was carried over when the rates were unbundled so that each component rate has a portion of the original discount embedded in it and there are corresponding implicit surcharges in the component rates for all other classes. For the expanded discounts, PEPCO applies for reimbursement from the RETF fund. For the original discounts, PEPCO reimburses itself from the revenues it collects from non-RAD classes.

Q. WHAT ARE THE SIGNIFICANT ISSUES REGARDING THE RAD DISCOUNTS?

A. First and most significant is that the discounts have not kept pace with the increases in energy prices and rates. Second, there is a lack of transparency, indeed, there is a certain amount of obfuscation to the discounts. For example, the need for the expanded discounts has resulted from the increase in energy rates, but the expanded discounts are functionally part of the distribution rates. Third, the funding of the discounts is complicated and opaque. Fourth, the Commission has set as its goal to eliminate funding via the RETF.

When the Commission approved an expansion of the RAD discount, the Commission explicitly directed that the expanded discount (1) be calculated as a fixed dollar amount, because this would "provide the greatest incentive for RAD customers to shop,"[1] and (2) be allocated among the distribution, transmission and generation component rates, requiring "each electricity supplier to be responsible for the production and transmission portion of the discount to customers' bills." Thus, the Commission obviously intended that RAD customers be able to shop and that the suppliers or aggregators with whom they shopped be reimbursed the expanded discounts on the generation and transmission component rates.

Q. HOW CAN THE DISCOUNTS BE MADE MORE TRANSPARENT?

A. The implicit surcharges funding the original discounts should be removed from the non-RAD distribution and SOS transmission and generation component rates. The implicit surcharges should then be replaced with a non-bypassable RAD surcharge on all non-RAD customers, to be collected by PEPCO. Under the current situation (and any continuation of the current situation), the original RAD discounts are underfunded and paid disproportionately by the residential classes, where little or no supplier switching has occurred. Funding of the expanded discounts should be removed from the RETF and also placed in the non-bypassable surcharge.

Q. HOW WOULD THE DISCOUNTS BE APPLIED?

A. A 28 percent discount should be applied to the residential distribution and SOS transmission and generation rates. PEPCO would be explicitly reimbursed from the surcharge for the distribution rate discount. Whoever supplied generation and transmission service to a RAD customer (PEPCO, alternative supplier or aggregation supplier) would be reimbursed for the generation and transmission discounts from the surcharge funds.

Q. WHAT WOULD BE THE RESULTS OF THESE CHANGES?

A. The results would be (1) a transparent rate/discount structure that would encourage RAD customers to shop and allow alternative/aggregation suppliers to efficiently pursue such customers, (2) elimination of the possibility of under/over funding of the discounts, and (3) a clear public view of the costs of the RAD discount program.

VIII. Issue 20 – Standard Offer Service

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY ON ISSUE 20?

A. Issue 20 poses two questions. "Do PEPCO's Standard Offer Service and any associated surcharges and administrative fees insulate PEPCO from business and regulatory risk? If so, what adjustment, if any, should be made to PEPCO's rate of return on common equity?" My testimony addresses the first question regarding business and regulatory risk. OPC Witness Rothschild addresses the second question regarding return on common equity.

[1] DC PSC Formal Case No. 945, Order No. 11876, §§ 34-5, December 29, 2000.

Q. WHAT IS THE PURPOSE OF STANDARD OFFER SERVICE?

A. The sale of retail electric energy in the District of Columbia was deregulated and opened to competitive suppliers in 2000. As part of the implementation of the retail energy market, PEPCO sold its generating facilities and purchased power contracts and unbundled its rates into three separate tariff rates for distribution service, transmission service and generation (i.e., energy) service. Retail customers were then free to take transmission and generation service from competitive suppliers who chose to enter the District retail electric market. Standard Offer Service was created for those customers who either do not to select a competitive electric supplier or for whom no competitive electric suppliers make offers of service. The vast majority of residential (99%) and small commercial (88%) customers take Standard Offer Service.

Q. WOULD YOU PLEASE BRIEFLY DESCRIBE PEPCO'S STANDARD OFFER SERVICE.

A. In Order Nos. 13115 and 13118 in Formal Case No. 1017, the Commission adopted rules (15 DCMR 2950) governing what is referred to as wholesale Standard Offer Service and thereby designated PEPCO the Standard Offer Service provider in the District. A copy of the 2950 rules is attached to my testimony as Exhibit OPC (E)-8. Under Commission oversight PEPCO conducts competitive auctions for wholesale energy supply, contracting with the winning bidder(s), and then provides transmission and generation service to SOS customer under tariff rate schedules approved by the Commission. The rules under Sections 2951, 2952, 2954, 2956 and 2958 govern the procurement of wholesale supply contracts. The rules under Sections 2953, 2955 and 2957 govern the recovery of PEPCO's costs as SOS provider via the rates in PEPCO's SOS tariff schedule.

Q. HOW SPECIFICALLY DOES PEPCO RECOVER THE COSTS OF PROVIDING STANDARD OFFER SERVICE?

A. Rule 2953.1 specifies that the SOS retail rates are to consist of four components: (1) the wholesale supply contract price, (2) PJM transmission charges, (3) an administrative charge, and (4) applicable taxes. The actual rates are designed in the traditional way, translating these four cost items into customer class rates with a structure consisting of (1) a minimum or customer charge, (2) a single and/or multiple block kwh charge, and, for certain rate classes, (3) a kw charge.

Q. DOES PEPCO RECOVER ALL OF THE COSTS IT INCURS AS SOS PROVIDER VIA THE SOS RETAIL RATES?

A. Yes, unlike traditional tariff electric rates which provided for only the opportunity to recover all of its expenses and a reasonable return on its investment, PEPCO is guaranteed recovery of all its costs, including a cost of capital, via the rates.

Q. HOW IS PEPCO GUARANTEED RECOVERY OF ALL ITS COSTS?

A. Section 2957 of the wholesale rules contains provision for true-up and recovery of the actual costs comprising the rate components via adjustments to the rates. Rules 2957.4 and 2957.5 provide for true-up against the actual costs comprising the supply contract component. Rule 2957.10 provides for true-up against the actual costs comprising the transmission component.

Rules 2957.7 and 2957.12 provide for true-up against the actual costs comprising the administrative charge component. Finally, just in case the true-ups of the components should somehow fail to produce recovery of all its costs, Rules 2957.3 and 2957.13 provides for a true-up of "[PEPCO's] total costs for providing each type of service … with its total billed revenues for that service" and a true-up against PEPCO's "actual costs incurred by [PEPCO] pursuant to [Rule] 2953.1." The results of all these true-ups are gathered up in a tariff Procurement Cost Adjustment ("PCA") that consists of a per kilowatthour surcharge that is adjusted "at least four (4) times per year" and is applied each month to customers billed kilowatthours. PEPCO has double-belted guaranteed recovery of all its costs.

Q. ARE THERE ANY RISKS TO PEPCO FROM THE WHOLESALE SUPPLY CONTRACTS?

A. Speaking generally, there are three types of risk. The first is that PEPCO would contract for more SOS supply than it needed, for example, as a result of SOS load migration to competitive suppliers. The second is that a wholesale supplier would default on a contract and PEPCO would incur additional costs to replace the defaulting wholesale supply. The third is that the SOS rates would at some point in the future be capped at a level below the wholesale supply cost for which PEPCO had contracted.

Q. IS THERE IN FACT ANY RISK THAT PEPCO WOULD FIND ITSELF WITH MORE CONTRACTED SUPPLY THAN IT NEEDED DUE TO LOAD MIGRATION OR ANY OTHER CAUSE?

A. No. The wholesale supply contracts are for a percentage of actual load. As PEPCO witness

Browning stated in response to a data request from Commission Staff in Formal Case No. 1017,

> Under the proposed contracts Pepco will have with the wholesale suppliers to meet the requirements of SOS customers, payments to the wholesale suppliers will vary with the amount of SOS load served. If 50% of customers (and 50% of the load) were to switch to alternate suppliers, then the payments from Pepco to the wholesale supplier will decline by 50%.

Q. IS THERE IN FACT ANY RISK TO PEPCO FROM THE DEFAULT OF A WHOLESALE SUPPLIER?

A. No. There is, of course, always the possibility that a supplier could default on its contracted supply. There is no risk to PEPCO, however, because the wholesale supply contracts contain financial capability requirements the contracting suppliers in the form of a bond, letter of credit, or corporate guarantee.[2] In the case of default, the proceeds from the bond, letter of credit or corporate guarantee would cover any additional costs incurred in replacing the defaulted supply.[3] Moreover, if somehow PEPCO failed to recover all costs associated with replacing supply through the financial capability instruments, Rule 2959.3 provides for recovery of those costs via the rates.

Q. IS THERE ANY RISK TO PEPCO THAT AT SOME FUTURE TIME THE SOS RATES WOULD BE CAPPED AT A LEVEL BELOW THE PRICE OF THE SUPPLY PEPCO HAD UNDER CONTRACT?

A. Whether there would be a risk of under recovery to PEPCO would depend on the provisions and conditions of the Commission order imposing the rate caps. I note, however, that an order capping rates in a way that actually caused under recovery would be in stark

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[2] Rule 2956.1 and Rule 2956.2.
[3] Rule 2956.5.

contradiction to the Commission's Rules 2957.3, 2957.4, 2957.5, and 2957.13. As a practical matter, the risk to PEPCO is so small as to be non-existent.

Q. DOES PEPCO HAVE ANY SIGNIFICANT CAPITAL AT RISK IN PROVIDING STANDARD OFFER SERVICE?

A. The only capital PEPCO has at risk is the cash working capital required for the lag between payments to suppliers and the collection of billed revenue from SOS customers. To the extent that this capital is at risk PEPCO is handsomely recompensed through the return and margin components of the administrative charge.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

VERIFICATION

______________________________________)
MONTGOMERY COUNTY, MARYLAND)   SS
______________________________________)

KARL R. PAVLOVIC, being first duly sworn, deposes and says that he is the KARL R. PAVLOVIC whose Direct Testimony accompanies this Verification; 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 his sworn testimony in this proceeding.

Karl R Pavlovic

KARL R. PAVLOVIC

SUBSCRIBED AND SWORN TO before me this 24th day of May, 2007.

Michelle A. Lease

Notary Public

My Commission Expires 3/10/09

MICHELLE A. LEASE
NOTARY PUBLIC STATE OF MARYLAND
My Commission Expires March 10, 2009

EXHIBITS OF
OPC WITNESS
KARL R. PAVLOVIC, Ph.D.

EXHIBIT OPC (E)-1

DOXA provides clients with economic and operations analyses and simulations to support strategic business planning, negotiation and litigation. DOXA's analyses and studies are distinguished by (1) systematic articulation and testing of analysis assumptions, (2) thorough evaluation of the soundness of data, (3) innovative application of statistical tools and economic principles, and (4) clarity and precision of presentation. DOXA's fees for services are very competitive, providing cost-effective quality support for commercial activities and litigation.

The types of analyses and studies performed by DOXA include:

- analysis and restatement of regulatory accounting for costs and revenues,
- determination of the economic costs of services, products, and lines of business,
- economic valuation of services, products, and lines of business,
- projection of costs and revenues,
- definition and quantification of markets,
- quantification of market value and the factors affecting market value,
- determination and quantification of market constraints, and
- calculation of economic damages.

In projects involving litigation, DOXA assists counsel in:

- case analysis and planning,
- assessing risks and outcomes,
- analysis of technical evidence and testimony by other parties,
- technical discovery,
- identification of favorable and unfavorable evidence and lines of argumentation, and
- ensuring the consistency of technical evidence and testimony.

The founder and principal of DOXA, Karl Richard Pavlovic, holds undergraduate and graduate degrees in Philosophy from Yale College and Purdue University. By education and professional experience Dr. Pavlovic has expertise in formal and mathematical logic, statistics, economics, financial analysis, econometrics, and computer modeling. He is also knowledgeable of commercial and industrial operations in the energy, transportation, and telecommunications industries and familiar with a wide range of experimental and investigative methods in science and engineering.

22 Brookes Avenue - Gaithersburg, MD 20877
(240) 246-0028 - (240) 246-0051 fax

DOXA
BUSINESS &
LITIGATION
CONSULTING

Karl Richard Pavlovic

Dr. Pavlovic is the founder and President of DOXA, Inc. He is responsible for the design and execution of statistical, economic and financial analyses of discrete commercial operations, individual firms, and industry sectors for use by management and counsel in formulating and implementing commercial and litigation strategy. In some cases, these analyses are the basis for commercial negotiation and testimony by Dr. Pavlovic or others in regulatory and civil court proceedings.

Dr. Pavlovic's projects in the energy field have included analyses of crude oil and petroleum product markets and investigations of the operating and plant investment cost of electric and gas distribution systems. His projects in telecommunications have included assistance to independent telephone companies in the formulation and implementation of corporate strategic plans, applications for long-distance service authority, and negotiations with major domestic and foreign carriers. His transportation projects have included studies of transportation systems (pipeline, rail, truck and water) and individual firms in the Caribbean, Hawaii, Alaska and the contiguous 48 states.

Dr. Pavlovic has served as the Treasurer of the Legal Aid Society of the District of Columbia since 1998.

Snavely, King & Associates, Inc., Washington, D.C.

Vice President (1988-1994)
Consultant (1983-1987)

Responsible for economic analysis in civil court and regulatory proceedings, and consulting assignments in corporate strategic planning including investigations of rate structures, cost of service studies, market identification, and economic projections.

University of Florida, Gainesville, FL

Associate Director,
Center for Applied Philosophy
(1982-1983)

Primary responsibility for implementation and management of daily operations of the center. Major projects included reorganization of finances of the Humanities and Agriculture Project, assembly and direction of a multi-disciplinary team in design of the Caribbean Inter-Sector Forecasting Project, and conception and direction of the Applied Philosophy Feasibility and Implementation Project.

Research Associate, Civil Engineering
(1980-1983)

Responsibilities included direction of the Caribbean Agricultural Transportation Study, design of the planning component of the Honduran Water Port Project, and redesign and completion of the Florida Domestic and Export Agricultural Transportation Projects.

Assistant Professor, Philosophy
(1978-1983)

Responsibilities included undergraduate and graduate courses in scientific methodology and ethics and professionalism as well as research on the social context and impact of scientific and technological growth.

EDUCATION

Yale College, B.A.
Purdue University, M.A.
Universitaet Heidelberg
Purdue University, Ph.D.

PROJECTS

Emergency Application of the Potomac Electric Power Company For A Certificate of Public Convenience and Necessity To Construct Two 69kV Overhead Transmission Lines and Notice Of The Proposed Construction of Two Underground 230kV Transmission Lines (2005 - 2006)
D.C. Public Service Commission Formal Case No. 1044

Investigation Into Potomac Electric Power Company's Distribution Service Rates (2003 - 2005)
D.C. Public Service Commission Formal Case No. 1032

Investigation of the Feasibility of Removing Pre-Existing Aboveground Utility Lines and Cables and Relocating Them Underground in the District of Columbia (2003 -)
D.C. Public Service Commission Formal Case No. 1026

Guadalupe L. Garcia v. Ann Veneman, Secretary, US Department of Agriculture (2003 -)
U.S. District Court for the District of Columbia

Mirant Corporation, et al., Debtors (2003 -)
U.S. District Court for the Northern District of Texas

Complaint: Office of the People's Counsel of the District of Columbia v. Mirant Americas Energy Marketing, L.P. (2003)
Federal Energy Regulatory Commission

Investigation into the Effect of the Bankruptcy of Mirant Corporation on Retail Electric Service in the District of Columbia (2003 -)
D.C. Public Service Commission Formal Case No. 1023

Development and Designation of Standard Offer Service in the District of Columbia (2003 -)
D.C. Public Service Commission Formal Case No. 1017

Independent Review Panel, Project Management Plan, Ohio River Main Stem Study (2003 - 2005)
U.S. Army Corps of Engineers

Investigation into Affiliated Activities, Promotional Practices, and Codes of Conduct of Regulated Gas and Electric Companies (2002 - 2004)
D.C. Public Service Commission Formal Case No. 1009

Independent Review Panel, Ohio River Main Stem Study, System Investment Plan (2001)
U.S. Army Corps of Engineers

Joint Application of PEPCO and New RC, Inc. for Authorization and Approval Of Merger Transaction (2001 - 2002)
D.C. Public Service Commission Formal Case No. 1002

Investigation into Explosions Occurring in Underground Distribution Systems of PEPCO (2001 - 2006)
D.C. Public Service Commission Formal Case No. 991

PROJECTS

Trans Alaska Pipeline System 1996 Quality Bank Complaint Remand (2000 -)
Federal Energy Regulatory Commission

Ohio River Main Stem Study, Independent Technical Review (1999)
U.S. Army Corps of Engineers

Investigation of January 1999 Electric Service Interruption (1999 -)
D.C. Public Service Commission Formal Case No. 982

Trans Alaska Pipeline System 1996 Quality Bank Complaint Appeal (1998 -2000)
U.S. Court of Appeals for the District of Columbia

Electric Retail Competition Investigation (1997 -)
D.C. Public Service Commission Formal Case No. 945

Trans Alaska Pipeline System 1996 Quality Bank Complaint (1996 - 1998)
Federal Energy Regulatory Commission

Trans Alaska Pipeline System 1989 Quality Bank Complaint Remand (1995- 1998)
Federal Energy Regulatory Commission

Prudhoe Bay Unit Operating Agreement Hearings (1995)
Alaska Oil and Gas Conservation Commission

Prudhoe Bay Unit Natural Gas Liquids Hearings (1995)
Alaska Department of Natural Resources/Department of Revenue (1995)

Potomac Electric Power Co. 3rd Integrated Least-Cost Plan (1995)
D.C. Public Service Commission Formal Case No. 917, Phase II

All American Pipeline Quality Bank Complaint (1994-1995)
Federal Energy Regulatory Commission

Trans Alaska Pipeline System 1989 Quality Bank Complaint Appeal (1994-1995)
U.S. Court of Appeals for the District of Columbia

Investigation of the January 1994 Energy Crisis (1994)
D.C. Public Service Commission Formal Case No. 936

Washington Gas Light Co. Gas Rate Case (1994)
D.C. Public Service Commission Formal Case No. 934

Washington Gas Light Co. 3rd Integrated Least-Cost Plan (1994)
D.C. Public Service Commission Formal Case No. 921

PROJECTS

Potomac Electric Power Co. Electric Rate Case (1993)
D.C. Public Service Commission Formal Case No. 929

Washington Gas Light Co. Gas Rate Case (1993)
D.C. Public Service Commission Formal Case No. 922

Trans Alaska Pipeline System Pumpability Complaint (1992)
Federal Energy Regulatory Commission

Potomac Electric Power Co. 2nd Integrated Least-Cost Plan (1992)
D.C. Public Service Commission Formal Case No. 917

Potomac Electric Power Co. Electric Rate Case (1992)
D.C. Public Service Commission Formal Case No. 912

Potomac Electric Power Co. Fuel Clause Audit and Productivity Improvement Plan (1991-)
D.C. Public Service Commission Formal Case No. 766

Potomac Electric Power Co. Electric Rate Case (1991)
D.C. Public Service Commission Formal Case No. 905

Anchorage Telephone Utility (1991-1995)
Federal Communications Commission

Trans Alaska Pipeline System 1989 Quality Bank Complaint (1990-1993)
Federal Energy Regulatory Commission

Telefonica Larga Distancia de Puerto Rico International Service Tariffs (1990-1992)
Federal Communications Commission

Southern Bell Intrastate Depreciation Study (1989-1990)
Florida Public Service Commission

Lake Erie Iron Ore Antitrust Litigation: Erie-Western Pennsylvania Port Authority v.
Penn Central et al. (1988-1989)
U.S. District Court for the Eastern District of Pennsylvania

Unimar International Chapter 11 Reorganization (1988)
U.S. Bankruptcy Court for the Western District of Washington at Seattle

National Forest Road Cost Analysis System (1986)
U.S. Department of Agriculture, Forest Service

Puerto Rico Telephone Company Long Distance Facilities and Service Applications (1985-1990)
Federal Communications Commission

PROJECTS

All American Cable and Radio/ AT&T de Puerto Rico International Rate Complaint (1985-1990)
Federal Communications Commission

Caribbean Telecommunications Facilities Planning Docket (1984-1990)
Federal Communications Commission

EXHIBITS OF
OPC WITNESS
KARL R. PAVLOVIC, Ph.D.

EXHIBIT OPC (E)-2

TABLE 2.2-B: Historical District of Columbia Loads

Loads in Mega-Volt-Amperes (MVA)

Ward 1

Sub. Number	1999	2000	2001	2002	2003	2004	2005	2006	
10	63.1	62.0	67.0	73.6	68.6	83.0	92.6	97.2	
13 (4.33kV)	15.3	15.9	13.8	13.1	12.2	11.9	14.2	15.2	
13	24.9	30.0	27.5	27.0	25.3	24.8	31.5	34.5	
25	38.6	35.4	40.7	40.7	39.4	37.9	45.2	46.6	
Subtotal - Ward 1	**141.9**	**143.3**	**149.0**	**154.4**	**145.5**	**157.6**	**183.5**	**193.5**	Avg. Trend = 4.53%

Ward 2

Sub. Number	1999	2000	2001	2002	2003	2004	2005	2006	
2	167.9	161.6	168.7	172.2	165.0	167.5	175.9	178.4	
12	114.9	111.9	112.7	114.0	109.8	111.2	119.2	121.9	
18	157.6	148.7	152.6	146.1	143.5	139.8	152.4	150.3	
21	31.2	42.2	43.8	43.5	41.7	41.9	43.7	43.2	
52	149.8	161.6	169.1	176.9	185.5	173.2	186.1	193.8	
74	54.4	52.6	53.2	53.4	51.1	51.5	52.9	52.2	
124	112.1	109.6	115.9	115.9	117.3	112.0	117.7	115.4	
197	121.9	117.9	119.4	117.7	117.1	122.4	128.3	129.8	
Subtotal - Ward 2	**909.8**	**906.1**	**935.4**	**939.7**	**931.0**	**919.5**	**976.2**	**985.0**	Avg. Trend = 1.14%

Ward 3

Sub. Number	1999	2000	2001	2002	2003	2004	2005	2006	
38	49.8	50.9	50.9	54.6	51.0	51.2	58.4	59.9	
38 (4.33kV)	2.9	2.3	2.3	2.7	3.1	2.4	3.8	3.3	
77	58.2	54.5	59.2	60.3	58.8	58.5	64.8	67.6	
93 (4.33kV)	3.8	3.0	3.3	4.3	3.7	3.5	3.4	6.1	
129	141.5	153.8	144.0	144.1	138.9	137.4	149.4	145.7	
145 (4.33kV)	3.6	2.8	3.2	3.9	3.3	2.9	3.3	3.7	
146 (4.33kV)	3.4	2.7	3.4	4.2	3.1	3.2	3.1	5.3	
Subtotal - Ward 3	**263.2**	**270.0**	**266.3**	**274.1**	**261.9**	**259.1**	**286.2**	**291.6**	Avg. Trend = 1.47%

Ward 4

Sub. Number	1999	2000	2001	2002	2003	2004	2005	2006	
27	36.4	31.4	45.3	37.9	35.9	33.7	45.8	42.3	
190	91.9	80.4	91.2	95.0	86.6	86.0	97.9	101.9	
Subtotal - Ward 4	**128.3**	**111.8**	**136.5**	**132.9**	**122.5**	**119.7**	**143.7**	**144.2**	Avg. Trend = 1.68%

Ward 5

Sub. Number	1999	2000	2001	2002	2003	2004	2005	2006	
133	122.7	115.7	127.0	127.2	122.1	122.5	133.6	138.4	
Subtotal - Ward 5	**122.7**	**115.7**	**127.0**	**127.2**	**122.1**	**122.5**	**133.6**	**138.4**	Avg. Trend = 1.73%

Ward 6

Sub. Number	1999	2000	2001	2002	2003	2004	2005	2006	
Sta. 'B'	80.9	79.9	92.2	98.0	86.5	88.3	98.0	99.7	
33	10.5	9.2	17.8	17.5	16.9	19.3	18.3	18.2	
117	131.5	129.3	130.9	132.0	128.7	137.8	134.3	122.4	
161	114.8	113.5	116.3	114.8	113.8	116.5	122.0	126.1	
Subtotal - Ward 6	**337.7**	**331.9**	**357.2**	**362.3**	**345.9**	**361.9**	**372.6**	**366.4**	Avg. Trend = 1.17%

Ward 7

Sub. Number	1999	2000	2001	2002	2003	2004	2005	2006	
98 (4.33kV)	1.9	1.1	1.9	2.3	2.3	2.3	2.3	2.5	
7	152.8	163.2	155.8	159.1	150.5	148.6	178.2	185.6	
Subtotal - Ward 7	**154.7**	**164.3**	**157.7**	**161.4**	**152.8**	**150.9**	**180.5**	**188.1**	Avg. Trend = 2.83%

Ward 8

Sub. Number	1999	2000	2001	2002	2003	2004	2005	2006	
8 (4.33kV)	3.2	4.1	3.7	4.0	4.0	4.7	4.5	5.0	
8	25.6	30.8	24.6	26.3	27.5	26.1	28.6	31.0	
136	65.4	61.8	68.1	68.1	63.4	66.4	74.0	73.4	
168	13.7	18.6	26.3	18.1	19.8	20.1	21.5	21.9	
Subtotal - Ward 8	**107.9**	**115.3**	**122.7**	**116.5**	**114.7**	**117.3**	**128.6**	**131.3**	Avg. Trend = 2.84%
DC TOTAL	**2166.2**	**2158.4**	**2251.8**	**2268.5**	**2196.4**	**2208.5**	**2404.9**	**2438.5**	Avg. Trend = 1.71%

Notes: All substations supply 13.8kV of primary power unless otherwise noted.
Loads shown are actual readings taken during peak summer conditions.
Trends shown are based on the straight line regression of the loads.

EXHIBITS OF
OPC WITNESS
KARL R. PAVLOVIC, Ph.D.

EXHIBIT OPC (E)-3

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ending September 30, 2006
(Six Months Actual; Six Months Projected)

(Thousands of Dollars)

Line No.	Adjustment 1 - Weather Normalization/Annualization of Revenues		
1	Adjustment to weather normalize billed distribution revenues	$	(315)
2	Adjustment to reflect 365 billing days		(454)
3	Adjustment to annualize D.C. revenues (excluding surcharges) to current rates		(3,700)
4	Total adjustment to District of Columbia revenues	$	(4,469)
5	Adjustment for RAD generation subsidy	$	550
6	Adjustment to D.C. income tax expense	$	(501)
7	Adjustment to Federal income tax expense	$	(1,581)

3

11/3/2

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Potomac Electric Power Company

[redacted]10/31/2006[redacted]

Weather Corrected Amounts for DC BILLED MWH, OCT 2005 TO SEP'2006 1000

CLASS	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	YEAR
DCRES	-19,510	2,442	-8,112	4,624	14,843	-351							-4,064
DCRAD	0	0	0	0	0	0							
DCRTM	-85	25	-71	80	209	6							163
DCRTMX	0	0	0	0	0	0							0
DCMMA	-1,111	147	-367	278	890	-22							-186
DCGSND	-808	149	-394	363	1,049	2							361
DCGSD	-2,642	251	-628	473	1,521	-37							-1,062
DCGTLV	-10,719	1,387	-3,769	3,816	10,515	144							1,377
DCGT3A	-9,879	0	-35	140	244	40							-9,490
DCGT3B	60	41	-106	91	272	-2							356
DCMET	-287	19	-47	35	113	-3							-169
DCSL	0	0	0	0	0	0							0
DC	-44,981	4,461	-11,528	9,899	29,857	-223							-12,715

Base Dist Rates Cents/KWH

CLASS	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	YEAR
DCRES	1.954	1.273	1.412	1.439	1.366	1.386							
DCRAD													
DCRTM	3.442	3.550	3.497	3.457	3.530	3.489							
DCRTMX													
DCMMA	1.833	1.268	1.259	1.252	1.008	1.258							
DCGSND	4.827	4.190	4.076	4.074	4.095	3.891							
DCGSD	3.985	3.226	3.159	3.085	3.253	3.078							
DCGTLV	2.099	2.211	2.156	2.091	2.214	2.146							
DCGT3A	1.381	1.409	1.371	1.330	1.400	1.382							
DCGT3B	0.111	0.125	0.093	0.106	0.126	0.111							
DCMET	1.588	1.707	1.650	1.607	1.699	1.668							

Base Distribution Revenue, Oct'2005 to Sep'2006

CLASS	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	YEAR
DCRES	$ (381,171)	$ 31,091	$ (86,324)	$ 66,519	$ 202,826	$ (4,872)							$ (171,931)
DCRAD	$ -	$ -	$ -	$ -	$ -	$ -							$ -
DCRTM	$ (2,926)	$ 887	$ (2,481)	$ 2,751	$ 7,371	$ 195							$ 5,797
DCRTMX	$ -	$ -	$ -	$ -	$ -	$ -							$ -
DCMMA	$ (20,367)	$ 1,864	$ (4,623)	$ 3,461	$ 8,972	$ (272)							$ (10,966)
DCGSND	$ (38,999)	$ 6,243	$ (16,059)	$ 14,790	$ 42,956	$ 78							$ 9,009
DCGSD	$ (105,302)	$ 8,098	$ (19,838)	$ 14,591	$ 49,474	$ (1,139)							$ (54,115)
DCGTLV	$ (224,974)	$ 30,670	$ (81,241)	$ 79,850	$ 232,843	$ 3,101							$ 40,249
DCGT3A	$ (136,440)	$ -	$ (479)	$ 1,857	$ 3,419	$ 556							$ (131,086)
DCGT3B	$ 66	$ 51	$ (98)	$ 97	$ 342	$ (2)							$ 456
DCMET	$ (4,558)	$ 324	$ (770)	$ 565	$ 1,922	$ (46)							$ (2,562)
DCSL	$ -	$ -	$ -	$ -	$ -	$ -							$ -
DC	$ (914,672)	$ 79,229	$ (211,914)	$ 184,481	$ 550,127	$ (2,400)							$ (315,149)
DC Average Rate Check (Cents/KWH)	2.033	1.776	1.838	1.864	1.855	1.078							

Historical Res rate is form Res excluding RAD
Forecasted Res Rate is a combined Res+RAD Rev and Kwh
No separate rates between GSND and D provided by Rates Group in forecast

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Billing Days in the Test Year
September 2006 District of Columbia

Input Revenue in cell E22

		Avg No. of Days in the Billing Month 1/
October	2005	31.24
November	2005	29.38
December	2005	32.52
January	2006	32.33
February	2006	28.48
March	2006	30.59
Apr	2006	30.10
May	2006	29.38
June	2006	30.71
July	2006	30.57
August	2006	29.71
September	2006	30.71
12 months ended	September 2006	365.72

	Revenue	No. Days in test yr	Revenue/day	Target No. Days in test yr.	365 Days of Revenue for test yr.	RMA - Billing Day Adjustment
Billed Maryland Distribution based revenue (excludes surcharges)	**$ 230,752,407.00**	365.72	$ 630,953.75	365.00	$ 230,298,120.30	$ (454,286.70)

1/ Souce: Pepco Meter Reading Schedule from Meter Reading Dept.

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BILLED BASE DIST REVENUE
ANNUALIZED TO FEBRUARY 8, 2005 RATES

	Annualized Base Distribution Revenue 12 Months Ended Sep-06	6 Months Actual & 6 Months Forecast Sep-06
R	$ 21,718,313.92	$ 22,950,972.16
AE	7,284,997.01	7,541,002.97
RAD	1,666,166.04	1,842,291.04
Residential - TOU	882,367.74	890,779.23
Total Residential	$ 31,551,844.71	$ 33,225,045.40
MMA	$ 6,221,406.27	$ 6,918,435.76
GS-Low Voltage	41,452,934.30	40,754,142.71
GS-High Voltage	49,797.20	40,926.50
GT-Low Voltage	102,147,965.75	103,415,578.56
GT-High Voltage - 3A	39,564,866.84	40,037,882.16
General Service	$ 189,436,970.36	$ 191,166,965.69
Large Power (GT - 3B)	310,809.56	345,340.27
Total Commercial	$ 189,747,779.92	$ 191,512,305.96
Street Lighting - Energy	$ 142,430.30	$ 162,842.35
Street Lighting - Service	387,347.45	513,883.64
Rapid Transit	5,223,158.38	5,338,329.78
Total Retail - Annualized	$ 227,052,560.77	$ 230,752,407.13
Actual/Forecast Billed Base Distribution Revenue	$ 230,752,407.13	
Difference	($3,699,846.36)	
% Difference	**-1.60%**	

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EXHIBITS OF
OPC WITNESS
KARL R. PAVLOVIC, Ph.D.

EXHIBIT OPC (E)-4

OPC (E)-4

PEPCO SYSTEM
Coincident System Peak Analysis 4-Year Average 2002 - 2005
Using 4-year Average Loses

	JURIS	DELIVERY LEVEL		Sales To GEN EFF FACTOR	GENERATION LEVEL		EUM ADJSTMNT	EUM ADJUSTED DEMANDS		Exclude SMECO, VA, XC	
	DC	2,075,573	35.36%	0.924302395	2,245,556	35.45%	0	2,245,556	35.45%	2,245,556	40.01%
	MD	3,092,020	52.68%	0.918425488	3,366,653	53.14%	0	3,366,653	53.14%	3,366,653	59.98%
	SM	688,854	11.74%	0.972536251	708,307	11.18%	0	708,307	11.18%		0.00%
	VA	788	0.01%	0.952297143	828	0.01%	0	828	0.01%	828	0.01%
	XC	12,652	0.22%	0.915899613	13,813	0.22%	0	13,813	0.22%		0.00%
		5,869,887	100.00%		6,335,157	100.00%		6,335,157	100.00%	5,613,037	100.00%

PEPCO SYSTEM
Coincident System Peak Analysis July 27, 2005 - 14:00
Using 2005 Loses

OBS	JURIS	DELIVERY LEVEL		Sales To GEN EFF FACTOR	GENERATION LEVEL		EUM ADJSTMNT	EUM ADJUSTED DEMANDS	
1	DC	2194014	35.19%	0.924883811	2,372,205	35.27%	0	2,372,205	35.27%
2	MD	3254879	52.21%	0.918307644	3,544,432	52.71%	0	3,544,432	52.71%
3	SM	774182	12.42%	0.972855665	795,783	11.83%	0	795,783	11.83%
4	VA	295	0.00%	0.951612903	310	0.00%	0	310	0.00%
5	XC	11243	0.18%	0.916299919	12,270	0.18%	0	12,270	0.18%
		6,234,613	100.00%		6,725,000	100.00%	0	6,725,000	100.00%

PEPCO SYSTEM
Coincident System Peak Analysis June 17, 2004 - 16:00
Using 2004 Loses

OBS	JURIS	DELIVERY LEVEL		Sales To GEN EFF FACTOR	GENERATION LEVEL		EUM ADJSTMNT	EUM ADJUSTED DEMANDS	
1	DC	2047219	36.24%	0.926163235	2,210,430	36.32%	0	2,210,430	36.32%
2	MD	2924584	51.76%	0.919942021	3,179,096	52.23%	0	3,179,096	52.23%
3	SM	665146	11.77%	0.974234588	682,737	11.22%	0	682,737	11.22%
4	VA	979	0.02%	0.954191033	1,026	0.02%	0	1,026	0.02%
5	XC	11830	0.21%	0.91733871	12,896	0.21%	0	12,896	0.21%
		5,649,758	100.00%		6,086,185	100.00%	0	6,086,185	100.00%

PEPCO SYSTEM
Coincident System Peak Analysis August 22, 2003 - 16:00
Using 2003 Loses

OBS	JURIS	DELIVERY LEVEL		Sales To GEN EFF FACTOR	GENERATION LEVEL		EUM ADJSTMNT	EUM ADJUSTED DEMANDS	
1	DC	1999056	34.96%	0.924802138	2,161,604	35.06%	0	2,161,604	35.06%
2	MD	3034054	53.06%	0.919507269	3,299,652	53.51%	0	3,299,652	53.51%
3	SM	667746	11.68%	0.972734146	686,463	11.13%	0	686,463	11.13%
4	VA	1058	0.02%	0.953153153	1,110	0.02%	0	1,110	0.02%
5	XC	15742	0.28%	0.916778289	17,171	0.28%	0	17,171	0.28%
		5,717,656	100.00%		6,166,000	100.00%	0	6,166,000	100.00%

PEPCO SYSTEM
Coincident System Peak Analysis July 29, 2002 - 16:00
Using 2002 Loses and EUM Adjustments

OBS	JURIS	DELIVERY LEVEL		Sales To GEN EFF FACTOR	GENERATION LEVEL		EUM ADJSTMNT	EUM ADJUSTED DEMANDS	
1	DC	2062004	35.08%	0.921360396	2,237,999	35.17%	0	2,237,999	35.17%
2	MD	3154561	53.67%	0.915945019	3,444,051	54.12%	0	3,444,051	54.12%
3	SM	648343	11.03%	0.970320605	668,174	10.50%	0	668,174	10.50%
4	VA	821	0.01%	0.950231482	864	0.01%	0	864	0.01%
5	XC	11791	0.20%	0.913181537	12,912	0.20%	0	12,912	0.20%
		5,877,520	100.00%		6,364,000	100.00%	0	6,364,000	100.00%

PEPCO SYSTEM
Coincident System Peak Analysis August 9, 2001 - 19:00
Using 2001 Loses

OBS	JURIS	DELIVERY LEVEL		Sales To GEN EFF FACTOR	GENERATION LEVEL		EUM ADJSTMNT	EUM ADJUSTED DEMANDS	
1	DC	1929593	33.81%	0.927607331	2,080,183	33.88%	0	2,080,183	33.88%
2	MD	3132388	54.89%	0.922049381	3,397,202	55.33%	0	3,397,202	55.33%
3	SM	631952	11.07%	0.974122145	648,740	10.57%	0	648,740	10.57%
4	VA	1584	0.03%	0.956521739	1,656	0.03%	0	1,656	0.03%
5	XC	11247	0.20%	0.920451756	12,219	0.20%	0	12,219	0.20%
		5,706,764	100.00%		6,140,000	100.00%	0	6,140,000	100.00%

EXHIBITS OF
OPC WITNESS
KARL R. PAVLOVIC, Ph.D.

EXHIBIT OPC (E)-5

Pepco

Cost of Service Summary w/ CP Subtransmission Allocation

12 Months Ended September 30, 2006

6 Months Actual & 6 Months Forecasted

		Other		District of Columbia	
	System	Ratio	Amount	Ratio	Amount
Average Rate Base:					
Electric Plant In Service	$ 4,191,094,639	0.5309	$ 2,225,201,197	0.4691	$ 1,965,893,442
Materials and Supplies	30,935,805	0.4949	15,310,672	0.5051	15,625,133
Cash Working Capital	21,275,059	0.4798	10,208,833	0.5202	11,066,226
Accumulated Depreciation	(1,705,806,079)	0.6219	(1,060,917,197)	0.3781	(644,888,882)
Accumulated Amortization	(28,871,767)	0.5516	(15,926,087)	0.4484	(12,945,680)
Accumulated Deferred Income Taxes	(551,696,902)	0.3422	(188,793,658)	0.6578	(362,903,244)
Customer Deposits Exclusions	(31,134,036)	0.4980	(15,504,203)	0.5020	(15,629,833)
Contributions In Aid of Construction	(275,437,065)	0.7239	(199,389,164)	0.2761	(76,047,901)
Net of Tax Prepaid Pension/OPEB Liability	61,722,412	0.6230	38,453,063	0.3770	23,269,349
Total	$ 1,712,082,066	0.4723	$ 808,643,456	0.5277	$ 903,438,610
Revenue:					
Sale of Electricity	$ 782,256,295	0.5587	$ 437,082,290	0.4413	$ 345,174,005
Other Operating Revenues	7,521,505	0.4796	3,607,079	0.5204	3,914,426
Total Revenues	$ 789,777,800	0.5580	$ 440,689,369	0.4420	$ 349,088,431
Expenses:					
Operation and Maintenance Expense	$ 217,659,135	0.6202	$ 134,993,619	0.3798	$ 82,665,516
Depreciation Expense	139,171,795	0.6461	89,917,906	0.3539	49,253,889
Amortization Expense	8,202,121	0.5436	4,458,316	0.4564	3,743,805
Income Tax - Federal	30,013,800	0.3275	9,829,657	0.6725	20,184,143
Income Tax - DC	4,167,135	0.0000	0	1.0000	4,167,135
Other Taxes	281,950,665	0.5476	154,402,560	0.4524	127,548,105
Total	$ 681,164,651	0.5778	$ 393,602,058	0.4222	$ 287,562,593
Operating Income	$ 108,613,149	0.4335	$ 47,087,311	0.5665	$ 61,525,838
Rate of Return					
12 Months Ended September 30, 2006					6.81%

EXHIBITS OF
OPC WITNESS
KARL R. PAVLOVIC, Ph.D.

EXHIBIT OPC (E)-6

Pepco
District of Columbia
Unadjusted Proforma Class of Business
12 Months Ending September 30, 2006
Based on CP Allocators
6 Months Actual and 6 Months Forecast

Summary

Cost of Service and Return Summary

	Total	Residential	RAD	RTM	MMA	GS-LV	GS-HV	Total GS
Rate Base								
Plant in Service	1,968,471,728	437,151,576	32,822,971	7,242,945	87,517,016	267,018,008	76,915	267,094,923
Materials and Supplies	15,638,889	3,744,419	283,699	62,306	743,057	2,223,336	379	2,223,715
Cash Working Capital	11,074,529	2,562,079	192,575	42,446	492,821	1,507,432	461	1,507,893
Accumulated Depreciation	(645,858,920)	(149,372,513)	(11,230,112)	(2,474,953)	(28,758,844)	(87,908,694)	(26,490)	(87,935,184)
Accumulated Amortization	(12,961,962)	(2,960,082)	(222,753)	(49,087)	(571,927)	(1,743,697)	(509)	(1,744,206)
Accumulated Deferred Income Taxes	(363,325,031)	(79,921,601)	(5,933,989)	(1,409,492)	(16,531,958)	(49,409,026)	(11,958)	(49,420,984)
Customer Deposits	(15,629,833)	(1,858,743)	(142,234)	(31,087)	(680,733)	(1,983,943)	(1,853)	(1,985,796)
Net Tax Prepaid Pension/OPEB Liability	23,294,038	9,154,779	757,038	75,281	724,951	3,231,458	3,958	3,235,416
Contributions In Aid of Construction	(76,047,901)	(547,357)	0	(9,152)	(3,454,771)	(10,068,786)	0	(10,068,786)
Total Rate Base	904,655,537	217,952,557	16,527,195	3,449,207	39,479,612	122,866,088	40,903	122,906,991
Operating Revenues								
Sale of Electricity	345,174,005	46,417,787	3,002,670	1,126,222	10,634,025	51,735,762	57,796	51,793,558
Other Operating Revenues	3,914,426	1,002,589	771,727	9,483	127,542	446,795	15	446,810
Total Operating Revenues	349,088,431	47,420,376	3,774,397	1,135,705	10,761,567	52,182,557	57,811	52,240,368
Expenses								
Operation and Maintenance	82,745,927	32,519,952	2,689,214	267,349	2,575,198	11,478,783	14,049	11,492,832
Depreciation Expense	49,326,840	11,400,422	857,132	188,899	2,195,196	6,709,570	2,021	6,711,591
Amortization Expense	3,748,593	858,153	64,564	14,228	165,665	505,397	149	505,546
Income Tax - Federal	20,104,964	(7,551,333)	(572,424)	96,095	160,436	5,783,708	6,812	5,790,520
Other Taxes	131,742,259	18,520,386	1,367,848	299,641	4,307,208	13,678,093	20,950	13,699,043
Total Expenses	287,668,583	55,747,580	4,406,334	866,212	9,403,703	38,155,551	43,981	38,199,532
Operating Income	61,419,848	(8,327,204)	(631,937)	269,493	1,357,864	14,027,006	13,830	14,040,836
Rate of Return	6.79%	-3.82%	-3.82%	7.81%	3.44%	11.42%	33.81%	11.42%

Pepco
District of Columbia
Unadjusted Proforma Class of Business
12 Months Ending September 30, 2006
Based on CP Allocators
6 Months Actual and 6 Months Forecast

Cost of Service and Return Summary

	GT-LV	GT-HV-69KV	GT-HV	Total GT-HV	Total GT	Metro	St Lgt-E	St Lgt-S
Rate Base								
Plant in Service	792,177,714	15,733,231	259,455,551	275,188,782	1,067,366,496	51,635,551	6,998,440	10,641,810
Materials and Supplies	6,767,131	89,074	1,465,605	1,554,679	8,321,810	151,153	83,580	25,150
Cash Working Capital	4,458,687	90,947	1,499,421	1,590,368	6,049,055	155,363	41,223	31,074
Accumulated Depreciation	(260,220,647)	(5,297,010)	(87,320,760)	(92,617,770)	(352,838,417)	(9,044,659)	(2,416,740)	(1,787,498)
Accumulated Amortization	(5,170,779)	(112,627)	(1,858,630)	(1,971,257)	(7,142,036)	(191,790)	(46,685)	(33,396)
Accumulated Deferred Income Taxes	(148,843,135)	(3,062,623)	(50,492,931)	(53,555,554)	(202,398,689)	(5,216,023)	(1,409,588)	(1,082,707)
Customer Deposits	(6,259,280)	0	(4,671,960)	(4,671,960)	(10,931,240)	0	0	0
Net Tax Prepaid Pension/OPEB Liability	7,283,599	102,035	1,721,373	1,823,408	9,107,007	191,004	42,773	5,789
Contributions In Aid of Construction	(31,765,708)	0	47	47	(31,765,661)	(24,777,253)	0	(5,424,921)
Total Rate Base	358,427,582	7,543,027	119,797,716	127,340,743	485,768,325	12,903,346	3,293,003	2,375,301
Operating Revenues								
Sale of Electricity	150,607,550	2,971,660	68,511,470	71,483,130	222,090,680	8,522,065	1,073,114	513,884
Other Operating Revenues	1,078,842	27,248	407,214	434,462	1,513,304	34,809	8,035	127
Total Operating Revenues	151,686,392	2,998,908	68,918,684	71,917,592	223,603,984	8,556,874	1,081,149	514,011
Expenses								
Operation and Maintenance	25,872,968	362,478	6,114,743	6,477,221	32,350,189	678,538	152,089	20,566
Depreciation Expense	19,861,727	405,944	6,692,593	7,098,537	26,960,264	693,078	184,115	136,143
Amortization Expense	1,497,983	32,236	531,886	564,122	2,062,105	54,926	13,586	9,820
Income Tax - Federal	14,078,625	(247,156)	7,230,534	6,983,378	21,062,003	1,133,908	(101,766)	87,525
Other Taxes	54,601,541	2,717,562	31,690,486	34,408,048	89,009,589	3,570,546	935,685	32,313
Total Expenses	115,912,844	3,271,064	52,260,242	55,531,306	171,444,150	6,130,996	1,183,709	286,367
Operating Income	35,773,548	(272,156)	16,658,442	16,386,286	52,159,834	2,425,878	(102,560)	227,644
Rate of Return	9.98%	-3.61%	13.91%	12.87%	10.74%	18.80%	-3.11%	9.58%

EXHIBITS OF
OPC WITNESS
KARL R. PAVLOVIC, Ph.D.

EXHIBIT OPC (E)-7

Residential Annual Bill Comparison

	Current Rates ($)					Customer/Demand Charge Rates ($)			
KWH	**Summer**	**Winter**	**Avg Mo**	**Annual**	**KW**	**Summer**	**Winter**	**Avg Mo**	**Annual**
0	0.47	0.47	0.47	5.64	**0.3**	6.50	6.50	6.50	78.01
10	0.47	0.47	0.47	5.64	**0.3**	6.50	6.50	6.50	78.01
20	0.47	0.47	0.47	5.64	**0.3**	6.50	6.50	6.50	78.01
30	0.47	0.47	0.47	5.64	**0.3**	6.50	6.50	6.50	78.01
40	0.56	0.56	0.56	6.77	**0.3**	6.50	6.50	6.50	78.01
50	0.66	0.66	0.66	7.91	**0.3**	6.50	6.50	6.50	78.01
100	1.13	1.13	1.13	13.58	**0.3**	6.50	6.50	6.50	78.01
200	2.08	2.08	2.08	24.92	**0.6**	7.70	7.70	7.70	92.41
300	3.02	3.02	3.02	36.26	**0.9**	8.90	8.90	8.90	106.82
400	3.97	3.97	3.97	47.60	**1.3**	10.10	10.10	10.10	121.23
500	6.81	5.91	6.28	75.42	**1.6**	11.30	11.30	11.30	135.63
600	9.66	7.85	8.60	103.24	**1.9**	12.50	12.50	12.50	150.04
700	12.50	9.79	10.92	131.06	**2.2**	13.70	13.70	13.70	164.45
750	13.92	10.76	12.08	144.96	**2.4**	14.30	14.30	14.30	171.65
800	15.35	11.73	13.24	158.87	**2.5**	14.90	14.90	14.90	178.85
850	16.77	12.71	14.40	172.78	**2.7**	15.50	15.50	15.50	186.06
900	18.19	13.68	15.56	186.69	**2.8**	16.11	16.11	16.11	193.26
950	19.61	14.65	16.72	200.60	**3.0**	16.71	16.71	16.71	200.47
1000	21.04	15.62	17.88	214.51	**3.1**	17.31	17.31	17.31	207.67
1250	28.15	20.47	23.67	284.06	**3.9**	20.31	20.31	20.31	243.69
1500	35.26	25.33	29.47	353.61	**4.7**	23.31	23.31	23.31	279.70
1750	42.37	30.18	35.26	423.15	**5.5**	26.31	26.31	26.31	315.72
2000	49.49	35.04	41.06	492.70	**6.3**	29.31	29.31	29.31	351.74
2250	56.60	39.89	46.85	562.25	**7.1**	32.31	32.31	32.31	387.75
2500	63.71	44.75	52.65	631.80	**7.9**	35.31	35.31	35.31	423.77
3000	77.94	54.46	64.24	770.89	**9.4**	41.32	41.32	41.32	495.81
3500	92.16	64.17	75.83	909.99	**11.0**	47.32	47.32	47.32	567.84
4000	106.39	73.88	87.42	1049.08	**12.6**	53.32	53.32	53.32	639.87
5000	134.84	93.30	110.61	1327.27	**15.7**	65.33	65.33	65.33	783.94

Residential AE Annual Bill Comparison

	Current Rates ($)					Customer/Demand Charge Rates ($)			
KWH	**Summer**	**Winter**	**Avg Mo**	**Annual**	**KW**	**Summer**	**Winter**	**Avg Mo**	**Annual**
0	0.47	0.47	0.47	5.64	**0.3**	6.50	6.50	6.50	78.01
10	0.47	0.47	0.47	5.64	**0.3**	6.50	6.50	6.50	78.01
20	0.47	0.47	0.47	5.64	**0.3**	6.50	6.50	6.50	78.01
30	0.47	0.47	0.47	5.64	**0.3**	6.50	6.50	6.50	78.01
40	0.56	0.56	0.56	6.77	**0.3**	6.50	6.50	6.50	78.01
50	0.66	0.66	0.66	7.91	**0.3**	6.50	6.50	6.50	78.01
100	1.13	1.13	1.13	13.58	**0.3**	6.50	6.50	6.50	78.01
200	2.08	2.08	2.08	24.92	**0.6**	7.70	7.70	7.70	92.41
300	3.02	3.02	3.02	36.26	**0.9**	8.90	5.64	7.00	83.96
400	3.97	3.97	3.97	47.60	**1.3**	10.10	10.10	10.10	121.23
500	6.81	5.52	6.06	72.69	**1.6**	11.30	11.30	11.30	135.63
600	9.66	7.07	8.15	97.78	**1.9**	12.50	12.50	12.50	150.04
700	12.50	8.62	10.24	122.87	**2.2**	13.70	13.70	13.70	164.45
750	13.92	9.40	11.28	135.41	**2.4**	14.30	14.30	14.30	171.65
800	15.35	10.17	12.33	147.95	**2.5**	14.90	14.90	14.90	178.85
850	16.77	10.95	13.37	160.50	**2.7**	15.50	15.50	15.50	186.06
900	18.19	11.73	14.42	173.04	**2.8**	16.11	16.11	16.11	193.26
950	19.61	12.50	15.47	185.59	**3.0**	16.71	16.71	16.71	200.47
1000	21.04	13.28	16.51	198.13	**3.1**	17.31	17.31	17.31	207.67
1250	28.15	17.16	21.74	260.85	**3.9**	20.31	20.31	20.31	243.69
1500	35.26	21.04	26.96	323.58	**4.7**	23.31	23.31	23.31	279.70
1750	42.37	24.92	32.19	386.30	**5.5**	26.31	26.31	26.31	315.72
2000	49.49	28.80	37.42	449.02	**6.3**	29.31	29.31	29.31	351.74
2250	56.60	32.68	42.65	511.74	**7.1**	32.31	32.31	32.31	387.75
2500	63.71	36.56	47.87	574.47	**7.9**	35.31	35.31	35.31	423.77
3000	77.94	44.32	58.33	699.91	**9.4**	41.32	41.32	41.32	495.81
3500	92.16	52.08	68.78	825.36	**11.0**	47.32	47.32	47.32	567.84
4000	106.39	59.84	79.23	950.80	**12.6**	53.32	53.32	53.32	639.87
5000	134.84	75.36	100.14	1201.69	**15.7**	65.33	65.33	65.33	783.94

EXHIBITS OF
OPC WITNESS
KARL R. PAVLOVIC, Ph.D.

EXHIBIT OPC (E)-8

PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
RULES AND REGULATIONS GOVERNING
THE PROVISION OF STANDARD OFFER SERVICE
IN THE DISTRICT OF COLUMBIA

(to be published at 15 DCMR XXXX *et seq.*)

D.C. Code, Title 34, Chapter 15, Subtitle III

2950 GENERAL PROVISIONS; SCOPE AND APPLICABILITY; AVAILABILITY OF STANDARD OFFER SERVICE; ELIGIBILITY FOR STANDARD OFFER SERVICE

2950.1 The purpose of this chapter is to set forth the policies and procedures for the implementation of the "Retail Electric Competition and Consumer Protection Act of 1999," as amended.

2950.2 This chapter establishes the Public Service Commission of the District of Columbia ("Commission") Rules and Regulations Governing the Provision of Standard Offer Service ("SOS"), the terms and conditions for wholesale electric power supply procurement for SOS, reporting and monitoring procedures, pricing and true-up procedures, other services, and miscellaneous provisions and reservations. The procurement process is for full-requirements wholesale electric supply service to meet the SOS retail load. This chapter shall be cited as the "District of Columbia Wholesale Standard Offer Service Rules."

2950.3 This chapter shall be applicable to the Electric Company designated by the Commission as the SOS provider to retail customers in the Electric Company's distribution service territory. This chapter also establishes the rules by which the Electric Company shall obtain electric supply for SOS pursuant to a competitive wholesale procurement process and will apply to wholesale bidders who compete for the provision of wholesale full requirements services to the Electric Company. The provisions of this chapter are promulgated pursuant to authority set forth in Sections 34-1509(c) and 34-1504(c)(7) of the D.C. Code.

2950.4 SOS shall be available on and after the initial implementation date to: (1) customers who contract for electricity with an electricity supplier, but who fail to receive delivery of electricity under such contracts; (2) customers who cannot arrange to purchase electricity from an electricity supplier; and (3) customers who do not choose an electricity supplier.

2950.5 The Commission shall determine the length of the award of SOS to the Electric Company however, such award shall be up to a 6-year period for Residential and for Small Commercial customers. For Large Commercial customers, the Electric Company will serve as the SOS provider for two (2) years. The Commission may extend the length of the award of SOS to the Electric Company in its review of the SOS program as provided for in Section 2951.2.

2950.6 The Electric Company shall obtain electric supply for SOS pursuant to a competitive wholesale procurement process.

2950.7 The specific procurement format, form of request, process, timeline, and evaluation process, evaluation criteria and process and model contract for electricity supply shall be submitted for Commission approval by the Electric Company at least ten (10) months prior to the commencement of service.

2950.8 Subject to the review and approval of the Commission, the Electric Company shall solicit for wholesale full requirements service pursuant to a Wholesale Full Requirements Service Agreement ("WFRSA") with the wholesale suppliers of SOS, which shall include the provision of electric energy, energy losses, generation capacity, ancillary services and any other PJM- or FERC-approved services associated with the Electric Company's load obligation, except for network integration transmission service, which will be obtained by the Electric Company. The wholesale supplier will be responsible for all congestion costs up to the delivery point at which the Electric Company takes the power to serve its SOS load.

2950.9 The Electric Company shall solicit seasonally differentiated summer and winter prices.

2950.10 Contracts for electricity supply may be of varied duration, as approved by the Commission, to stabilize prices for customers.

2950.11 All Electric Company retail distribution customers ("SOS Customers") are eligible for SOS, subject to the general terms and conditions of the Electric Company's tariffs and the Commission's regulations, as they may change from time to time subject to Commission approval.

2951 SELECTION OF WHOLESALE SOS PROVIDERS

2951.1 The Electric Company shall procure full requirements service to meet its SOS obligations using a competitive wholesale procurement process described in this chapter, as amended from time to time, for each SOS Customer Group (as those SOS Customer Groups are defined in Section 2952), until the Commission orders, following the major policy review outlined in Section 2951.2 below, that an alternative SOS procurement process shall be implemented.

2951.2 Following the first SOS year, the Commission will conduct a review of the Electric Company's SOS program. The Commission will conduct additional reviews as it deems necessary in subsequent years in order to make any appropriate adjustments to SOS as competitive developments in the District of Columbia change. All adjustments shall be prospective and all contracts entered into prior to these changes will remain in full force and effect pursuant to the contract terms.

2952 COMPETITIVE WHOLESALE BID STRUCTURE

2952.1 The Electric Company shall establish three (3) groups of customers ("SOS Customer Groups"):

(a) Residential Customers shall include customers served under Electric Company Rate Schedules: R, AE, R-TM, R-TM-EX, RAD, subject to any revisions made to those tariff sheets made by the Commission;

(b) Small Commercial Customers shall include the customers served under Electric Company Rate Schedules: GS-LV non-demand, GS-3A non-demand, T, SL, TS, TN and SL-TN, subject to any revisions made to those tariff sheets made by the Commission; and

(c) Large Commercial Customers shall include all commercial customers except those defined as Small Commercial customers.

2952.2 The Electric Company will issue RFPs to competitive wholesale bidders for contracts for the supply of SOS in order to maintain the following contract term balances for the various customer portfolios:

(b) Small Commercial Customers: The Electric Company shall solicit fixed-price offers of one-year and two-year terms. The Electric Company's portfolio shall contain contracts such that two-year offers comprise at least fifty percent (50%) of each year's portfolio and one-year offers comprise at least thirty percent (30%) of each year's portfolio.

(a) Residential Customers: The Electric Company shall solicit fixed-price offers for terms of one year, two years, or three or more years. The Electric Company's portfolio shall contain contracts such that three or more -year offers comprise at least forty percent (40%) of each year's portfolio, unless the Commission has directed the Electric Company to solicit fixed-price offers based on a different mix of terms. The Electric Company and other parties may propose alternative portfolios of supply options for consideration by the Commission. The Electric Company will compile a portfolio of conforming offers consistent with the mix of terms determined by the Commission. The Electric Company will select conforming offers to meet the Commission's percentage target(s) in accordance with the evaluation provision included in the RFP. In the case where no reasonable bids are received for a particular contract length, the Electric Company may reduce the contract length and change the contract mix in the subsequent tranches. The final contract mix should include contracts of at least three years for no less than forty percent (40%) of the total load.

(b) Small Commercial Customers: The Electric Company will solicit fixed price offers for Wholesale Full Requirements Service for some combination of one, two, and three year terms. The Electric Company will compile a portfolio of one, two, and three year term conforming offers such that at least forty percent (40%) of the load will be served under contracts of 3 or more -year terms. The Electric Company will select one, two, and three year conforming offers to meet this percentage target in accordance with the evaluation provision included in the RFP. The Electric Company and other parties may propose an alternative portfolio of supply options for consideration by the Commission.

(c) Large Commercial Customers: For customers with billing demand of less than 500 kw, the Electric Company shall offer fixed–price SOS. For customers with billing demand of 500 kw or greater, the Electric Company will offer Hourly-Priced Non-Residential Service subject to the Electric Company's tariff approved by the Commission. The Electric Company will solicit fixed price offers for Wholesale Full Requirements Service for some combination of one and two-year terms. At least forty percent (40%) of the load will be served under contracts of two-year terms. SOS for customers with billing demand of less than 500 kw shall be fixed-price service. SOS for customers with billing demand of 500 kw or greater shall be Hourly-Priced Non-Residential Service. The manner in which supply for Hourly-Priced Non-Residential Service is obtained will be at the Electric Company's discretion, although the Electric Company will provide to the Commission the bases and/or rationale for the manner of the procurement. The price of the Large Commercial hourly priced standard offer service will be based on PJM locational marginal price ("LMP"). This hourly priced service will be determined by the PJM hourly integrated real time LMP for energy used by PJM for settlement with all load servicing entities within the Electric Company's District of Columbia service territory, the PJM posted and verifiable market capacity price, FERC-approved transmission, ancillary services, line losses, administrative charges, appropriate taxes, and any other price element(s) related to this service identified and approved by the Commission.

2952.3 The Electric Company will continue to solicit offers for Wholesale Full-Requirements Service for each SOS Customer Group until the Commission orders otherwise, subsequent to Commission review of the SOS procurement process

2952.4 The Electric Company shall solicit wholesale bids for SOS supply using the existing rate structures of its existing rate classes. Nothing herein, however, precludes Electric Company from filing for a different rate structure for any rate schedule or SOS Customer Group, subject to Commission review and approval, and provided that any such changes, adjustments, alterations, or modifications do not change or impact existing WFRSAs .

2953 STANDARD OFFER SERVICE RETAIL RATES

2953.1 The retail rates to SOS customers of the Electric Company will consist of the sum of the following components:

(a) The seasonally-differentiated and, if applicable, time-of-use differentiated load weighted average price of all awarded contracts for Wholesale Full Requirements Service for each SOS Customer Group;

(b) Retail charges designed to recover, on an aggregate basis, FERC-approved Network Integrated Transmission Service charges ("NITS") and related charges and any other PJM charges and costs incurred by the Electric Company directly related to the Electric Company's SOS load obligation for each SOS Customer Group. According to Commission Order No. 12395 and the PEPCO/Conectiv merger Settlement Agreement, the Electric Company has agreed to accept a "transmission deadband" which would adjust transmission and distribution rates so that the overall rates remain constant, unless transmission rates increase or decrease more than ten (10) percent. Any future increase in transmission rates will be constrained by the "transmission deadband" provision approved in Order No. 12395;

(c) An administrative charge; and

(d) Applicable taxes.

2953.2 When the winning wholesale bidders are selected, the Electric Company will submit:

(a) Names of winning bidders to the Commission;

(b) Retail rates for all the customer classes according to the Commission pre-approved time schedule;

(c) Such rates will consist of all the components included in Section 2953.1; and

(d) In such filing, the Electric Company should also include:

(1) Detailed calculation and explanation of an administrative charge and

(2) Administrative charge true-up provisions.

2953.3 Parties to the proceedings can file comments within seven (7) days of the Electric Company's submission in Section 2953.2. If there are no comments filed, the retail rates are deemed approved. If there are comments filed, the reply comments should be due within five (5) days after the comments are filed.

2953.4 The Administrative Charge will be designed to recover the Electric Company's incremental costs for procuring and providing the service. Actual incremental costs shall include, but not be limited to, a proportionate share of SOS customer uncollectibles for each SOS Customer Group, Commission Consultant expenses (as described in Section 2958.2), wholesale bidding expenses, working capital expenses related to SOS for each SOS Customer Group, wholesale supply transaction costs related to wholesale supplier administration and transmission service administration, wholesale payment and invoice processing, incremental billing process expenses, customer education costs, incremental system costs, and legal and regulatory filing expenses related to SOS requirements.

2953.5 Prior to the submission of bids, the Electric Company shall file a request with the Commission (with notice to all the Parties) for determination of the appropriate amount of its Administrative Charge to be included in the retail rates to SOS customers. In calculating the Administrative Charge, any return component on the Administrative Charge, if the inclusion of a return component is approved by the Commission, shall not be reflected for rate-making purposes in the establishment of the Electric Company's distribution rates, including the determination of the Electric Company's return for providing distribution service.

2953.6 All customers eligible for SOS will be informed of the applicable SOS retail rates, to the extent practical, for the service at least two (2) months prior to the beginning of each service year. If it is not practicable to provide such notice, the Electric Company shall file with the Commission and serve upon the Parties notice of that fact, the reasons for the delay, and the expected date for the provision of such information. For the low-income Residential Aid Discount ("RAD") class, the price cap on total rates (as specified in Phase I Divestiture Sharing Settlement) will be maintained until February 7, 2007. Pursuant to this Settlement, the difference between the winning bidder(s)' prices and the price cap will be paid by PEPCO until February 7, 2007.

2953.7 Retail prices to customers shall be adjusted at least twice a year to reflect seasonal pricing and other appropriate price changes. Prior to each year of SOS, the Electric Company shall file with the Commission estimates of actual incremental costs for the upcoming year. Such costs will be collected from customers, on a load weighted average, subject to an annual adjustment to reflect actual costs.

2953.8 All customers eligible for SOS from the Electric Company are subject to the general terms and conditions of the Electric Company's tariffs and the Commission's regulations, as they may change from time to time subject to the Commission's approval or adoption of new regulations.

2953.9 All investment, revenue and expenses associated with the provision of SOS by the Electric Company shall be separate from investment, revenues and expenses associated with the Electric Company's distribution service so that there will be no subsidization of the Electric Company's distribution rates.

2954 COMPETITIVE WHOLESALE BIDDING AND CONTRACTING PROCESS

2954.1 The Electric Company will solicit offers for Wholesale Full-Requirements Service via the RFP approved by the Commission. The Electric Company will remain the NITS provider and will be the designated PJM Load Serving Entity ("LSE") for all SOS. The Electric Company, as the PJM LSE, will provide the rights to nomination and make available to the wholesale suppliers all Firm Transmission Rights/Auction Revenue Rights ("FTR/ARRs") to which it has rights pursuant to the PJM procedures applicable to FTR and ARRs.

2954.2 The Electric Company will solicit seasonally differentiated and, if applicable, time-of-use differentiated prices. In the case of multi-year-term contracts, prices will, in addition, be annually specified. The solicitation will be conducted through as many as four bidding rounds, as specified in the RFP.

2954.3 The total load associated with each SOS Customer Group will be divided into bid blocks of approximately 50 MW to promote diversity of supply and reliable supply contract performance. Each bid block will represent a percentage of the total SOS load that each supplier will be obligated to supply for the term of the contract regardless of changes in the magnitude of the total load for that SOS Customer Group. The size of the total load may vary from the 50 MW guideline for a particular group if the total load associated with a specific SOS Customer Group indicates that such variation is warranted.

2954.4 The first SOS service period ends May 31, 2006, and the second year begins June 1, 2006. Service years will then extend annually starting each June 1, consistent with PJM planning periods, until modified by and through Commission Order.

2954.5 Potential wholesale suppliers must demonstrate their qualifications to provide Wholesale Full Requirements Service by providing proof that they are qualified to participate in the PJM Markets and have all the necessary FERC authorizations to enter into wholesale energy contracts. Furthermore, the RFP and WFRSA shall specify the financial credit requirements that potential or actual wholesale SOS suppliers must demonstrate.

2954.6 The Electric Company's RFP will include specific forms of bid request, evaluation plan, and the WFRSA. The evaluation plan contained in the RFP will specify that all bids to serve the load associated with a specific SOS Customer Group and for a specific contract length will be compared on a discounted price basis to select the lowest cost winning bids.

2954.7 Upon completion of the bid evaluation process, the Electric Company will notify the winning bidders and execute a WFRSA with each winning bidder. Such contract execution will be contingent, however, on Commission approval of the bid awards, contracts and credit support provisions therein. The contract(s) will be deemed approved by the Commission unless the Commission orders otherwise within two (2) business days following the submission. Winning bidders will receive the actual prices in their offers for each year of the term of their supply contract. Winning bidders will not be permitted to revise prices or any other terms and conditions of the WFRSA, except as provided for in the WFRSA.

2955 ESTABLISHMENT AND RE-ESTABLISHMENT OF STANDARD OFFER SERVICE; CUSTOMER SWITCHING RESTRICTIONS

2955.1 For Non-selecting Customers existing on February 8, 2005: SOS under these regulations shall be provided beginning on February 8, 2005, to any customer who has not obtained electric generation service from a competitive electricity supplier as of that date. There shall be no fee for a customer to establish SOS in this manner.

2955.2 For New Customers after February 7, 2005: SOS shall be provided to any customer who begins to purchase a new service within the District of Columbia after February 7, 2005, and who does not obtain electric generation service from an alternative retail electricity supplier at that time. There shall be no fee for a customer to establish SOS in this manner.

2955.3 For Customers Returning from the competitive retail electricity suppliers: Any customer taking service from a competitive retail electricity supplier may terminate service with the electricity supplier and elect SOS, upon notice to the Electric Company as required by Section 2955.6.

2955.4 For customers returning from retail electricity suppliers who default: Any customer who takes service from a retail electricity supplier may terminate service with the electricity supplier who defaults, upon notice to the Electric Company as required by Sections 2955.6 and 2955.7.

2955.5 For customers returning from the retail electricity suppliers because the customers have been slammed: Any customer who is slammed and switched to a competitive supplier by mistake can terminate with the competitive supplier upon notice to the Electric Company as required by Section 2955.7.

2955.6 Termination of SOS, Termination of SOS by Large Commercial Customers; Applicability of Opt-Out Fee: All Residential and Small Commercial customers shall be eligible to switch from Standard Offer Service to competitive suppliers and return to Standard Offer Service without restrictions. Large Commercial customers with a billing demand of less than 500 kw will be provided fixed-price SOS and shall adhere to the minimum stay requirement of twelve (12) months. After February 8, 2005, Large Commercial customers taking fixed-price Standard Offer Service may switch to a competitive supplier:

(a) Without payment of an opt-out fee if 12 months or more have elapsed since the customer most recently established Standard Offer Service ; or

(b) Upon payment of an opt-out fee.

The opt-out fee shall equal two times the amount of the highest standard offer bill (generation portion of the bill only) of the customer during the most recent period that the customer has taken SOS. If the customer has not taken SOS for a full month, the Electric Company shall calculate a monthly bill amount using the customer's average daily consumption. The customer is required to pay the opt-out fee before switching from SOS to a competitive retail electricity supplier. The Electric Company shall make reasonable efforts to collect the opt-out charge and pass on the opt-out charge to the relevant wholesale SOS supplier. The customer shall notify the Electric Company and pay an opt-out fee pursuant to this provision prior to the termination of SOS.

The contract provisions and exit fees of the competitive electricity suppliers remain valid and will be enforced before a customer will be permitted to switch to the SOS supplier or another competitive electricity supplier.

2955.7 Notice of Tranfers; Transfer of Service; Bill Calculation

(a) Notice of Transfer into SOS: A customer who intends to transfer into SOS shall do so by notifying the Electric Company or by canceling service with its competitive electricity supplier.

(b) Transfer into SOS: If the customer notifies the Electric Company no less than 17 days before the customer's next normally scheduled meter read date, the Electric Company shall transfer the customer on the customer's next meter read date. Otherwise, transfer will occur on the following meter read date. The cost of transfer is determined by Section 2955.8. The Electric Company shall accommodate the request to the greatest extent practicable.

(c) Notice of Transfer out of SOS: Notice that a SOS customer will terminate SOS and obtain service from a competitive electricity supplier shall be provided to the Electric Company by the customer's competitive electricity retail supplier pursuant to provisions in the Interim Consumer Protection Standards adopted by the Commission by Order No. 11796.

(d) Transfer out of SOS: If the alternative electricity supplier notifies the Electric Company no less than 17 days before the customer's next meter read date, the Electric Company shall transfer the customer on the customer's next meter read date. Otherwise, transfer will occur on the subsequent meter read date.

2956 FINANCIAL CAPABILITY REQUIREMENTS

2956.1 Financial capability requirements shall be imposed on wholesale suppliers of SOS and shall be consistent with provisions established herein.

2956.2 Each wholesale SOS provider shall obtain and file with the Commission a bond, a letter of credit, or a corporate guarantee that will provide assurances of financial integrity and funding for replacement service in the event that the wholesale provider fails to provide for uninterrupted service.

2956.3 The amount of the financial capability requirement for the wholesale SOS provider in the Electric Company's service territory shall be equal to fifteen (15) percent of the wholesale SOS provider's bid obligation for the SOS class(es) the provider is awarded, and expected to serve, in the Electric Company's service territory.

2956.4 The amount of the financial capability requirement shall be commensurate with the remaining outstanding bid obligation of the wholesale SOS provider throughout the term of the SOS provider's awarded contract period, and reduced annually from the initial amount determined at the beginning of the term of the wholesale SOS's provider's service.

2956.5 The proceeds of the bond, or letter of credit, or corporate guarantee, as necessary, shall be payable to the Electric Company to whom the wholesale bidder is obligated to provide service. The proceeds of the bond, letter of credit, or corporate guarantee shall be used only to defray the additional costs of replacement SOS in the event of interrupted service. For purposes of this provision, additional costs are all costs that are incurred or will be incurred to acquire replacement SOS, including supply and administrative costs, through the remaining SOS term that exceed the amounts paid or to be paid by SOS customers at the SOS rates in effect at the time of the Commission's declaration of a wholesale provider's default.

2956.6 A corporate guarantee permitted by subparagraph 2956.2, 2956.3, and 2956.4, must be issued by the wholesale SOS provider or the ultimate corporate parent of the wholesale SOS provider.

(a) The corporate guarantee must meet all of the requirements of subparagraphs 2956.2, 2956.3, and 2956.4, and shall be unconditional and irrevocable and provide for immediate payment for the period of the standard offer term.

(b) A corporate guarantee may be used to satisfy the requirement of subparagraphs

2956.2, 2956.3, and 2956.4 if the corporate guarantor meets the following financial qualifications and capabilities:

(1) The senior secured debt obligations of the guarantor are publicly rated, at a minimum, "BBB+" from Standard & Poor's, Fitch or "Baa1" from Moody's;

(2) The total assets of the guarantor are at least 5.0 times the amount of the corporate guarantee amount required by subparagraphs 2956.2, 2956.3, and 2956.4; and

(3) The total common equity of the guarantor is at least 2.5 times the amount of the corporate guarantee amount required by subparagraphs 2956.2, 2956.3, and 2956.4.

(c) If a corporate guarantor's senior secured debt obligations are rated by : (i) two of the agencies listed above, the guarantor's rating will be determined by the lower assigned rating; or (ii) all three of the agencies listed above, two of those agencies must have assigned ratings equal to or higher than the required ratings described above.

(d) If, at any time, the senior secured debt obligations of the corporate guarantor fail to meet the requirements of Section 2956.6(b), the corporate guarantor or the SOS wholesale provider shall immediately notify the Commission in writing.

(e) If the corporate guarantor fails to meet any of the financial capability requirements, the Commission may, at its option, require the SOS provider to post a bond or file a letter of credit as described in subparagraphs 2956.2, 2956.3, and 2956.4.

2957 REPORTING REQUIREMENTS AND TRUE UP PROVISIONS

2957.1 Within ninety (90) days of the conclusion of each year of SOS bidding, the Electric Company will submit a report to the Commission on its wholesale electric supply procurement process and results, SOS retail prices produced, and on the aggregated SOS enrollment activity for each service class (including the number of customers, megawatt peak load, megawatt hour energy and switching to and from the service) and a report of all true-ups conducted for that year. This requirement is not intended to replace or supercede any other reporting requirements imposed by the Commission on the Electric Company.

2957.2 If the Electric Company conducts wholesale bidding for a type of service on the basis of aggregated rate classes, the Electric Company will make any needed true-ups on an aggregated basis.

2957.3 In addition to the other true-ups described herein, the Electric Company will true up its total costs for providing each type of service (Residential, Small Commercial, and

Large Commercial) with its total billed revenues for that service. If the service type is still being provided when the true-up is completed, rates will be adjusted to reflect any over- or under-recoveries established in the true up. In the event that there is any net over- or under-collection at the end of any type of service (Residential, Small Commercial, Large Commercial), the balance will be paid or collected through a mechanism to be determined in accordance with the procedures set forth in Section 2957.13. All retail price changes resulting from the true-up filings shall be reviewed annually by the Commission.

2957.4 The Electric Company will conduct the true-ups described herein to reflect the start of summer rates and concurrent with the start of non-summer rates. The Electric Company may conduct more frequent true-ups if it so chooses. Any revisions to retail electric rates resulting from the application of the true-up provisions shall be reflected in the prices posted on the Electric Company's web page. The true-ups are subject to audit by the Commission.

2957.5 The Electric Company will true up its billings to retail customers for services provided pursuant to section 2953.1(a) against its payments to wholesale suppliers. The Electric Company will also true up its billings to retail customers to reflect any net damages recovered by the Electric Company from a defaulting supplier in accordance with Sections 2959.3 - 2959.4 above. The Commission may audit true-ups annually. In the event that there is any net over- or under-collection at the end of any type of service (Residential, Small Commercial, Large Commercial), the balance will be paid or collected through a mechanism to be determined in accordance with the procedures set forth in Section 2957.13.

2957.6 For the purpose of determining such true up, the Electric Company's payments to its wholesale suppliers will exclude payments made with respect to the upward adjustment in the suppliers' load arising from the activation of the Electric Company's load response programs.

2957.7 The retail price to Residential, Small Commercial, Large Commercial customers posted pursuant to Section 2953.7 will not change until after the first billing cycle following the start of service. Any difference between the Electric Company's incremental cost for serving SOS load and the Electric Company's revenue from serving SOS load based on the awarded bid prices will be included as part of the retail rate true-up.

2957.8 Price elements. Section 2953.1(a) will include the additional costs (if any) that a wholesale supplier incurs in meeting any future statutory renewables requirements with respect to residential, small commercial, large commercial SOS. In the event that legislation is enacted that provides for a renewable energy resource requirement during the term of any WFRSA that has already been executed, wholesale suppliers under the WFRSA may pass through their commercially reasonable additional costs, if any, associated with complying with the new requirement.

2957.9 If at any time any additional price elements directly related to the SOS are identified by the Electric Company or a wholesale supplier, the Electric Company "and" "or" the wholesale supplier may file a request with the Commission (with notice to all the Parties) for approval of recovery of those costs and, to the extent the costs are found to arise from provision of SOS, and are prudently incurred as determined by the Commission, the costs will thereafter be included in the service price.

2957.10 The net costs included in retail prices pursuant to Section 2953.1(b) will be recovered on a cents/kWh basis (energy basis) for non-demand tariff schedules and/or on a $/kW basis (demand basis) for demand tariff schedules. However, the Electric Company may request Commission approval to use alternate rate designs to recover NITS-related costs. The Electric Company may true up its billings to retail customers for transmission services provided pursuant to Section 2953.1(b) against its payments for these services to PJM. The Commission may audit these true-ups annually. In the event that there is any net over- or under-collection at the end of any type of service (Residential, Small Commercial, Large Commercial), the balance will be paid or collected through a mechanism to be determined in accordance with the procedures set forth in Section 2957.13.

2957.11 To the extent not already recovered through the PJM Network Integration Transmission Service charges, any future surcharges assessed to network transmission customers for PJM-required transmission enhancements pursuant to the PJM Regional Transmission Expansion Plan, or for transition costs related to elimination of through-and-out transmission charges will be included in the charges under Section 2953.1(b). Pursuant to the WFRSA, the wholesale suppliers bear the risk of any other changes in PJM products and pricing during the term of their WFRSAs. Subject to the transmission rate deadband specified in Section 2953.1, the Electric Company will not bear the risk of any changes in regulation or PJM rules related to such costs or charges. However, if there are any other new FERC-approved PJM transmission charges or other new PJM charges and costs charged to network transmission customers, the Electric Company may recover them through retail rates.

(a) The Electric Company will file with the Commission, and provide notice to all parties to the proceeding, a request for approval to recover such new charges through the Electric Company's retail rates under Section 2953.1(b).

(b) The wholesale supplier will charge the Electric Company only for those new costs that the Commission determines may be recovered in rates by the Electric Company. In no event will the Electric Company bear the risk of any changes in regulation or PJM rules related to such costs or charges. Also, in no event shall any PJM charges to other than network transmission customers be recovered through the Electric Company's retail transmission rates for SOS service, except to the extent (if any) provided in Section 2953.1.

2957.12 The actual administrative costs for a given SOS year shall be used to true up the estimated administrative costs for that same year, and any over- or under-collection of costs shall be applied to the estimated administrative costs for the next SOS program year for each SOS Customer Group. The Commission may audit such true-ups annually.

2957.13 At the end of any SOS period for a Customer Group, and after actual costs incurred by the Electric Company pursuant to Section 2953.1 have been determined, the parties to the proceeding will agree upon a mechanism with respect to actual costs, to return any over-collection to, and to collect any under-collection from, all active customers who would have been eligible for the service type at the conclusion of any service type period. If the parties to the proceeding fail to agree within a reasonable period, the matter will be submitted to the Commission for decision.

2958 BID DOCUMENTS

2958.1 The Request For Proposal ("RFP") is the document pursuant to which the Electric Company will solicit Wholesale Full Requirements Service to meet its SOS obligations. The RFP shall include the bid request process, the bid evaluation methodology, the timeline for the RFP process, and the following five appendices:

(a) Expression of Interest Form;

(b) Confidentiality Agreement;

(c) Credit Application;

(d) Bid Form Spreadsheets; and

(e) Binding Bid Agreement.

2958.2 The Consultant RFP is the document to be used to hire the Commission's Consultant. The Electric Company shall procure and pay for an independent consultant hired pursuant to the Consultant RFP. The Consultant will be responsible for monitoring all aspects of the procurement of the SOS services. Specifically:

(a) The Consultant will be selected by, will take its direction from, and will provide its consultation and work products to, the Commission.

(b) The costs incurred by the Electric Company in hiring the Consultant may be included in the Electric Company's incremental costs and may be recovered through the Administrative Charge, subject to Commission review and approval.

(c) The Consultant will provide the Commission with a final report as to each supply procurement and award.

(d) The Commission will determine the qualifications of and evaluate all bidders. The Commission will further direct the Electric Company, in writing, as to which bidder to hire, and under what terms and conditions such candidate is to be hired. The Electric Company will complete the hiring of the Consultant no later than four (4) weeks prior to the date of the initial pre-bid conference. The Electric Company will be required to pay only for work that the Consultant does in reviewing the Electric Company's compliance with Section 2954 and any other work that the Commission asks the Consultant to perform.

2959 MISCELLANEOUS PROVISIONS

2959.1 The Electric Company may at any time request Commission approval to make changes in its tariffs. However, to the extent that those tariff changes would require conforming changes to either the RFP, the WFRSA generally, or any WFRSA that may be in effect from time to time:

(a) No such tariff changes may alter the rights and obligations of any wholesale supplier with respect to any WFRSA for which an RFP has already been issued, unless the supplier consents to have its rights or obligations changed;

(b) The Electric Company will serve notice of the tariff changes, and copies of the proposed conforming changes to the RFP and/or WFRSA, on all parties; and

(c) Any such tariff changes must be consistent with the regulations, orders or other obligations to which the Electric Company is subject.

2959.2 If, after conducting the bid procedures in accordance with the RFP, the Electric Company still has SOS load that has not been awarded to a supplier, then:

(a) The Electric Company will initially supply the unserved load by purchasing energy and all other necessary services through the PJM-administered markets, including but not limited to the PJM energy, capacity, and ancillary services markets, and any other service required by PJM to serve such unserved load, and will include all the costs of such purchases on to customers in the retail rates charged for the service for which the purchases are made, and

(b) Within five (5) business days of it being determined by the Electric Company that the load is unserved, the Electric Company will convene a meeting of all parties to the proceeding and Commission staff to discuss alternative ways to fill the unserved load, including but not limited to a rebid or a bilateral contract. The meeting process will conclude within ten (10) business days of the load being determined to be unserved, and within twenty (20) calendar days of it being determined that the load is unserved, the Electric Company will file with the Commission, and serve upon the all parties to the proceeding, any proposal it has for serving the load in lieu of the procedure set forth in sub-paragraph 2959 (a).

(c) The Commission will resolve the Electric Company's filing on an expedited basis. Any alternative means that the Commission approves will expressly provide that the Electric Company's costs for filling the load, will be recovered in retail rates in the same manner as all other charges pursuant to Section 2953.1. Until the Commission approves an alternate means of filling the load, sub-paragraph 2959.2 (a) will apply.

2959.3 If any load is left unserved after a wholesale supplier defaults:

(a) The Electric Company will initially supply the defaulted load by purchasing energy and all other necessary services through the PJM-administered markets, including but not limited to the PJM energy, capacity, and ancillary services markets, and any other service required by PJM to serve such defaulted load, and will include all the costs of such purchases, net of any offsetting recovery from the defaulting wholesale supplier, in the retail rates charged for the service for which the purchases are made; and

(b) As soon as practicable after it is determined by the Electric Company that the load is unserved, the electric company will file with the Commission a plan to fill the remaining term of the defaulted WFRSA. Such a plan should be submitted to the Commission within ten (10) business days after a supplier default. Until the Commission approves a plan to fill the remaining term of the defaulted WFRSA, subparagraph 2959.3(a) will apply.

2959.4 Access to confidential information relating to the Electric Company's procurement of SOS power supply will be governed by the OPC Confidentiality Agreement, the Consultant's Confidentiality Agreement contained in the Bidder RFP, and the Confidentiality Agreement contained in the RFP and the confidentiality provisions of the WFRSA (collectively the "Confidentiality Agreements").

2959.5 Any information about the supply procurement results that does not identify individual wholesale bidders, provide supplier-specific information, or disclose any individual bid prices may be made public by the Commission, or OPC, at their discretion, after all tranches of bidding for that year of SOS service are completed. Examples of such information that can be released include, but are not limited to, the total number of bids submitted, or the range in price between the lowest and the highest bids submitted.

2960 WAIVER OR EXEMPTION

2960.1 Upon the request of any person subject to the provisions of these regulations or upon its own motion, the Commission, for good cause, may waive any of the requirements of these regulations that are not required by statute. No waiver granted pursuant to this provision shall apply retroactively to any wholesale supply agreement.

2961 DEFINITIONS

2961.1 When used in this chapter, the following terms and phrases shall have the following meaning:

"Aggregator" means a person who acts on behalf of customers to purchase electricity by organizing customers into a single purchasing unit.

"Availability of Standard Offer Service" means the Standard Offer Service available on and after the initial implementation date to: (1) customers who contract for electricity with an electricity supplier, but who fail to receive delivery of electricity under such contracts; (2) customers who cannot arrange to purchase electricity from an electricity supplier; and (3) customers who do not choose an electricity supplier.

"Commission" means the Public Service Commission of the District of Columbia.

"Competitive Electricity Supplier" means person, including an aggregator, broker, or marketer, who generates electricity; sells electricity; or purchases, brokers, arranges, or markets electricity for sale to retail customers. The term excludes the following: (A) Building owners, lessees, or managers who manage the internal distribution system serving such building and who supply electricity solely to occupants of the building for use by the occupants; (B) (1) Any person who purchases electricity for its own use or for the use of its subsidiaries or affiliates; or (2) Any apartment building or office building manager who aggregates electric service requirements for his or her building or buildings, and who does not: (a) Take title to electricity; (b) Market electric services to the individually-metered tenants of his or her building; or (c) Engage in the resale of electric services to others; (C) Property owners who supply small amounts of power, at cost, as an accommodation to lessors or licensees of the property; and (D) A consolidator.

"Distribution Customer Class" means the tariffed rate class under which a customer takes distribution delivery service from the Electric Company.

"Electric Company" means the company that provides distribution service.

"Network Integrated Transmission Service" or "NITS" "is the transmission service provided pursuant to the rates, terms, and conditions set forth in the PJM tariff.

"PJM" means the Pennsylvania-New Jersey-Maryland Interconnection, LLC, or any successor thereto.

"Retail Access" means the right of electricity suppliers and consumers to use and interconnect with the electric distribution system on a nondiscriminatory basis in order to distribute electricity from any electric supplier to any customer. Under this right, consumers shall have the opportunity to purchase electricity supply from their choice of licensed electricity suppliers.

"Slamming" means the unauthorized switching of a customer's Electricity Supplier.

"Standard Offer Service" means electricity supply made available to: (1) Customers who contract for electricity with an electricity supplier, but who fail to receive delivery of electricity under such contracts; (2) Customers who cannot arrange to purchase electricity from an electricity supplier; and (3) Customers who do not choose an electricity supplier.

"Standard Offer Classes" means the customer groupings within the Electric Company's utility service territory as specified in Section 2953.3 of this chapter.

"Tranche" means a round of bidding for a set of bid blocks for each customer group—Residential, Small Commercial, and Large Commercial.

"Wholesale Standard Offer Service Provider(s)" means the entity(ies) selected pursuant to this chapter to provide all or a specified portion of electric generation service to consumers receiving Standard Offer Service.

"Wholesale Full Requirements Service" means all necessary energy delivered to the PJM grid, capacity, transmission other than Network Integrated Transmission Service, ancillary services, energy losses from transmission and distribution, congestion management, as all these services are defined pursuant to the PJM tariffs and procedures.

"Wholesale Full Requirements Service Agreement" is the document that will specify the terms and conditions that govern the contractual relationship between the Electric Company and each of the wholesale suppliers that is awarded a contract pursuant to the bidding procedures specified in the RFP.

VERIFICATION

MONTGOMERY COUNTY, MARYLAND) SS

KARL R. PAVLOVIC, being first duly sworn, deposes and says that he is the KARL R. PAVLOVIC whose Direct Testimony accompanies this Verification; 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 his sworn testimony in this proceeding.

Karl R Pavlovic

KARL R. PAVLOVIC

SUBSCRIBED AND SWORN TO before me this 24th day of May, 2007.

Michelle A. Lease

Notary Public

My Commission Expires 3/10/09

MICHELLE A. LEASE
NOTARY PUBLIC STATE OF MARYLAND
My Commission Expires March 10, 2009

DIRECT TESTIMONY OF
OPC WITNESS
CHARLES W. KING

EXHIBIT OPC (F)

BEFORE
THE DISTRICT OF COLUMBIA
PUBLIC SERVICE COMMISSION

In the Matter of	)	
	)	
The Application of the Potomac Electric Power Company For Authority to Increase Existing Retail Rates and Charges For Electric Distribution Service	)	**Formal Case No. 1053**

DIRECT TESTIMONY AND EXHIBITS
OF
CHARLES W. KING
EXHIBIT OPC (F)

ON BEHALF OF
THE OFFICE OF THE PEOPLE'S COUNSEL

MAY 31, 2007

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BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of	)	
	)	
The Application of Potomac Electric	)	Formal Case No. 1053
Power Company for an Increase in Its	)	
Retail Rates for the Sale of Electric Energy	)	

DIRECT TESTIMONY OF CHARLES W. KING

QUALIFICATIONS

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

A. My name is Charles W. King. I am President of the economic consulting firm of Snavely King Majoros O'Connor & Lee, Inc. ("Snavely King"). My business address is 1111 14th Street, N.W., Suite 300, Washington, D.C. 20005.

Q. PLEASE DESCRIBE SNAVELY KING.

A. Snavely King, formerly Snavely, King & Associates, Inc., was founded by the late Carl M. Snavely and myself in 1970 to conduct research on a consulting basis into the rates, revenues, costs and economic performance of regulated firms and industries. The firm has a professional staff of 12 economists, accountants, engineers and cost analysts. Most of its work involves the development, preparation and presentation of expert witness testimony before federal and state regulatory agencies. Over the course of its 37-year history, members of the firm have participated in over 1000 proceedings before almost all of the state commissions and all Federal commissions that regulate utilities or transportation industries.

Q. HAVE YOU PREPARED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. Attachment A is a summary of my qualifications and experience. I might add to this resume the fact that I received my primary and secondary education in the public schools of the District of Columbia.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN REGULATORY PROCEEDINGS?

A. Yes. Attachment B is a tabulation of my appearances as an expert witness before state and federal regulatory agencies.

__**SUMMARY**__

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Office of the People's Counsel of the District of Columbia.

Q. WHAT IS THE OBJECTIVE OF YOUR TESTIMONY?

A. The objective of this testimony is to present OPC's position with respect to the following issue no 4:

> 4. Are PEPCO's depreciation reserves and expenses reasonable and consistent with Commission policy.

Q. WHAT ARE YOUR CONCLUSIONS AND RECOMMENDATIONS WITH REGARD TO ISSUE NO. 4?

A. I conclude that PEPCO's depreciation reserves and expenses are not reasonable because they are inconsistent with the Commission's policy of requiring that depreciation rates be based on reasonably current data. There are two consequences from using these dated depreciation rates. The first is that PEPCO is avoiding recognition that its plant is lasting much longer than appeared to be the case in 1989 when the present rates were prescribed. The second is that PEPCO is not reflecting changes in accounting rules and conventions that now require depreciation to be separated from accruals for future removal costs.

I cannot vouch for the propriety of PEPCO's D.C. depreciation reserves because PEPCO does not maintain any on-going record of reserves by jurisdiction, except at the functional account (distribution, general) level.

I recommend that the Commission direct PEPCO to perform a new depreciation study to update the life, survivor curve and net removal cost parameters underlying its depreciation rates. This study should recommend separate plant-only depreciation rates and removal cost rates. The present removal cost reserve should be recognized as a regulatory liability, in accordance with current accounting standards. Additionally, I recommend that PEPCO be directed to develop a more transparent and straight-forward method for recording depreciation and depreciation reserves on its D.C. jurisdictional plant.

<u>DEPRECIATION- GENERAL</u>

Q. WHAT IS DEPRECIATION?

A. In 1958, the National Association of Railroad and Utility Commissioners sanctioned the following definition of depreciation:

"Depreciation," as applied to depreciable utility plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of elements, inadequacy, obsolescence, changes in the art, changes in demand, and requirements of public authorities.[1]

The second commonly cited definition of depreciation is that of the American Institute of Certified Public Accountants:

Depreciation accounting is a system of accounting which aims to distribute the cost or other basic value of tangible capital assets, less salvage (if any) over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner. It is a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation may properly take into account occurrences during the year, it is not intended to be a measurement of the effect of all such occurrences.[2]

If depreciation can be defined in a single sentence, I would say that it is the process of recovering the initial investment in tangible capital assets, adjusted for salvage, in a systematic fashion over the useful service life of the plant, recognizing that utility plant is typically a group of investments.

Q. CAN DEPRECIATION BE CALCULATED WITH PRECISION?

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[1] *Uniform System of Accounts for Class A and Class B Electric Utilities,* 1958, rev. 1962.

[2] American Institute of Certified Public Accountants, *Accounting Research and Terminology Bulletin #1.*

A. No. Depreciation can no more be calculated with precision than can the required rate of return to equity investors. Both are developed from analyses that, while based on quantitative values, require considerable application of judgment. In the case of rate of return, that judgment pertains to the earnings expectations of investors as indicated by the stock market and corporate financial data. In the case of depreciation, the judgment pertains to the estimation of the future surviving life of plant as indicated by past patterns of retirements.

Q. HOW DOES THIS JUDGEMENTAL CHARACTERISTIC OF DEPRECIATION INFLUENCE THE COMMISSION'S APPROACH TO THE SUBJECT?

A. The Commission must recognize that the development of depreciation rates is not a refined science subject to mathematical precision. Because depreciation analysts use judgment in their estimation of depreciation, the Commission must necessarily exercise its own judgment in assessing the rationale and data that underlie alternative depreciation rates.

Q. WHAT ARE THE BASIC PARAMETERS REQUIRED TO DEVELOP A DEPRECIATION RATE?

A. At its simplest level, the only parameter that is absolutely required is an estimate of the service life of the plant. The reciprocal of that number can be used as the depreciation rate.

However, because most utility depreciation is applied to accounts that are multiple units of plant, it is usually necessary to estimate the dispersion of retirements around an average service life. In the gas and electric utility industries, this dispersion is usually described in terms of "Iowa Curves," so named because they were developed at Iowa State University. These curves describe how closely the retirements are grouped around the average service life and whether they tend to occur more rapidly before, after or coincident with the average service life.

Another parameter that is typically included in the calculation of a depreciation rate is net salvage. Net salvage is the difference between the positive scrap or sale value of the asset's material and the cost of dismantling and removing the asset when it is retired. It is currently expressed as a ratio to the cost of the asset and included as a subtraction (when salvage value exceeds removal cost) or an addition (when removal cost exceeds salvage) to the amount to be recovered in depreciation charges. With a few exceptions (e.g. vehicles, work equipment) most utility plant has a higher removal cost than its salvage value, so that the inclusion of net salvage in depreciation adds to the amount to be recovered.

Finally, virtually all major utilities, including PEPCO, employ what is known as "remaining life depreciation." This procedure computes the depreciation rate by dividing the unrecovered net investment by the estimated remaining years of the asset (or group of assets). It effectively ensures that any past under- or over-accruals of depreciation are recovered during the remaining life of the asset.

Q. PLEASE ILLUSTRATE HOW THE PARAMETERS YOU HAVE JUST DESCRIBED ARE USED TO DEVELOP DEPRECIATION RATES?

A. Beginning with the simplest example, assume a single asset with a 20 year life. Its depreciation rate is the reciprocal of 20:

$$1/20 = 5\%$$

Now, let us assume that the asset is expected to have salvage value equivalent to 5 percent of its investment value. The depreciation rate declines:

$$\frac{1-.05}{20} = \frac{.95}{20} = 4.75\%$$

Assume next that the cost of removing this asset amounts to 15 percent of its value. The depreciation rate increases:

$$\frac{1 -.05 + .15}{20} = \frac{1.10}{20} = 5.55\%$$

This is called a “whole life” rate because it is based on the whole life of 20 years. To develop the remaining life rate, we must identify some additional items of data: the original investment, the depreciation reserve (the amount of depreciation that has already been recovered), and the remaining life of the asset.

In this illustration, let us assume that the asset originally cost $1 million and that past depreciation charges have recovered $400,000. This means that we have yet to recover $600,000 in original cost, plus a negative net salvage (i.e. net cost of removal) amounting to 10% of the original cost, or $100,000. The total amount yet to be recovered is thus $700,000. Let us further assume that the asset is 10 years old, leaving

10 years of remaining life. In remaining life depreciation, the unrecovered amount is divided by the remaining life years:

$$\frac{\$700{,}000}{10 \text{ years}} = \$70{,}000 \text{ required annual accrual}$$

The depreciation rate is then calculated by dividing the annual amount to be recovered by the gross investment, in this case:

$$\frac{\$70{,}000}{\$1{,}000{,}000} = 7.0\%$$

PEPCO'S DEPRECIATION RATES

Q. HAVE YOU REVIEWED PEPCO'S DEPRECIATION RATES AND ACCRUALS?

A. Yes, I have.

Q. WHAT DEPRECIATION RATES HAS PEPCO USED IN ITS FILING IN THIS CASE?

A. PEPCO uses depreciation rates that were approved by the Commission in Formal Case No. 869 in 1989.

Q. ARE THESE DEPRECIATION RATES CONSISTENT WITH COMMISSION POLICY?

A. No. As noted, the depreciation rates that PEPCO uses were set in 1989 in Formal Case No. 869. In that case, the Commission rejected PEPCO's 1981-1982 study as being outdated.[3] It adopted instead a study presented by Staff that was based on the year ending December 31, 1987.[4] It is therefore Commission policy to approve depreciation rates that reflect a reasonably recent evaluation of plant life and net salvage characteristics.

If the Commission found that PEPCO's seven-year-old depreciation rates were outdated, then it would certainly find that the current 20-year-old rates are outdated. PEPCO has "stonewalled" this issue by declining to produce a depreciation study for the District of Columbia. This is true notwithstanding that PEPCO did submit a depreciation study of its Maryland plant in its concurrent Maryland rate case.[5] The only conclusion that can be drawn from this action – or inaction – is that PEPCO is happy with its present D.C. depreciation rates. It does not wish to have them changed.

Q. ARE PEPCO'S DEPRECIATION RATES REASONABLE?

A. No. They are outdated, and that creates two problems. The first problem is that the life patterns of PEPCO's plant appear to have changed over the last 20 years. Our analysis indicates that PEPCO's plant is surviving much longer than was anticipated

[3] Order No. 8930, 9 D.C.P.S.C. 6 (1988).
[4] Order No. 9216, 10 D.C.P.S.C. 22, 68 (1989).
[5] Maryland P.S.C. Case No. 9092, PEPCO Exhibit No. 28.

in 1989. The second problem is that PEPCO's depreciation rates fail to reflect changes in accounting rules and conventions that have occurred since 1989.

<u>PEPCO'S PLANT SERVICE LIVES</u>

Q. WHAT INFORMATION DID YOU RECEIVE FROM PEPCO TO ASSIST YOU IN YOUR STUDY OF PEPCO'S PLANT ACCOUNT SERVICE LIVES?

A. I received the record of plant additions, retirements, transfers, adjustments, and balances for each account each year as far back as the plant account has been maintained, which can be as far back as 1910. This information I refer to as "vintage data." I also received a record of plant retirements by year of placement for each of the major distribution plant accounts for each year. I refer to this information as "actuarial data."

Q. WHAT ANALYSIS HAVE YOU PERFORMED THAT LEADS TO YOUR CONCLUSION THAT PEPCO'S PLANT IS SURVIVING LONGER THAN WAS PERCEIVED IN 1989?

A. The actuarial data allowed us to obtain, for each FERC plant account, a dispersion or retirements by age, which we call "observed life tables." Using our proprietary software, we then test these aged retirement dispersions against combinations of service lives and survivor curves. There are 31 of these "Iowa" survivor curves that describe two variables: the dispersion of unit retirements around the average life of the account, and the skewing of rate of those retirements before and after the average service life.

Our actuarial analysis permitted us to identify the life/curve combination that best fit the retirements experience of each plant account. We then compared these life/curve combinations with those that underlie PEPCO's current depreciation rates.

Q. WHAT DID YOUR COMPARISON REVEAL?

A. A summary of this comparison is presented in OPC Exhibit (F)-1. Column (b) shows the life/curve parameters produced in the 1988 study that underlies PEPCO's current distribution plant depreciation rates. The 50 S2 parameters for Account 361, Structures & Improvements, means that the average service life of this plant is 50 years and that retirements are distributed according to a symmetrical curve, where the mode (most retirements) occurs at the average service life. The "2" means that the retirements are spread out over an extended period before and after the average service life.

Column (f) shows the best fit life/curve combinations from our actuarial analysis. A comparison of this column with column (b) reveals that in every case the current life indication is longer than the life parameter used to calculate the Company's present depreciation rate.

Columns (c), (e) and (g) show "average remaining lives" computed by subtracting the expired life of each vintage from the expected average service life. As discussed earlier, these remaining lives are used to calculate the final depreciation rates used by PEPCO. Column (c) shows the remaining lives that were used to calculate the present depreciation rates in 1988. Column (e) shows the remaining lives if recomputed now using current information as regards vintage expired lives. Note that in every case the remaining life is shorter now than it was in 1987. That is because the expired lives of the respective vintages are much longer now than they were in 1987, again indicating that service lives are getting longer. Column (g) shows the remaining lives that result from our best fit calculations. All of these lives are much longer than those assumed in 1988. If these remaining lives were used to calculate revised depreciation rates, the new rates would be much lower than the current rates shown in column (d).

Visual presentations of these relationships are shown in the charts in OPC Exhibit (F)-2. The vertical axis of each chart is the percent surviving; the horizontal axis the age of the plant. The “x”s show the actual data, the dark line our best fit, and the light line the fit assumed by the present rates. Note that in every case, our fit is much closer to the actual data than the fit assumed by the present rates.

Q. WHAT DO YOU CONCLUDE FROM THESE COMPARISONS?

A. I conclude that the present depreciation rates are not reasonable because they no longer reflect the life characteristics of PEPCO’s distribution plant. If a new study were conducted, it would reveal that PEPCO’s distribution plant assets have much longer lives than previously assumed. As a result, the new depreciation rates would be much lower than the current rates.

ACCOUNTING CHANGES

Q. WHAT ACCOUNTING CHANGES HAVE OCCURRED SINCE 1989 THAT REQUIRE REVISIONS TO PEPCO'S DEPRECIATION PROGRAM?

A. There have been some important changes in the accounting rules and conventions relating to the treatment of removal costs.

Q. WHAT DO YOU MEAN BY "REMOVAL COSTS?"

A. Removal costs are any costs that are required to retire a unit of plant. They include dismantlement, physical removal and restoration of the site to a permanent, stable condition.

Q. DOES PEPCO INCUR REMOVAL COSTS?

A. Yes. PEPCO incurs removal costs for all but two of its distribution plant accounts. It also incurs removal costs for three of its general plant accounts.

Q. WHAT HAS BEEN THE RELATIONSHIP BETWEEN DEPRECIATION AND REMOVAL COSTS IN THE PAST?

A. PEPCO has traditionally employed the procedure described earlier in this testimony that combines depreciation, salvage and removal costs. This procedure adjusts depreciation rates to capture an estimate of future "net salvage" costs. Net salvage is the difference between positive salvage and removal costs. Except for the vehicles account, there is very little positive salvage, so most "net salvage" is negative, which means that the depreciation rate is increased to capture future removal costs.

The procedure begins with a "net salvage ratio," which is the ratio of net salvage to plant in service. This ratio is used to inflate (or deflate in the case of positive salvage) the amount to be recovered through depreciation. The "whole life" depreciation rate is calculated as follows:

$$\frac{\text{Plant investment x (1-net salvage ratio)}}{\text{Average service life}} = \text{Depreciation rate}$$

Most utilities use the remaining life technique, but the effect of the net salvage ratio is the same:

$$\frac{\text{(Plant investment x (1-net salvage ratio)) – Depreciation reserve}}{\text{Remaining life}} = \text{Annual accrual}$$

$$\frac{\text{Annual accrual}}{\text{Plant investment}} = \text{Depreciation rate}$$

Q. WHAT ACCOUTING CHANGES REQUIRE RECONSIDERATION OF THIS PROCEDURE?

A. Recent pronouncements from the Financial Accounting Standards Board ("FASB"), the Federal Energy Regulatory Commission ("FERC") and the Securities and Exchange Commission ("SEC") require all companies, including public utilities, to abandon the traditional practice of capturing net removal costs through adjustments in the depreciation rates, at least for financial accounting purposes.

1. FINANCIAL ACCOUNTING STANDARDS BOARD

Q. WHAT PRONOUNCEMENTS FROM FASB REQUIRE A CHANGE FROM THE TRADITIONAL PRACTICE OF CAPTURING NET REMOVAL COSTS THROUGH ADJUSTMENTS IN DEPRECIATION?

A. In June 2001, FASB promulgated Statement of Financial Accounting Standards No. 143 ("SFAS 143"), *Accounting for Asset Retirement Obligations*. In March 2005, it issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations – an Interpretation of FASB Statement No. 143.*

Q PLEASE DESCRIBE SFAS 143.

A. SFAS 143 addresses long-lived assets for which there are legal obligations to incur retirement costs. A legal obligation is defined as "an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel." A good example of such an obligation is the requirement to dismantle, entomb or decontaminate a nuclear generating plant.

When a company finds that it has a legal obligation that fits this description, it must declare the retirement cost as a liability on its balance sheet. That liability is not the ultimate cost of the retirement, but the "fair value" of that cost, defined as the cost of a contract with an independent party to retire the asset, negotiated when the asset is installed. In effect, this fair value is the present value of the future cost, using as the discount factor the risk-adjusted interest rate when the liability was recognized. The company also adds a value corresponding to that liability to the asset being booked. The initial fair value estimate is considered to be part of the original cost of the asset, which in turn is depreciated over the asset's life.

The annual expense associated with this liability consists of two parts. One is the depreciation of the liability, which is the present value of the liability divided by the life of the asset. The second expense is the annual accretion in the present value of the liability, similar to interest expense.

Q. CAN YOU DESCRIBE HOW THIS PROCESS WORKS?

A. Assume that PEPCO installs a transformer station that it expects to last for 40 years, and that it is legally obligated to dismantle that station when it retires at an estimated cost of $1 million. PEPCO would record an asset and book a liability for this retirement cost, not at $1 million, but at $1 million discounted at the risk-adjusted interest rate. If the risk-adjusted interest rate over 40 years is 5 percent, then the asset and the liability would be booked as $142,046 ($1 mil/1.05^{40}).

Each year, PEPCO would show two items of expense. The first would be the depreciation of the asset, $142,046/ 40 years = $3,551. The second expense would be the annual accretion in present value of the liability. In this instance, it would be $1 million times $1/1.05^{39} – 1/1.05^{40}$. This is $1 million x (0.149148 - 0.142046) =.00710 or $7,100. Total expense in the first year of operation would be $3,551 + $7,100 = $10,651**.**

The first expense item, the depreciation of the initial Asset Retirement Obligation ("ARO"), stays the same each year throughout the asset's life. The second item, the annual accretion in the liability, increases as the discount period shortens and the present value factors increase.

Q. WHAT IS FASB INTERPRETATION NO. 47?

A. FASB Interpretation 47 was issued in March 2005 to clarify "that the term *conditional asset retirement obligation* as used in FASB Statement 143 . . . refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity." The Interpretation clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when incurred if the liability's fair value can reasonably be estimated.

Q. DOES FASB INTERPRETATION NO. 47 SIGNIFICANTLY CHANGE THE UTILITIES' INTERPRETATION OF SFAS 143?

A. It should cause the utilities to reconsider their evident dismissal of what appear to be legal obligations to retire plant when the specific date of retirement is indeterminate. The Interpretation emphasizes that if there is any doubt about the date of the retirement, that doubt should be reflected in the discount factor. It should not become an excuse for disregarding the obligation for purposes of SFAS 143.

Q. DOES SFAS 143 DEAL ONLY WITH LEGAL RETIREMENT OBLIGATIONS?

A. Most of SFAS 143 deals with legal retirement obligations. However, in the "Background Information and Basis for Conclusions" section of the document is found a paragraph that address non-legal obligations, and specifically non-legal obligations of rate-regulated entities. Paragraph B73 of that section states as follows:

> Many rate-regulated entities currently provide for the costs related to asset retirement obligations in their financial statements and recover those amounts in rates charged to their customers. Some of those costs relate to asset retirement obligations within the scope of this Statement [legal ARO"s]; others are not within the scope of this Statement [non-legal AROs] and, therefore, cannot be recognized as liabilities under its provisions. The objective of including those amounts in rates currently charged to customers is to allocate costs to customers over the lives of those assets. The amount charged to customers is adjusted periodically to reflect the excess or deficiency of the amounts charged over the amounts incurred for the retirement of long-lived assets. <u>The Board concluded that if asset retirement costs are charged to customers of rate-regulated entities but no liability is recognized, a regulatory liability should be recognized if the requirements of Statement 71 are met.</u> (emphasis added)

Thus, the FASB states quite clearly that a separate regulatory liability should be recognized for non-legal asset retirement obligations if the costs of those obligations are being recovered in rates.

Q. WHAT IS THE RELEVANCE OF SFAS 143 TO THE ISSUES IN THIS PROCEEDING?

A. There are three ways in which SFAS 143 is relevant to this proceeding. First, with respect to legal AROs, SFAS 143 establishes a clear-cut procedure for recording these obligations on PEPCO's balance sheet and a procedure for recognizing them in income statements. This Commission does not necessarily have to adopt these procedures for ratemaking purposes. However, I believe there should be a clear and demonstrable reason for overriding SFAS 143 if the Commission decides not to use these accounting practices for regulation.

The second way in which SFAS 143 is relevant relates to paragraph B73 quoted above. It is clear that the accounting community has determined that even non-legal retirement obligations should be separately identified as regulatory liabilities.

Finally, SFAS 143 provides a template for the principles and procedures that might govern the recognition and accrual of reserves for future retirement obligations, that is, future removal and dismantlement costs. Specifically, SFAS 143 establishes that future costs should not be recognized in the current period at their future value, but rather at their present value. Furthermore, the annual recognition of those costs should reflect the depreciation of their original present value and the annual accretion in present value.

2. FEDERAL ENERGY REGULATORY COMMISSION

Q. WHAT PRONOUNCEMENTS OF THE FERC CAST DOUBT ON THE CONTINUED RECOVERY OF REMOVAL COSTS THROUGH DEPRECIATION CHARGES?

A. On April 9, 2003, FERC issued Order No. 631. It relates to accounting, financial reporting, and rate filing requirements for asset retirement obligations.

Q. PLEASE DESCRIBE FERC ORDER 631.

A. Most of FERC Order 631 deals with the effects of SFAS 143, which prescribes the treatment of future costs associated with legal obligations to retire assets. As noted, that standard requires entities to declare those future obligations as liabilities on their balance sheets, and it establishes procedures for recognizing those obligations on annual income statements.

FERC declined to apply the SFAS 143 standards to removal costs that were not legal obligations. It did, however, require all jurisdictional entities to maintain separate records for cost of removal for non-legal retirement obligations when allowances for these costs could be identified. Accordingly, the FERC added a new paragraph 2C to its instructions with regard to Account 108 – "Accumulated Provision for Depreciation of Electric Utility Plant:"

> Separate subsidiary records shall be maintained for the amount of accrued cost of removal other than legal obligations for the retirement of plant recorded in account 108, Accumulated provision for depreciation of electric utility plant.

This new provision requires utilities to identify separately annual additions and deletions from this account. Each utility must show the annual accrual for removal costs and the annual amount of removal costs incurred.

This requirement is a major change from the previous treatment of removal costs. In the past, removal costs have always been incorporated into depreciation. Depreciation rates were inflated to recover removal costs. These removal cost allowances were recorded as part of depreciation expense, and plant removal expenditures were charged to depreciation reserves. Except through careful analysis, it has been impossible to identify how many dollars of annual depreciation went to recover past capital expenditures – true depreciation – and how many dollars were accrued to offset future removal costs.

Q. WHAT IS THE RELEVANCE OF FERC ORDER 631 TO THE ISSUES IN THIS PROCEEDING?

A. FERC Order 631 builds into the regulatory accounting system the requirements of SFAS 143, setting the stage for regulators to apply SFAS 143 for ratemaking purposes. Additionally, FERC Order 631 establishes a requirement to account separately for non-legal retirement obligations, specifically to separate depreciation reserves for capital recovery from reserves for future removal costs.

Several qualifiers are appropriate, however. First, FERC's accounting pronouncements are not binding on the District of Columbia P.S.C. The Commission can prescribe its own accounting standards.

Additionally, it must be acknowledged that FERC has not yet decoupled removal costs accounting from depreciation. While it requires utilities to maintain subsidiary records of removal cost accruals, those accruals are still captured in the depreciation reserve.

3. <u>SECURITIES AND EXCHANGE COMMISSION</u>

Q. WHAT DIRECTIVES FROM THE SEC ARE RELEVANT TO THE ISSUES IN THIS PROCEEDING?

A. The accounting profession was apparently uncertain as to the interpretation of paragraph B73 of SFAS 143, and the firm of Deloitte and Touche took the lead in soliciting an interpretation from the SEC. The SEC then issued directives that all rate-regulated utilities must report as "regulatory liabilities" the accrual of reserves against future removal costs.

Q. PLEASE DEFINE THE TERM "LIABILITIES."

A. Liabilities are defined by FASB as "probable future sacrifices of economic benefits arising from present obligations of a particular entity to transfer assets or provide services to other entities in the future as a result of past transactions or events."[6]

Q. PLEASE DEFINE "REGULATORY LIABILITIES."

A. Paragraph 11 of Statement of Financial Accounting Standards No. 71 describes regulatory liabilities as follows:

[6] FASB Concepts Statement No. 6, *Elements of Financial Statements.*

Rate actions of a regulator can impose a liability on a regulated enterprise. Such liabilities are usually obligations to the enterprise's customers. The following are the usual ways in which liabilities can be imposed and the resulting accounting:

a. A regulator may require refunds to customers. Refunds that meet the criteria of paragraph 8 (accrual of loss contingencies) of FASB Statement No. 5, *Accounting for contingencies*, shall be recorded as liabilities and as reductions of revenue or as expenses of the regulated enterprise.

b. A regulator can provide current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred future rates will be reduced by corresponding amounts. If current rates are intended to recover such costs and the regulator requires the enterprise to remain accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose, the enterprise shall not recognize as revenues amounts charged pursuant to such rates. Those amounts shall be recognized as liabilities and taken to income only when the associated costs are incurred.

c. A regulator can require that a gain or other reduction of net allowable costs be given to customers over future periods. That would be accomplished, for rate-making purposes, by amortizing the gain or other reduction of net allowable costs over those future periods and reducing rates to reduce revenues in approximately the amount of the amortization. If a gain or other reduction of net allowable costs is to be amortized over future periods for rate-making purposes, the regulated enterprise shall not recognize that gain or other reduction of net allowable costs in income of the current period. Instead, it shall record it as a liability for future reductions of charges to customers that are expected to result.

Q. HOW WOULD YOU DEFINE THE REGULATORY LIABILITY FOR REMOVAL COSTS?

A. This liability represents funds collected from ratepayers that the utility is expected to spend in the future to remove or dismantle plant. If it appears that the utility will not spend these funds for their intended purpose, then it should refund them to ratepayers by means of amortization that is recognized in rates.

Q. WHAT DO YOU CONCLUDE FROM THE FOREGOING SURVEY OF ACCOUNTING PRONOUNCEMENTS?

A. I conclude that the utilities in general, and PEPCO in particular, are now being required to separate their accounting for removal costs from their accounting for depreciation, and that they must record the outstanding removal cost reserve as a regulatory liability on their financial books.

Q. WHAT RECOMMENDATION DO YOU DRAW FROM THIS CONCLUSION?

A. I recommend that the Commission require PEPCO formally to separate the accounting for removal costs from the accounting for depreciation and to recognize accrued removal cost reserves as regulatory liabilities for ratemaking purposes.

Q. WHAT ARE YOUR REASONS FOR THIS RECOMMENDATION?

A. First, it appears that PEPCO is already performing this separate accounting by reason of SFAS 143, FERC Order 631 and the SEC directives.

Second, the separation of removal cost accounting from depreciation will provide a much needed improvement in the transparency of PEPCO's accounting reports. Heretofore, the incorporation of net salvage into depreciation rates has obscured its impact on accrual rates. Except through careful and detailed analysis it has been difficult to determine how much of the annual depreciation charge was related to recovery of capital – pure depreciation – and how much was accrual against future removal cost. It was virtually impossible to determine how much of the depreciation reserve related to removal costs and how much was recovered capital. With the total separation of removal cost accounting from depreciation, the Commission will have a very clear idea of the relative impact of these two very different functions.

Third, the greater transparency of the regulatory liability treatment of removal cost accrual will enhance the ability of the Commission to monitor these accruals so that if the money collected from ratepayers is not spent, it can be refunded, or alternatively, if the costs exceed the funds collected, adjustments can be made in the accruals to compensate the utility.

Fourth, the function of depreciation is very different from the function of removal cost accrual. Depreciation recovers costs that have already been incurred. Removal cost accrual is intended to build reserves for costs that have yet to be incurred. More important, depreciation deals with historical costs that are known and certain, while removal cost accrual deals with future costs that are unknown and estimated. Given these very disparate characteristics, it is altogether appropriate that these two accounting activities be separated entirely.

Q. DO YOU HAVE ANY INDICATION WHETHER PEPCO AGREES WITH THIS RECOMMENDATION?

A. Yes. In its current Maryland rate case, M.P.S.C. Case No. 9092, PEPCO has proposed separate plant-only depreciation rates and removal cost rates. It has also separated its Maryland depreciation reserves between "pure" depreciation reserves and removal cost accruals. However, PEPCO has resisted the final component of my recommendation, which is to identify its removal cost accruals as regulatory liabilities.

DEPRECIATION RESERVE

Q. DOES PEPCO KEEP A RECORD OF ITS D.C. DEPRECIATION RESERVE BY PLANT ACCOUNT?

A. No. PEPCO maintains depreciation reserves on a plant account basis using "blended" D.C., Maryland and FERC depreciation rates. Separately, it maintains jurisdictional reserves on a functional account (i.e., transmission, distribution, general) basis. It reconciles these reserves through a complex process described in PEPCO's updated response to Staff data request No. 2-35, which I have attached as OPC Exhibit (F)-3.

Q. CAN YOU STATE WHETHER THE D.C. DEPRECIATION RESERVES THAT FALL OUT OF THIS PROCESS ARE REASONABLE?

A. No. As noted, the process is complex, and it is not transparent.

Q. COULD PEPCO CREATE A MORE TRANSPARENT PROCEDURE FOR IDENTIFYING D.C. DEPRECIATION RESERVES?

A. The Commission Staff asked this very question, and PEPCO responded that because many assets are shared between the jurisdictions, it is impossible to apply a single rate to each asset. That may be true for some assets, particularly those in the "general plant" category. However, most distribution assets are discretely assigned to one or the other of PEPCO's two main jurisdictions. If so, then it would appear feasible to accrue jurisdictionally specific depreciation for most distribution plant. The only depreciation that would then have to be allocated would be for the relatively small portion that is shared between the jurisdictions.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes. It does.

Experience

Snavely King Majoros O'Connor & Lee, Inc. Washington, DC

President (1989 to Present)
Vice President (1970 - 1989)

Mr. King, a founder of the firm and acknowledged authority on regulatory economics, brings over thirty years of experience in economic consulting to his direction of the firm's work in transportation, utility and telecommunications economics.

Mr. King has appeared as an expert witness on over 300 separate occasions before more than thirty state and nine U.S. and Canadian federal regulatory agencies, presenting testimony on rate base calculations, rate of return, rate design, costing methodology, depreciation market forecasting, and ratemaking principles. Mr. King has also testified before House and Senate Committees on energy and telecommunications legislation pending before the U.S. Congress.

In telecommunications, Mr. King has testified before the Federal Communications Commission on a number of policy issues, service authorization, competitive impacts, video dialtone, and prescription of interstate depreciation rates. Before state regulatory bodies, he has presented testimony in proceedings on intrastate rates, costs earnings and depreciation.

Mr. King has testified in electric, gas and water utility cases on virtually every aspect of regulation, including cost of capital, revenue requirements, depreciation, cost allocation and rate design. Mr. King is one of the nation's leading authorities on utility depreciation practices, having testified on this subject in several dozen cases before state regulatory bodies.

In addition to his appearances as a witness in judicial and administrative proceedings, Mr. King has negotiated settlements among private parties and between private parties and regulatory offices. Mr. King also has directed depreciation studies, investment cost benefit analyses, demand forecasts, cost allocation studies and antitrust damage calculations. Mr. King directed analyses of the prices of services under Federal Government's FTS2000 long distance system.

In Canada, Mr. King designed and directed an extended inquiry into the principles and procedures for regulating the telecommunication carriers subject to the jurisdiction of the Canadian Transport Commission. He also was the principal investigator in the Canadian Transport Commission's comprehensive review of rail costing procedures.

EBS Management Consultants, Inc., Washington, DC

Director, Economic Development Department (1968-1970)

Mr. King organized and directed a five-person staff of economists performing research, evaluation, and planning relating to economic development of depressed areas and communities within the U.S. Most of this work was on behalf of federal, state, and municipal agencies responsible for community or regional economic development.

Principal Consultant (1966-1968)

Mr. King conducted research on a broad range of economic topics, including transportation, regional economic development, communications, and physical distribution.

W.B. Saunders & Company, Inc., Washington, DC

Staff Economist (1962-1966)

For this economic consulting firm, which later merged with EBS Management Consultants, Inc., Mr. King engaged in numerous research efforts relating primarily to economic development and transportation.

U.S. Bureau of the Budget, Office of Statistical Standards

Analytical Statistician (1961-1962)

Mr. King was responsible for the review of all federal statistical and data-gathering programs relating to transportation.

Education

Washington & Lee University, B.A. in Economics

The George Washington University, M.A. in Government Economic Policy

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EXHIBIT OPC (F)-1

Potomac Electric Power Company
Comparison of Depreciation Parameters
Company Existing vs. Snavely King Analysis as of December 31, 2006

			Current Rates					
	Account	12/31/2006 Plant Balance	Life/ Survivor Curve	Average Remaining Life	Annual Depreciation Rate	Average Remaining Life 2006	Best Fit	Average Remaining Life
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Distribution Plant								
361.00	Structures and Improvements	46,146,934	50 S2	36.8	1.97%	30.3	75 R2	56.1
362.00	Station Equipment	223,505,058	40 L0	33.0	2.16%	31.4	53 L2	38.5
364.00	Poles, Towers and Fixtures	40,294,313	30 L0	23.5	4.12%	23.3	55 R1	45.1
365.00	Overhead Conductors and Devices	49,985,520	32 L0	25.8	2.69%	25.6	62 S1	50.7
366.00	Underground Conduit	495,138,884	48 S3	36.5	1.97%	30.4	97 L3	78.2
367.00	Underground Conductors and Devices	417,983,502	30 R1.5	22.3	2.82%	18.9	62 R2	48.5
368.00	Line Transformers	253,749,535	30 S2	20.9	2.93%	18.3	34 R1.5	23.7
369.10	Overhead Services	4,359,618	40 R0.5	26.6	2.17%	25.7	65 R2.5	43.3
369.20	Underground Services - Conduit	71,313,363	40 S4	29.0	2.33%	25.0	65 R4	49.2
369.30	Underground Services - Cable	103,605,561	35 R2	27.1	2.44%	23.1	65 R2	52.0
370.00	Meters	60,947,434	36 L0	30.3	2.69%	29.4	52 L2	40.7
371.00	Installations on Customers' Premises	1,828,978	22 L0	14.7	4.16%	10.7	60 R4	31.2
373.00	Street Lighting and Signals	4,931,550	21 L0	15.6	4.27%	14.4	60 R2.5	44.9

Sources:

Col. (a) from OPC 1-74.
Cols. (b) - (e) from PEPCO 1987 Depreciation Study, provided in response to OPC 1-81.
Col (e) - average remaining life using PEPCO life/curve and 2006 database. Remaining life calculated using BG/VG.
Cols. (f) - (g) from SK analysis using 2006 database provided in response to OPC 1-78. Best fit life with no T-cut. ARL is calculated using BG/VG.

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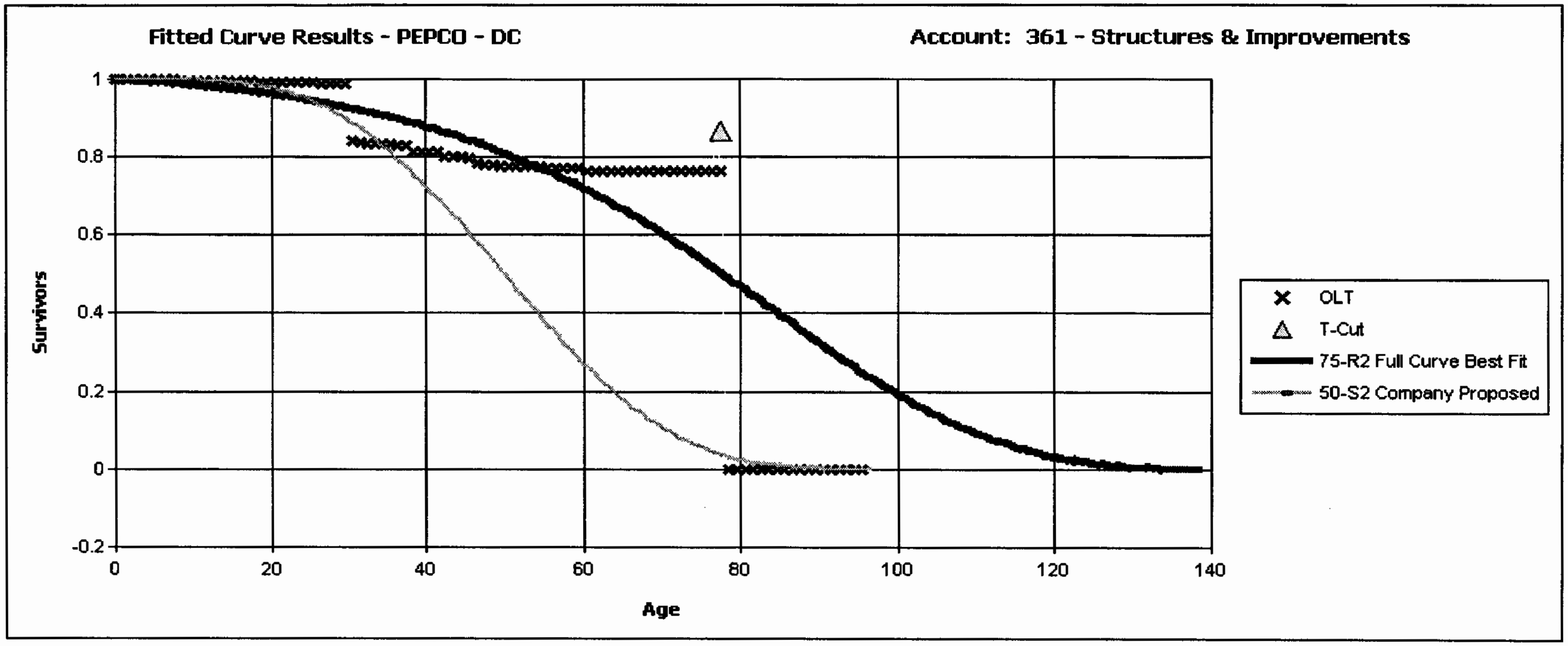
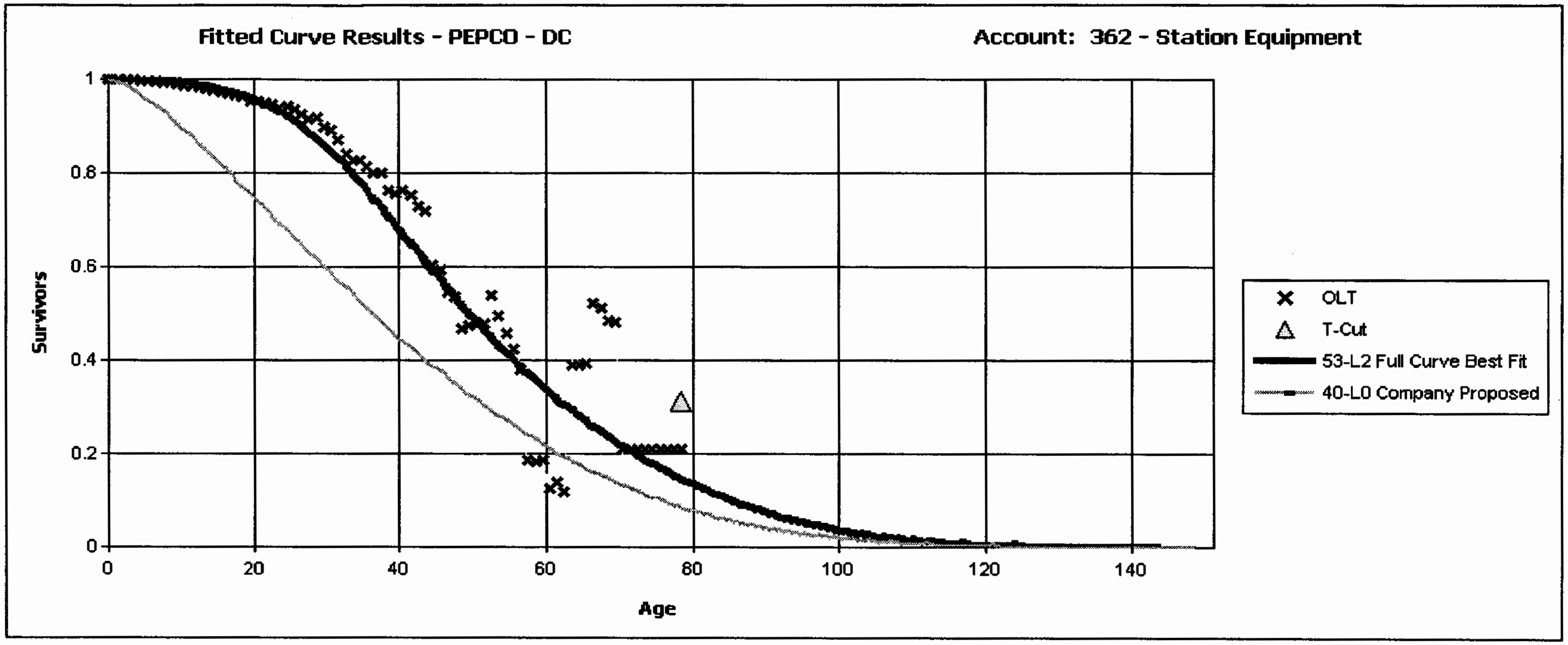
CHARLES W KING

EXHIBIT OPC (F)-2



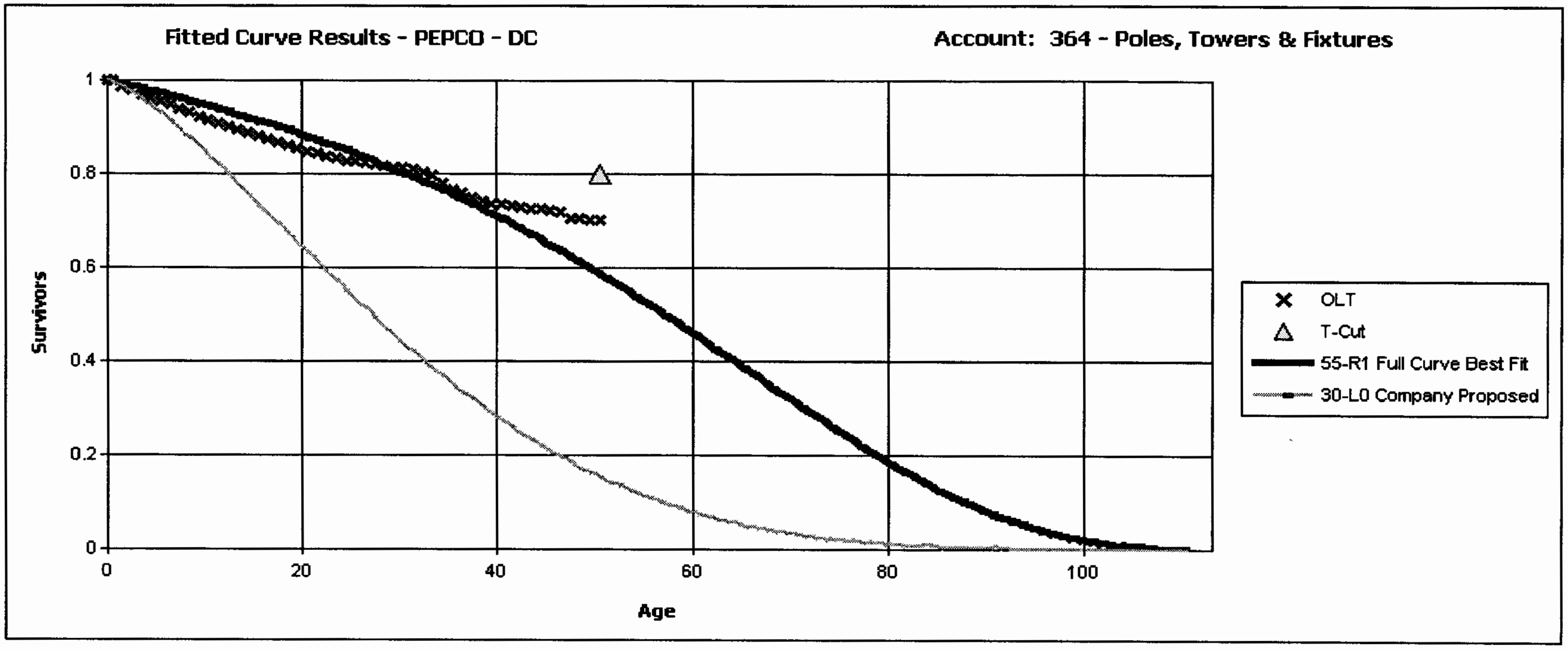
Analytical Parameters

OLT Placement Band:	1910 - 2006
OLT Experience Band:	1910 - 2006
Minimum Life Parameter:	4
Maximum Life Parameter:	75
Life Increment Parameter:	1
Max Age (T-Cut):	79.0

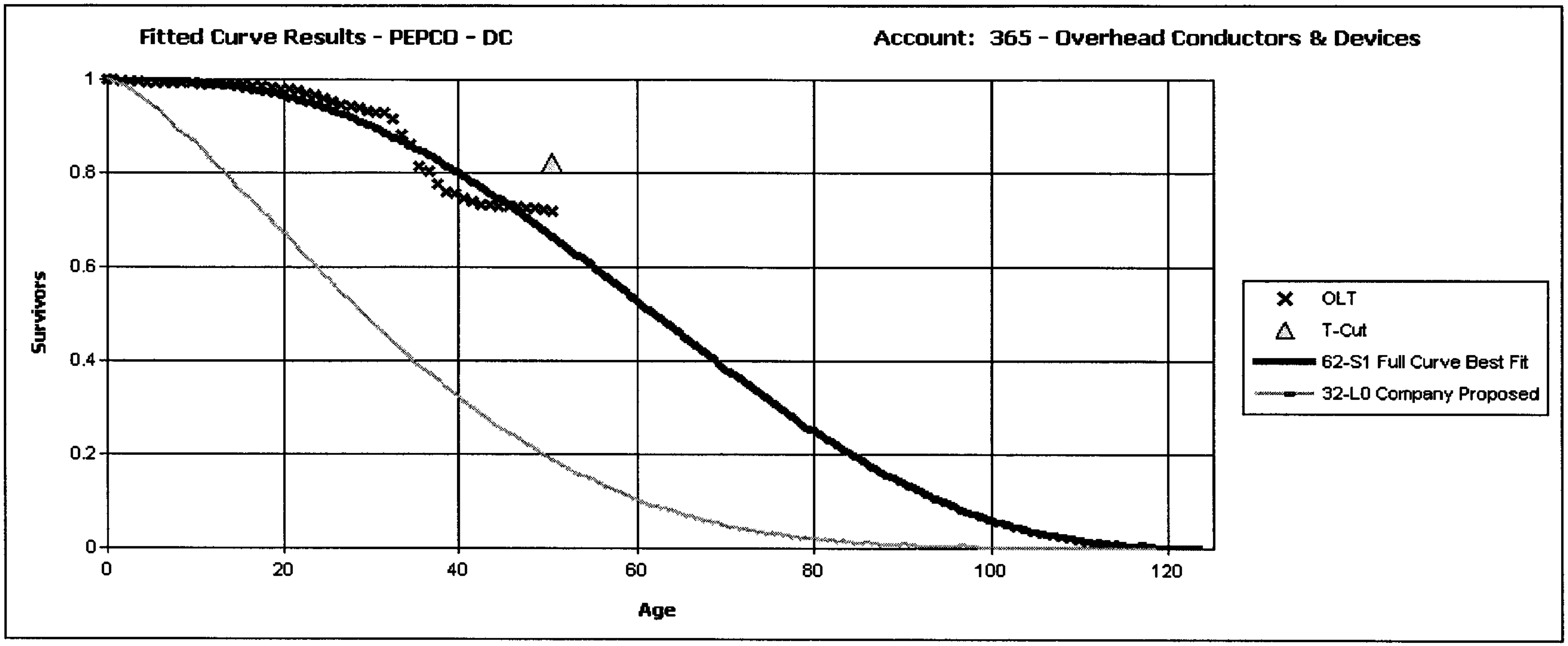


Analytical Parameters

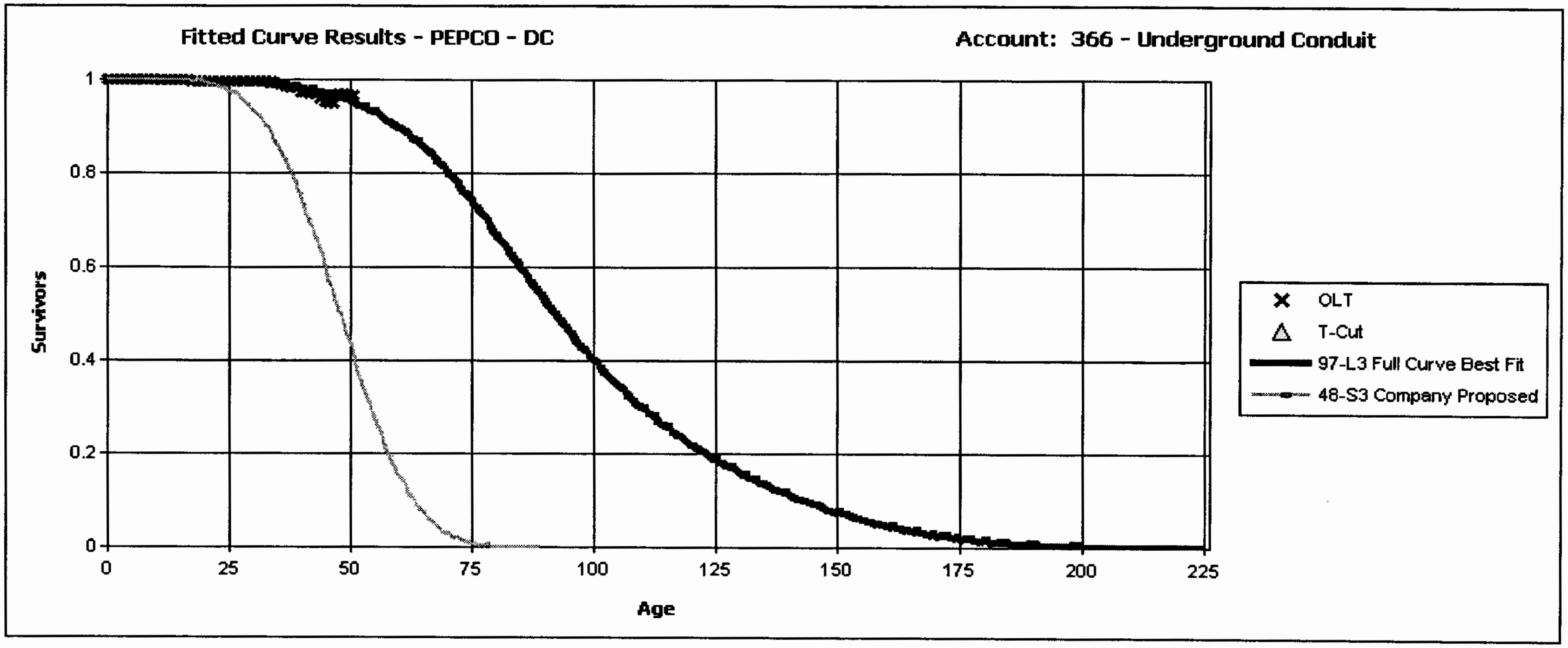
OLT Placement Band:	1927 - 2006
OLT Experience Band:	1927 - 2006
Minimum Life Parameter:	4
Maximum Life Parameter:	53
Life Increment Parameter:	1
Max Age (T-Cut):	80.0



Analytical Parameters	
OLT Placement Band:	1955 - 2006
OLT Experience Band:	1955 - 2006
Minimum Life Parameter:	3
Maximum Life Parameter:	55
Life Increment Parameter:	1
Max Age (T-Cut):	52.0

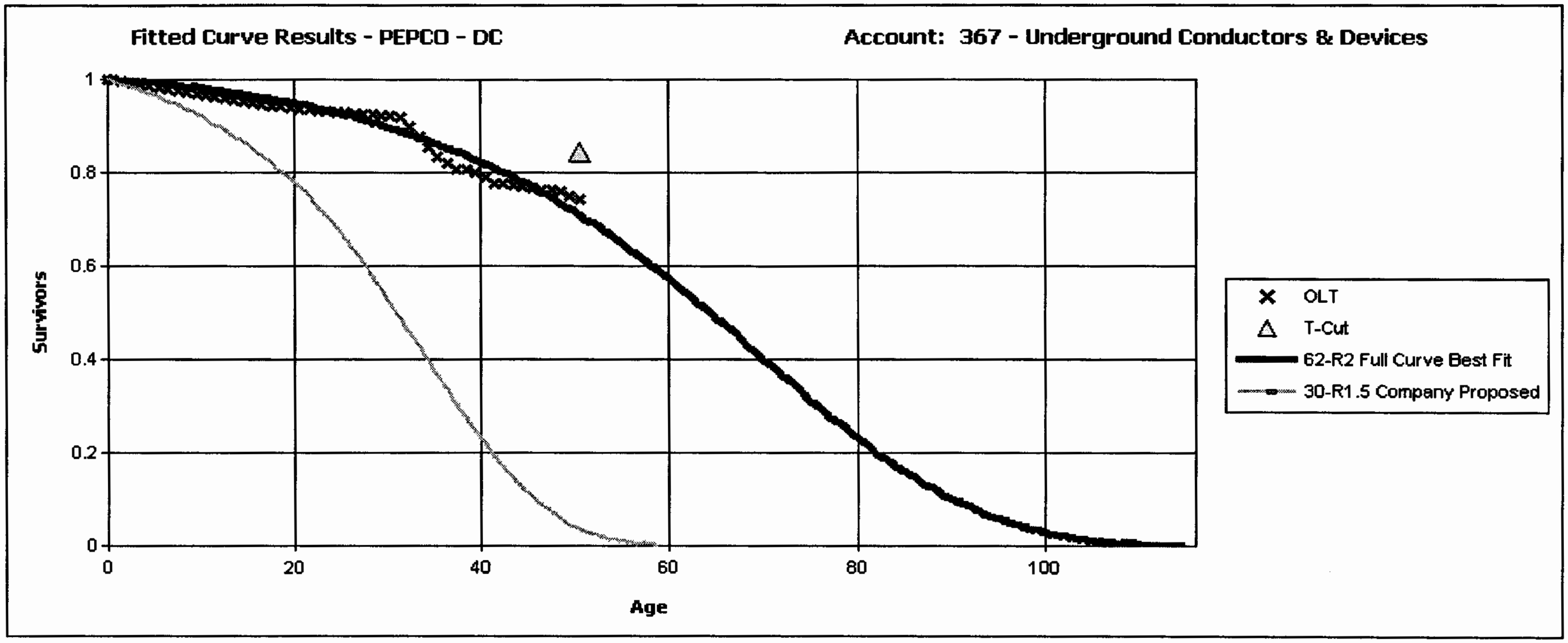


Analytical Parameters	
OLT Placement Band:	1955 - 2006
OLT Experience Band:	1955 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	52.0



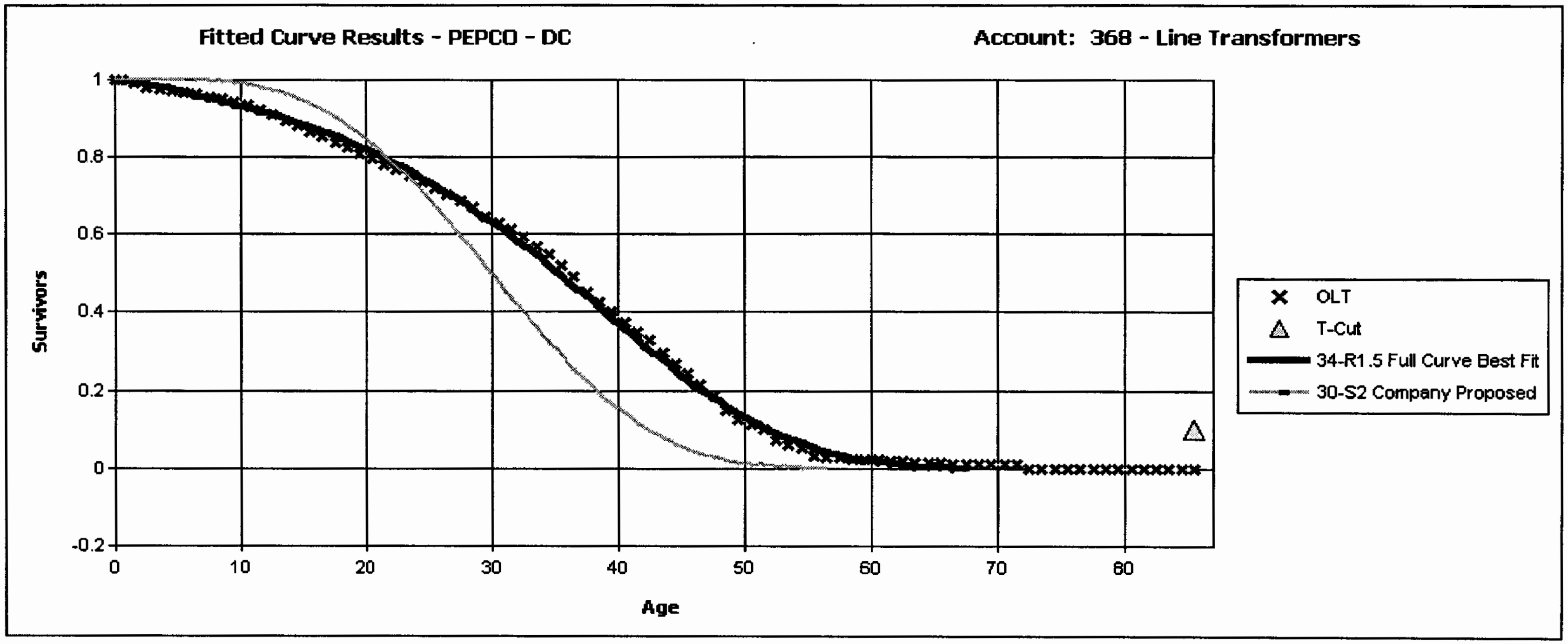
Analytical Parameters

OLT Placement Band:	1955 - 2006
OLT Experience Band:	1955 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	52.0



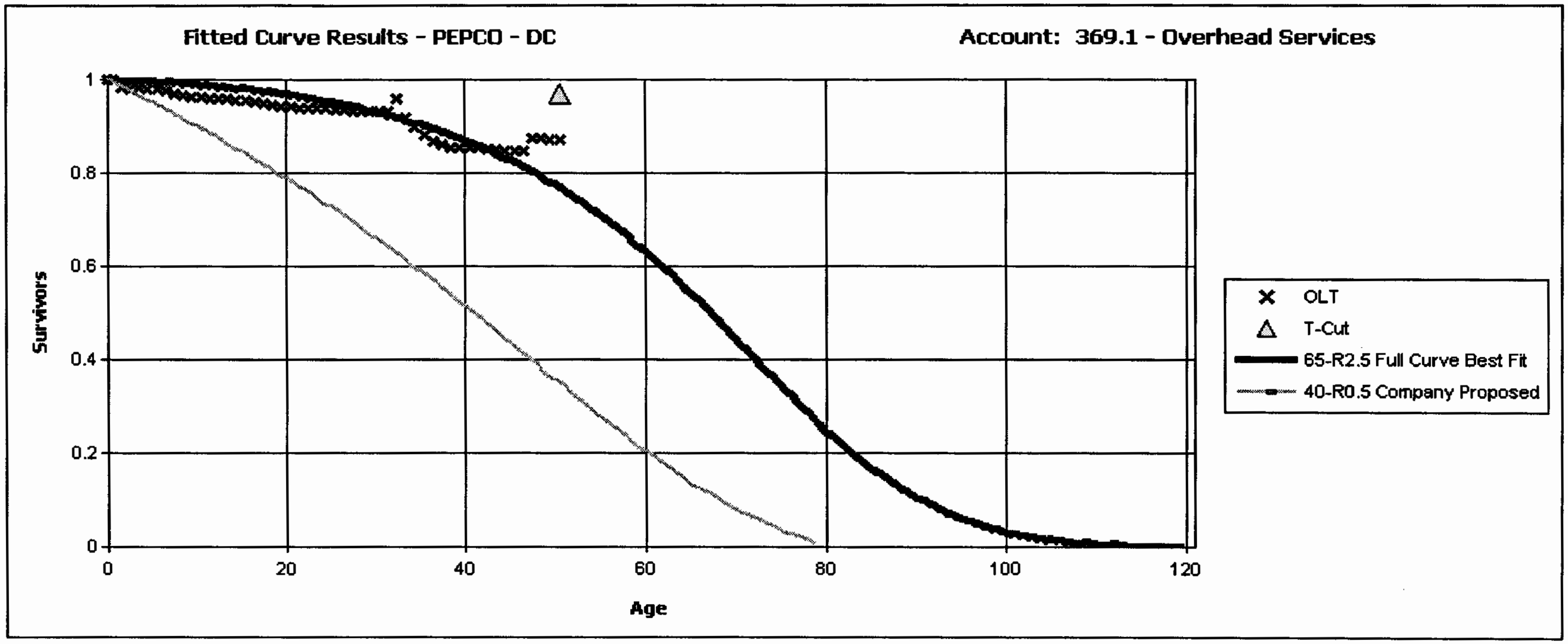
Analytical Parameters

OLT Placement Band:	1955 - 2006
OLT Experience Band:	1955 - 2006
Minimum Life Parameter:	4
Maximum Life Parameter:	65
Life Increment Parameter:	1
Max Age (T-Cut):	52.0

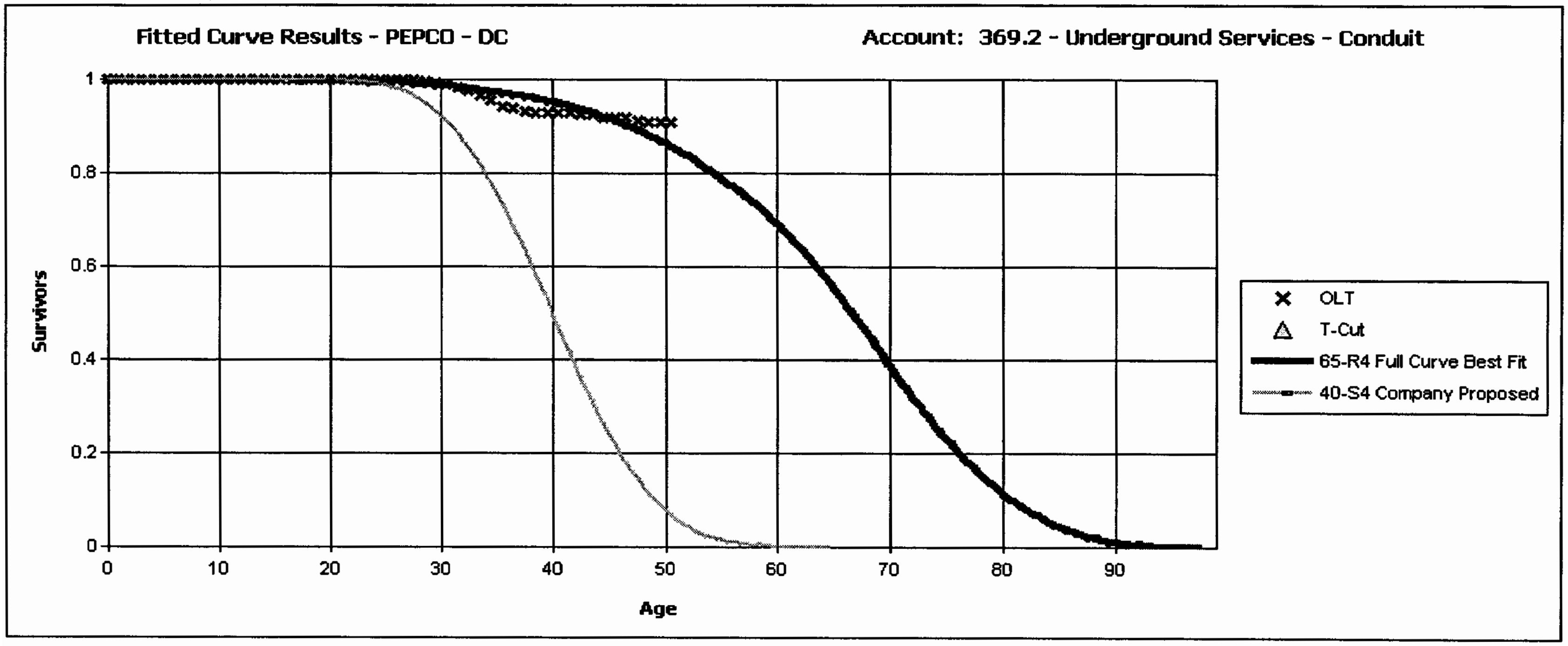


Analytical Parameters

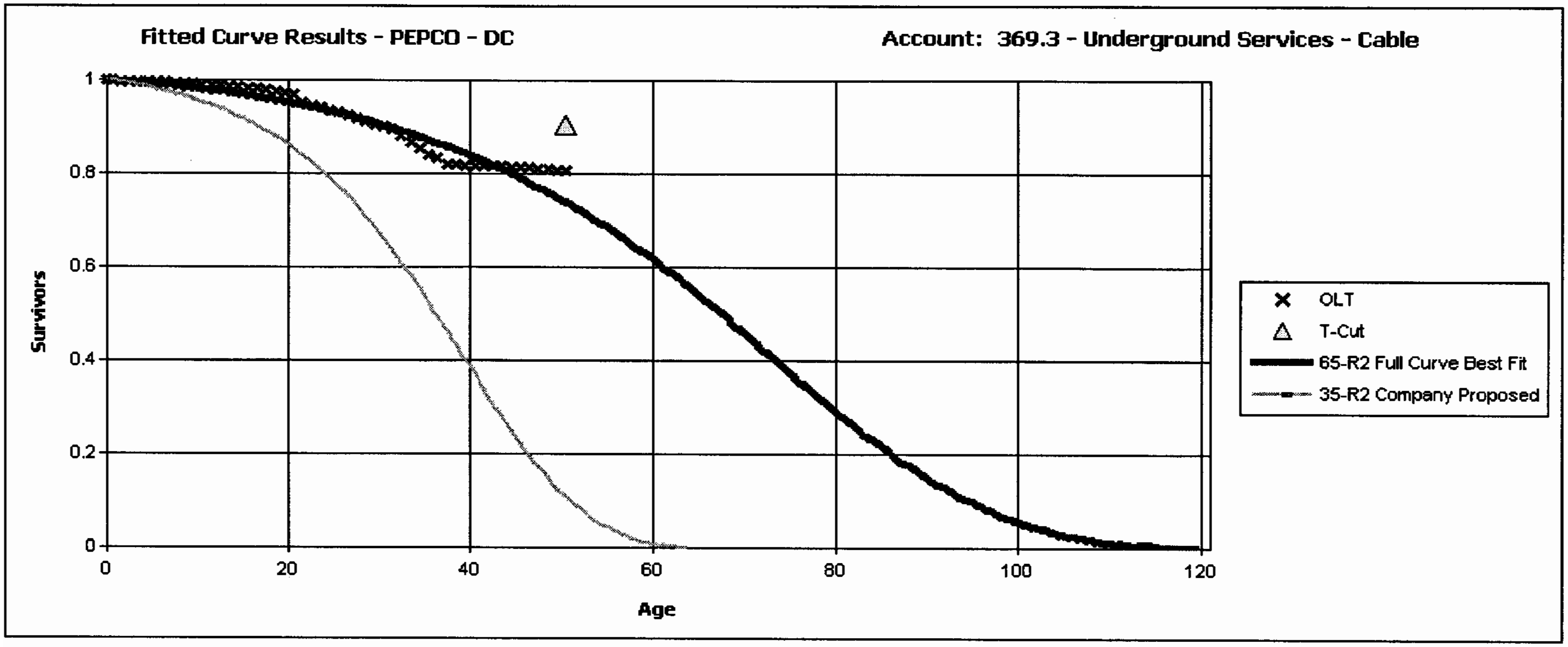
OLT Placement Band:	1920 - 2006
OLT Experience Band:	1920 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	100
Life Increment Parameter:	1
Max Age (T-Cut):	87.0



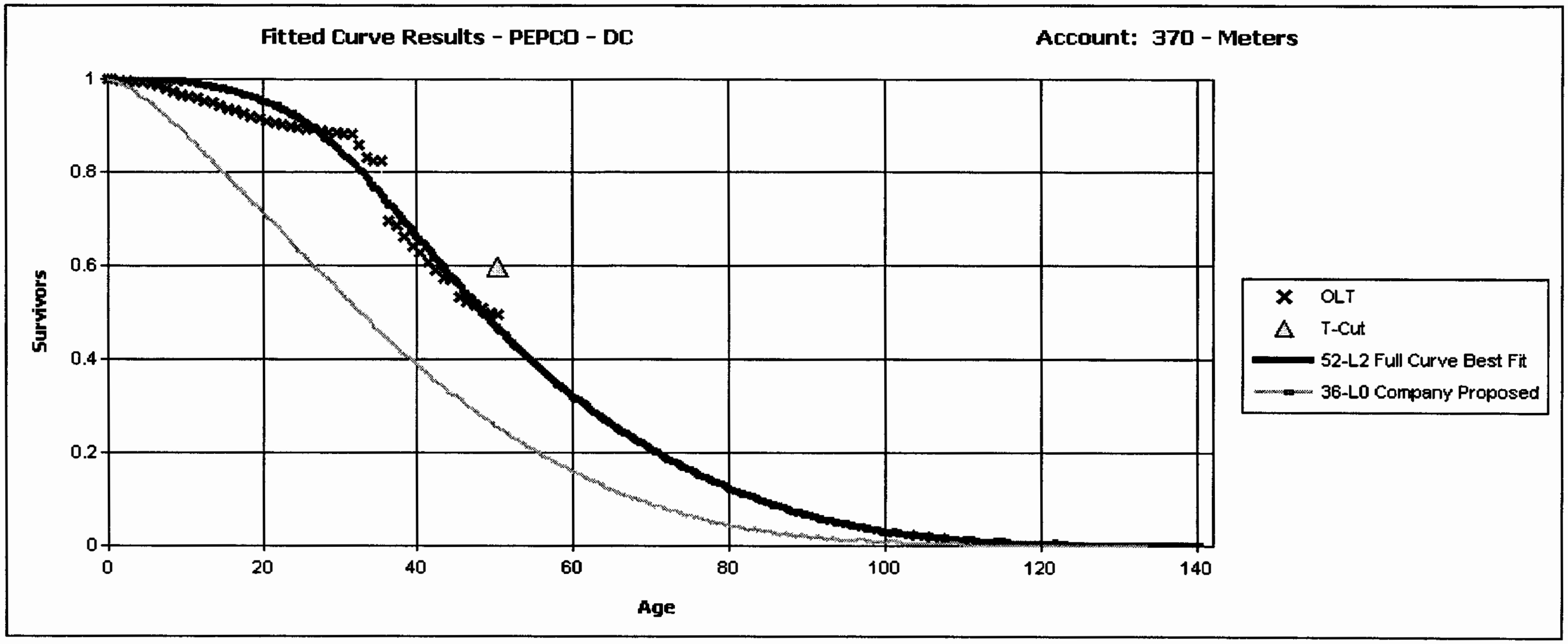
Analytical Parameters	
OLT Placement Band:	1955 - 2006
OLT Experience Band:	1955 - 2006
Minimum Life Parameter:	3
Maximum Life Parameter:	65
Life Increment Parameter:	1
Max Age (T-Cut):	52.0



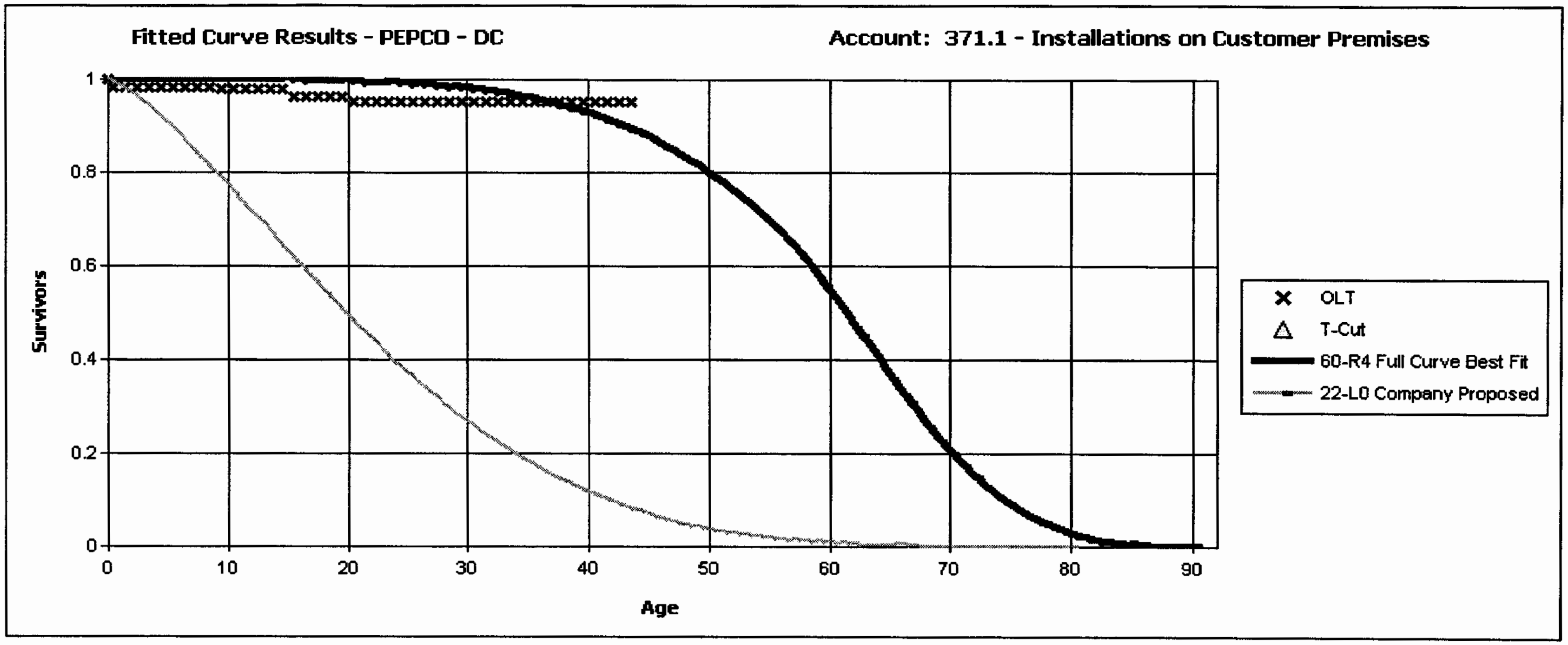
Analytical Parameters	
OLT Placement Band:	1955 - 2006
OLT Experience Band:	1955 - 2006
Minimum Life Parameter:	3
Maximum Life Parameter:	65
Life Increment Parameter:	1
Max Age (T-Cut):	52.0



Analytical Parameters	
OLT Placement Band:	1955 - 2006
OLT Experience Band:	1955 - 2006
Minimum Life Parameter:	3
Maximum Life Parameter:	65
Life Increment Parameter:	1
Max Age (T-Cut):	52.0

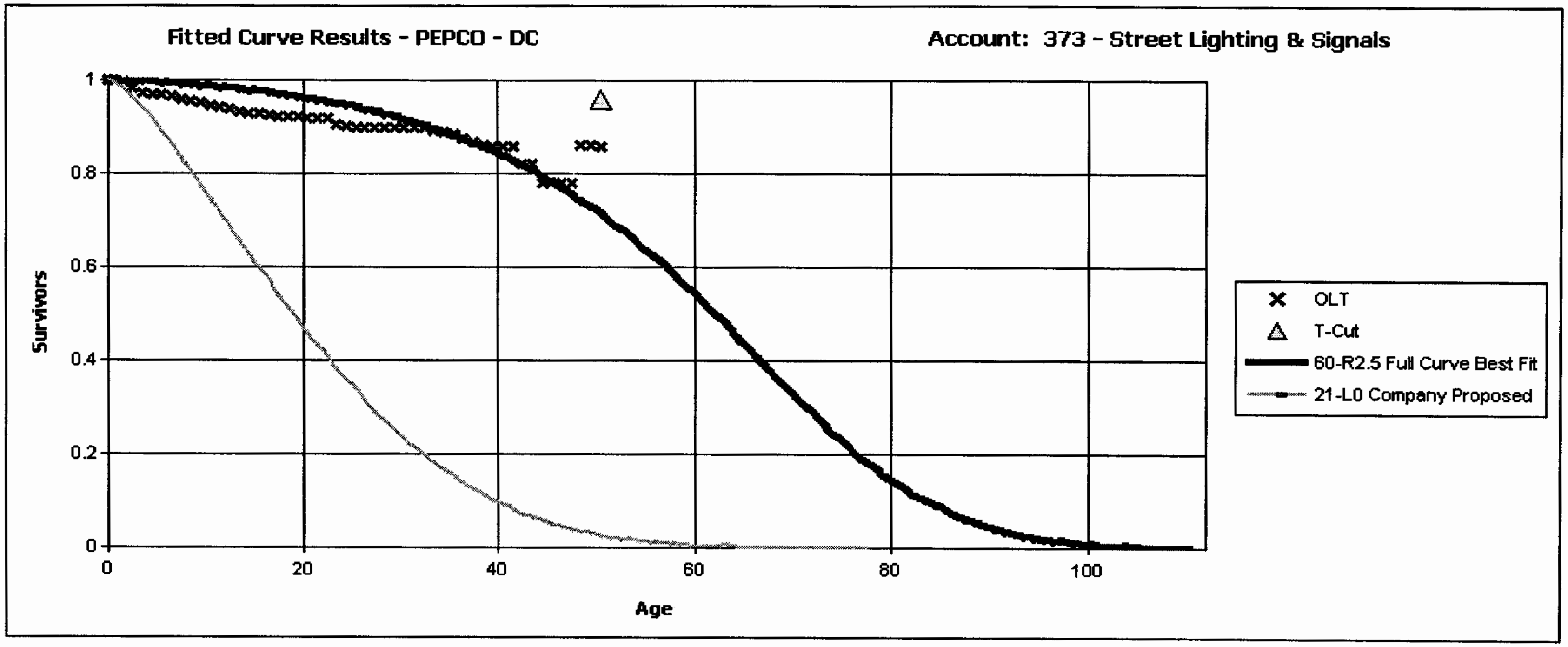


Analytical Parameters	
OLT Placement Band:	1955 - 2006
OLT Experience Band:	1955 - 2006
Minimum Life Parameter:	3
Maximum Life Parameter:	60
Life Increment Parameter:	1
Max Age (T-Cut):	52.0



Analytical Parameters

OLT Placement Band:	1962 - 2006
OLT Experience Band:	1962 - 2006
Minimum Life Parameter:	5
Maximum Life Parameter:	60
Life Increment Parameter:	1
Max Age (T-Cut):	45.0



Analytical Parameters

OLT Placement Band:	1955 - 2006
OLT Experience Band:	1955 - 2006
Minimum Life Parameter:	1
Maximum Life Parameter:	60
Life Increment Parameter:	1
Max Age (T-Cut):	52.0

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EXHIBIT OPC (F)-3

UPDATE
March 26, 2007

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9092
OFFICE OF PEOPLE'S COUNSEL DATA REQUEST NO. 11

11-27 Q. RECONCILE THE PLANT AND RESERVE BALANCES USED TO CALCULATE THE RATES IN THE DEPRECIATION STUDY WITH THE PLANT BALANCES SHOWN IN THE COMPANY'S FERC FORM 1 REPORT FOR 2005.

A.

Plant balances:	
MD Distribution Plant included in the Depreciation Study:	$1,830,320,977
MD jurisdiction meter adjustments	(115,371,044)
Add: Land	9,321,059
Reclassified Account 361	(62,918)
MD Distribution Plant per Plant in Service included In 12/31/05 FERC Form 1	$1,724,208,074
Reserve balances:	
MD Distribution Plant Depreciation Reserve included in the Depreciation Study	$832,152,278
Adjustments for:	
Meter jurisdictional allocation	(29,608,858)
Blended depreciation rates vs. jurisdictional rates	(26,602,420)
MD Distribution Depreciation Reserve included in the 12/31/05 FERC Form 1	$775,941,000

The Company's book depreciation reserve schedule is contained within the "Company PIS Statement" and "Company Depr Resr Statement" tabs of the Excel workbook included in the response to OPC Data Request 3, Question 2 (3 of 6).

The above documents the Company's filed position. In developing this response, it was discovered that the blended depreciation rates vs. jurisdictional rates figure of ($26,602,420) shown above does not fully adjust for the differences between blended rates and the Maryland approved jurisdictional depreciation rates. The Company is in the process of quantifying the appropriate difference between the booked Maryland depreciation rates (which reflect blended rates) and the Maryland approved jurisdictional rates, and will supply the information as soon as it is available. An update of this information affects the arithmetic calculations in Table 4, Table 2 and Table 1 of Exhibit PEPCO___(EMR-1). This change does not affect the underlying study of net salvage, average service lives and resulting average remaining lives. The update will also require a straightforward adjustment to Ratemaking Adjustment 16 (Reflection of New Depreciation Rates) which will require updates to Exhibit PEPCO___(WMV-1). Updates to these schedules will also be provided.

UPDATE

A. Attached are updated files which develop an estimated depreciation reserve by FERC account for the plant located in Maryland which was studied by Mr. Robinson in his depreciation analysis. This estimated reserve is based on the historical depreciation rates approved by the Maryland Commission and is consistent with the functional reserves by jurisdiction that the Company has tracked for cost of service purposes. The Company does not maintain jurisdictional account level reserves on its books of record. The Company's books of record are calculated using blended depreciation rates. Blended depreciation rates are based on weighted averages of the Maryland, District of Columbia and (for some accounts) FERC approved jurisdictional depreciation rates.

The account level reserves were developed in four steps. First, the Company at the end of 2003 converted its asset accounting system to the SAP software. Up through 2003, the Company maintained depreciation reserves at the Pepco system level by FERC plant account, but not on an asset by asset basis. The SAP accounting software required that depreciation reserve be assigned on an asset by asset basis. As part of this conversion, an estimated depreciation reserve was assigned to each individual asset. To do this, schedules of the historical blended depreciation rates were developed which showed the accumulative blended depreciation rates for each vintage of asset for each FERC plant account. For instance, if an asset in an account went into service at the end in 1993 and the depreciation rate for that account was 2.5%, then by the end of 2003 it would have been depreciated 25%. As an initial step, each asset was assigned an accumulative reserve amount based on these vintage depreciation rate schedules. The sum of the individual asset reserve amounts was then compared to the system depreciation reserve for each FERC plant account and a ratio of the two was calculated. The individual asset reserve amounts were then adjusted by the ratio so that the sum of the individual asset amounts matched the books of the Company for each FERC plant account on a system basis.

The adjustment was required, because the depreciation reserve reflect more than just the current asset base and the amount of depreciation that would have occurred for those assets. For instance, net salvage and cost of removal are booked to the depreciation reserve at the time an asset is retired. In addition, when an asset is retired, both the plant accounts and the accumulated depreciation reserve accounts are reduced by the original cost of the plant, so that any difference between the original cost of the plant and the accumulated reserve for that asset (plus or minus) remains in the depreciation reserve.

The individual assets were then depreciated starting in 2004 at the blended rates. The assets studied by Mr. Robinson are the plant assets that are located in Maryland. Thus the depreciation reserves as of 12/31/2005 shown in Mr. Robinson's original schedule are calculated from the individual assets located in Maryland and thus reflect the blended depreciation rates and contain other accumulated differences between the reserve for any current assets and the other components of the reserve.

The next step in developing estimates of the FERC account level balances that reflect Maryland jurisdictional rates was to redo the analysis that assigned the depreciation reserve for each asset in Maryland as of 12/31/2003 using Maryland specific historical depreciation rates, rather than the blended rates. The resulting estimated amounts that were developed for Maryland depreciation reserve balances by account were then adjusted by the same ratio that was applied to the system amounts, which implicitly assumes that any of the differences discussed above (salvage, removals costs, etc.) are evenly distributed between Maryland and other assets (primarily assets located in the District of Columbia or Virginia). A difference between the amount of accumulated depreciation reserve by account for 12/31/2003 was then calculated between what was assigned on the books and the estimate using Maryland specific depreciation rates.

The third step in the process was to adjust the 12/31/2005 reserve for Maryland assets on the books of the Company, as explained in step 1, by the difference as of 12/31/2003 calculated in step 2 above, and by the 2004 and 2005 differences by account provided in Table 4 of Mr. Robinson's original exhibits. This provided an initial estimate of the account level depreciation reserve for Maryland located assets based on Maryland jurisdictional depreciation rates as of 12/31/2005.

The last step in the process was to make the amounts consistent with the Company's cost of service study, as the results of the depreciation study will be used to adjust the cost of service. The amounts of depreciation reserve in the Company's cost of service study are based on historical studies which have maintained, at the functional plant level (distribution and general), Maryland specific depreciation reserve balances. For both distribution accounts and for general accounts, a ratio between the amount of plant allocated or assigned to Maryland as of 12/31/2005 compared to the amount of plant located in Maryland was developed. These ratios were used to adjust the Maryland specific cost of service depreciation reserves to be consistent with the amount of plant in Mr. Robinson's depreciation. The adjustment to the cost of service depreciation reserve amount for distribution plant was quite minor – less than one-tenth of one percent. The adjustment for general plant was approximately fifteen percent, as all general plant is allocated to jurisdictions in the cost of service, and relatively more plant is physically located in Maryland than is allocated to Maryland in the cost of service. The cost of service amounts at the functional level were then compared to the functional amounts calculated in step 3 above, and adjustment ratios was developed for each functional comparison. The last step in the process was to adjust the account level depreciation reserve amounts by the appropriate functional adjustment ratio, to develop estimated account level depreciation reserves for Mr. Robinson's depreciation study that are consistent with historical Maryland jurisdictional Maryland depreciation rates and that are consistent with the functional level depreciation reserves used in the Company's cost of service study.

Spreadsheets documenting the first step above are provided in files "DIST04.xlw", "dist04ADC.xls", "dist04AMD.xls", "genl04xls", "genl04ADC.xls", "genl04AMD", and "gen04ASM.xls". The spreadsheet documenting steps 3, 4 and 5 is provided as "SUMMARY MD 2003 AD.xlw.xls", except for the development of the cost of service depreciation reserve consistent with the asset base studied by Mr. Robinson, which is provided as "COS Depreciation reserve for Robinson study.xls." Updated tables for the depreciation study are provided in "TABLES PEPCO 12-2005 (Distr&Gen(Plant Reserve Comp) Adjd).xls ". The tables show a decrease in the proposed depreciation expense of $6,490,899.83 for distribution accounts and an increase of $3,465,283.46 for general accounts. File "COS Depreciation reserve for Robinson study.xls" shows that for cost of service purposes the decrease in depreciation expense, from current rates is $9,955,345 and this decrease is $3,623,964 less than the originally proposed decrease in depreciation expense.

Sponsor: Dr. Mark E. Browning

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In The Matter of the Application of the Potomac Electric Power Company for for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service.	)))))	**Formal Case No. 1053**

AFFIDAVIT OF CHARLES W. KING

CITY OF WASHINGTON)
) ss
DISTRICT OF COLUMBIA)

Charles W. King, of lawful age and being first duly sworn, deposes and states:

1. My name is Charles W. King. I am a Public Utility Consultant for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my direct testimony consisting of 32 pages, designated as OPC (F), two attachments and three exhibits.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Charles W. King
Public Utility Consultant

Subscribed and sworn to me this 24th day of May 2007

Notary Public

My commission expires March 14, 2011

DIRECT TESTIMONY OF
OPC WITNESS
KAJAL B. KAPUR

EXHIBIT OPC (G)

BEFORE
THE DISTRICT OF COLUMBIA
PUBLIC SERVICE COMMISSION

In the Matter of	**)**	
	)	
The Application of the	**)**	**Formal Case No. 1053**
Potomac Electric Power Company	**)**	
For Authority to Increase	**)**	
Existing Retail Rates and Charges	**)**	
For Electric Distribution Service	**)**	

DIRECT TESTIMONY AND EXHIBITS
OF
KAJAL B. KAPUR
EXHIBIT OPC (G)

ON BEHALF OF
THE OFFICE OF THE PEOPLE'S COUNSEL

MAY 31, 2007

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BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

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DIRECT TESTIMONY OF KAJAL B. KAPUR

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Kajal B. Kapur and my business address is 1 Steubin Lane, Charlottesville, VA 22911.

Q. **PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.**

A. I completed my Ph.D. in Economics from Cornell University in 1990. My dissertation, in the field of Industrial Organization comprised of an econometric analysis of panel data and assessed concentration and profit adjustment in U.S. industries. I earned my Masters degree in Economics from the University of California at Davis in 1986 and a Bachelors degree with Honors in Economics from University of Delhi, India in 1984.

Currently, I am Principal of Kajal B. Kapur, a small consulting firm that I founded in 1999. The business specializes in economic, policy, regulatory and environmental issues for the energy industry. Some of our recent clients include federal agencies such as the Environmental Protection Agency and United States Trade and Development Agency; state agencies such as Offices of the Attorney

Generals of Michigan and Kentucky. From 1999 to 2001, I taught economics and econometrics to students at Virginia Commonwealth University, School of Business.

As an Adjunct Professor from 1997 to 1998, I taught undergraduate and graduate courses in economics to students at Northwood University, University of Michigan, Dearborn and Kettering University. I consulted on energy and environment issues as an independent consultant from 1994 through 1998. I was Principal Economist for the Office of Utility Consumer Counselor (OUCC), State Of Indiana from 1991 through 1993. In this position, I represented the public on economic and policy issues dealing with the regulation of electric and gas utilities. I acted as an integrated resource planning (IRP) and energy sector modeling expert for OUCC. I reviewed the least-cost planning and modeling efforts of Indiana utilities and presented testimony related to the utilities' capacity and environmental compliance modeling. I reviewed the state-wide demand modeling and forecasting activities of Indiana's State Utility Forecasting Group (SUFG).

In addition to these responsibilities, I have trained national and international energy specialists, conducted research, published energy industry articles and served as a reviewer for a prestigious international energy journal.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. This testimony addresses Issue No. 5b:

Is the Company's proposed adjustment to reflect sales repression as a result of price increases reasonable and appropriate?

In the course of addressing this issue, I will examine the District of Columbia Public Service Commission's (DCPSC or Commission) established criteria for performing repression adjustments. Second, I will determine whether Potomac Electric Power Company (Pepco or Company) has satisfied the DCPSC's criteria for calculating repression adjustments. A repression adjustment is an adjustment to reflect the price elasticity of demand[1].

Q. WHAT ARE THE INVESTIGATIONS AND ANALYSIS YOU PERFORMED IN ORDER TO UNDERSTAND PEPCO'S REPRESSION ADJUSTMENT?

A. I have read the testimony and examined the exhibits of Pepco's repression adjustment witness, Mr. Mark E. Browning. I have reviewed PEPCO'S responses to Office of People's Counsel (OPC) and Commission Staff (Staff) Data Requests. I have reviewed the DCPSC's 1981 decision related to Repression Adjustments in Chesapeake and Potomac Telephone Company's Order No. 7323. I have read the DCPSC's decision related to repression adjustments in Order No. 12986 issued in Washington Gas Light Company's 2003 rate case.

SUMMARY

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. In my opinion, Pepco has not satisfied the DCPSC's established criteria for performing repression adjustments. First, Pepco has not explained the method used to calculate the repression factor or the price elasticity of demand. Pepco has not developed its own models to estimate the price elasticity of demand. The

[1] Chesapeake and Potomac Telephone Company Order No. 7323, May 28 1991, pages 252.

company bases its -0.05 elasticity of demand estimate on studies and analyses prepared by outside experts. Second, the company has not disaggregated service categories for determining the price elasticity of demand. Third, the company has not shown the methodology or estimated the dollar amounts of repression adjustments by customer class.

Q. HOW HAVE YOU ORGANIZED THE REST OF YOUR TESTIMONY?

A. The rest of my testimony is divided into two sections. In the first section, I describe the DCPSC's established criteria for performing repression adjustments as described in Chesapeake and Potomac (C&P) Telephone Company's Order No. 7323 and Washington Gas Light Company's Order No. 12986. In the second section, I explore PEPCO's justification for its price elasticity of demand estimate. I conclude with a determination of whether PEPCO has satisfied DCPSC's criteria for estimating repression adjustments.

Q. PLEASE SUMMARIZE PEPCO'S PROPOSAL.

A. PEPCO has petitioned to increase the Company's retail rates and charges for electric distribution service in the District of Columbia. These rates will lead to approximately $392.8 million dollars in total revenues. This is an increase in PEPCO's weather-normalized annual revenues of $50.5 million, an increase of 14.74 percent.

<u>DCPSC CRITERIA FOR PERFORMING REPRESSION ADJUSTMENTS</u>

Q. **WHAT ARE THE DCPSC'S GUIDELINES FOR THE VALIDITY AND RELIABILITY OF A COMPANY'S PROPOSED PRICE ELASTICITY OF DEMAND ESTIMATE?**

A. In its C&P Order No. 7323 of May 28, 1991, the DCPSC provided the following guidelines for an adequate demonstration of a proposed repression adjustment's validity:

> "First, we require that all econometric models be shown to be free of significant statistical impairment.
>
> Second, service categories should be disaggregated for purposes of determining the price elasticity of demand and calculating the dollar amounts of "repression" adjustments required…
>
> Third, the Company must submit a description of the methodology used to estimate the changes in test-year costs which are expected to have resulted from the effects of "repression." Estimates of these changes in costs should be identified for each of the twelve service categories set forth above." (C&P Order No. 7323, May 28 1991, pages 253-254).

The DCPSC used these guidelines to grant a repression adjustment to WGL in its 2003 rate case. The Commission wrote in Order No. 12986:

> "Over the past twenty years, our opinions have suggested that given a proper showing, a repression adjustment would be recognized. WGL has made a credible good faith effort in this case to provide valid price elasticity studies and justify a repression adjustment under the standards that this Commission has articulated in earlier cases…Thus the Commission is persuaded that WGL has made a sufficient showing to entitle it to a repression adjustment.
>
> The standards for obtaining a repression adjustment are laid out in *Chesapeake and Potomac Telephone Co.*, Formal Case No. 729, Order No. 7323, 2 D.C.P.S.C.181 252-253 (1981). In a good faith attempt to satisfy those standards, WGL submitted a class-by-class price elasticity study…
>
> The Commission finds that WGL has made a sufficient showing to justify a repression adjustment." (WGL Order No. 12986, November 10, 2003, pages 37-38).

Q. WHAT MUST PEPCO DEMONSTRATE IN ORDER TO JUSTIFY ITS REPRESSION ADJUSTMENT?

A. The repression adjustment is an adjustment to test-year revenues to reflect the price elasticity of demand. PEPCO is proposing a $2.3 million adjustment to base distribution revenues. To justify this repression adjustment, PEPCO must satisfy three criteria. First PEPCO must show that the economic models used to develop the repression adjustment are free of statistical problems such as multicollinearity[2]. Second, the Company must disaggregate by service categories to estimate the price elasticity of demand. Third, PEPCO must show the methodology and calculate the dollar amounts of the repression adjustment by class.

Q. HAS PEPCO FULFILLED THESE REQUIREMENTS?

A. No. I believe PEPCO has not fulfilled these requirements because it has not developed its own economic models to estimate the price elasticity of demand and repression adjustment; the company has not disaggregated by service categories for calculating the price elasticity of demand; and has not shown the methodology or estimated the dollar amounts of repression adjustments by customer class.

PEPCO'S JUSTIFICATION FOR PRICE ELASTICITY OF DEMAND AND REPRESSION ADJUSTMENT

Q. HOW HAS PEPCO ESTIMATED THE PRICE ELASTICITY OF DEMAND?

A. PEPCO"s witness, Dr. Browning presented testimony on price elasticity of demand and repression adjustments. He testified that his estimate of the price

[2] Multicollinearity exists when there is a strong interrelationship between independent variables of an estimating equation. This makes it difficult to identify the separate effects of each independent variable on the dependent variable.

elasticity of demand was based on previous studies of the demand for electricity. Some of the studies he used to determine the price elasticity of demand include Dr. Bohi's book <u>Analyzing Demand Behavior – A Study of Energy Elasticities;</u> the Energy Information Administration's (EIA) National Energy Modeling System in the 2003 Annual Energy Outlook and other studies. Based on these studies he used -0.05 as an estimate of the price elasticity of demand.

Q. DID PEPCO CONDUCT ITS OWN STUDIES TO ESTIMATE THE PRICE ELASTICITY OF DEMAND?

A. No, PEPCO has not conducted its own study of the price elasticity of demand. Request 158 in OPC Data Request No. 1 is pertinent in this respect:

Request 158:

"For this proceeding has Dr. Browning or the Company conducted a price elasticity study using District of Columbia specific data?

A. If yes, provide a copy of those results.

B. If no, why not?"

Pepco's Response was:

"No. Given the difficulty in obtaining estimates of price elasticities, Dr. Browning based his conservative estimate on the published literature."

PEPCO did not develop any economic models to estimate the price elasticity of demand and did not show that the economic models were free of statistical problems. Pepco refers to the difficulty in obtaining price elasticity estimates. Given the fact that other District of Columbia utilities such as WGL have successfully submitted class-by-class price elasticity studies to the Commission, it is hard to understand why it would be difficult for Pepco to do the same.

Q. HAS PEPCO EXPLAINED THE DIFFICULTIES IN CONDUCTING ITS OWN STUDIES OF PRICE ELASTICITY OF DEMAND?

A. No, Pepco has not explained the difficulties in conducting studies of price elasticity of demand. Pepco has merely mentioned the difficulty in obtaining estimates of price elasticities and Dr. Browning has referred to the outside studies used by him as a basis for the -0.05 price elasticity of demand estimate. Request 159 in OPC Data Request 2 is relevant in this issue:

Request 159:

"Has Pepco derived an estimation of the elasticity effect based on recent price responses by its own customers in its own territory? If so, please provide the results of this study. If not, please explain why Mr. Browning chose to rely on academic studies of price elasticity of demand as opposed to Pepco's own experience since June 2006? "

Response 159:

"No. There is insufficient data as of yet to develop a reliable statistical estimate. Dr. Browning discounted the results of the academic studies in developing his conservative estimate of the likely response to higher prices."

Pepco simply mentions that there is insufficient data to develop a reliable statistical estimate. The Company does not explain why there is insufficient data to develop the price elasticity estimate and why this estimate would be unreliable.

Q. HAS PEPCO USED DIFFERENT PRICE ELASTICITIES OF DEMAND FOR DIFFERENT SERVICE CATEGORIES?

A. No. PEPCO has not used different price elasticities of demand for different customer classes. Dr. Browning offers only one estimate of -0.05 for the price elasticity of demand. This means that for a 10% increase in prices, electricity sales will decline by .5% regardless of customer class. Request 45 in OPC Data Request 3 shows that PEPCO used only one elasticity coefficient in estimating the repression adjustment.

Request 45:

"If there is indeed a difference in price elasticity between different classes of customers, why has the Company only used one elasticity coefficient in recommending its repression adjustment?"

Response 45:

"Dr. Browning's purpose was to develop a conservative estimate of the effect on jurisdictional revenues and while he looked at price elasticity estimates for different classes of customers, he did not differentiate between the classes in developing the effect on jurisdictional revenues."

Hence the Company has not fulfilled Commission requirements of disaggregated service categories for price elasticity of demand.

Q**.** **HAS PEPCO SHOWN THE METHODOLOGY AND CALCULATED THE DOLLAR AMOUNTS OF THE REPRESSION ADJUSTMENT BY CLASS?**

A. Pepco has not shown the methodology or calculated the dollar amounts of the repression adjustment by service category. The Company offered Exhibit PEPCO (F) – 7 in support of the $2.3 million repression adjustment. However, Exhibit PEPCO (F) – 7 does not describe the dollar amount of adjustment by customer class or the methodology used by service category. This is also evident by the Company's response to Staff Data Request No. 2-102:

Request 102:

"For (F)-7 please disaggregate into each customer/rate class and then perform the calculation using class appropriate price change and test year annualized revenue (by class)."

Response 102:

"The requested calculations have not been performed."

Hence, PEPCO has not satisfied the Commission requirement of specifying the methodology and estimating the dollar amounts of repression adjustments by customer class.

Q. WHAT IS YOUR CONCLUSION REGARDING PEPCO'S JUSTIFICATION FOR ITS REPRESSION ADJUSTMENT?

A. I conclude that PEPCO has satisfied none of the Commission's criteria for performing repression adjustments. It has not conducted its own studies to estimate the price elasticity of demand for the District of Columbia. The Company's price elasticity of demand estimate is based on studies conducted by outside experts and is not based on District of Columbia specific data. It has not disaggregated its price elasticity of demand by service category. Finally, the company has not specified the dollar amount of the adjustment by customer class or described the methodology for calculating this adjustment by class. Hence the adjustment proposed by PEPCO does not conform to the DCPSC standards set out in the 1981 C&P order.

Q. DOES THIS CONCLUDE YOUR PREFILED TESTIMONY?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In The Matter of the Application of the Potomac Electric Power Company for for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service.	)))))	**Formal Case No. 1053**

AFFIDAVIT OF KAJAL B. KAPUR

COUNTY OF ALBEMARLE)
) ss
STATE OF VIRGINIA)

Kajal B. Kapur, of lawful age and being first duly sworn, deposes and states:

1. My name is Kajal B. Kapur. I am a Public Utility Consultant for the Office of the Public Counsel.

2. Attached hereto and made a part hereof for all purposes is my direct testimony consisting of eleven pages.

3. I hereby swear and affirm that my statements contained in the attached testimony are true and correct to the best of my knowledge and belief.

Kajal B. Kapur
Kajal B. Kapur
Public Utility Consultant

Subscribed and sworn to me this 24th day of May 2007

Notary Public

My commission expires 01 | 31 /2010

DIRECT TESTIMONY OF
OPC WITNESS
HUGH LARKIN, JR.

EXHIBIT OPC (H)

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of

the Application of	)	
Potomac Electric Power Company	)	**Formal Case No. 1053**
for An Increase In Its Retail Rates	)	
for the Sale of Electric Energy	)	

DIRECT TESTIMONY AND EXHIBITS
OF
HUGH LARKIN, JR.
EXHIBIT OPC (H)

ON BEHALF OF
THE OFFICE OF PEOPLE'S COUNSEL

May 31, 2007

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DIRECT TESTIMONY OF HUGH LARKIN, JR.

I. INTRODUCTION

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

A. My name is Hugh Larkin, Jr. I am a Certified Public Accountant licensed in the States of Michigan and Florida and the senior partner in 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 (public counsels, public advocates, consumer counsels, attorneys general, etc.) 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. I have testified before Public Service/Utility Commissions in 35 state jurisdictions, United States District courts, the Federal Energy Regulatory Commission and the Canadian National Energy Board in over 300 proceedings during the last 37 years.

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

A. Yes. I have attached Appendix I, which is a summary of my regulatory experience and qualifications.

Q. ON WHOSE BEHALF ARE YOU APPEARING?

A. Larkin & Associates, PLLC, was retained by the Office of the People's Counsel ("OPC") of the District of Columbia to review Potomac Electric Power Company's ("PEPCO") proposed Bill Stabilization Adjustment ("BSA") included as part of its request for an increase in rates. Accordingly, I am appearing on behalf of the OPC.

Q. WHICH OF THE DESIGNATED ISSUES IN FORMAL CASE NO. 1053 DOES YOU TESTIMONY ADDRESS?

A. The Public Service Commission of the District of Columbia's ("Commission") Order and Report on Prehearing Conference, Order No. 14232, dated March 8, 2007, included Attachment A, specifically identifying the Designated Issues in this case. My testimony addresses Issue 13:

Issue 13: Is PEPCO's proposed Bill Stabilization Adjustment (BSA) reasonable?

a. Describe the process for implementing an increase or decrease under a BSA.
b. What other ratemaking issues and policies are impacted by BSA and how should they be addressed?
c. Define the BSA. What does it achieve? What are the benefits and downside factors to the Company and customers?
d. How would the BSA affect energy efficiency/demand response and environmental protection?
e. Is the calculation of the BSA verifiable, the mechanism timely, and related time lag reasonable?
f. Is the BSA being applied appropriately to rate classes and subclasses?
g. Does the Company's level of commitment to demand-side resources justify implementation of a BSA at this time?

II. ISSUE 13 - BILL STABILIZATION ADJUSTMENT (BSA)

Q. WOULD YOU PLEASE PROVIDE A BRIEF SUMMARY OF THE COMPANY'S PROPOSED BILL STABILIZATION ADJUSTMENT?

A. Yes. Company witness John H. Chamberlin sponsors testimony supporting the Company's BSA. Mr. Chamberlin's testimony and the testimony of Company witness Browning, claim the Company's BSA as being beneficial to the customer and to the Company. Company witness Bumgarner describes the mechanical procedures which the Company will follow in calculating and implementing the proposed BSA. The Company proposes to reduce its requested return on equity by 25 basis points, which allegedly will reduce the revenue requirement by approximately $2 million. In addition, the Company's repression adjustment, which has the effect of increasing the revenue requirement by $2.3 million will also eliminated. The BSA adjustment that the Company proposes would adjust revenues on a quarterly basis. In other words, any adjustment required by the BSA, either positive or negative, would be implemented in the quarter subsequent to its calculation and would be limited to a 10% plus or minus adjustment of the average customer per kWh rate for that quarter.

Q. ISSUE 13 SPECIFICALLY ASKS: "IS PEPCO'S PROPOSED BILL STABILIZATION ADJUSTMENT (BSA) REASONABLE?" WHAT IS YOUR RESPONSE?

A. No, it is not. The BSA which the Company proposes would, in effect, shift a significant amount of risk associated with the operation of PEPCO's distribution system from the stockholders to the ratepayers. Under the Company's proposal, quarterly revenue per customer, calculated from the rates which the Commission finds appropriate in this case, would be the guaranteed minimum level which the Company would receive on a going-forward basis. Risks associated with colder or warmer than normal weather would be shifted from the Company's stockholders to the Company's ratepayers. Risks associated with conservation on the part of customers would be shifted from stockholders to ratepayers. Risks associated with efficiency improvements in electric appliances would be shifted from the Company's stockholders to the Company's ratepayers. Risks associated with system failures or weather outages, which reduce the Company's revenues because of their inability to deliver kWhs would be shifted from the Company's stockholders to ratepayers.

The claim made by the Company that the BSA will stabilize customers bill's is unlikely to occur because the mechanics of the BSA adjust a subsequent quarter for the BSA adjustment in the current quarters. The BSA, in and of itself, cannot and will not incent the Company to implement or assist ratepayers in reducing consumption. At best, if the BSA is implemented by the Commission, without other Commission action, the BSA will only insure that the Company can recover pre-authorized revenue irrespective of weather, conservation and improvements in appliance efficiencies and system outages.

Issue 13(a)

Q. WOULD YOU PLEASE ADDRESS ISSUE 13(a), WHICH STATES: "DESCRIBE THE PROCESS FOR IMPLEMENTING AN INCREASE OR DECREASE UNDER A BSA."?

A. The implementation of the BSA is not clearly defined in either the Company's testimony or exhibits. Company witness Bumgarner provides an illustration of calculations in PEPCO (H)-4. However, this illustration is devoid of references as to where the Commission or anyone else would obtain the data in order to calculate the basis of any quarterly adjustment.

The calculation is based on quarterly averages of customers, base revenues per customer, and average revenues per kWh. Neither the Commission, nor any rate order or other Commission precedent that I am aware of, provides any basis or parameters for determining how such information is to be determined. All calculations when rates will be determined in this case will be based on annual calculations. Therefore, as proposed by PEPCO, any quarterly calculations will be left entirely to the Company's discretion as to how those quarterly amounts will be calculated and the associated basis of each calculation. The Company's testimony, exhibits, or workpapers do not describe or define how each calculation is made.

Q. WOULD YOU GIVE A MORE DETAILED DESCRIPTION OF THE COMPANY'S SAMPLE BILL STABILIZATION ADJUSTMENT SHOWN ON EXHIBIT PEPCO (H)-4, PAGES 1 OF 2, AND 2 OF 2?

A. Yes, I will describe my understanding of what the exhibits show along with the deficiencies in the methodology. I will confine my comments to the first column which represents residential customers and is labeled "R". The first number in the residential column is labeled "Actual Quarter Based Distribution Revenue." There is no description by the Company whether this amount represents actual billed revenue during the quarter, or actual revenue derived from delivered kWhs. There may be a substantial difference between the use of what is actually billed to customers in terms of delivered and metered kWhs and what has actually been delivered during the quarter. This information has not been defined by the Company.

The next amount is "Test Year Quarterly Average Base Revenue Per Customer." Presumably, this is an average per customer which is calculated based on the Commission's decision in the current case. However, the Commission does not determine revenues by quarter for the residential customers, nor does the Commission determine in any case what the average revenue per customer would be. Therefore, the Company would be left to make these calculations without any party participating in the determination or verification of the quarterly revenues in the test year or the average per customer during the test year. One would also have to question how you would calculate the average number of customers per quarter. Would you take the average at the end of each month and average those in order to determine the average number of customers? Or would you take a daily average in order to determine the average number of customers? In any case, either methodology will derive a different average test year quarterly revenue per customer. The Company has not disclosed how those calculations will be made.

The third line in the calculation is labeled "Current Quarterly Total Number of Customers." Again, there is no statement of how the number of customers will be determined. If you take the total number of customers at the end of each quarter and there have been increases in customers daily, or at least on a monthly basis, then clearly, there will not be a match between the revenues generated on an actual basis and the calculation of what the Company terms "Normalized Revenues." Normalized Revenues are calculated by taking the average quarterly base revenues per customer times the current quarterly total number of customers. That product will end up with a number which is either larger or smaller than the actual quarterly based distribution revenue. The calculated "Normalized Revenue" will be compared to the actual quarterly based distribution revenue and the difference will be determined. The dollar amount of the difference will be divided by the budgeted kWh sales for the next quarter to arrive at a factor which will be in cents per kWh. This will be the preliminary BSA adjustment The BSA adjustment in cents per kWh will be compared to 10% of the revenue per kWh for that quarter in the test year. Any amount which exceeds 10% will be deferred to a subsequent quarter.

The following calculations are used in the BSA calculation and how those calculations are to be conducted are neither explained in the PEPCO testimony nor established in Commission precedent and rate orders.

1. Average quarterly customers.

Neither this Commission nor any regulatory commission that I aware of calculates or verifies the average number of customers on a quarterly basis. At best, a commission makes educated estimates of customers during the test year to calculate annual revenues.

2. Quarterly revenues.

Neither this Commission nor any regulatory commission that I am aware of calculates or verifies the quarterly revenues by customer class. Revenue requirements are calculated on an annual basis without regard to how those revenues might be collected on a monthly or quarterly basis.

3. Average revenue per kWh per quarter.

Neither this Commission nor any regulatory commission that I aware of calculates or verifies the average revenue per kWh per quarter.

4. Budgeted kWh per quarter.

Neither this Commission nor any regulatory commission that I am aware of reviews or analyzes future budgeted kWh sales either on an annual or a quarterly basis.

As can be seen, the calculation is based on a number of assumptions which are not explicitly stated by PEPCO or established by Commission precedent and rate orders.

Q. WHAT HAPPENS IN THE SUBSEQUENT QUARTER WHEN THE BSA ADJUSTMENT IS APPLIED TO THE ACTUAL KWH SALES?

A. Obviously, there will be an over or under collection of the BSA from the current quarter in the subsequent quarter when the adjustment is applied, because sales will either be greater or less than what was budgeted. So, the Company will either over or under collect the BSA in the subsequent quarter. Thus, that over or under collection will have to be factored into the next quarter's BSA.

Q. WHAT OTHER FACTORS WILL AFFECT THE BSA IN THE SECOND QUARTER AFTER THE INITIAL CALCULATION OF A BSA DEFICIENCY OR EXCESS?

A. The second quarter will have the same calculations to determine whether there is an adjustment required to "normalize revenues." To that amount will be added any excess over or under collection of the BSA from the prior quarter. In addition, any amount that exceeded the 10% cap would be added to the BSA. So, in any subsequent quarter at least three different items will affect the size of the BSA in total and then it again would be limited to 10% of the test year quarterly average revenue per kWh.

Clearly, there will be an on going factor which will encompass at least two factors and possibly three. These factors are the current quarterly adjustment to "normalize revenue" and over or under recovery of the prior quarter's BSA and any possible carryover from prior quarter's excess over the cap.

Q. ONE OF THE CLAIMS THAT THE COMPANY'S WITNESSES MAKE IS THAT THE BSA WILL STABILIZE CUSTOMER'S BILLS. DO YOU BELIEVE THAT IS A CORRECT CLAIM?

A. No, I do not. The Company would have no knowledge as to whether any particular quarter would produce a positive or negative adjustment to the BSA. The Company would have no knowledge as to whether any particular quarter would over or under collect the BSA from the prior quarter. The Company would have no knowledge as to whether the BSA, in any particular quarter, would exceed the 10% cap. So for the Company to make the statement that it would stabilize customer's bills is unfounded. For example, the third quarter of each fiscal year is a quarter in which the Company generates its largest revenues. Presumably, this is the quarter with the highest load associated with air conditioning. If, in fact, the second quarter of any particular year generated less revenue then the test year revenue on an average quarterly customer basis, then that amount would have to be recovered in the third quarter when the air conditioning load is most prevalent. Instead of that quarter being reduced if the weather were warmer than normal the BSA would have the opposite effect by exacerbating the effects of warmer than normal weather with a rate that is increased because the BSA from the prior quarter would have to be collected during a period when the weather was warmer than normal. Thus, the Company's claim that the customer's bills will be stabilized is not a valid claim.

<u>Issue 13(b)</u>

Q. WOULD YOU PLEASE DISCUSS ISSUE 13(b), WHICH STATES: "WHAT OTHER RATEMAKING ISSUES AND POLICIES ARE IMPACTED BY THE BSA AND HOW SHOULD THEY BE ADDRESSED?"

A. There are several ratemaking and policy issues that the BSA impacts that the Commission should be aware of. I will discuss each one of these issues separately:

1. The BSA adjustment decouples the delivery of energy with the amount of revenue that the Company will collect. Under the current regulatory framework, the Company's revenues are dependent on the actual delivery of kWhs. In other words, the more kWhs the Company delivers under the current rates the higher its revenues will be. The less energy the Company delivers under the current rates, the lower revenues will be. The BSA will tie the Company's revenues <u>not</u> to its performance in delivering kWhs to customers, but to the revenues as calculated on a quarterly basis from the Commission's last rate order. This means that there is no longer an incentive for the Company to ensure that its system is up and running and providing delivery service to customers. If, for instance, a summer thunderstorm were to down power lines and reduce the Company's ability to deliver energy, under the current system the Company would be incentivized to get its system up and running because the revenue it derives is dependent upon the kWh delivered. Under the BSA, if the same storm were to occur, it would not matter how long the Company took to get the system back up and running because the Company would receive the same dollar amount of revenue based on the Commission's last rate order. The fact that more or less kWhs were delivered would be irrelevant to the Company because their revenues are now tied to the Commission's last rate order and not to a rate per kWh.

2. As previously pointed out, the BSA will require an adjustment each and every month regardless of whether the weather is warmer or colder than normal.

The calculation is based on a comparison of actual quarterly revenue per customer with test year quarterly revenue per customer. There is little likelihood what was found to be appropriate in the test year would ever occur in actual operations. Either weather, customer growth, conservation or improvements in electrical appliance efficiency will cause actual quarterly revenue per customer to vary from the test year quarterly revenue per customer.

3. The BSA will only affect the distribution component of customer's bills and only to the extent of the 10% cap. The quarterly revenue per kWh of distribution rates amounts to approximately 19% of residential customer bills and 29% of GS and GT customer bills. The Company claims that by implementing the BSA it will send proper pricing signals to the customer regarding the cost of delivering energy to them. Clearly, this is not the case. First, there is no relationship between the Company's actual cost of providing delivery service in any month or any quarter and the revenues generated in any month or any quarter. Distribution rates are determined on an annual basis. The Company's total cost, as allocated in the Cost of Service Study to customer categories, is recovered through a customer charge and through block rate charges per kWh. Rates are designed to collect the total annual cost and return from the customer class. The rates are not designed to collect a particular month's cost or particular quarter's cost. So, the Company's claim that the BSA will give proper pricing signals related to the cost of delivering energy services is fallacious. It is based on the assumption that revenues generated in any month or quarter are somehow directly

related to the cost incurred by the Company in that month or quarter. This is clearly not true.

4. Individual customer actions may be partially circumvented by the implementation of the BSA. The BSA will decouple the delivery of kWh from the revenue generated from customers. Thus, if an individual customer were to desire to conserve energy and reduce his consumption, that reduction in consumption by that individual customer would be circumvented because if the Company did not collect the average revenue per customer as calculated by the Company from the rate case, then the total customer group would have to make up that shortfall in revenue through the BSA. Thus, at least for the portion of the bill related to distribution rate, individual customer actions could be circumvented by the implementation of the BSA.

5. The BSA will not stabilize customer's bills, but will stabilize or increase the Company's revenue. As I have previously pointed out, any shortfall in average customer revenue per quarter or excess of average customer revenue per quarter would be recovered from customers in the next quarter along with over or under recoveries from the current quarter and any excess above the 10% cap. This will not stabilize customer's bills, but will insure that the Company's revenues are stabilized.

Q. HOW WILL THE COMPANY'S REVENUES BE STABILIZED?

A. The Company will most likely accrue any BSA revenue over or under recovery on a monthly basis. The Company will not recognize these revenues as they are billed on a quarterly basis, but will recognize them as they occur monthly. Therefore, the Company's financial statements will show an accrual for BSA revenue in each and every month and, therefore, this will stabilize the Company's revenues as opposed to stabilizing customer bills.

<u>Issue 13(c)</u>

Q. PLEASE ADDRESS ISSUE 13(c), WHICH STATES: "DEFINE THE BSA. WHAT DOES IT ACHIEVE? WHAT ARE THE BENEFITS AND DOWNSIDE FACTORS TO THE COMPANY AND CUSTOMERS?"

A. 1. Define the BSA.

The BSA is a quarterly rate adjustment mechanism which will prevent PEPCO's revenues from falling below the average rate per customer found in the Commission's last rate proceeding. It, in effect, sets a floor below which PEPCO's revenues cannot decline. Regardless of what factors might affect customers consumption of kWhs, this mechanism will protect PEPCO's revenues from downturns which result from economic activities, weather, conservation and improvements in appliance efficiencies. The mechanism will ensure that PEPCO's revenues will never experience a downturn as a result of any of these factors.

2. What does it achieve?

Because the BSA decouples the Company's collection of revenue from its delivery of kWhs the BSA will guarantee that the Company will receive, at a minimum, the average rate per customer as calculated by the Company from the Commission's last rate order.

The BSA will remove weather as a factor affecting PEPCO's base rate revenues. Because the Commission's last rate order would be based on normal weather any variance from normal weather in a quarter where the BSA was in effect would be adjusted for in a subsequent quarter through the BSA. Thus, if weather were cooler than normal in the summer and PEPCO's actual revenues on average per customer during the summer quarter fell below the average found in the rate case then PEPCO would be able to adjust rates in the subsequent quarter to capture any shortfall in revenues as a result of cooler than normal weather.

Q. THE BSA IS SUBJECT TO A 10% CAP OF THE AVERAGE kWh RATE IN ANY PARTICULAR QUARTER, ISN'T THAT CORRECT?

A. Yes, it is. However, any under collection in a particular quarter because of the 10% limitation is carried over to a subsequent quarter; therefore, it is possible that a BSA adjustment in the summer quarter may actually affect rates two or three quarters into the future.

Q. WHAT ELSE DOES THE BSA ACHIEVE?

A. Obviously, if individual customers are currently conserving energy, or have taken steps on their own to improve the efficiencies of their consumption, the BSA would neutralize or mask their conservation efforts and thus obfuscate any direct benefit to the individual customer.

Q. PLEASE EXPLAIN THAT FURTHER.

A. If an individual customer were to conserve energy and that particular quarter's average revenue per customer fell below what the Company calculated that rate to be from the Commission's last order then the Company would calculate a BSA adjustment which would be implemented and added to the customer's bill who had made a concerted effort to conserve energy. Obviously, his effort to conserve energy would be somewhat muted by his bill going up in part because of the BSA.

Q. EXPLAIN WHY IT WOULD BE ONLY MUTED IN PART.

A. The distribution rate is only 19% of the total customer bill. The energy charge and transmission charge make up the rest of the bill. The BSA would not affect those components of the bill and if the customer conserves he will obviously have savings on the other 80% of the bill. However, that part associated with the delivery charge will not see the total effect of his conservation.

Q. WHAT OTHER EFFECTS WILL THE BSA ACHIEVE?

A. Customers generally experience reductions in energy consumption when they replace electrical appliances, particularly those associated with air conditioning. Electrical appliances such as air conditioners, refrigerators, small household electrical appliances, etc., generally are more efficient than their predecessors. If customers replace these appliances after a BSA is implemented, the BSA will have the effect of reducing the amount of cost reduction the customer experiences. This is so because the BSA ties the Company's revenues, not to its delivery of kWhs, but to the average revenues per customer, which the Company calculated from the Commission's last rate order. Thus, if a customer improves the efficiency of his air conditioner and, thus, his average consumption declines, his bill, in part, will be tied to the Commission's last rate order rather than his current consumption of energy.

Q. WHAT WILL THE BSA ACHIEVE IN TERMS OF MAINTAINING THE SYSTEM RELIABILITY?

A. In my opinion, the BSA will not provide any motivation for the Company to ensure that outages are repaired promptly and that the system is maintained in order to provide reliable service. Currently, the Company's earnings and revenues are tied directly to its delivery of kWhs. That is, if there is a system outage, if a storm brings down power lines, if there is a failure in a substation, the Company's revenues will be affected. It will be unable to deliver kWhs and, therefore, will not be able to bill for those kWhs. There is no mechanism in place which will compensate the Company for this loss of delivered energy. The Company is currently motivated to quickly replace or repair the system so that energy can be delivered and that revenues can be generated. The BSA will decouple the Company's revenues from the delivery of energy. Revenues will be directly affected not by the delivery of energy, but by the average rate per customer calculated from the last Commission order. If in any particular quarter there was a substantial decline in energy delivery because of storm or other natural disasters the Company would continue to collect in subsequent quarters the average rate per customer in that particular quarter. It seems that the BSA would remove some motivation for the Company to ensure that the system was quickly repaired and was reliable.

Q. WHAT ELSE WOULD THE BSA ACHIEVE?

A. The BSA will ensure that the Company will always receive from new customers added to the system no less than the average revenue per customer which the Company calculated from the Commission's last rate order for each quarter. For instance, if customers were added on the last day of each month and the quarterly average was calculated by taking the number of customers at the end of each month then the Company would receive, through the BSA, revenues for customers who had not consumed energy for each day of the quarter. This would also be true for customers in smaller homes or condominiums whose average consumption is less than the total of all average residential customers. The Company will receive the average quarterly revenue as determined in the last rate case rather than the revenue that this customer would have generated from the consumption of kWhs on an actual basis. The opposite is also true, that if the Company adds customers whose consumption is greater than the average revenue per customer as determined on a quarterly basis from the last rate case, then that additional revenue will provide a reduction to all customers.

3. Benefits to the Company:

Q. WHAT BENEFITS DOES THE COMPANY DERIVE FROM THE BSA?

A. All of the achievements which the BSA accomplishes, which I have discussed in the previous section are benefits to the Company. The BSA will protect the Company from the effects of weather effecting revenues. The BSA will benefit the Company by removing the effects of conservation on the Company's revenues. The BSA will benefit the Company by removing the effects of improvements in electrical appliance efficiencies which would have the effect of decreasing the Company's revenues. The BSA will benefit the Company by removing the effects of outages from affecting the revenues collected by the Company. Lastly, the BSA will benefit the Company by ensuring that any customers added to the system will generate revenues equal to average revenue per quarter as determined by the Company's calculation from the Commission's last rate order.

4. Downside Factors to Company

Q. DOES THE BSA HAVE ANY DOWNSIDE FACTORS TO THE COMPANY?

A. There are possibly two downside factors to the Company. The first is if there is a continuous increase in weather that makes weather warmer than normal in the summer and colder than normal in the winter where the Company would deliver more kWhs because of the effects of weather the BSA will cause the additional revenues as a result of weather that is more extreme than normal to be flowed through the BSA. The second possible downside to the Company would be that if customers are added to the system who generate revenues on an average quarterly basis which is greater than the average rate per quarter calculated by the Company from the last rate case then those increases in revenues would not flow to the Company, but would be averaged in and flow back to customers.

5. Downside Factor to Customers

Q. ARE THERE DOWNSIDE FACTORS TO CUSTOMERS IF THE BSA IS IMPLEMENTED?

A. Yes. All of the benefits derived by the Company from implementation of a BSA will be at the expense of the ratepayer. The risk of weather being cooler than normal in the summertime and warmer than normal during the wintertime is a risk that the Company has borne and is compensated through the return on equity. The BSA will now shift that risk from the Company's stockholders to the Company's ratepayers.

The risk associated with customers conservation efforts will also be shifted from the Company's stockholders to the Company's ratepayers. Currently, if a customer conserves energy it would directly affect the Company's revenues. The BSA will mute that effect on customers who conserve and if the conservation reduces the Company's average revenue per quarter per customer it will be able to recover that reduction as a result of conservation from all customers including the customer that has conserved.

Currently the risk associated with improvements in the efficiencies of electrical appliances are borne by the Company's stockholders and compensated through the return on equity. That risk will be shifted from the Company's stockholders to the Company's ratepayers through the BSA. The BSA will ensure that the Company receives no less than the average revenue per quarter as calculated by the Company from the Commission's last rate order.

The risk associated with outages and weather damages will also be shifted from the Company's stockholders to the Company's ratepayers. Currently, if the Company failed to promptly and efficiently return customers to service their revenues would be reduced by the effect of their failure to deliver kWhs to customers. That risk will no longer be borne by the Company, but will be shifted to ratepayers. If outages occur and the Company fails deliver as much energy as it normally might, it will always collect the average revenue per customer as determined in the last rate order as calculated by the Company.

Lastly, the downside to customers will be in the BSA mechanism itself. Very few, if any, customers will understand its purpose or its mechanics. Currently, customers understand that if the weather is exceedingly hot in the summertime their bills will go up. However, under the BSA it is possible for the bills to go up even higher because revenues not collected in a prior quarter would be added onto revenues collected in a hot summer month. Any refund associated with that warmer than normal period would not flow back to the ratepayer until a subsequent quarter. There would be a disconnect between what the customer is experiencing and when that experience will affect his bill. Although the amount is small in comparison to the total bill, it will still shift increases or decreases in customers' bills from the period when the weather occurred to a subsequent quarter.

Issue 13(d)

Q. PLEASE RESPOND TO ISSUE 13(d) QUESTION: "HOW WOULD THE BSA AFFECT ENERGY EFFICIENCY/DEMAND RESPONSE AND ENVIRONMENTAL PROTECTION?"

A. As I have previously stated, the BSA will protect the Company from energy efficiency initiatives either by individual customers or by increases in the efficiency of electrical appliances. From the standpoint of the Company, any efficiency or demand side responses will not affect the Company's revenue since the BSA will allow it to recover such revenues in a future quarter. From the customer's standpoint, any attempt at conservation or improvements in efficiencies will be somewhat muted since the delivery component of that customers bill might be effected by BSA adjustments currently or in a future period. The BSA would, therefore, somewhat mute customers attempts to obtain electrical efficiencies and demand reductions because the efforts of the customer would not be fully reflected in his/her annual bill.

From the Company's standpoint the BSA will not motivate the Company to engage in efficiency/demand responses because there is no motivation to do so. The BSA itself protects the Company from reductions and consumption related to efficiencies/demand response, but it does not motivate the Company to engage in efficiencies/demand response. At best the BSA would make the Company neutral to activities which result in efficiency/demand response in environmental protection.

<u>Issue 13(e)</u>

Q. PLEASE RESPOND TO THE QUESTION: "IS THE CALCULATION OF THE BSA VERIFIABLE, THE MECHANISM TIMELY AND RELATED TIME-LAG REASONABLE?"

A. The BSA calculation itself is verifiable because it utilizes simple mathematics of addition, subtraction, division and multiplication. However, the components that go into these calculations maybe somewhat less verifiable. For instance, the actual revenue per quarter could be affected by weather and how the Company calculated unbilled revenue. If the calculation is based only on energy delivered and billed then it may not be comparable to the quarterly revenue derived from the last Commission order. Another area where it may be difficult to verify what is the appropriate calculation is the average number of customers. The calculation will be affected by how that number is calculated. The calculations are made on a quarterly basis. If the Company were to take the number of customers at the end of each month and average those three numbers to get a quarterly average number of customers that would result in a different calculation then if the Company used the beginning and ending of each month or used a daily average of the number of customers. There is no statement in the Company's testimony as to how these amounts would be calculated. Each number will affect the BSA and might be subject to different interpretations by different parties. The calculation is also dependent upon the Company's projection of future kWh sales in subsequent quarters. This is subject to the Company's budgeting process and will affect the amount of revenue collected in a subsequent quarter if the BSA were authorized.

Q. THE QUESTION ALSO ASKS WHETHER THE MECHANISM IS TIMELY, WOULD YOU ALSO COMMENT ON THAT COMPONENT OF THIS ISSUE?

A. The BSA mechanism is not timely. The mechanism is based on a prior quarter and could include positive and negative amounts that exceed the 10% cap. The mechanism would also include over or under recoveries from the prior quarter which will be flowed back or collected in the current quarter. The mechanism will also include any positive or negative component of the current quarters BSA. In essence, the BSA in any quarter could include three components: 1) the current quarters BSA adjustment; 2) any positive or negative amount exceeding the 10% cap; 3) any over or under recovery of the BSA from the prior quarter. All of these components would be subject again to a 10% cap of the average kWh rate in that particular quarter based on the Commission's last order.

Q. THIS QUESTION ALSO ASKS WHETHER "BSA RELATED TIME-LAGS ARE REASONABLE?"

A. This question can be answered in the positive or the negative. If the purpose of BSA is to insure that PEPCO never receives less than the average revenue per customer found in the last rate case then the related time-lags have no discernable effects. A Company will accrue each month what it feels will be due to it under the quarterly BSA. It will adjust that amount each month until the actual billing takes place in a subsequent quarter. The Company's revenues will be no less than those found appropriate in the last Commission order as calculated by the Company per average customer quarterly revenues. Of course, the Company's revenues will grow as the number of customers will grow. Clearly, this is beneficial to the Company and the related time-lag would be reasonable if the only purpose of the BSA is to insure that the Company's revenues do not decline below the average per customer per quarter found in the Commission's last rate order.

From the customers standpoint it may be difficult to understand just exactly what is occurring in each customer's delivery component of the bill because the BSA is both time-lagged by a full quarter and is affected by the 10% cap and over and under recoveries. Thus, from the customer's standpoint the BSA time-lags would cause confusion at best.

Issue 13(f)

Q. ISSUE 13(f) STATES THE FOLLOWING: "IS THE BSA BEING APPLIED APPROPRIATELY TO RATE CLASSES AND SUB-CLASSES?"

A. The Company's calculations, as shown on Exhibit PEPCO (H)-4, indicate that the BSA will be applied to eight rate classes. The Company states that it will cover all rate classes except street lighting and some other minor rate classes. Whether rate classes can be subdivided and a separate BSA applied to sub-classes has not been discussed or proposed by the Company.

Issue 13(g)

Q. PLEASE DISCUSS ISSUE 13(g) WHICH IS STATED AS: "DOES THE COMPANY'S LEVEL OF COMMITMENT TO DEMAND-SIDE RESOURCES JUSTIFY IMPLEMENTATION OF A BSA AT THIS TIME?"

A. The Company was asked to answer the following question:

> In reference to Exhibit PEPCO (G), page 9, lines 2-6, please provide a list of each demand side management program that PEPCO has proposed to implement in conjunction with its proposed BSA. If no programs have been proposed, please so state.

PEPCO' response was as follows:

> PEPCO's proposed demand side management programs are described in the Company's April 4, 2007 Commission filing titled "Application of Potomac Electric Power Company for Authorization to Establish a Demand Side Management Cost Recovery Mechanism and An Advanced Metering Infrastructure Rate Adjustment Mechanism and to Establish a DSM Collaborative and An AMI Advisory Group," District of Columbia Formal Case No. 1056.

It is apparent that there is no current demand-side management program that the Company is proposing to be implemented in conjunction with the BSA. Apparently the Company, in another case, is proposing that the Commission authorize a recovery mechanism for demand-side management programs. Obviously, if a BSA is authorized, which I and the OPC oppose, it should only be authorized in conjunction with the implementation of appropriate and effective demand-side resources committed to reducing customer consumption. However, the BSA does not require the implementation of demand-side management programs, nor does the implementation of demand-side management programs require the implementation of a BSA. There does not appear to be any equal or offsetting benefits to customers which the Company has agreed to implement in this case. The BSA is a one-sided mechanism which will primarily benefit the Company and does not and will not require the implementation of any demand-side management programs. It would be more appropriate to examine demand-side management programs individually and measure their effectiveness and allow the Company to recover any lost revenues and expenses independent of a requirement to implement a BSA.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

CURRICULUM VITAE

Q. WHAT IS YOUR OCCUPATION?

A. I am a certified public accountant and a partner in the firm of Larkin & Associates, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan.

Q. PLEASE DESCRIBE YOUR EDUCATION AND EXPERIENCE.

A. I graduated from Michigan State University in 1960. During 1961 and 1962, I fulfilled my military obligations as an officer in the United States Army.

In 1963 I was employed by the certified public accounting firm of Peat, Marwick, Mitchell & Co., as a junior accountant. I became a certified public accountant in 1966.

In 1968 I was promoted to the supervisory level at Peat, Marwick, Mitchell & Co. As such, my duties included the direction and review of audits of various types of business organizations, including manufacturing, service, sales and regulated companies.

Through my education and auditing experience of manufacturing operations, I obtained an extensive background of theoretical and practical cost accounting.

I have audited companies having job cost systems and those having process cost systems, utilizing both historical and standard costs.

I have a working knowledge of cost control, budgets and reports, the accumulation of overheads and the application of same to products on the various recognized methods.

Additionally, I designed and installed a job cost system for an automotive parts manufacturer.

I gained experience in the audit of regulated companies as the supervisor in charge of all railroad audits for the Detroit office of Peat, Marwick, including audits of the Detroit, Toledo and Ironton Railroad, the Ann Arbor Railroad, and portions of the Penn Central Railroad Company. In 1967, I was the supervisory senior accountant in charge of the audit of the Michigan State Highway Department, for which Peat, Marwick was employed by the State Auditor General and the Attorney General.

In October of 1969, I left Peat, Marwick to become a partner in the public accounting firm of Tischler & Lipson of Detroit. In April of 1970, I left the latter firm to form the certified public accounting firm of Larkin, Chapski & Company. In September 1982 I re-organized the firm into Larkin & Associates, a certified public accounting firm. The firm of Larkin & Associates performs a wide variety of auditing and accounting services, but concentrates in the area of utility regulation and ratemaking. I am a member of the Michigan Association of Certified Public Accountants and the American Institute of Certified Public Accountants. I testified before the Michigan Public Service Commission and in other states in the following cases:

U-3749	Consumers Power Company - Electric Michigan Public Service Commission
U-391	Detroit Edison Company Michigan Public Service Commission
U-4331	Consumers Power Company - Gas Michigan Public Service Commission
U-4332	Consumers Power Company - Electric Michigan Public Service Commission
U-4293	Michigan Bell Telephone Company Michigan Public Service Commission
U-4498	Michigan Consolidated Gas sale to Consumers Power Company Michigan Public Service Commission
U-4576	Consumers Power Company - Electric Michigan Public Service Commission
U-4575	Michigan Bell Telephone Company Michigan Public Service Commission
U-4331R	Consumers Power Company - Gas - Rehearing Michigan Public Service Commission
6813	Chesapeake and Potomac Telephone Company of Maryland, Public Service Commission, State of Maryland

Formal Case No. 2090	New England Telephone and Telegraph Co. State of Maine Public Utilities Commission
Dockets 574, 575, 576	Sierra Pacific Power Company, Public Service Commission, State of Nevada
U-5131	Michigan Power Company Michigan Public Service Commission
U-5125	Michigan Bell Telephone Company Michigan Public Service Commission
R-4840 & U-4621	Consumers Power Company Michigan Public Service Commission
U-4835	Hickory Telephone Company Michigan Public Service Commission
36626	Sierra Pacific Power Company v. Public Service Commission, et al, First Judicial District Court of the State of Nevada
American Arbitration Association	City of Wyoming v. General Electric Cable TV
760842-TP	Southern Bell Telephone and Telegraph Company, Florida Public Service Commission
U-5331	Consumers Power Company Michigan Public Service Commission
U-5125R	Michigan Bell Telephone Company Michigan Public Service Commission
770491-TP	Winter Park Telephone Company, Florida Public Service Commission
77-554-EL-AIR	Ohio Edison Co., Public Utility Commission of Ohio
78-284-EL-AEM	Dayton Power and Light Co., Public Utility Commission of Ohio
0R78-1	Trans Alaska Pipeline, Federal Energy Regulatory Commission (FERC)

78-622-EL-FAC	Ohio Edison Co., Public Utility Commission of Ohio
U-5732	Consumers Power Company - Gas, Michigan Public Service Commission
77-1249-EL-AIR, et al	Ohio Edison Co., Public Utility Commission of Ohio
78-677-EL-AIR	Cleveland Electric Illuminating Co., Public Utility Commission of Ohio
U-5979	Consumers Power Company, Michigan Public Service Commission
790084-TP	General Telephone Company of Florida, Florida Public Service Commission
79-11-EL-AIR	Cincinnati Gas and Electric Co., Public Utilities Commission of Ohio
790316-WS	Jacksonville Suburban Utilities Corp., Florida Public Service Commission
790317-WS	Southern Utility Company, Florida Public Service Commission
U-1345	Arizona Public Service Company, Arizona Corporation Commission
79-537-EL-AIR	Cleveland Electric Illuminating Co., Public Utilities Commission of Ohio
800011-EU	Tampa Electric Company, Florida Public Service Commission
800001-EU	Gulf Power Company, Florida Public Service Commission
U-5979-R	Consumers Power Company, Michigan Public Service Commission
800119-EU	Florida Power Corporation, Florida Public Service Commission

810035-TP	Southern Bell Telephone and Telegraph Company, Florida Public Service Commission
800367-WS	General Development Utilities, Inc., Port Malabar, Florida Public Service Commission
TR-81-208**	Southwestern Bell Telephone Company, Missouri Public Service Commission
810095-TP	General Telephone Company of Florida, Florida Public Service Commission
U-6794	Michigan Consolidated Gas Company, 16 refunds Michigan Public Service Commission
U-6798	Cogeneration and Small Power Production -PURPA, Michigan Public Service Commission
0136-EU	Gulf Power Company, Florida Public Service Commission
E-002/GR-81-342	Northern State Power Company Minnesota Public Utilities Commission
820001-EU	General Investigation of Fuel Cost Recovery Clauses, Florida Public Service Commission
810210-TP	Florida Telephone Corporation, Florida Public Service Commission
810211-TP	United Telephone Co. of Florida, Florida Public Service Commission
810251-TP	Quincy Telephone Company, Florida Public Service Commission
810252-TP	Orange City Telephone Company, Florida Public Service Commission
8400	East Kentucky Power Cooperative, Inc., Kentucky Public Service Commission

U-6949	Detroit Edison Company - Partial and Immediate Rate Increase Michigan Public Service Commission
18328	Alabama Gas Corporation, Alabama Public Service Commission
U-6949	Detroit Edison Company - Final Rate Recommendation Michigan Public Service Commission
820007-EU	Tampa Electric Company, Florida Public Service Commission
820097-EU	Florida Power & Light Company, Florida Public Service Commission
820150-EU	Gulf Power Company, Florida Public Service Commission
18416	Alabama Power Company, Public Service Commission of Alabama
820100-EU	Florida Power Corporation, Florida Public Service Commission
U-7236	Detroit Edison-Burlington Northern Refund Michigan Public Service Commission
U-6633-R	Detroit Edison - MRCS Program, Michigan Public Service Commission
U-6797-R	Consumers Power Company - MRCS Program, Michigan Public Service Commission
82-267-EFC	Dayton Power & Light Company, Public Utility Commission of Ohio
U-5510-R	Consumers Power Company - Energy Conservation Finance Program, Michigan Public Service Commission
82-240-E	South Carolina Electric & Gas Company, South Carolina Public Service Commission

8624 8625	Kentucky Utilities, Kentucky Public Service Commission
8648	East Kentucky Power Cooperative, Inc., Kentucky Public Service Commission
U-7065	The Detroit Edison Company (Fermi II) Michigan Public Service Commission
U-7350	Generic Working Capital Requirements, Michigan Public Service Commission
820294-TP	Southern Bell Telephone Company, Florida Public Service Commission
Order RH-1-83	Westcoast Gas Transmission Company,Ltd., Canadian National Energy Board
8738	Columbia Gas of Kentucky, Inc., Kentucky Public Service Commission
82-168-EL-EFC	Cleveland Electric Illuminating Company, Public Utility Commission of Ohio
6714	Michigan Consolidated Gas Company Phase II, Michigan Public Service Commission
82-165-EL-EFC	Toledo Edison Company, Public Utility Commission of Ohio
830012-EU	Tampa Electric Company, Florida Public Service Commission
ER-83-206**	Arkansas Power & Light Company, Missouri Public Service Commission
U-4758	The Detroit Edison Company (Refunds), Michigan Public Service Commission
8836	Kentucky American Water Company, Kentucky Public Service Commission
8839	Western Kentucky Gas Company, Kentucky Public Service Commission

83-07-15	Connecticut Light & Power Company, Department of Utility Control State of Connecticut
81-0485-WS	Palm Coast Utility Corporation, Florida Public Service Commission
U-7650	Consumers Power Company - (Partial and Immediate), Michigan Public Service Commission
83-662**	Continental Telephone Company, Nevada Public Service Commission
U-7650	Consumers Power Company – Final Michigan Public Service Commission
U-6488-R	Detroit Edison Co. (FAC & PIPAC Reconciliation), Michigan Public Service Commission
Docket No. 15684	Louisiana Power & Light Company, Public Service Commission of the State of Louisiana
U-7650	Consumers Power Company (Reopened Reopened Hearings) Michigan Public Service Commission
38-1039**	CP National Telephone Corporation Nevada Public Service Commission
83-1226	Sierra Pacific Power Company (Re application to form holding company) Nevada Public Service Commission
U-7395 & U-7397	Campaign Ballot Proposals Michigan Public Service Commission
820013-WS	Seacoast Utilities Florida Public Service Commission
U-7660	Detroit Edison Company Michigan Public Service Commission
U-7802	Michigan Gas Utilities Company Michigan Public Service Commission

830465-EI	Florida Power & Light Company Florida Public Service Commission
U-7777	Michigan Consolidated Gas Company Michigan Public Service Commission
U-7779	Consumers Power Company Michigan Public Service Commission
U-7480-R	Michigan Consolidated Gas Company Michigan Public Service Commission
U-7488-R	Consumers Power Company – Gas Michigan Public Service Commission
U-7484-R	Michigan Gas Utilities Company Michigan Public Service Commission
U-7550-R	Detroit Edison Company Michigan Public Service Commission
U-7477-R	Indiana & Michigan Electric Company Michigan Public Service Commission
U-7512-R	Consumers Power Company – Electric Michigan Public Service Commission
18978	Continental Telephone Company of the South - Alabama, Alabama Public Service Commission
9003	Columbia Gas of Kentucky, Inc. Kentucky Public Service Commission
R-842583	Duquesne Light Company Pennsylvania Public Utility Commission
9006*	Big Rivers Electric Corporation Kentucky Public Service Commission *Company withdrew filing
U-7830	Consumers Power Company - Electric (Partial and Immediate) Michigan Public Service Commission

7675	Consumers Power Company - Customer Refunds Michigan Public Service Commission
5779	Houston Lighting & Power Company Texas Public Utility Commission
U-7830	Consumers Power Company - Electric – "Financial Stabilization" Michigan Public Service Commission
U-4620	Mississippi Power & Light Company (Interim) Mississippi Public Service Commission
U-16091	Louisiana Power & Light Company Louisiana Public Service Commission
9163	Big Rivers Electric Corporation Kentucky Public Service Commission
U-7830	Consumers Power Company - Electric - (Final) Michigan Public Service Commission
U-4620	Mississippi Power & Light Company - (Final) Mississippi Public Service Commission
76-18788AA & 76-18788AA	Detroit Edison (Refund - Appeal of U-4807) Ingham County Circuit Court Michigan Public Service Commission
U-6633-R	Detroit Edison (MRCS Program Reconciliation) Michigan Public Service Commission
19297	Continental Telephone Company of the South - Alabama, Alabama Public Service Commission
9283	Kentucky American Water Company Kentucky Public Service Commission
850050-EI	Tampa Electric Company Florida Public Service Commission
R-850021	Duquesne Light Company Pennsylvania Public Service Commission

TR-85-179**	United Telephone Company of Missouri Missouri Public Service Commission
6350	El Paso Electric Company The Public Utility Board of the City of El Paso
6350	El Paso Electric Company Public Utility Commission of Texas
85-53476AA & 85-534855AA	Detroit Edison-refund-Appeal of U-4758 Ingham County Circuit Court Michigan Public Service Commission
U-8091/ U-8239	Consumers Power Company-Gas Michigan Public Service Commission
9230	Leslie County Telephone Company, Inc. Kentucky Public Service Commission
85-212	Central Maine Power Company Maine Public Service Commission
850782-EI & 850783-EI	Florida Power & Light Company Florida Public Service Commission
ER-85646001 & ER-85647001	New England Power Company Federal Energy Regulatory Commission
Civil Action * No. 2:85-0652	Allegheny & Western Energy Corporation, Plaintiff, - against – The Columbia Gas System, Inc. Defendant
Docket No. 850031-WS	Orange Osceola Utilities, Inc. Before the Florida Public Service Commission
Docket No. 840419-SU	Florida Cities Water Company South Ft. Myers Sewer Operations Before the Florida Public Service Commission
R-860378	Duquesne Light Company Pennsylvania Public Service Commission
R-850267	Pennsylvania Power Company Pennsylvania Public Service Commission

Docket No. 900329-WS	Southern States Utilities, Inc. Florida Public Service Commission
Docket Nos. ER89-* 678-000 & EL90-16-000	System Energy Resources, Inc. (Surrebuttal) Federal Energy Regulatory Commission
Application No. 90-12-018	Southern California Edison Company California Public Utilities Commission
Docket No. 90-0127	Central Illinois Lighting Company Illinois Commerce Commission
Docket No. FA-89-28-000	System Energy Resources, Inc. Federal Energy Regulatory Commission
Docket No. U-1551-90-322	Southwest Gas Corporation Before the Arizona Corporation Commission
Docket No. R-911966	Pennsylvania Gas & Water Company The Pennsylvania Public Utility Commission
Docket No. 176-717-U	United Cities Gas Company Kansas Corporation Commission
Docket No. 860001-EI-G	Florida Power Corporation Florida Public Service Commission
Docket No. 6720-TI-102	Wisconsin Bell, Inc. Wisconsin Citizens' Utility Board
(No Docket No.)	Southern Union Gas Company Before the Public Utility Regulation Board of the City of El Paso
Docket No. 6998	Hawaiian Electric Company, Inc. Before the Public Utilities Commission of the State of Hawaii
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Docket No. 910890-EI	Florida Power Corporation Before the Florida Public Service Commission
Docket No. 910890-EI	Florida Power Corporation, Supplemental Before the Florida Public Service Commission
Case No. 3L-74159	Idaho Power Company, an Idaho corporation In the District Court of the Fourth Judicial District of the State of Idaho, In and For the County of Ada - Magistrate Division
Cause No. 39353*	Indiana Gas Company Before the Indiana Utility Regulatory Commission
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Cause No. 39498	PSI Energy, Inc. - Surrebuttal testimony Before the State of Indiana - Indiana Utility Regulatory Commission
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Docket No. 92-47	Diamond State Telephone Company Before the Public Service Commission of the State of Delaware
Docket Nos. 920733-WS & 920734-WS	General Development Utilities, Inc. Before the Florida Public Service Commission

Docket No. 92-11-11	Connecticut Light & Power Company State of Connecticut, Department of Public Utility Control
Docket Nos.EC92-21-000 & ER92-806-000	Entergy Corporation Before the Federal Energy Regulatory Commission
Docket No. 930405-EI	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. UE-92-1262	Puget Sound Power & Light Company Before the Washington Utilities & Transportation Commission
Docket No. 93-02-04	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Docket No. 93-02-04	Connecticut Natural Gas Corporation, Supplemental State of Connecticut, Department of Public Utility Control
Docket No. 93-057-01	Mountain Fuel Supply Company Before the Utah Public Service Commission
Cause No. 39353 (Phase II)	Indiana Gas Company Before the Indiana Utility Regulatory Commission
PU-314-92-1060	US West Communications, Inc. Before the North Dakota Public Service Commission
Cause No. 39713	Indianapolis Water Company Before the Indiana Utility Regulatory Commission
93-UA-0301*	Mississippi Power & Light Company Before the Mississippi Public Service Commission
Docket No. 93-08-06	SNET America, Inc. State of Connecticut, Department of Public Utility Control
Docket No. 93-057-01	Mountain Fuel Supply Company - Rehearing on Unbilled Revenues - Before the Utah Public Service Commission

Case No. 78-T119-0013-94	Guam Power Authority vs. U.S. Navy Public Works Center, Guam - Assisting the Department of Defense in the investigation of a billing dispute. Before the American Arbitration Association
Application No. 93-12-025 - Phase I	Southern California Edison Company Before the California Public Utilities Commission
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Case No. 94-0035-E-42T	Monongahela Power Company Before the Public Service Commission of West Virginia
Docket No. 930204-WS**	Jacksonville Suburban Utilities Corporation Before the Florida Public Service Commission
Docket No. 5258-U	Southern Bell Telephone and Telegraph Company Before the Georgia Public Service Commission
Case No. 95-0011-G-42T*	Mountaineer Gas Company Before the West Virginia Public Service Commission
Case No. 95-0003-G-42T*	Hope Gas, Inc. Before the West Virginia Public Service Commission
Docket No. 95-02-07	Connecticut Natural Gas Corporation State of Connecticut, Department of Public Utility Control
Docket No. 95-057-02*	Mountain Fuel Supply Before the Utah Public Service Commission
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BRC Docket No. EX93060255 OAL Docket PUC96734-94	Generic Proceeding Regarding Recovery of Capacity Costs Associated with Electric Utility Power Purchases from Cogenerators and Small Power Producers Before the New Jersey Board of Public Utilities

Docket No. U-1933-95-317	Tucson Electric Power Before the Arizona Corporation Commission
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Docket No. 96-UA-389	Generic Docket to Consider Competition in the Provision of Retail Electric Service Before the Public Service Commission of the State of Mississippi
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Docket NO. 99-02-05	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
Docket No. 99-03-36	Connecticut Light & Power Company State of Connecticut Department of Public Utility Control
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Docket No. 99-08-09	CTG Resources, Inc. State of Connecticut Department of Public Utility Control
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Docket No. 99-09-03 Phase II	Connecticut Natural Gas State of Connecticut Department of Public Utility Control
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Docket No. 99-057-20*	Questar Gas Company Public Service Commission of Utah
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Docket No. T-1051B-99-105	U.S. West Communications, Inc. Arizona Corporation Commission
Docket No. 01-035-10*	PacifiCorp dba Utah Power & Light Company Public Service Commission of Utah
Docket No. 991437-WU	Wedgefield Utilities, Inc. Before the Florida Public Service Commission
Docket No. 991643-SU	Seven Springs Before the Florida Public Service Commission
Docket No. 98P55045	General Telephone and Electronics of California California Public Utilities Commission
Docket No. 00-01-11	Consolidated Edison, Inc. and Northeast Utilities Merger State of Connecticut Before the Department of Public Utility Control
Docket No. 00-12-01	Connecticut Light & Power Company State of Connecticut Before the Department of Public Utility Control
Docket No. 000737-WS	Aloha Utilities/Seven Springs Utilities Before the Florida Public Service Commission
Consolidated Docket Nos. EL00-66-000 ER00-2854-000 EL95-33-000	Entergy Services, Inc. Before the Federal Energy Regulatory Commission
Docket No. 950379-EI	Tampa Electric Company Before the Florida Public Service Commission
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Docket No. 01-07-06*	The Towns of Durham and Middlefield State of Connecticut Before the Department of Public Utility Control
Docket No. 99-09-12-RE-02	Connecticut Light & Power/Millstone State of Connecticut Before the Department of Public Utility Control

Civil Action No. C2-99-1181	The United States et al v. Ohio Edison et al U.S. District Court, S.D. Ohio
Docket No . 001148-ET****	Florida Power & Light Company Before the Florida Public Service Commission
Civil Action No. 99-833-Per *	The United States et al v. Illinois Power Company U.S. District Court, S.D. Illinois
Civil Action No . IP99-1692-C-M/s *	The United States et al v. Southern Indiana Gas and Electric Company U.S. District Court, S.D. Indiana
Docket No. 02-057-02*	Questar Gas Company Public Service Commission of Utah
Docket No. EL01-88-000	Entergy Services, Inc. et. al. Mississippi Public Service Commission
Docket No. 9355-U	Georgia Power Company Before the Georgia Public Service Commission
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Docket No. 050045-EI *	Florida Power & Light Corporation Before the Florida Public Service Commission

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Civil Action No. 04-34-KSF	The United States et al. v. East Kentucky Power Cooperative, Inc. ET AL.
Case No. 05-0304-G-42T *	Hope Gas, Inc. d/b/a Dominion Hope Consumer Advocate Division of the Public Service Commission of West Virginia
Case No. 05-E-1222	New York State Electric & Gas Corporation Before the New York Public Service Commission
Case Nos. 05-E-0934 05-G-0935	Central Hudson Gas & Electric Corporation Before the New York Public Service Commission
Case No. 05-G-1494	Orange and Rockland Utilities, Inc. Before the New York Public Service Commission
Docket No. 060038-EI	Florida Power & Light Company Before the Florida Public Service Commission
Docket No. 060154-EI*	Gulf Power Company Before the Florida Public Service Commission
Docket No. 060300-TL	GTC, Inc. d/b/a GT Com Before the Florida Public Service Commission
Case Nos. 06-G-1185 06-G-1186	KeySpan Gas East Corporation Before the New York Public Service Commission
Docket No. U-29203 (Phase II)	Gulf States, Inc. and Entergy Louisiana, Inc. Before the Florida Public Service Commission

*Case Settled
**Issues Stipulated
***Testimony Withdrawn
****Case Settled, Testimony Not Filed

AFFIDAVIT

COUNTY OF WAYNE)
) SS:
STATE OF MICHIGAN)

HUGH LARKIN, JR., being first duly sworn, deposes and says that he is the HUGH LARKIN, JR. 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.

Hugh Larkin Jr

HUGH LARKIN, JR.

Subscribed and sworn to before me this 24 day of May 2007.

Kathleen K Niemiec

NOTARY PUBLIC

KATHLEEN K. NIEMIEC
NOTARY PUBLIC WAYNE CO., MI
MY COMMISSION EXPIRES Jul 31, 2008

DIRECT TESTIMONY OF
OPC WITNESS
JEROME S. PAIGE

EXHIBIT OPC (I)

BEFORE
THE DISTRICT OF COLUMBIA
PUBLIC SERVICE COMMISSION

In the Matter of	)	
	)	
The Application of the	)	**Formal Case No. 1053**
Potomac Electric Power Company	)	
For Authority to Increase	)	
Existing Retail Rates and Charges	)	
For Electric Distribution Service	)	

DIRECT TESTIMONY AND EXHIBITS
OF
JEROME S. PAIGE
EXHIBIT OPC (I)

ON BEHALF OF
THE OFFICE OF THE PEOPLE'S COUNSEL

MAY 31, 2007

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BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of	)	
	)	
The Application of Potomac Electric	)	Formal Case No. 1053
Power Company for an Increase in Its	)	
Retail Rates for the Sale of Electric Energy	)	

DIRECT TESTIMONY OF JEROME S. PAIGE

STATEMENT OF QUALIFICATIONS

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

A. My name is Jerome S. Paige. I am the principal associate in Jerome S. Paige & Associates, LLP. Jerome S. Paige & Associates. My office address is 1691 Tamarack St. NW, Washington, DC 20012.

Q. PLEASE BRIEFLY DESCRIBE JEROME S. PAIGE & ASSOCIATES, LLP.

A. Jerome S. Paige & Associates, LLC was formed in March 2002. It is an economic, business and organizational consulting firm that provides services in the area of forensic economics, strategic planning and organizational development.

Q. FOR WHOM ARE YOU APPEARING IN THIS PROCEEDING?

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

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

A. Yes.

Q. HAVE YOU ATTACHED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE TO THIS TESTIMONY?

A. Yes. Appendix I provides a summary of my qualifications and experience.

<u>SCOPE AND PURPOSE OF TESTIMONY</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address Issue 15:

Are the changes in the tariff language proposed by PEPCO reasonable?

In addition, I am also addressing Issue 16(g):

Should the minimum charge be replaced by a customer charge? What would be the impact on customers, customer education required and conservation?

<u>ISSUE 15: TARIFF LANGUAGE</u>

Q. HOW DID YOU ANALYZE PEPCO'S TARIFF LANGUAGE?

A. I read the testimony and examined the exhibits of PEPCO's witness, J. Reed Bumgarner, Pricing Manager, PEPCO Holdings, Inc and the exhibit (H)-2. Additionally, I the testimony prepared by the Office of People's Counsel's witnesses Karl Pavlovic, Nancy Bright, John Rothschild, and Hugh Larkin.

Q. ARE YOU ADDRESSING ALL THE TARIFF LANGUAGE?

A. No. I'm addressing the tariff language as it pertains to the following five areas:

1. R-3 to R-14

2. Residential Aid Discount-Rider "(RAD)

3. Standard Offer Service-Rider “SOS”

4. Bill Stabilization Adjustment –Rider “BSA”

5. Pension/Other Post Employment Benefits Surcharge-Rider “POPEB”

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. In my opinion, PEPCO’s proposed tariff language needs to reflect the findings and conclusions of the OPC witnesses.

Q. PLEASE SUMMARIZE PEPCO’S PROPOSAL REGARDING R-3 to R-14.

In its Exhibit PEPCO (H)-2, PEPCO proposes to increase a number of charges for several rate schedules. Those increases include, for example, per lamp, standard night burning, 24-hour burning, minimum charge, kilowatt hour charge, customer charge, kilowatt charge, and customer charge. For some classes “rating periods” are eliminated as are “billing demands on peak”. In addition the “reserved delivery capacity rider”, “bill stabilization adjustment rider”, and the “pension/other post employment benefits surcharge rider” are added to several of the tariffs. See Paige Exhibit OPC (I)-1 for a matrix that summarizes the changes.

Q. BASED ON OPC WITNESS TESTIMONY WHY IS THIS TARIFF LANGUAGE FOR R-3 TO R-14 INAPPROPRIATE?

A. OPC witness Dr. Karl Pavlovic addressed a number issues in this case: Issue 11, Issue 12, 13, and 16 that relate to Issue 15: *Are the changes in the tariff language proposed by PEPCO reasonable?*

Q. WHAT ARE DR. PAVLOVIC'S CONCLUSIONS REGARDING ISSUE 11.

A. Dr. Pavlovic concludes that "PEPCO's proposed distribution of its revenue requirement among the rate classes is not reasonable, because it is based on a flawed class cost study and uses the study in an arbitrary manner." Dr. Pavlovic goes on to recommend "that the Commission direct PEPCO to perform the class cost study correcting the flaws" that he identifies in his and "to distribute the revenue requirement among the rate classes on the basis of class cost causation using a proper and accurate class cost study."

Q. WHAT ARE DR. PAVLOVICS' CONCLUSIONS REGARGING ISSUES, 12, 13 AND 16?

A. Dr. Pavlovic concludes that "The class rates proposed by PEPCO are not just and reasonable because they do not properly reflect cost causation." He goes on to recommend "that the Commission direct PEPCO to construct Customer/Demand Charge rates based on cost causation as reflected in a proper and accurate class cost study." Dr. Pavlovic goes on to note: "Such rates would (1) send the proper economic price signal to customers, (2) stabilize both customer bills and PEPCO's distribution revenue, and (3) decouple revenue from usage."

Q. DOES DR. PAVLOVIC ADDRESS SPECIFIC COMPONENTS OF THE TRAIFFS?

A. Yes. He addresses the minimum charge and the volumetric charge, as well as other components. According to Dr. Pavlovic:

The current residential rate structure consists of a minimum charge element and a usage or volumetric element. The minimum charge is actually a volumetric charge as well, because it simply consists of 30 kilowatthours of the volumetric charge. The company proposes to replace the minimum charge with a customer

> *charge, but a customer charge set at only 22 percent of what it calculates the full customer cost to be, and maintain a volumetric charge element.* ***The proposed rate elements clearly reflect neither the cost structure nor the costs of residential distribution service.*** *[Emphasis added.]*
>
> *The current commercial rate structure consists of a customer charge element, a volumetric element, and in some cases a demand element. The company proposes to increase the customer charge elements to half of what it calculates the full customer cost to be, increase the demand elements to half of what it calculates the full demand cost to be (in the case of one class the demand charge is increased to 100 percent of cost), and maintain a the volumetric element.* ***As is the case with the proposed residential rates, the proposed commercial rate elements clearly reflect neither the cost structure nor the costs of commercial distribution service.*** *[Emphasis added.]*

Q. PLEASE RE-STATE YOUR CONCULSIONS REGARDING ISSUE 15G?

A. The proposed tariff language changes proposed by PEPCO for R-3 to R-14 are not appropriate, as explained by Dr. Pavlovic's testimony.

Q. PLEASE SUMMARIZE PEPCO'S PROPOSAL REGARDING THE RESIDENTIAL AID DISCOUNT RIDER "RAD".

A. PEPCO, in its Exhibit (H)-2 is proposing to lower RAD-STANDARD Kilowatt-hour Charge in excess of 400 kilowatt-hours (Summer) to $0.02845 per kwhr from $0.02850 and to increase; to increase the RAD-STANDARD Kilowatt-hour Charge in excess of 400 kilowatt-hours (Winter) to $0.02742 from $0.01947 per kwhr.

PEPCO is proposing to increase RAD-AE Kilowatt-hour Charge for 401-700 kilowatt-hours (Winter) to $0.01765 per kwhr from $0.00770; and to increase the Kilowatt-hour Charge in excess of 700 kilowatt-hours (Winter) to $0.02552 per kwhr from $0.01557 per kwhr.

Q. BASED ON OPC WITNESS TESIMONY WHY IS THIS RAD TARIFF LANGUAGE INAPPROPRIATE?

A. Dr. Pavlovic identifies four reasons that the RAD tariff is mis-aligned and they are:

First and most significant is that the discounts have not kept pace with the increases energy prices and rates. Second, there is a lack of transparency, indeed, there is a certain amount of obfuscation to the discounts. For example, the need for the expanded discounts has resulted from the increase in energy rates, but the expanded discounts are functionally part of the distribution rates. Third, the funding of the discounts is complicated and opaque. Fourth, the Commission has set as its goal to eliminate funding via the RETF.

Dr. Pavlovic, in his testimony elaborates on each of these four reasons, and he also offers some recommendations. Further, he concludes that if his recommendations are followed:

The results would be (1) a transparent rate/discount structure that would encourage RAD customers to shop and allow alternative/aggregation suppliers to efficiently pursue such customers, (2) elimination of the possibility of under/over funding of the discounts, (3) a clear public view of the costs of the RAD discount program, and (4) an RETF program free to pursue energy efficiency unencumbered by the RAD discount program.

Dr. Pavlovic concludes in his testimony regarding Issues 18 and 19 that "RAD and RAD-AE rates (distribution, transmission and generation) should be revised to reflect a 28 percent discount from the residential rates (as was the case prior to the unbundling of PEPCO's rates) and the discounts should be funded by a non-bypassable surcharge on commercial and residential non-RAD customers."

Q. PLEASE RE-STATE YOUR CONCULSIONS REGARDING ISSUE 15G?

A. The proposed tariff language changes proposed by PEPCO for the Residential Aid Discount-Rider "(RAD) are not appropriate as explained by Dr. Pavlovic.

Q. PLEASE SUMMARIZE PEPCO'S PROPOSAL REGARDING THE STANDARD OFFER SERVICE-RIDER "SOS".

A. In its Exhibit_ (H)-2, PEPCO proposes one change to the tariff language and that is to eliminate Schedule R-TM-EX (Time Metered Residential Service Experimental Program).

Q. DOES PEPCO OFFER AN EXPLANATION FOR THE ELIMINATION OF R-TM-EX?

A. Yes. Mr. Bumgarner notes that "the RTM-EX has been offered on an experimental basis since 1990. There is no longer any reason to continue the administrative burden of these separate rates for the small number of customers currently served, particularly since there is no basis in cost difference for distribution service."

Q. DO YOU HAVE ANY OBJECTIONS TO THAT CHANGE?

A. No. As noted above in my testimony, Dr. Pavlovic in his testimony suggests the need for PEPCO to undertake new cost allocation studies. Dr. Pavlovic also suggests a new residential rate structure.

Q. ALTHOUGH PEPCO IS NOT PROPOPSING ANY CHANGES TO THE SOS TARIFF LANGUAGE, IS THE TARIFF LANGUAGE INAPPROPRIATE?

A. Based on Dr. Pavlovic's findings and conclusions, the SOS tariff language is not appropriate because as Dr. Pavlovic concludes (regarding Issue 20):"PEPCO's Standard Offer Service and associated surcharges and administrative fees insulate PEPCO from business and regulatory risk." Following Dr. Pavlovic's analysis and conclusions until the surcharges and administrative fees reflect the appropriate risks, I recommend that the SOS tariff language not be approved the Commission.

Q. ARE THERE OTHER FACTORS THAT SUGGEST THE SOS TARIFF LANGUAGE IS INAPPROPRIATE ?

A. Yes. In PEPCO Exhibit (H)-2, on revised page R-41.1 there is an indication that the customers receiving the Standard Offer Service will pay charges "including applicable riders". As noted below, I conclude that the tariff language for the Bill Stabilization Adjustment Rider and the Pension/Other Post Employment Benefits Surcharge Rider is not appropriate; therefore, the language of relating to the Standard Offer Service is inappropriate.

Q. DO YOU HAVE ANY OBJECTIONS TO PEPCO'S BILL STABILIZATION ADJUSTMENT –RIDER "BSA"?

A. Yes. OPC Witnesses Pavlovic, Larkin and Rothschild in their pre-filed testimony note that the BSA Rider poses a number of issues as constructed. 1) The formula itself is not clearly constructed and defined. 2) The BSA Rider does not stabilize bills. It in effect stabilizes the revenue of the company. 3) The Rider shifts risks to the ratepayers and away from PEPCO.

According to Dr. Pavlovic:

… adding the BSA mechanism to the proposed changes in rate structure (1) negates the improvement in the rate structure alignment of costs, (2) misdirects the remaining spurious conservation price signal in the rate structure, (3) does not stabilize revenue, (4) insulates the company from the consequences of, and makes it indifferent to, the quality of distribution service that its provides; and (5) does not decouple revenue from usage.

Q. IN WHAT WAYS IS THE BSA RIDER RELATED TO R-3 TO R-14?

A. For R-3 to R-12, PEPCO notes in the tariff language that the BSA Rider is an applicable rider to each of the tariffs. PEPCO does not apply the BSA Rider to R-13 and R-14. See OPC Exhibit (I)-1.

Q. DOES APPLYING THE BSA RIDER TO R-3 TO R-14 HAVE IMPLICATIONS FOR YOUR TESTIMONY?

A. Yes. Since the OPC witnesses have testified that the BSA Rider (R-44) that PEPCO calculates is inappropriate, the addition of that rider to R-3 to R-12 makes PEPCO's proposed tariff language inappropriate.

Q. PLEASE SUMMARIZE PEPCO'S PROPOSAL REGARDING THE PENSION/OTHER POST EMPLOYMENT BENEFITS SURCHARGE-RIDER "POPEB".

A. According to OPC witness Nancy Bright:

*Pepco's proposal is to institute an annual automatic rate adjustment that would allow recovery of both employee pension and OPEB expenses on a dollar for dollar basis. Unlike the rate proceedings approved by the Commission in Formal Case 929 and 939 for OPEB, these annual rate adjustments would receive no scrutiny by the Commission through a rate proceeding. Instead, any variance in annual pension or OPEB expenses incurred by Pepco above or below the annual amounts set in the current proceeding would be automatically recovered from (or refunded to) ratepayers in the following year. In addition, an over or under recovery would be calculated based on the difference between actual base distribution revenue and the test period level of distribution revenue. In other words, if actual base distribution revenue were less than the base level of distribution revenue in this rate proceeding for **any** reason, then the surcharge would allow additional recovery of pensions/OPEB based on the ratio of the actual base revenue to the test year base revenue times the test year pension/OPEB expense. Finally, in its response to Staff Data Request No. 3-52, Pepco even acknowledges that it is not aware of any other utilities that have adopted the surcharge mechanism that it is proposing in this proceeding.*

Q. DO YOU HAVE ANY OBJECTIONS TO PEPCO THE PENSION/OTHER POST EMPLOYMENT BENEFITS SURCHARGE-RIDER "POPEB"?

A. Yes. According to OPC witness Nancy Bright PEPCO the POPEB surcharge should not be allowed for the following reasons: 1) Pension expenses do not vary enough and are not high enough; 2) Guaranteed recovery turns the ratemaking process in favor of PEPCO and away from ratepayers; 3) The proposed surcharge calculation includes items unrelated to an increase or decrease in the Pension/OPEB expense level (for example variations in sales and weather); 4) Including the proposed expenses in the test period will give PEPCO the opportunity to earn an adequate rate of return without a surcharge.

Q. IS THERE AN OVER-ARCHING PRINCIPLE THAT GUIDES YOUR OPINION?

A. Yes. I agree with Nancy Bright that PEPCO should not be able to recover normal operating utility expenses through the operation of a surcharge, and the inclusion of POPEB would allow for the recovery of normal operating utility expenses through the operation of a surcharge. Based on this, I recommend that the POPEB tariff language be eliminated.

Q. IN WHAT WAYS IS THE POPEB RIDER RELATED TO R-3 TO R-14?

A. PEPCO in its proposed tariff language applies the POPEB Rider to R-3 to R-11. (See OPC Exhibit (I)-1).

Q. IS THERE OTHER TARIFF LANGUAGE TO WHICH PEPCO APPLIES THE POPEB RIDER?

A. Yes. Since the OPC witnesses have testified that the POPEB Rider (R-45) PEPCO calculates is inappropriate, the addition of that rider to R-3- to R-11 and to R-14 and R-29 makes PEPCO’s proposed tariff language inappropriate and I recommend that the tariff language not be adopted.

<u>ISSUE 16(g): CUSTOMER CHARGE</u>

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address issue 16g: Should the minimum charge be replaced by a customer charge? What would be the impact on customers, customer education required and conservation?

Q. ARE YOU ADDRESSING BOTH ISSUES IN YOUR TESTIMONY?

A. Yes.

Q. HOW DID YOU GO ABOUT DETERMINING THE ANSWERS TO THESE QUESTIONS?

A. I read the testimony and examined the exhibits of PEPCO’s witness, J. Reed Bumgarner, Pricing Manager, PEPCO Holdings, Inc and the exhibit (H)-2. Additionally, I read the testimony prepared by the Office of People’s Counsel.

Q. PLEASE SUMMARIZE PEPCO’S POSITION ON THE CUSTOMER CHARGE?

Dr. Pavlovic summarizes PEPCO’s position as follows:

As PEPCO witness Chamberlin explains at pages 10-11 of his direct testimony, Exhibit PEPCO (G), PEPCO’s rate design proposal consists of (1) increases to customer charge rate elements, (2) decreases to volumetric charge rate elements, together with (3) the Bill Stabilization Adjustment (“BSA”). Mr. Bumgarner shows the proposed tariff rate element changes on pages R-3 to R-14 of the revised tariff pages in Exhibit PEPCO (H)-2 to his direct testimony. Mr. Bumgarner explains the changes to the rate elements (which he refers to as rate components) on pages 8 to 12 of his direct testimony, Exhibit PEPCO (H)-1. Pages 3a to 16 of Exhibit PEPCO (H)-1 show the development of the proposed rate components. Mr. Bumgarner shows the BSA on page R-44 of the revised tariff pages in Exhibit PEPCO (H)-2 and presents a sample calculation of the BSA in Exhibit PEPCO (H)-4. The calculation of the BSA is explained at pages 19 to 20 of his direct testimony, Exhibit PEPCO (H).

Q. SHOULD THE MIMIMUM CHARGE BE REPLACED BY A CUSTOMER CHARGE?

A. Yes. The question of whether the minimum charge should be replaced by a customer charge is address by OPC witness Dr. Karl Pavlovic in his pre-filed testimony. In his testimony, Dr. Pavlovic concludes that a customer charge should replace the minimum charge, and I agree with Dr. Pavlovic because such a change would move the existing rate structure towards one that is appropriate for a distribution company.

Q. WHAT WOULD BE THE IMPACT OF A CUSTOMER CHARGE ON CUSTOMERS?

A. By impact, we mean a financial impact on consumers. I agree with OPC witness Pavlovic: The overall impact of changing to his proposed customer/demand charge rate structure “is to increase the monthly bills of small customers and decrease the bills of large customers”. See Exhibit OPC(E)-7

Q. WHAT WILL UTLILITY CONSUMERS NEED TO UNDERSTAND ABOUT THE NEW RATE STRUCTURE?

A. One of the major things that consumers will need to understand is that since de-regulation, PEPCO is not the company they most likely think it is. Many electric consumers in the District of Columbia consider that PEPCO is still a generation company, when it is not. PEPCO is a "distribution" company, and Dr. Pavlovic, in his testimony, provides an illustration of how a customer charge/demand charge rate design would look for residential customers. Dr. Pavlovic's "illustrative rates" include a customer charge.

As Dr. Pavlovic notes: The customer charge is for activities for providing electric distribution service can be divided into two groups:

1) customer-related activities: construction, operation and maintenance of the facilities connecting the customer to the distribution system (services and meters) and construction, operation and maintenance of billing facilities (meters, meter reading, bill preparation and payment processing), and

2) distribution system-related activities: construction, operation and maintenance of secondary, primary and subtransmission facilities.

What is significant from the standpoint of the customer, and what the consumer needs to understand is that the "customer charge" does not vary with rate at which electricity is consumed, nor with the change in seasons (e.g. winter/summer). These are "fixed" charges, as Dr. Pavlovic's "illustrative" rate design points out.

Q. WHAT WOULD BE THE IMPACT ON ENERGY CONSERVATION?

A. There would be no direct effect on energy conservation. Again, as Dr. Pavlovic notes:

Customer-related activities and the costs of those activities are driven by the number of customers. System-related activities and the costs of those activities are driven by the aggregate customer peak demand on the system. The quantity of electricity delivered to customers over a month or a year has no effect on the level and costs of customer-related and system-related activities, and thus has no effect on distribution costs. A rate structure that is aligned with the distribution cost structure consists of a customer element and a demand or capacity element.

Because the minimum customer charge is not designed to change with kilowatt hour usage, it plays no role in providing a price signal to consumers to conserve energy. By energy conservation we mean the reduction in energy consumption due to changes in consumer behavior. Conservation actions would include such things turning off light bulbs and appliances, setting the thermostat lower, insulating, and generally being wise energy consumers. As a result of this wise energy behavior, consumers can reduce the amount of electricity they use (by changing their kilowatt hour usage) based on changes in the prices of electricity.

Q. ARE THERE ADDITIONAL ASPECTS OF CUSTOMER EDUCATION THAT NEEDS TO BE CONSIDERED?

A. Yes. The format of the customer's bill will change and the customer will have to be "educated" on how to read the new bill and what the new bill means. In fact, as consumers understand the elements of their bills more clearly, they will have a better understanding of the ways in which their behavior will affect the amount of energy they consume.

Q**. DOES THIS CONCLUDE YOUR PREFILED TESTIMONY?**

A. Yes it does.

Jerome S. Paige, Ph.D.

Dr. Paige, who holds a Ph.D. in economics, is a principal in Jerome S. Paige & Associates, LLC -- an economic consulting firm that specializes in the areas of pubic policy research, business and economic analysis, forensic economics and organizational change.

Since 1984, he has been consulting as an expert witness in litigation and administrative matters. He has brought together experts in economics, finance, accounting and insurance to provide litigation support. He has provided expert testimony in matters related to economic losses in personal injury, wrongful death, and business cases for plaintiffs and for defendants. He has taught courses in regulatory economics and has provided expert testimony before the DC Public Service Commission and the California Department of Insurance.

Dr. Paige has been involved in energy-related issues since the late 1970s when he was founding member of the DC Consumer Utility Board. He has provided expert testimony on behalf of the DC Office of the People's Counsel before the DC Public Service Commission on telephone issues. He was a lead consultant on the comprehensive energy plans I and III for the DC Energy Office. His firm also developed the 2006 strategic energy plan for the Metropolitan Washington Council of Governments.

From July 1996-March 2002 Dr. Paige held the position of Professor of Systems Management in the Information Resources Management College (IRMC) of the National Defense University (NDU) in Washington, D.C. At IRMC, Dr. Paige taught in the Information Strategies (IS) Department. His focused on information resources management and technology and their economic and policy implications for government, military, and civilian organizations. His primary teaching was in the areas of organizational strategic planning and performance measurement and management. In addition to his teaching duties, he served as department chair from July 1999 to March 2002.

Prior to joining the faculty of IRMC, Dr. Paige was Associate Provost at the University of Baltimore (UB) from July 1990 to July 1996. From 1977 to 1990, Dr. Paige was on the economics faculty --first as an assistant and subsequently as an associate professor -- of the University of the District of Columbia (UDC). While on leave from UDC (1986-1988), he served as the Deputy Director of the Mayor's Policy Office in the District of Columbia. He was an American Council of Education (ACE) Fellow during the 198889 academic year. At UDC, Dr. Paige taught undergraduate courses in economic theory, regulatory economics and urban economics and master's-level courses related to the city. He was interim Director of the Institute for District Affairs (IDA) at UDC and a Senior Research Scholar at IDA's successor, the Center for Urban Policy and Research (CARUP), where he participated in and/or directed studies related to housing, neighborhood revitalization, cable television, economic development, tourism, supermarket demand, and politics in the District of Columbia.

Dr. Paige has held adjunct faculty positions at UB (economics and urban policy), the Afro-American Studies Program at the University of Maryland College Park (public policy), the School of Information Studies, Syracuse University (information studies), and George Washington University (organizational sciences).

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JEROME S. PAIGE, Ph.D.

Educational Background

Ph.D., Economics (1982) American University, Washington, D.C.

M.A., Economics (1974) American University, Washington, D.C. B.A., Economics (1971) Howard University, Washington, D.C.

Diploma, (1996) Advanced Management Program, Information Resources Management College, National Defense University.

Fellow, (1988-89), American Council on Education.

Current Positions

Principal, Jerome S. Paige and Associates.
JSP & Associates is a professional services firm that specializes in the areas of areas of forensic economics, public policy report writing, and organizational strategic planning and performance measurement. Dr. Paige has been conducting economic analysis for personal injury, wrongful death, and business loss cases since 1984. He has been able to bring together a range of experts in economics, finance, accounting and insurance to meet the litigation needs of both plaintiff and defense attorneys. In addition, undertakes studies related to economic and public policy issues. He also provides organizational support services in the areas of strategic planning and performance measurement and management.

Adjunct Professor, School of Information Studies, Syracuse University.
Teaches a master's level course titled ***Applied Economics for Information Managers***. Have been teaching that course since 2000.

Adjunct Professor, Organizational Sciences Department, George Washington University.
Teaches a master's level course titled **Managerial Economics.**

Previous Positions

Professor of Systems Management, Information Resources Management College (IRMC), National Defense University (Since July 1996)
At IRMC, Dr. Paige taught in the Information Strategies Department. His focus was on information resources management and technology and their economic and policy implications for government, military, and civilian organizations. Dr. Paige chaired the Information Strategies department from July 1999 to March 2002.

Associate Provost, University of Baltimore (1990-1996)
Responsibilities included overseeing of institutional research, sponsored research, academic computing, and academic planning, assessment and self-study activities. Coordination of activities for the major university-wide governance and planning committees. Oversaw the formulation of academic and faculty-related policies. Was a liaison to the University of Maryland System (of which UB is a part) and to the Maryland Higher Education Commission.

As part of duties, served as **Acting Director of the University of Maryland System Downtown Center for Continuing Education**. This center served as a site for the eleven degree-granting institutions of UMS to offer courses in downtown Baltimore. In addition to credit courses, the center engaged in non-credit courses, contract training, conference facilities rental, and information brokering for the campuses.

From September 1991 through August 1992 served as **Interim Provost** of University of Baltimore (UB), an upper division undergraduate institution with master's and professional programs. As the interim chief academic officer, oversaw the academic management and direction of the institution's three academic units, the Law School, the Robert G. Merrick School of Business, and the Yale Gordon College of Liberal Arts. Also had line responsibility for the Langsdale Library, the Schaefer Center for Public Policy, the Hoffberger Center for Professional Ethics, the Office of Sponsored Research, the Office of Institutional Research, and Academic Computing.

Adjunct Associate Professor, UB's Department of Economics, and Finance and Department of Public Administration.
Courses included: introductory and intermediate economic theory and urban policy and research.

Adjunct Faculty, Afro-American Studies Program, University of Maryland College Park (Spring Semester 1995).
Taught a course on public policy theory and methodology.

Associate Professor, University of the District of Columbia (1977-1990)
As first an Assistant Professor and later an Associate Professor in the Department of Economics, taught undergraduate courses in introductory and intermediate economic theory and history of economic thought, American economic history, urban economics and public utility economics and graduate courses in urban policy. While at UDC, held a number of positions: **Senior Research Scholar**, (1986) Center for Applied Research and Urban Policy; **Associate Director**, (1984-1985), Institutional Self-Study, University of the District of Columbia; **Acting Director** (June-December 1982), Institute for District Affairs (IDA), **and Chairman** (1979-1981), Department of Economics.

American Council on Education Fellow, University of Baltimore (1988-1989)
While on leave from UDC, participated in the ACE Fellows Program -- a program to train academic administrators. As part of my fellowship year, I worked with the Provost at the University of Baltimore. Primary responsibilities included assisting with the development of reports needed as part of the reorganization of public higher education in Maryland.

Deputy Director, Office of the Mayor, District of Columbia (1986-1988)
Held this position while on leave from UDC. The Office of Policy was in the Executive Office of the Mayor, District of Columbia. Oversaw the formulation of major policy positions and the analysis of policy issues that addressed economic, social, budget and administrative aspects of the District and its government. Worked with other District agencies to develop an inter-agency approach to issues. Worked with universities, private organizations, non-profit organizations, and community groups in the identification of policy issues and the formulation of policy actions. Assisted in the overall management and the setting of the direction of fourteen professionals and four support staff. Evaluated personnel. Served in the absence of the Director.

Post-Secondary Education Accreditation/Licensure Reviews (Since 1985)

Reviewer (Volunteer): Since 1985 have been involved with accreditation reviews for the Commission Higher Education, Middle States Association and the New England Commission of Higher Education. Have conducted institutional self-studies, served on site visits teams, and have served on periodic review teams.

Commissioner, D.C. Education Licensure Commission (August 1991 - April 1994)
This five-member commission licenses proprietary schools, institutions outside of the District that offer academic programs within the city, and District-based postsecondary institutions not chartered by the U.S. Congress. Provides assessment and evaluation of academic programs and operations. Conducted site visits.

Continuing Legal Education Panel (2003)

"Estimating Individual Economic Losses: A Brief Summary of Some Key Points". For the DC Bar Continuing Legal Education Program, "The Far Side of Damages." April 4, 2003.

Regulatory Proceedings (Since 1994)

In the Matter of the Rate Filing of: The California Earthquake Authority, File No. PA-96-0072-00.

In the Matter of: The Automobile Rate Application of 20th Century, File No. PA-94-0012-00 (California)

In the Matters of: The Homeowners, Automobile, Commercial, and Liability Rate Applications of State Farm, Files Nos. PA-93-0014-00, PA-93-0015-00, PA-93-0017-00, PA-93-0014-0A, and PA-93-0018-00, et. al. (California)

In the Matter of: The Cease and Desist Hearing Regarding Farmers Personal Homeowners and Commercial Earthquake Deductibles (California)

In the Matters of: The Personal Homeowners and Commercial Rate Applications of Farmers, Files Nos. PA-95-0031-0A and PA-95-0031-0B (California)

In the Matter of: The Personal Homeowners Earthquake Rate Application of State Farm, File No. PA-95-0054-00 (California)

In the Matter of: The Commercial Earthquake Rate Applications of State Farm, File No. PA-95-0055-00 (California)

In the Matter of Investigation into the AT&T Divestiture and Decisions of the Federal Communication Commission on Bell Atlantic Wash. D.C. Inc.'s Jurisdictional Rates, FC 814 Phase IV (Washington, DC) July 1995.

In the Matter of the Application of the Potomac Electric Power Company for an Increase in Retail Rates for the Sale of Electric Power in the District of Columbia, Formal Case Number 939 May 1995.

Newsletter Articles (1995-1997)

"The Bills are in the Mail: Ratepayers asked to Pay for Competition's Benefits" Economic Agenda, December 1997.

"A Virtual Business Partner: Communication and Commerce in Market Space," Economic Agenda, September 6, 1997.

"A Starter Kit for the Digital Age," Economic Agenda, September 6, 1997.
"On the Other Hand: The California Earthquake Authority's "Meaningless" Insurance Product," Economic Agenda, June 7, 1997.

"EDI/EC and The Redistribution of Economic and Social Risk," Economic Agenda, Spring 1997, March 7, 1997.

"Politics and the New Economy," Economic Agenda, Winter 1996/1997, December 7, 1996.

"Can Cities and Suburbs Get Along Together?" Economic Agenda, September 7, 1996.

"Women, Financial Planning and Politics," Economic Agenda, Summer 1996.

"Tele-Futures: Accessibility, Affordability, and Accountability in the Information Age, Economic Agenda, March 12, 1996.

"Credit Scoring: Efficiency, Responsibility and Insurance Redlining," with Martha Gilbert. Economic Agenda, Winter 1995/1996.

"Insurer, Insured and Insurance: Reflections on the Structural Dimensions of the Homeowners Property/Casualty Insurance Crisis In California," Economic Agenda, Spring 1995.

"Money, Money, Money: Mutual Company Property/Casualty Insurance Premiums and the Cost of Capital," Economic Agenda, Summer 1995.

"Homeowners' Insurance and Social Policy," Economic Agenda, Fall 1995
"Accelerating the Transition to E-Government", E-Gov 2001, Washington, DC, July 2001.

"Organizational E-Strategies: Emerging Frameworks for E-Services Delivery," E-Gov Conference, Washington, DC (July 2000).

"Organizational Innovation," Strategic Leadership Forum, Fairfax, VA, (December 1999).

"Promoting the Benefits of Enhanced Customer Interaction Management," Federal Computer Week, CIO Summit, Newport, RI, (November 1999).

"Electronic Commerce, Customer Service, & Agency Strategy", Upcoming E-Gov Conference, June 28, 1999, Washington, DC.

"Linking Service Levels & Performance Measures; Translating Service into Action". Workshop conducted at the Federal Computer Week, CIO Summit: The Information Utility: Ensuring Service Levels... Creating Business Value" May 23 - May 26, 1999, St. Petersburg, Fl.

"Performance Measures & Organizational Success Translating Strategy into Customer Service & Satisfaction" Staff Training Presentation, University of Pennsylvania Librarians, Phila, Pa. May 10, 1999

Selected Presentations (Public Policy)

Presenter: “Economic Integration and Political Fragmentation,” Symposium, DC-Based Member of the National Economic Association, December 10, 1996.

Moderator: Policy and Issues Symposium: Telecommunications Act of 1996, National Defense University, October 22, 1996.

Panelist: “Economic Empowerment of Women,” Economic Empowerment Foundation, Oakland, CA, September 7, 1996.

Panelist: “Regional Community and Economic Development in the Greater Washington Metropolitan Area,” Catholic University Law School Class, Washington, DC, September 17, 1996.
“Future of Central Cities,” presentation and discussion for an international study/tour sponsored by the Meridian Center (Washington, DC). Discussion held at the University Baltimore, August 20, 1996.

Presenter: “Economic Integration and Political Fragmentation,” Prof. Jessica Elfenbein’s class on the Modern City, University of Baltimore, April 23, 1996.

“Financial Control Boards: New York, Philadelphia, Washington, DC; Considerations, Questions, and Comments,” at the Seminar, “Dealing with Fiscal Crisis in the District of Columbia, Lessons from New York City and Philadelphia, Woodrow Wilson Center, Smithsonian Institution, Washington, DC, May 15, 1995.

“Reform the Norms: Economic Development, New Realities, New Individuals and New Institutions.” University of the District of Columbia, November 3, 1995.

“Education Institutions and Structural Change,” American Council on Education, Annual Seminar, Alexandria, VA, October 6, 1995.

“Roots of the Fiscal Crisis of the District of Columbia,” Social and Leadership School for Activists (SALSA), Institute for Policy Studies, Washington, DC, June 1, 1995.

“The Future of Higher Education and Demands on Academic Leadership: Reflections on the Role of Distance Learning and Distance Learning Technologies,” ACE 16th Annual Council of Fellows Day, Washington, D.C., May 8, 1995.

"Activism and Analysis: Some Reflections on Citizen Participation in Washington D.C." for Community Involvement: Blueprint for Successful Advocacy at the mid-year meetings of the National Association of State Utility Consumer Advocates (NASUCA), Washington D.C., June 10, 1992.

"Without Access: Removing Information Inequalities." Panel presentation: "Put Another & Another Nickel In," at the Conference on "Inventing the Future: New Technology, Perception and Meaning," sponsored by the Institute for Publication Design, University of Baltimore, April 4, 1992.

"Urban Future: Political Economy and Social Welfare in the District of Columbia," Presentation at the National Capital Area Political Science Association, Spring Conference, February 29, 1992.

"Comments on Social Activists in the 1960s: Julius Hobson, Geno Barone, Frank Kameny and Carlos Rosario," at the 19th Annual Conference on Washington, D.C. Historical Studies, February 29, 1992.

Testimony before the Committee on Consumer and Regulatory Affairs, Council of the District of Columbia in support of the Education Licensure Commission, February 27, 1992.

"Urban Policy and a Changing Economic Base: The Case of the District of Columbia," National Economics Association Meetings, December 28, 1990, Washington, DC.

"Philanthropy and Economic Development," National Economics Association Meetings, December 29, 1990, Washington DC.

Selected Publications

Revitalizing District of Columbia Neighborhoods: Proposals for "East of the Anacostia River" Development. Edited with M. Ali (May 1988) Studies in D.C. History and Public Policy, no. 11.

"History of Public Housing in D.C.," Chapter II, The Barry Administration Reports to the People on Public Housing, June 1986.

"Safe, Decent, and Affordable: Citizens' Struggles to Improve Housing in Washington D.C.," (1983). With M. Reuss. Studies in D.C. History and Public Policy, Paper no. 6. Also published in Housing Washington's People: Public Policy in Retrospect (1983) edited by S. Diner and H. Young, Department of Urban Studies, University of the District of Columbia.

"A Macroeconomic Impact Model for n-Trading Regions With an Application to the Washington D.C. Tourism Industry" (1982) with F. Siegmund and E. Ezeani. Papers in the Social Sciences, College of Liberal and Fine Arts, University of the District of Columbia. First appeared as Working Paper No. 11, Department of Economics, University of the District of Columbia.

"The Changing Urban Economic Base: An Essay on a Broader Framework for Analyzing Neighborhood Revitalization" (1980). With M. Reuss. Working Papers in the Social Sciences, College of Liberal and Fine Arts, University of the District of Columbia.
"Rent Control in Washington D.C.: Three Views," (1979) Working Paper No. 10, Department of Economics, University of the District of Columbia, Washington D.C.

"Private Neighborhood Revitalization, Low-Income Residents, and Public Policy." (1979) With M. Reuss. Unpublished Manuscript.

"The Process of Neighborhood Revitalization and its Implications for Public Policy: The Case of Washington D.C." (1979). With M. Reuss. Working Paper No. 7, Department of Economics, University of the District of Columbia, Washington D.C.

Selected Reports

"An Organizational Analysis and Development of a Strategic Market Plan to Promote Tourism in Washington, D.C." Phase I Report with Milton A. Grodsky, Arlene R. Malech, and Laura D. McCall of the Center for the Study of Management & Organizations, University of Maryland University College for the D.C. Tourism Task Force (August 20, 1992).

Report of the University of Maryland System Working Group on Access/Enrollment Management to Chancellor Donald N. Langenberg" Task Force Member (August 24, 1992).

"The Urgent Challenge: Educational Excellence for All," Mayor's Commission on Postsecondary Education, District of Columbia Government (1988). (Staff member)
"Overview of Retail Food Service Demand and Supply in the District of Columbia," Prepared by the D.C. Office of Business and Economic Development in conjunction with the Office of Policy, Executive Office of the Mayor (1988). Served as lead writer and analyst for project.

"Making D.C. Energy Efficient," Comprehensive Energy Plan of the District of Columbia (March 1986). Member of the D.C. Energy Office's research and report writing team.

"City-Wide Retail Food Service Project Report" (May 1982). D.C. Office of Business and Economic Development.

Past Project Directorships

"Conference 83, Cable Television: Community Medium for the District of Columbia" (Co-Project Director, 1982-1983)

Retail Food Service Facilities Study for the District of Columbia government (19811982)

U.S. Department of Housing and Urban Development, Project Director Conference on Urban Development and Public Finance: The Decade Ahead," (1981-1982)

Past Commission/Board Memberships

D.C. Educational Licensure Commission D..C Rental Accommodations Commission (Vice Chair)
D.C. Citizens Energy Advisory Commission
D.C. Community Humanities Council (Co-Chair)
D.C. Historical Society
D.C. Consumer Utility Board (First Vice Char) National Parks and Conservation Association
D.C. Tax Revision Commission, Member

Current Memberships and Organizational Affiliations

American Economic Association, Member
D.C. Fiscal Policy Institute, Advisory Board Chair
National Economics Association, Member
National Association of Forensic Economists, Member

EXHIBITS OF
OPC WITNESS
JEROME S. PAIGE

EXHIBIT OPC (I)-1

Matrix of Tariff Changes

Exhibit OPC (I)-1

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	RATE SCHEDULES FOR ELECTRIC SERVICE IN THE DISTRICT OF COLUMBIA													
2	SUMMARY OF PROPOSED CHANGES													
3			Schedule	Page No.	Per Lamp	Standard Night Burning	24-Hour Burning	Minimum Charge	Kilowatt Hour Charge	Kilowatt Charge	Customer Charge	Rating Periods	Billing Demands On Peak	Reserved Delivery Capacity Service Rider
4	DC-R	Residential Service	R	R-3				I	I					
5	DC-AE	Residential All-Electric	AE	R-4				I	I					
6	DC-R-TM	Time Metered Residential Service	R-TM	R-5					I		I	E		
7	CD-R_TM-EX	Time Metered Residential Service Experimental	R-TM-EX	R 5.2				Eliminated						
8	DC-GS ND	General Service - Non Demand Schedule "GS ND"	GS ND	R-6					I		I			
9	DC-GS LV	General Service-Low Voltage	GS LV	R-6.2					I		I			
10	DC-GS 3A	General Service-Primary Service	GS 3A	R-6.4					I	I	I			
11	DC-T	Temporary or Supplemental Service	T	R.7						I	I			
12	DC-GT LV	Time Metered Service Low Voltage	GT LV	R-8					I	I	I	E	E	Y
13	DC-GT 3A	Time Metered General Service	GT 3A	R-8.2					I	I	I	E	E	Y
14	DC-GT 3B	Time Metered General Service-HighVoltage Service	GT 3B	R-8.4					I	I	I	E	E	Y
15	DC-RT	Rapid Transit Service	RT	R-9					I	I	I			Y
16	DC-SL	Street Lighting Service	SL	R-10		I	I							
17	DC-TS	Traffic Signal Service	TS	R-11					I					
18	DC-SSL-OH	Charges for Servicing Street Lights Served from Overhead Lines	SSL-OH	R-12	I									
19	DC-SSL-UG	Charges for Servicing Street Lights Served from Underground Lines	SSL-UG	R-13	I									
20	DC-TN	Telecommunications Network Service	TN	R-14					I		I			
21	DC	Residential Aid Discount	RAD	R-29					I					
22														
23	I=Increase Proposed													
24	E=Elimination Proposed													
25	Y=Yes Applied Proposed													

AFFIDAVIT

WASHINGTON, DC }
} SS: 164-40-0308

JEROME S. PAIGE, being duly sworn deposes and states that the foregoing is his testimony, that he read the same and is familiar with the contents thereof and that the matters and facts set forth therein are true and correct to the best of his knowledge, information and belief.

Jerome S. Paige

JEROME S. PAIGE

Subscribed and sworn before me this
25th day of May 2007.

Linda R. Lee

Notary Public

LINDA R. LEE
District of Columbia
My Commission Expires
March 14, 2011

DIRECT TESTIMONY OF
OPC WITNESS
DONALD E. JONES

EXHIBIT OPC (J)

BEFORE
THE DISTRICT OF COLUMBIA
PUBLIC SERVICE COMMISSION

	)	
In the Matter of	)	
	)	
The Application of the	)	**Formal Case No. 1053**
Potomac Electric Power Company	)	
For Authority to Increase	)	
Existing Retail Rates and Charges	)	
For Electric Distribution Service	)	
	)	

DIRECT TESTIMONY AND EXHIBITS
OF
DONALD E. JONES
EXHIBIT OPC (J)

ON BEHALF OF
THE OFFICE OF THE PEOPLE'S COUNSEL

MAY 31, 2007

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BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of	)	
	)	
The Application of Potomac Electric	)	Formal Case No. 1053
Power Company for an Increase in Its	)	
Retail Rates for the Sale of Electric Energy	)	

DIRECT TESTIMONY OF DONALD E. JONES

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Donald E. Jones and my business address is Quality Environmental Solutions, Inc., 2521 Riva Road, Suite L3, Annapolis, Maryland 21401.

Q. **PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.**

A. I have a BA degree in Geology from Boston University (1975) and a MS in Water Resources Management from the University of Wisconsin (1978). I currently work for Quality Environmental Solutions, Inc. (QES), a company I founded 15 years ago. Prior to QES I worked for several small and large environmental consulting firms over a period of 14 years. My near 30 years of work experience has concentrated on the assessment and remediation of environmental contamination, particularly soil and ground-water impacts. I have been directly involved with thousands of projects including Phase I and Phase II Environmental Site Assessments, regulatory analyses, Environmental Impact Statements, comprehensive site development analyses, field exploration and sampling, and remedial action plan development and implementation. I have provided litigation support and testimony. I regularly prepare and give presentations at technical society meetings. I am a member of a local Water Board and I serve on the Technical Advisory Board of the Blacksmith Institute, a non-profit organization addressing the world's most polluted places. A copy of my resume is included as Appendix A.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to discuss and respond to the Potomac Electric Power Company (PEPCO) assertion that the environmental impacts of the new Northeast Substation have been adequately addressed and that PEPCO has provided for adequate remedial actions for such impacts.

Q. **WHAT ARE THE INVESTIGATIONS AND ANALYSES YOU PERFORMED IN ORDER TO UNDERSTAND THE ENVIRONMENTAL ASPECTS OF THE NEW SUBSTATION?**

A. I have read the testimony and examined the exhibits provided in PEPCO's environmental testimony by William M. Gausman. I have reviewed the District of Columbia Public Service Commission's (DCPSC) Order and Report on Pre-Hearing Conference (March 8, 2007) and supplemental Order (May 4, 2007). I have also reviewed the specific environmental information requests by the Office of People's Counsel for the District of Columbia (OPCDC) and PEPCO responses. I have also reviewed the DC Office of Planning Large Tract Review report (July 8, 2005) and required DC government environmental permits for the construction and operation of the new substation. A list of the documents reviewed is included as Exhibit OPC (J)-1.

<u>SUMMARY</u>

Q. **PLEASE SUMMARIZE YOUR FINDINGS.**

A. In my opinion, PEPCO has not "adequately considered the environmental impact of the substation and provided adequate remedial actions for such impacts." (DCPSC Designated Issue 3.c.iv). There are three primary environmental issues associated with the new substation: pre-construction environmental condition of the property; environmental impacts during construction; and, operational environmental impacts. Based on the documents provided, the environmental condition of the property prior to development was not adequately assessed. Construction permits were secured from the appropriate DC government agencies. The substation is nearing completion; there is an assumption that the construction permit requirements were followed or, if not, DC inspectors required implementation of corrective actions prior to continuation of the construction activity. Operational environmental issues are centered on the potential health effects associated with exposure to electric and magnetic fields (EMF). Epidemiologic studies show that magnetic field exposure above certain levels may be a risk factor for childhood leukemia. PEPCO has not adequately addressed the impact of elevated EMF exposure rates to pedestrians, bike path users and nearby residents.

Q. **PLEASE SUMMARIZE THE PEPCO PROPOSAL.**

A. PEPCO purchased a 6.65-acre parcel in October 2003 that was formerly part of the CSX rail yard. An approximate 2.2-acre portion of the property was proposed for development of the Northeast Substation. The substation includes a 69kV sub-transmission supply system and 13 kV distribution feeder systems. Prior to the purchase of the property, PEPCO Holdings Inc. contracted URS Corporation (URS) to complete a Phase I Environmental Site Assessment (ESA). Due to the presence of recognized environmental conditions (RECs), a follow-up Phase II investigation was completed with soil and ground-water sampling and analysis. Required DC construction permits were secured and based on information provided in PEPCO testimony, substation construction is nearly complete. The PEPCO schedule forecasts completion of the 13 kV distribution feeder network by June 2008.

Q. **HOW HAVE YOU ORGANIZED THE REST OF YOUR TESTIMONY?**

A. The rest of my testimony focuses on the three primary environmental issues associated with due diligence prior to property acquisition, substation construction activities, and environmental impacts associated with EMF once the substation is operational.

PROPERTY DUE DILIGENCE

Q. **WHAT DUE DILIGENCE WAS COMPLETED BY PEPCO PRIOR TO THE PURCHASE OF THE PROPOSED SUBSTATION PROPERTY?**

A. URS is an environmental engineering consulting firm that was contracted by PEPCO Holdings Inc. to complete a Phase I ESA of the 6.65-acre parcel prior to October 2003 purchase of the property from the railroad transportation company CSX Corporation (CSX). PEPCO provided a copy of the July 1, 2003 Draft Phase I ESA report (URS Phase I Report) as part of the response to OPCDC Data Request 4-155. The draft report identified several RECs, including the presence of oil staining and oily puddles, historic use of the property as a rail yard and refueling depot, and off-site properties with potential to adversely impact the subject property. The property had been utilized as a rail yard and fueling depot since construction of the Baltimore and Ohio Eckington Freight Yard in the early 1900's until operations ceased in the early 1980's. URS recommended further investigation based on visual observations and site history. The Phase I ESA report is deficient for the following reasons:

- The report is only in draft form with no cover letter, cover page, figures, or appendices. OPCDC has made repeated requests for a complete report with PEPCO stating a final report is not available. I am sure URS is in possession of a final report as one should have been required prior to the purchase of the property.

- The URS report notes that the site was previously filled with artificial fill. This represents a REC as the source of the material is not known. This was not a REC identified in the URS report.

- URS relied on an interview with PEPCO engineer Shahid Anis who "was not aware of any incidents, unusual odors, stains or other conditions that would indicate a potential environmental concern on the subject property" (URS Phase I Report page 3-1). This statement contradicts URS direct observations of "oil staining and oily puddles" on the property (URS Phase I Report page ES-1). In addition, the PEPCO engineer would not be aware of previous site activities; a CSX representative should have been contacted to ascertain the locations and activities associated with specific historical site operations.

URS completed a "Limited Phase II Environmental Investigation" in July 2003. The investigation included the completion of six soil borings with soil and ground-water sampling and analysis. The samples were analyzed for typical petroleum hydrocarbon constituents benzene, toluene, ethylbenzene and xylenes (BTEX) and total petroleum hydrocarbons diesel and gasoline range organics (TPH-DRO and TPH-GRO). The letter report states that none of the tested constituents were detected in the soil or ground-water samples. The Phase II investigation and report are deficient for the following reasons:

- The report is incomplete with none of the referenced attachments (scope of work, figure, and laboratory report). OPCDC has made repeated requests for a complete report with PEPCO stating a final report is not available. I am sure URS is in possession of a final report as one should have been required prior to the purchase of the property.

- Soil samples were not collected from borings B-4 and B-5.

- The site history necessitates a more rigorous subsurface investigation as volatile organic compounds (VOCs) other than BTEX would be anticipated along with heavy metals, polychlorinated bi-phenols (PCBs) and poly-aromatic hydrocarbons (PAHs).

- The previous property owner, CSX, may have conducted environmental investigations on the PEPCO property. Reports may be available from CSX, or alternatively, reports may be available from the DC Department of Health.

Q. **WHAT ARE THE CONSEQUENCES OF THESE DUE DILIGENCE DEFICIENCIES?**

A. The consequences of the noted due diligence deficiencies include:

- PEPCO purchasing the property with unknown levels of contamination;
- Inability of PEPCO to accurately forecast site development costs to account for unknown levels of contamination;
- Possibility of transferring contaminated media off site to an unsuitable location;
- Negating CERCLA liability relief that is otherwise applicable with proper due diligence; and,
- Minimizing the potential to recoup cleanup costs form the previous site owner.

Q. **WHY IS DUE DILIGENCE IMPORTANT PRIOR TO PURCHASING COMMERCIAL PROPERTY?**

A. Due diligence is a standard practice for evaluating the environmental conditions of a property. Completion of due diligence in accordance with standard practices (ASTM E 1527-00 at the time of the URS Phase I ESA) provides CERCLA ("Superfund") liability relief for the property buyer (assuming the buyer had no past property interest or use). Without proper due diligence, the motto "buyer beware" holds true. Due diligence is also completed (1) to verify that there should be no diminution in property value due to environmental contamination, (2) to estimate project development costs should there be an environmental cost component, (3) to evaluate the necessity of any remedial measures to ensure protection of human health and the environment based on the contaminant levels and site development plans, (4) as a risk management tool in the decision-making processes from property purchase through design and construction, and (5) to ensure that existing environmental issues will not impact the future marketability of the property. The federal EPA issued new regulations in November 2005 that require completion of Standards and Practices for All Appropriate Inquiries (40 CFR 312) to secure CERCLA liability protection for real estate transactions. It is my professional opinion that the URS Phase I ESA submitted by PEPCO does not meet the standards of the then-applicable ASTM E 1527-00 and would not meet the new standards.

Q. **WHAT WOULD YOU RECOMMEND TO SATISFY THE DUE DILIGENCE STANDARDS?**

A. I recommend completion of an updated Phase I ESA in accordance with EPA Standards and Practices for All Appropriate Inquiries (40 CFR 312) and ASTM Standard E-1527-05. This will require more extensive background research and additional soil and ground-water testing.

SUBSTATION CONSTRUCTION ACTIVITIES

Q. **WHAT ENVIRONMENTAL PERMITS AND APPROVALS WOULD HAVE BEEN REQUIRED PRIOR TO CONSTRUCTION OF THE NEW SUBSTATION?**

A. The DC government has an established process for securing permits prior to site construction activities. The July 8, 2005 Large Tract Review report was prepared by the Office of Planning with a recommendation for application approval. The Large Tract Review concluded that the proposed substation was consistent with the Comprehensive Plan for the property. Specific conditions included bike path and pedestrian easements and modifications to the storm-water management system.

A Building Permit was issued by the Building and Land Regulation Administration on November 2, 2005. The Building Permit included provisions for storm-water management, sediment and erosion control, and an environmental review process. The Building permit expired November 2, 2006.

Q. **DO YOU HAVE ANY COMMENTS OR CONCERNS REGARDING THE PERMITS AND APPROVALS?**

A. All Building Permit applications must be accompanied by an Environmental Intake Form (EIF). A follow-up Environmental Impact Screening Form (EISF) is required for any project with costs exceeding $1,400,000. Therefore, an EISF was required to be submitted. PEPCO has not provided a copy of the submitted EISF. There should be written correspondence regarding DC review of the EISF and a determination whether an Environmental Impact Statement would be required.

The Building Permit expired November 2, 2006. PEPCO should supply documentation that the permit was extended and that site construction activities since November 2, 2006 have been conducted under an active permit.

As far as sediment and erosion control measures and the design of the storm-water management system, I have to assume that DC inspections ensured proper controls were in place and that the systems were installed in accordance with the approved design specifications.

SUBSTATION OPERATION

Q. **WHAT ARE THE ENVIRONMENTAL CONCERNS WITH SUBSTATION OPERATIONS?**

A. The environmental concerns with the operation of the substation relate to the potential for electrical component fluid releases to the environment and the possible adverse impacts of EMF exposure to PEPCO workers, pedestrians and bicyclists.

Q. **HAS PEPCO ADEQUATELY ADDRESSED THE POTENTIAL FOR FLUID RELEASES?**

A. According to PEPCO testimony, the electrical equipment (transformers and capacitor banks) will be located inside the building with primary and secondary containment should there be a release of fluid. The containment systems are designed to prevent a fluids release from reaching the environment. PEPCO should verify that the containment systems are capable of handling the fluids volume of the individual component with an additional freeboard allowance. The containment systems appear adequate based on the brief description of the containment systems in PEPCO testimony and assuming the systems can handle the required component volumes.

Q. **HAS PEPCO ADEQUATELY ADDRESSED THE POTENTIAL ADVERSE IMPACTS OF EMF EXPOSURE?**

A. The EMF issue was not adequately addressed by PEPCO submitting a one-page EMF summary (attachment 5 of the Large Tract Review report). Regarding EMF exposure, PEPCO states that the Northeast Substation “will be substantially the same as other substations operated by PEPCO”, that “there is no established cause and effect between exposure and adverse health effects”, and that “the magnetic field strength decreases rapidly with distance from the source” (PEPCO March 9, 2005 letter from Mr. Walter Newcomb to the DC Office of Planning).

The electric power industry supports research through the Electric Power Research Institute (EPRI). EPRI has conducted numerous studies and published literature concerning EMF exposure and health effects. An April 2007 fact sheet discusses the results of a California Public Utilities Commission health risk evaluation in which the authors “believe that EMF exposure can increase the risk of childhood leukemia, adult brain cancer, ALS, and miscarriage.” (EPRI April 2007 Fact Sheet entitled “Frequently Asked Questions about Electric and Magnetic Fields (EMF)”). There is also recent research that the adverse health effects may be related to contact current exposure, not EMF. Another April 2007 EPRI fact sheet states that “although epidemiologic studies show that magnetic field exposure at 3 to 4 miligauss or above may represent a risk factor for childhood leukemia, it cannot be concluded that a cause-and-effect relationship exists." (EPRI April 2007 Fact Sheet entitled "Electric and Magnetic Fields (EMF)"). I am not an expert in this area of study and am only reporting what I have read in the EPRI literature.

A PEPCO consultant, Exponent, Inc. prepared a report entitled "Pre-Construction Measurements and Calculations of Magnetic Fields Associated with PEPCO Substation 212." The report states that for pedestrians "a few feet of sidewalk the field levels will approach 35 mG, and along a 68-foot stretch of sidewalk adjacent to the property the field levels will exceed 5 mG. A 28-ft-wide transverse section of roadbed – crossing over the North Feeder Extension – will have fields in excess of 5 mG, and a 40-ft-wide section will have fields over 5 mG crossing over the South Feeder Extension." Along the bicycle path the report estimates peak exposure of "8.6 mG over the duct-bank centerline near the substation. This value will drop off to 6.7 mG directly over the underground transmission line at a point 200 feet from the substation." These levels are projected to drop to 2.8 mG on the bike path a distance of 200 feet from the substation.

If as the literature states there are possible adverse health effects of EMF exposure above 3 to 4 mG, PEPCO should more fully address the EMF issue, especially in light of new research reported by EPRI. There may be additional mitigation measures that PEPCO could implement to reduce potential EMF exposure to pedestrians and users of the bike path. The PEPCO testimony also does not address EMF exposure to PEPCO workers at the substation.

Q. **DOES THIS CONCLUDE YOUR TESTIMONY?**

A. Yes, it does.

APPENDIX A

DONALD E. JONES, C.P.G.

Professional Qualifications

Senior manager with technical, sales, project and business management experience. Founder of Quality Environmental Solutions, Inc. Previously Director of the IT Corporation national program for clients with hydrocarbon-related environmental problems, including responsibility for quality, consistency, responsiveness, and cost-effectiveness and development of environmental management programs. Technical specialties include litigation support, environmental site assessments, hydrogeologic evaluations, remedial system design and implementation, permit strategy development, and technical training. Experience includes management of projects involving assessment and remediation of ground water contaminated by petroleum hydrocarbons and industrial chemicals.

Currently serves as a member of a local Water Board and is an active member of the Maryland Department of the Environment Ad Hoc Committee. He is also a Technical Advisory Board member of Blacksmith Institute, a non-profit organization that strives to accelerate cleanup of the world's most polluted places, primarily in the third world.

Education and Training

- M.S., Water Resources Management, University of Wisconsin, Madison, Wisconsin; 1978
- B.S., Geology, Boston University, Boston, Massachusetts; 1975
- OSHA 1910.120, 40-hour training and Annual Refreshers

Professional History

- 1992 - Present President and Founder, Quality Environmental Solutions, Inc.
- 1992 Field Services Program Office Manager, IT Corporation, Washington, DC
- 1990 - 1992 Corporate Sales Director, IT Corporation, Washington, DC
- 1988 - 1990 General Manager, IT Environmental Services, Edison, NJ
- 1987 - 1988 National Sales Manager, Groundwater Technology, Inc., Norwood, MA
- 1986 – 1987 District Manager, Groundwater Technology, Inc., Norwood, MA
- 1983 - 1986 Project Manager, Groundwater Technology, Norwood, MA
- 1981 - 1983 Hydrogeologist/Project Manager, ERT, Inc., Concord, MA
- 1979 – 1981 Hydrogeologist/Waste Management Specialist, HMM Associates, Needham, MA
- 1978 – 1979 Hydrogeologist, RMT, Inc., Madison, WI

Representative Experience

- Founder of company that provides environmental services to commercial customers. Responsible for all aspects of the business with the overall goal of cost consciousness, responsiveness to customer needs, quality, and providing a common sense approach to customer's environmental issues. Responsible for technical evaluation of all Company projects.

- Director of the IT National Groundwater Field Services Program Office. The program office was responsible for developing and implementing a delivery system which best met client needs. Responsible for technical and project management training, marketing, development of quality measurement systems, and product standardization to assure nationwide consistency and cost effectiveness. Also Technical Leader for the IT Technology Exchange Program and a presenter for IT's Ground Water Technology Course.

- Manager of national sales and marketing activities for clients with storage tank related environmental problems with primary focus on major oil and transportation-related companies. Responsible for ensuring that client needs are satisfied through the efficient, responsive, and cost-effective execution of projects.

- Responsible for the overall technical, administrative and financial operation of the northern region of IT Environmental Services. Manager of 150 staff in five offices with annual revenues of $20 million. Responsible for start-up operations in Maryland and Pennsylvania. Recipient of an IT Division Quality Award for performance in this position.

- Manager of thirty-five person sales force with overall national responsibilities. Involved in the operational and technical training of sales staff.

- Manager of approximately 100 technical and administrative staff providing ground-water assessment and remediation services throughout New England. Responsible for start-up, staffing and development of new office in Connecticut.

- Project Manager for hydrogeologic assessments and remediation system design, permitting and implementation. Primary projects involved assessment and remediation of contamination caused by leaking underground storage tanks and industrial releases.

- Manager of water resource and waste management related evaluations and permit studies, including site assessments, permit evaluations modeling studies, permit negotiations, and measurement and field programs.

- Provided technical support on waste management and water resource evaluations. Designated as lead staff person on regulatory interpretation and compliance activities.

- Participated in planning, design, and implementation of hydrogeologic studies related to industrial and municipal landfill development and assessment projects.

Registrations/Certifications

- Certified Groundwater Professional No. 161 (NGWA)
- Certified Professional Geological Scientist No. 6782 (AIPG)

Professional Affiliations

- American Institute of Professional Geologists (AIPG)
- National Ground Water Association (NGWA)
- Blacksmith Institute Technical Advisory Board (www.blacksmithinstitute.org)

Publications and Presentations

- "Ground-Water Remediation in Developing Countries," Presentation at the NGWA Ground-Water Summit, Albuquerque, New Mexico – April 2007.

- "Ethanol Replacement of Fuel Oxygenates: Inconsistency of Public Policy and Science," Presentation at the NGWA Ground-Water Summit, Albuquerque, New Mexico – April 2007.

- "EPA All Appropriate Inquiry and Maryland's Voluntary Cleanup Program," Presentation at the NGWA Ground Water and Environmental Law Conference, Baltimore, Maryland – July 2005.

- "Consequences of Enforcement Focus Shift from Leak Response to Prevention in Maryland," Poster Session at the NGWA Petroleum Hydrocarbons and Organic Chemicals in Ground Water Conference, Atlanta, GA – November 2002.

- "How MTBE Changed the Maryland Regulatory Program," Presentation at the NGWA Petroleum Hydrocarbons and Organic Chemicals in Ground Water Conference, Atlanta, GA – November 2002.

- "Consequences of Enforcement Focus Shift from Leak Response to Prevention in Maryland," Poster Session at the NGWA Northeast Ground Water Issues Conference, Burlington, VT – October 2002.

- "Consequences of Enforcement Focus Shift from Leak Response to Prevention in Maryland," Presentation at the NGWA Litigation, Ethics and Public Awareness Conference, Washington, DC – August 2002.

- "How MTBE Changed the Maryland Regulatory Program," Presentation at the NGWA Litigation, Ethics and Public Awareness Conference, Washington, DC – August 2002.

- "Navigating through Maryland's Regulatory Transition," Presentation at the NGWA Litigation, Ethics and Public Awareness Conference, Washington, DC – August 2002.

- "MTBE – The Maryland Experience," Presentation at the NGWA National Focus Conference on MTBE in Ground Water, Baltimore, Maryland - June 2001.

- Jones, D.E., 1991, "Strategic Technical Issues Related to the UST Market in the 90's," IT Corporation Technology Exchange Symposium Proceedings, Phoenix, Arizona - April 1991.

- Gailey, R.M. and D.E. Jones, 1987, "The Use of Sediment Permeability Variations in the Performance of Petroleum Recovery from Glacial Sediments," Focus on Eastern Regional Ground Water Issues, Burlington, Vermont.

- Haven, E.L. and D.E. Jones, 1985, "Petroleum Recovery in a Tidal Environment," Fifth National Symposium and Exposition on Aquifer Restoration, Columbus, Ohio.

- "Saving Time and Money on Environmental Data Collection and Analysis," Workshop at the NGWA Eighth National Outdoor Action Conference, Minneapolis, Minnesota - May, 1994.
- "Design of a DNAPL Recovery System for an Aquifer Containing Chlorinated Organic Compounds," HAZMACON, Anaheim, California - April 1988.
- "Current Treatment Technologies for Site Remediation," Maine Section ASCE - March 1988.
- "Assessment of Ground Water Contamination by Hydrocarbons," New England Fuel Institute - June 1987.

Litigation Experience

- Completion of a comprehensive site assessment and remedial design for a significant dry cleaning solvent release. The current owner purchased the property with full knowledge of the release with active participation in the Maryland Voluntary Cleanup Program by multiple parties. In addition to litigation support, evidence of property management oversight was discovered which resulted in the CERCLA portion of the case against the QES customer being dismissed in federal court. The parties eventually settled the state court law suit.

- Provided defendant litigation support for a civil trial where the plaintiff charged that negligence resulted in a multi-property fuel spill. Qualified as an expert in The Harford County, Maryland trial (Civil Case 12-C-05-81 CN). The case was dismissed by the judge due to QES evidence presented and a lack of support of the plaintiff argument.

- Provided expert witness testimony at an Ohio EPA administrative hearing regarding subsurface conditions and migration pathways of a radiological release at a medical equipment manufacturing facility.

- QES was initially hired by a citizen's group to provide assessment oversight of an oil company release that migrated from a Maryland gasoline station beneath numerous residential properties in the District of Columbia. Defensible data collection and litigation support services were later transferred to a consortium of several law firms.

- QES provided hydrogeologic and litigation support services for a resident group law suit against a municipality whose water supply wells adversely impacted the resident's domestic wells. The municipality was forced to rectify the situation.

- QES provided technical and litigation support services in support of a multi-party lawsuit over responsibility of releases from service area fueling systems along the New Jersey Turnpike. The case was eventually settled out of court.

- QES provided remediation oversight for a subsurface residential petroleum release. Future litigation is expected.

EXHIBITS OF
OPC WITNESS
DONALD E. JONES

EXHIBIT OPC (J)-1

Attachment B

Exhibit OPC (J)-1
Office of People's Counsel for the District of Columbia
Proposed PEPCO Northeast Substation
Formal Case No. 1053

Correspondence and Documents Reviewed for Testimony of Donald E. Jones

Date	Contents	Environmental Relevance
07/01/03	URS Draft Phase I Environmental Site Assessment	Incomplete draft report
07/29/03	URS Limited Phase II Environmental Investigation	Incomplete letter report describing soil and ground-water sampling and analyses
02/18/04	Northeast Substation List of Permits Required	Large Tract Review and Building Permit
09/08/04	PEPCO Criteria for Selecting Building Site	
03/09/05	PEPCO Letter Regarding Requested EMF Supplement to Large Tract Review	
06/05/05	Holland + Knight Large Tract Review Comments	Regarding substation location on tract
07/08/05	DC Office of Planning Report on Large Tract Review	Application approval with conditions
09/20/05	PEPCO NOI for Storm-Water Discharges	Application for NPDES General Permit for construction activities
11/22/05	Exponent Pre-Construction Measurements and Calculations of Magnetic Fields	
12/12/06	PEPCO Rate Increase Application	Gausman testimony (section E) - no environmental issues discussed
03/08/07	DCPSC Order & Report on Pre-Hearing Conference (Order No. 14232)	Designated Issue 3.c.iv. (adequate consideration of environmental impact)
03/22/07	PEPCO Supplemental Testimony	Wm Gausman, Page 24 line 15 - page 28 line 6
04/01/07	List of Construction Permits Issued by DC Agencies	
04/04/07	OPCDC Data Request No. 4	Environmental issues addressed in 4-155 to 4-171
05/01/07	Pepco response to OPCDC Data Request No.4	Response to 4-155 - identification of documents utilized regarding environmental impacts
05/04/07	DCPSC Order No. 14285 Regarding Testimony	
05/04/07	PEPCO Update to 05/01/07 Response to Data Request 4-155	Included copies of building permits
		PEPCO Follow-Up Response:
		-- Draft Phase I is all that exists
		-- Limited Phase II is all that exists

AFFIDAVIT

STATE OF MARYLAND }
ANNE ARUNDEL COUNTY } SS:

DONALD E. JONES, being duly sworn deposes and states that the foregoing is his testimony, that he read the same and is familiar with the contents thereof and that the matters and facts set forth therein are true and correct to the best of his knowledge, information and belief.

DONALD E. JONES

Subscribed and sworn before me this
25th day if May 2007.

Notary Public
My Commission Expires 5/01/2009

DIRECT TESTIMONY OF
OPC WITNESS
RICHARD LOCKLEY

EXHIBIT OPC (K)

BEFORE
THE DISTRICT OF COLUMBIA
PUBLIC SERVICE COMMISSION

In the Matter of	**)**	
	)	
The Application of the	**)**	**Formal Case No. 1053**
Potomac Electric Power Company	**)**	
For Authority to Increase	**)**	
Existing Retail Rates and Charges	**)**	
For Electric Distribution Service	**)**	

DIRECT TESTIMONY AND EXHIBITS
OF
RICHARD LOCKLEY
EXHIBIT OPC (K)

ON BEHALF OF
THE OFFICE OF THE PEOPLE'S COUNSEL

MAY 31, 2007

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BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

In the Matter of	)	
	)	
The Application of Potomac Electric	)	Formal Case No. 1053
Power Company For An Increase In Its	)	
Retail Rates For the Sale of Electric Energy	)	

DIRECT TESTIMONY OF RICHARD LOCKLEY

STATEMENT OF QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard Lockley and my business address is 5505 Connecticut Ave NW, #212, Washington, DC 20015.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I completed my MBA in Finance from The University of Chicago in 1997. My concentrations were finance, international business, and accounting. I earned my Bachelor of Science degree in Business Administration from West Chester University in 1983. Currently, I am Managing Partner of Phillip Partners, LLC, a small consulting firm that I started last year. Phillip Partners provides strategic and tactical advice in the areas of finance, business analysis, workflow analysis and redesign, benchmarking, and forecasting for small to mid-size business and government organizations. I am also a consultant with Jerome S. Paige and Associates, a professional services firm that specializes in the areas of business and economic analysis, organizational change, and forensic economics. My experiences include leading a team to create and implement the organizational structure, staffing levels, transition plans, policies & procedures for a newly created autonomous agency, Waste Management Authority, for the Government of the U.S. Virgin Islands. I have consulted on the review and assessment of internal controls of the District of Columbia's Capital Improvement Program. I have consulted on the restructuring and formation of a shared service center of the accounts payable, accounts receivable, and payroll business processes within the District of Columbia's Chief Financial Office. I have structured creative financing solutions for public and private corporations with market values of $300 million to $6 billion as a Structuring Specialist with Bank of America's investment banking division.

Q. HAVE YOU ATTACHED A SUMMARY OF YOUR QUALIFICATIONS AND EXPERIENCE TO THIS TESTIMONY?

A. Yes. Appendix A provides a summary of my qualifications and experience.

SCOPE AND PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address issue 16(c):

Is Pepco's proposed increase in the reconnection fee from $35 to $100 reasonable?

ISSUE 16 (C) – RECONNECTION FEES

Q. HOW DID YOU ANALYZE PEPCO'S PROPOSED INCREASE IN THE RECONNECTION FEE?

A. I read the testimony and examined the exhibits of PEPCO's witness, J. Reed Bumgarner, Pricing Manager, PEPCO Holdings, Inc. Additionally, I reviewed PEPCO's responses to Office of People's Counsel Data Request 2 and 4 as it relates to the proposed increase in reconnection fees.

Q. PLEASE SUMMARIZE YOUR FINDINGS.

A. In my opinion, PEPCO's proposed increase for reconnection fees is based on flawed and inconsistent data. First, the Cost of Field Collection Visits should not be included as these costs do not relate to the function of reconnection. Second, the Call Center costs have not been formulated to reasonably reflect costs related to District of Columbia ratepayers. Moreover, these call center costs include costs unrelated to the function of reconnecting District of Columbia ratepayers. Third, the estimated Dispatch costs include data that has not been formulated to reflect cost related to District of Columbia ratepayers. Last, the use of meter installers to perform reconnections results in an unreasonable cost.

Q. PLEASE SUMMARIZE PEPCO'S PROPOSAL.

A. PEPCO is proposing to increase the Reconnect fee from its current level of $35 per occurrence to a full cost-based level of $100 per occurrence. Additionally, according to PEPCO Witness Bumgarner, the proposed fee is designed to provide an incentive for customers to remain current on their electric bills. (See, Pepco (H), p. 21, lns. 17-20). PEPCO's estimated costs for reconnections total $106.25 per visit which is comprised of the following costs: field collection visits ($32.67); reconnection visit ($68.17); costs per Call Center call ($4.41); and the estimated dispatch cost is ($1.00) (See, PEPCO (H), Direct Exhibit H-6).

Q. WHAT CRITERIA DID YOU USE TO DETERMINE THE FAIRNESS OF PEPCO'S PROPOSED RECONNECTION FEE REVENUE REQUIREMENT?

A. First, I looked for consistency in how the calculations were used across all the reports related to the reconnection fee. Second, I looked at the data consistency across all reports to determine if the same data variables were used in a consistent manner. Third, I looked for relevancy of the data used as applied to the calculation.

Q. WHAT ARE YOUR CONCERNS REGARDING THE COSTS FOR THE FIELD COLLECTION VISIT?

A. My Concern with the Field Collection Visits costs is that the functions associated with this cost have no relationship to the function of reconnection. According to PEPCO Witness Bumgarner, a field collection visit entails a field collection specialist being sent to a customer's premise when the customer does not pay his bill in accordance with the terms and conditions of service as specified in the tariff. There are three results that can happen from a field visit by a field collector: 1) Collection of payment from the customer at the premise; 2) disconnection of electrical service; or 3) neither collection or disconnect, for example if the meter is inaccessible. (See, PEPCO Response to OPC DR 4-229) Because the consumer's electric service is still connected during the filed collection visit, I submit that neither of these functions have a nexus to the function of reconnection.

Q. SHOULD THE FIELD COLLECTION VISIT COSTS BE INCLUDED AS PART OF THE COSTS ASSOCIATED WITH THE RECONNECTION FEE?

A. No. At the time of the Field Collection Visit, the customer's service is still connected. Therefore, neither of the three aforementioned results involves the function of reconnecting a consumer. Thus, no part of the Field Collection Visit cost should be included in the proposed reconnection fee as it has nothing to do with the function of reconnecting electrical service.

Q. WHAT ARE YOUR CONCERNS WITH THE DISPATCH COSTS?

A. My concern with the dispatch cost is that it includes cost data from outside of the District of Columbia. (See, PEPCO's Response to OPC DR 2-171Attachment C)

Q. DOES THE $1 DISPATCH COSTS REFLECT THE DISTRICT OF COLUMBIA'S ACTUAL USAGE?

A. No. According to PEPCO witness Bumgarner, the $1 cost figure is an estimate of cost of dispatching for reconnecting and disconnecting service. (See, Pepco's Response to OPC DR 4-231 and OPC Follow-up DR 4-231) However, in the same response, Pepco Witness Bumgarner states that the actual cost for reconnect dispatch is $10.21 not $1.00. (See, Id.) A review of the workpapers supporting the $10.21 cost for reconnect dispatch revealed that the revised cost of $10.21 includes Maryland cost data. (See, Pepco's Response to OPC DR 2-171 Attachment C)

Q. DID PEPCO USE ANY FORMULA TO ALLOCATE THE PORTION OF THE COST DATA ATTRIBUTABLE TO THE DISTRICT OF COLUMBIA?

A. No. Pepco did not use any cost allocation process or formula to determine the District of Columbia's allocable portion for the dispatch cost.

Q. **IN YOUR OPINION, IS IT REASONABLE FOR PEPCO TO USE COST DATA THAT INCLUDES MARYLAND COSTS TO ESTIMATE RECONNECTION CHARGES FOR DISTRICT OF COLUMBIA CONSUMERS?**

A. No. In my opinion, because PEPCO failed to use any formula or methodology to allocate the District of Columbia's cost for the function of dispatch services, the $10.21 proposed cost for this service is an unreasonable cost figure to apply to District of Columbia ratepayers because it does not fairly and accurately reflect the cost attributable to District ratepayers for this function of reconnecting electric service. My opinion is based upon Commission Order No. 13063, para. 47, which requires utility companies to use a formula to separate out the portion of the utility company's out-of-District data to help separate out the portion of the utility company's expenses which pertain to service District ratepayers. Because PEPCO failed to do this, the proposed $10.21 for dispatch cost should not be allowed.

Q. WHAT IS YOUR CONCERN WITH THE CALL CENTER COSTS?

A. I have two concerns with PEPCO's Call Center costs. One, the Call Center cost includes cost data from outside of the District of Columbia. Two, the Call Center costs includes cost data for functions wholly unrelated to the function of reconnecting electric consumers.

Q. IN YOUR OPINION, DOES PEPCO'S CALL CENTER COSTS REPRESENT THE DISTRICT OF COLUMBIA'S ACTUAL USAGE?

A. No. According to PEPCO witness Bumgarner, the $4.41 is PEPCO's allocation costs per call for the entire Call Center No. 4315 that covers calls received from PEPCO's customers in Maryland and the District of Columbia. (See, PEPCO's Response to OPC Follow-up Data Request 4-227) Moreover, this proposed cost includes the cost of calls for reconnections, billing, repair service, disconnection, etc. (See, PEPCO's Response to OPC DR 2-171Attachment B)

Q. DOES PEPCO USE ANY FORMULA OR METHODOLOGY TO SEPARATE OUT THE COST OF NON-DISTRICT OF COLUMBIA COSTS OR CALLS NOT RELATED TO RECONNECTION?

A. No. Again, PEPCO failed to use any formula to separate out the cost data for calls received from the Company's Maryland customers and made no attempt to separate out any of the cost data not related to the function of reconnection from either the District of Columbia or Maryland. Therefore, PEPCO's $4.41 cost per call should not be included in the proposed cost for reconnection because it does not accurately reflect the cost for the function of reconnection for District ratepayers.

Q. DOES THE ACTUAL JUNE 2006 YTD COST PER CALL MATCH THE CALCULATION PERFORMED BY PEPCO?

A. No. In calculating the June 2006 YTD Cost Per Call, PEPCO only used data for the months of January 2006 thru May 2006 excluding the month of June 2006. (See, PEPCO's Response to OPC DR 2-171 Attachment B) This exclusion of the June 2000 data highlights the inaccuracy of PEPCO's calculation of this cost. Therefore, in addition to the other flaws mentioned concerning the calculation of the Cost per Call cost, the Commission should not include this cost in calculating the reconnection charge.

Q. WHAT ARE YOUR CONCERNS REGARDING THE ACTUAL COST FOR THE RECONNECTION VISIT?

A. My concern with the actual cost for the reconnection visit, $68.17, is that it is unreasonably high and includes costs not related to reconnecting customers. A majority of the actual cost for the reconnection visit is the cost for the meter installers who perform the function of reconnecting electric service.

Q. ARE "METER INSTALLERS" THE MOST EFFICIENT USE OF RESOURCES FOR RECONNECTION?

A. No. According to PEPCO, the cost for Meter Installers is $1,812,303 for the test period, which represents 89% of the $68.17 cost of the actual reconnect visit (See, PEPCO's Response to OPC DR 2-171 Attachment A). This costs reflects PEPCO's cost for a meter installer to install a meter not reconnect electric service. The assumption used is that the same level of skills and type of job are needed to reconnect electric service as to install a meter. In my opinion, this is a cost that PEPCO can reduce by outsourcing or changing internal job assignments to personnel who have a lower cost basis and are qualified to reconnect electric service.

Q. WHAT IS YOUR CONCLUSION REGARDING PEPCO'S JUSTIFICATION FOR ITS PROPOSED RECONNECTION FEE INCREASE?

A. I conclude that PEPCO's proposed reconnection fee increase is fatally flawed by 1) the use of data that should not be included for the function of reconnections and 2) PEPCO's failure to use a formula to separate out non District of Columbia data.

Q. IN LIGHT OF THE FLAWS IN PEPCO'S PROPOSED INCREASE IN RECONNECTION FEES, WHAT DO YOU RECOMMEND THE COMMISSION DO CONCERNING THE ISSUE OF RECONNECTION FEES?

A. Because of the flaws in Pepco's cost basis for the increase in reconnection fees, I propose that the Commission disregard Pepco's reconnection fee proposal altogether. However, if the Commission approves any portion of Pepco's costs, any increase in reconnection fees should be consistent with the Commission's precedent of gradualism articulated in Commission Order No. 12986, para. 381-382. In that case, the Commission only approved a slight increase in general service provisions rates ("GSP"), one of which was reconnection fees, stating that it was adopting a "gradual approach towards "full cost" general service provision rates, because of our concerns about gradualism, the need to protect consumers against sudden increases in price sensitive GSP tariffs, and the imperfections in [utility company] GSP cost studies."

Q. DOES THIS CONCLUDE YOUR PREFILED TESTIMONY?

A. Yes it does.

Appendix A

Professional Overview

Mr Lockley, a seasoned professional with a 20 year proven track record, is managing partner of Phillip Partners LLC, which provides strategic and tactical advice in the areas of finance, forecasting, benchmarking, workflow analysis and redesign, strategic planning, research analysis, policies and procedures, and valuations to small and mid-size businesses and government organizations.

Professional Accomplishments

- Led a team of 18 to create and implement the organizational structure, staffing levels, human resource policies & procedures, transition plans, procurement policies & procedures for a newly created autonomous agency for the Government of the U.S. Virgin Islands
- Led an experienced team of financial and programmatic professionals to **review and assess the internal controls** of the District of Columbia's $3.4 billion Capital Improvement Program.
- **Restructured the accounts payable, accounts receivable, and payroll business processes** to form shared services centers for the DC's Chief Financial Officer.
- Assessed and recommended strategies to improve the billing and collections processes for the Department of Consumer and Regulatory Affairs.
- P&L responsibility for managed projects ranging from $25,000 to $1 million.
- **Recommended and implemented business process reengineering strategies** to improve the District of Columbia's flow of information that included managing the development of new software to track and monitor capital spending.
- **Structured creative debt financing solutions** for public and private corporations with market values of $300MM - $6 billion.
- Developed annual and quarterly financial analyses of clients including sensitivity analysis of various short-term, long-term, and downside scenarios.
- Participated in credit agreement negotiations and the setting of contractual terms.
- **Provided investment strategy advice to middle market companies** on mergers and acquisitions, equity investments, corporate and real estate transactions, and creative debt financing solutions.
- Identified and **developed new business opportunities**, which generated approximately $500,000 in fee revenue.
- Developed client relationship strategies that seized opportunities to grow relationships.
- **Determined the valuation of public and private companies** through leveraged modeling, comparable company analysis, precedent transaction analysis and discounted cashflow analysis.
- Developed in-depth review of clients, which included client strategy, current and projected financial structure analysis, and analysis of market trends.
- Develop the U.S. Gatorade Division forecast, which generated over one billion dollars in sales.
- **Analyzed volume trends and drivers to explain risks** involved with Quaker Oats Company product lines.
- Reported volume rational in support of quarterly business plans to executive management.
- Streamlined the forecasting process by leveraging technology and eliminating non-value-added work.

Professional Profile

Phillip Partners LLC – Managing Partner
Jerome S. Paige and Associates – Consultant
African Ancestry, Inc. – Director, Business Analysis & Development
Government of the U.S. Virgin Islands – Consultant – Senior Manager, Business Process Redesign
District of Columbia – Consultant – Senior Manager, Business Process Redesign & Analysis
Bank of America – Structuring Specialist, Investment Banking
ABN Amro Bank – Corporate Finance
Quaker Oats Company – Manager, Business Analysis
CNA Insurance Companies – Technical Analyst
Time, Inc. – Systems Analyst

Professional Credentials

Master of Business Administration – University of Chicago, Graduate School of Business
Bachelors of Science, Business Administration – West Chester University

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RICHARD LOCKLEY, being duly sworn deposes and states that the foregoing is his testimony, that he read the same and is familiar with the contents thereof and that the matters and facts set forth therein are true and correct to the best of his knowledge, information and belief.

RICHARD LOCKLEY

Subscribed and sworn before me this
25th day of May 2007.

Linda R. Lee
Notary Public

LINDA R. LEE
District of Columbia
My Commission Expires
March 14, 2011