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An Exelon Company

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May 30, 2019

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street, N.W.
Suite 800
Washington, DC 20005

Re: <u>Formal Case No. 1156</u>

Dear Ms. Westbrook-Sedgwick:

Pursuant to the applicable rules of the Public Service Commission of the District of Columbia, Potomac Electric Power Company, hereby submits its Application for Authority to Implement a Multiyear Rate Plan for Electric Distribution Services in the District of Columbia, along with supporting testimony and exhibits.

Please feel free to contact me if you have any questions regarding this matter.

Sincerely,

Wendy E. Stark

Wendy E. Stark

WES/dmb

Enclosures

cc: Sandra Mattavous-Frye, Office of the People's Counsel

BEFORE THE
PUBLIC SERVICE COMMISSION
OF THE DISTRICT OF COLUMBIA

IN THE MATTER OF

THE APPLICATION OF POTOMAC ELECTRIC POWER COMPANY FOR AUTHORITY TO IMPLEMENT A MULTIYEAR RATE PLAN FOR ELECTRIC DISTRIBUTION SERVICE IN THE DISTRICT OF COLUMBIA	))))))	Formal Case No. 1156

APPLICATION OF
POTOMAC ELECTRIC POWER COMPANY
FOR AUTHORITY TO IMPLEMENT A MULTIYEAR
RATE PLAN FOR ELECTRIC DISTRIBUTION SERVICE

Pursuant to Sections 34-901 and 34-1504(d)(1)[1] of the District of Columbia Official Code ("D.C. Code"), Order No. 18846,[2] and Rules 101, 104, 200-207 and 211 of the Rules of Practice and Procedure of the District of Columbia Public Service Commission,[3] Potomac Electric Power Company ("Pepco" or the "Company") hereby submits its application for approval to increase rates through the implementation of a Multiyear Rate Plan ("MRP") for its electric distribution service in the District of Columbia ("Application") for the years 2020 through 2022. As set forth in more detail in this Application and accompanying testimonies,

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1 D.C. Code §34-1504(d)(1) (The Commission has the authority to adopt alternative forms of regulation that (i) protect consumers; (ii) ensure quality, availability and reliability of regulated electric services, and (iii) are in the interests of the public, including the Company's shareholders.).

2 *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. 1139 Order No. 18846 at ¶¶593-595 (July 25, 2017).

3 15 D.C.M.R. §§ 101, 104, 200-207 and 211 (1998).

if approved in full, the three-year MRP proposes to adjust rates in three steps, with the first adjustment occurring upon issuance of the order in this proceeding (proposed in this Application to be May 1, 2020), the second adjustment occurring on January 1, 2021, and the final adjustment occurring on January 1, 2022. A residential Standard Offer Service ("SOS") customer using an average of 692 kWh per month[4] will see a total monthly bill increase on average for each year of the MRP as shown in Table 1 below:

Table 1: Residential Bill Impacts

Date	Monthly Distribution Increase	Overall Net Increase	% Bill Increase
May 1, 2020	$8.57	$6.09	7.1%
Jan 1, 2021	$3.69	$3.86	4.2%
Jan 1, 2022	$3.19	$3.52	3.7%

In support of this Application, Pepco shows as follows:

I. The Applicant

Pepco is a wholly-owned subsidiary of Pepco Holdings LLC, a Delaware limited liability company, having its principal place of business at 701 Ninth Street, N.W., Washington, D.C. 20068. Pepco Holdings LLC is an indirect, wholly-owned subsidiary of Exelon Corporation, a Pennsylvania corporation. Pepco provides retail electric distribution service in the District of Columbia as well as major portions of Montgomery and Prince George's Counties, Maryland.

Pepco is subject to regulation by the Public Service Commission of the District of Columbia ("Commission") with respect to its public utility operations within the District of Columbia, pursuant to the *District of Columbia Public Utilities Act*, as amended, D.C. Code §§ 34-101 *et seq.*

[4] As indicated in the testimony of Company Witness Blazunas, the average usage level was derived by dividing total actual kWh sales by total customers for the Traditional Test Period.

II. Service

All correspondence and communications concerning this Application should be sent to the following persons at the addresses specified:

Kim Hassan, Associate General Counsel
Andrea H. Harper, Assistant General Counsel
Dennis P. Jamouneau, Assistant General Counsel
Potomac Electric Power Company
701 Ninth Street, N.W.
Washington, DC 20068
Kim.hassan@exeloncorp.com
ahharper@pepcoholdings.com
djamouneau@pepcoholdings.com

Brian Doherty, Manager – Regulatory Affairs, District of Columbia
Rhodena Jefferson, Sr. Analyst—Regulatory Affairs, District of Columbia
Potomac Electric Power Company
701 Ninth Street, N.W.
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bdoherty@pepcoholdings.com
Rhodena.jefferson@exeloncorp.com

III. The District of Columbia Is Implementing Transformative Energy Policies Changes

The District of Columbia is leading the nation in adopting progressive approaches to address climate action, clean energy and sustainability, as demonstrated by the August 2018 Department of Energy and the Environment's Clean Energy DC Plan and the landmark Clean Energy DC Omnibus Amendment Act (Clean Energy Act) which became law in March of this year.[5] Mayor Muriel Bowser also has appointed a Chief Resilience Officer to oversee the city's resilience strategy as part of its participation in the national 100 Resilient Cities effort.

As Company Witness Velazquez emphasizes, the Company is committed to working towards the efficient deployment of infrastructure that promotes the adoption of climate resilient

[5] D.C. Law 22-257.

guidelines, including more prevalent distributed energy resources, integration of transportation electrification and deployment of emerging technology, such as microgrids and battery storage.

The Clean Energy Act dramatically changes energy policies in the District of Columbia. For example, by 2032, 100% of electricity sold in the District of Columbia must come from renewable sources;[6] by 2041, the amount of solar energy deployed must be doubled,[7] and all public transportation and privately-owned fleet vehicles must be emission-free by 2045.[8] The Company is an essential and enthusiastic partner in helping the District to achieve these goals.

Coincident with these trends is recognition that the electric utility grid must evolve and become a platform that enables connection of various devices, wider use of generation and renewable resources, and the flow of energy in multiple directions. Such technologies require an ever-increasing emphasis on reliability, creation of a smarter, "self-healing" grid, and minimal system disruptions.

Pepco intends to be a fundamental and effective partner in helping to meet the policy goals of the District of Columbia, the Commission and our customers. This proceeding will help position the Company to better advance grid modernization, support connected communities, and better align the Company's plans with the District of Columbia's policy goals and evolving customer needs.

IV. Explanation of the Components of this Application

This filing incorporates two primary components. First, the Company is proposing a three-year plan that forecasts the expected capital investments and operating and maintenance costs for

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6 Clean Energy Act at §101(b)(1)(A).

7 *Id.* at §101(b)(1)(B).

8 *Id.* at §502.

2020 through 2022, assuming an effective date of May 1, 2020. The three-year MRP incorporates three rate adjustments, as well as annual reconciliations, to ensure that the Company is recovering costs that are prudently incurred and that produce the revenue required to maintain and operate its electric distribution business in the District of Columbia.

Second, since the Company's MRP represents a transition from a historic test period recovery to a future three-year test period, the Company includes a traditional test period compliance filing with 12-month test year that includes six months of actual 2018 costs and six months of projected 2019 costs. The traditional filing includes recovery of capital investments and operating and maintenance costs after the Company's last rate case filing (Formal Case No. 1150), which was based on a test period ended December 31, 2017.[9]

V. Explanation of the Benefits of a Multiyear Rate Plan

Pepco's proposed MRP for the years 2020-2022 is a fundamental component to enabling the change that consumers, the Commission, the District of Columbia, the Company, and other stakeholders desire and deserve. Authorizing Pepco to implement the proposed MRP introduces additional transparency with respect to Pepco's plans and cost projections, providing the Commission, stakeholders, and customers with a longer-term view of future capital and O&M investments before the utility makes those investments. The MRP will provide the necessary framework to allow the Company to make the necessary investments to enable greater customer optionality and allows Pepco to better align its system investments with the policy goals set by the District and the Commission. The introduction of performance incentive mechanisms ("PIMs") promotes Company performance in areas critical to successful modernization of the distribution

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9 *See,* Formal Case No. 1150, Order No. 19433 (Aug. 9, 2018).

system: reliability and resilience, customer service, and efficient integration of distributed energy resources.

The MRP framework better aligns rates that customers pay with costs that the Company incurs. Further, the inclusion of an annual reconciliation mechanism will provide transparent information to the Commission and stakeholders that will allow for a review of cost variances to ensure that rates appropriately reflect the costs needed to operate the system. The forward-looking rates in the MRP lead to more gradual and deterministic rate increases for customers and enables them to make more informed decisions about potential investments in energy efficiency, distributed energy resources and/or other technologies or options.

The MRP proposed by Pepco will also drive administrative efficiencies for the Commission, the Company, and stakeholders by reducing the frequency of rate case filings by the Company. In addition to allowing Commission resources to be focused elsewhere, this will also lead to lower rate case expenses being included in costs of service over time.

VI. Explanation of the Need for a Rate Increase

Authorization of the requested rate increase through the proposed MRP will allow the Company to recover prior investments in its electric distribution infrastructure, other costs necessary to operate the system, as well as those investments and costs that will be made in the near-term. A rate increase is needed to enable the Company to continue to make significant investments in the electric distribution system, continue to improve reliability and customer service, modernize the distribution system through increased interconnection of distributed energy resources ("DER") and other advanced technologies, provide tools to assist customers in managing their energy usage, and advance the forward-focused policy goals of the District of Columbia on reliability, resiliency, clean energy integration and addressing climate change.

The Company has made, and has plans to continue to make, significant investments in the electric distribution system to maintain and improve reliability gains, continue to improve customer satisfaction, interconnect DER, and align to the District's environmental policy goals.[10] However, as Company Witness McGowan explains, the Company's existing electric distribution rates do not allow Pepco to fully recover the cost of providing electric distribution to its District of Columbia customers.

Furthermore, as customers use the grid differently by interconnecting DER, feeding excess generation back to the grid, and changing load patterns by charging electric vehicles at night, Pepco must make the modifications to the grid necessary to facilitate these changes. Pepco is excited to support the District in meeting its forward-looking policy goals and keeping pace with the fast-changing energy environment in the District of Columbia. The proposed MRP marries the traditional principles of cost of service rate design with the District's forward-looking policies, incentivizes the Company to meet the customer's needs in the face of the changing energy landscape through the proposed PIMs, and decreases the frequency, administrative burden, and costs associated with traditional rate cases. Pepco requires the proposed rate increases that will provide the Company a reasonable opportunity to earn a fair return for its District of Columbia operations.

Moreover, as Company Witness McGowan explains, the Company's proposal will allow Pepco to Maintain its investment-grade credit ratings which is vital to the financial health of Pepco and is critical to its ability to access capital markets for financing essential capital projects on

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[10] As Company Witness Clark testifies, the Company is projected to spend in excess of $600 million over the 2018-2019 time period and more than $950 million during the term of the MRP (2020-2022) on upgrades and improvements to Pepco's distribution system.

reasonable terms. Pepco's customers and its investors benefit from a financially strong utility as it enables the Company to attract capital on reasonable terms.

VII. Pepco's Traditional Base Rate Case Compliance Filing

In compliance with Order No. 18846, this filing—and its supporting testimonies—also includes all elements of a traditional test year filing.[11] This traditional test period compliance filing consists of a twelve-month test period with six months of actual data (July 1, 2018 to December 31, 2018) and six months of projected data (January 1, 2019 through June 30, 2019).[12] If the MRP is not authorized in this case and the traditional test period compliance filing is approved in full, a residential SOS customer using an average of 692 kWh per month will see a total monthly bill increase as shown in Table 2 below:

Table 2: Residential Bill Impacts

	Monthly Distribution Increase	Overall Net Increase	% Bill Increase
Traditional Test Year	$9.55	$6.65	7.8%

VII. Compliance with Commission Rules and Directives

Section 104.1(g) of the Commission's Rules of Practice and Procedure requires that the applicant indicate whether the proceeding should be considered a "rate case" or an "other investigation" for purposes of D.C. Code § 34-912. This proceeding should be considered a "rate case" for purposes of that D.C. Code section.

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[11] Order No. 18846 at ¶594.

[12] The specific elements of the traditional rate case compliance filing are found in the following Pepco Exhibits: PEPCO (D): Ziminsky Direct; PEPCO (E): Schafer Direct; PEPCO (F): Blazunas Direct; PEPCO (G): Hevert Direct; PEPCO (H): Giese Direct; PEPCO (I): Clark Direct; PEPCO (K): Sanford Direct. Several of these witnesses also support the MRP.

In Order No. 18846, the Commission permitted Pepco to include in a future rate case a request for a fully forecasted test year or multiyear rate proposal. The Company was also required, however, to submit with such a filing a traditional test year filing, subject to four enumerated conditions, described below. Pepco's compliance with these directives is indicated after each enumerated condition:[13]

(1) There must be a baseline revenue and cost evaluation which is equivalent to a historic test year;[14]

- *See* PEPCO (D): Ziminsky Direct.

(2) Pepco must explain how to escalate or trend a myriad of revenues and expenses;[15]

- *See* PEPCO (C): Wolverton Direct; PEPCO (L) Barnett Direct; PEPCO (M) Sullivan Direct; PEPCO (N) Ortega Direct; PEPCO (O) Fisher Direct; PEPCO (P) Maxwell Direct; PEPCO (Q). Poncia Direct; and PEPCO (R) Calabrese Direct.

(3) Additional time must be allowed for the first examination of the new paradigm []; and[16]

- *See* attached proposed procedural schedule and Application, Section IX.

(4) Pepco needs to provide a mechanism which allows parties to reconcile any forecasted components to subsequent actuals for the same test year.[17]

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13 Order No. 18846 at ¶594.

14 *Id.*

15 *Id.*

16 *Id.*

17 *Id.*

- *See* PEPCO (C): Wolverton Direct.

The Commission also commented that its focus in considering any alternative mechanism will include a review of the benefits that accrue to customers, to include PIMs, as opposed to solely focusing on the utility.[18]

- *See* PEPCO (A): Velazquez Direct and PEPCO (B): McGowan Direct, and Sections III and IV of this Application; *see also* PEPCO (C): Wolverton Direct; PEPCO (I): Clark Direct and PEPCO (Q) Poncia Direct.

Statements setting forth the requirements of Rules 200.1–200.3, 200.5 and 200.8-200.11 are contained in Appendix A. Pursuant to Rule 200.10, Pepco will submit the information described in Rules 201-207 and 211 within 21 days after the filing of this Application. At the same time, Pepco will submit the additional accounting information required in Merger Commitment 31.

Pursuant to D.C. Code § 34-912(a)(9)(A), Appendix B provides a statement of costs anticipated to be incurred in this proceeding.

This Application and supporting testimony and exhibits are in full compliance with each of the Commission's filing requirements and precedential directives, including the pre-filing requirements, as currently applicable, stemming from Formal Case Nos. 1103, 1116, and 1119, and 1139 (*See* PEPCO(A)-1 and PEPCO(A)-2, respectively).[19] However, in the event the Commission determines that Pepco has failed to conform in any respect to the

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[18] *Id.* at ¶¶594-595.

[19] The Company is not filing a proposed Issues List and requests that the Commission waive the requirement for an Issues List, consistent with the Commission's recent decision in Formal Case No. 1154, Order No. 19919 at ¶8 (May 3, 2019). *See also,* Formal Case No. 1150, Order 19263 at ¶12 (Commission declined to designate issues in the proceeding at that time).

filing requirements of its Rules or orders, Pepco respectfully requests, pursuant to Rules 146.1 and 200.11, a waiver of such filing requirements. Alternatively, Pepco respectfully requests a reasonable opportunity to supplement this Application with the required information.

VIII. List of Testimony Exhibits

Support for Pepco's request is provided by the prepared direct testimonies from various witnesses sponsoring specific subjects pertaining to the Company's operations, function, and/or activities. The table below lists the direct testimony and associated exhibits, subject matter of the testimony, and the sponsoring witness.

Table 1: Pepco Prepared Direct Testimony Exhibits and Sponsoring Witnesses

PEPCO EXH#	SUBJECT	WITNESS
A	Company Overview	David Velazquez
B	Policy Overview	Kevin M. McGowan
C to C-5	MRP Revenue Requirement and Ratemaking Adjustments, Earnings Sharing Mechanism, Annual Reconciliation Filing, Deferred Accounting, Jurisdictional Cost of Service	Tyler W. Wolverton
D to D-10	Revenue Requirement, Certain Ratemaking Adjustments, Test Year Selection, Capital Structure	Jay C. Ziminsky
E to E-5	Class Cost of Service	Lance Schafer
F to F-16	Rate Design, Bill Impacts	Peter Blazunas
G to G-10	Cost of Capital Expert	Robert B. Hevert
H to H-2	Accounting/Allocations	Julie E. Giese
I to I-3	Pepco DC Capital Program and Reliability (Construction Report), Operational and Policy Performance Incentive Mechanisms	Bryan L. Clark
J to J-1	Multiyear Rate Plan and Performance Based Ratemaking Expert	William Zarakas

PEPCO EXH#	SUBJECT	WITNESS
K to K-4	Environmental	Tammy Sanford
L to L-22	Long-Range Plan Process, Revenue and Sales Projections	Phillip S. Barnett
M to M-2	Electric Operations O&M	William "Bill" Sullivan
N to N-2	Technical Services O&M	Miguel A. Ortega
O to O-2	Transmission & Substation O&M	Sandra Fisher
P to P-2	Support Services O&M	Michael Maxwell
Q to Q-2	Customer Operations O&M, Operational Performance Incentive Mechanisms	Michael S. Poncia
R to R-2	IT O&M and IT Capital Plan	James Calabrese

IX. Proposed Procedural Schedule

Previously, the Commission has set forth a policy of deciding base rate proceedings within nine months of the filing of the application. *See,* Formal Case No. 929, Order No. 10295 (1993) ("It is the general policy of this Commission to make every reasonable effort to decide all base rate proceedings within nine months of the filing of the application commencing the case"); Formal Case No. 905, Order No. 9742 (1991). The length of time that passes before a final decision on the adequacy of current rates is an important issue for the Company and other stakeholders. Indeed, in two recent cases, Formal Case No. 1150 and Formal Case No. 1142, the Commission has appeared to desire a more streamlined approach to processing formal proceedings, including rate cases, which would decrease the typical time to render its orders.[20] The Commission recently issued a request for proposal to engage a consultant to assist it in revising the Commission's Rules

[20] *See In the Matter of the Merger of AltaGas, Ltd and WGL Holdings, Inc.*, Formal Case No. 1142, Order No. 19161 (Nov. 1, 2017); *see also, 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. 1150, Order No. 19263 at ¶8 (Feb. 2, 2018).

of Practice and Procedure as the Commission has determined they should be "revised to ensure that cases proceed as quickly and efficiently as possible without negatively impacting the parties' rights to a fair hearing with the goal of reducing the litigation costs ultimately passed on to District of Columbia ratepayers."[21]

The apparent desire to streamline and shorten the time for consideration of cases, however, must be balanced against the fact that the Company's proposed MRP, and the detail provided herein, will require additional time for the Commission and the parties to process such information, a fact also recognized in Order No. 18846.[22] Pepco has therefore proposed a procedural schedule that balances the move toward streamlining formal cases with the need to review the details of Pepco's proposed MRP and provides for a Commission decision more than nine months after filing.

Importantly, in order to provide detail regarding the background, reasoning, and structure of the MRP to parties, Pepco held four formal technical conferences between June 2018 and March 2019, which were well attended by typical rate case participants and other critical stakeholders. The Company's will also hold two technical conferences following the filing of this Application to address: 1) the Construction Report attached as an exhibit to the testimony of Company Witness Clark; and, 2) the Class Cost of Service Study ("CCOSS") model used by Company Witness Schaefer. The Commission Staff, OPC and all intervenors will be invited to attend these technical conferences at which Pepco will review the Construction Report and the CCOSS model and provide an opportunity for participants to ask questions. These technical conferences will provide

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21 Request for Proposals No. PSC-19-08 at 3 (March 15, 2019).

22 Formal Case No. 1139, Order No. 18846 at ¶594.

the Commission and parties a venue in which their questions can be addressed directly and will assist in streamlining any subsequent discovery.

Pepco respectfully requests that the Commission render a decision on the merits of the Company's MRP and other proposals so as to allow rates to go into effect no later than May 1, 2020. Appendix C sets forth a proposed procedural schedule that is consistent with this request.

X. Conclusion

WHEREFORE, Pepco respectfully requests that the Commission:

1. Approve the MRP requested in this Application, including the PIMs, the annual reconciliation filing process, the use of deferred accounting for qualifying exogenous events such as major storms and the re-opener;
2. Find the appended revised rate schedules for retail distribution service to be just and reasonable;
3. Permit the rate schedules to become effective at the earliest possible time and in any event no later than May 1, 2020; and,
4. Consider this Application, and grant all other relief requested herein.

Respectfully submitted,

POTOMAC ELECTRIC POWER COMPANY

By: Wendy E. Stark

Wendy E. Stark
Sr. VP, Legal & Regulatory Strategy and General Counsel

Wendy E. Stark, D.C. Bar No. 1011577
Kim Hassan, D.C. Bar No. 489367
Andrea H. Harper, D.C. Bar No. 483246
Dennis P. Jamouneau, D.C. Bar No. 983375
701 Ninth Street, N.W., 10th Floor
Washington, D.C. 20068

Counsel for Potomac Electric Power Company

Washington, D.C. 20068
May 30, 2019

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing Application of Potomac Electric Power Company has been served this 30th day of May, 2019, on:

Sandra Mattavous-Frye
People's Counsel
Office of the People's Counsel
1133 15th Street, N.W.
Suite 500
Washington, D.C. 20005

Wendy E. Stark
Sr. VP, Legal & Regulatory Strategy and General Counsel

APPENDIX A

FILING REQUIREMENTS FOR RATE CHANGES (15 D.C.M.R. § 200)

200.1 All rate change applications, other than tariff filings not affecting existing rates, shall include the following information:

(a) A statement of a historical test year and the basis for choosing this test year;

See PEPCO C and PEPCO D.

(b) A statement of a proposed test year and the basis for choosing this test year;

See PEPCO C and PEPCO D.

(c) A description of the nature and basis of the changes proposed;

See PEPCO C and PEPCO D.

(d) A listing of the tariff pages affected by the changes proposed;

See PEPCO F-8 and F-16.

(e) A listing of the existing rates and proposed rates for each service for which changes are being proposed;

See PEPCO F-8 and F-16.

(f) A full statement and description of any new or revised tariff rules and regulations;

See PEPCO F.

(g) A statement listing the jurisdictional operating revenues of the utility for the historical test year and the proposed test year;

See PEPCO C-1 and PEPCO D-3.

(h) A listing of the total number of jurisdictional customers or accounts served for the historical test year and the proposed test year;

See PEPCO C.

(i) A calculation of the number of jurisdictional customers or accounts in each customer classification whose bills will be affected or a calculation of the average effect of the proposed change on jurisdictional customers in each customer classification based upon data for the historical test year and the proposed test year; and

See PEPCO F.

(j) A calculation of the total proposed revenue change in dollars, by customer classification, projected on an annual basis.

See PEPCO F.

200.2 Whenever, in a rate change application, a party proposes to change the ratemaking principles adopted in its most recent rate case, the party shall also file with its § 200.1 filing a statement describing each proposed change in the ratemaking principles adopted by the Commission in the applicant's last general rate proceeding, showing the effect of each such change upon the applicant's request if no such changes were made.

See PEPCO C and PEPCO D.

200.3 Any rate change application that proposes to increase a utility's jurisdictional operating revenues by more than one percent (1%) when projected on an annual basis shall include, in addition to the statements required by §§ 200.1 and 200.2 and §§ 201 through 213, the following information:

(a) A statement showing the utility's calculation of the jurisdictional rate of return earned or to be earned in the historical test year and the proposed test year;

See PEPCO C-1 and PEPCO D-3.

(b) The anticipated jurisdictional rate of return to be earned when proposed rate changes become effective;

See PEPCO C and C-3.

(c) The jurisdictional rate base(s) used in the rate of return calculation supported, if available, by summaries of original cost or other factors used in its determination;

See PEPCO C-1 and PEPCO D-3.

(d) A summary, on a functional basis, of the book value (actual or projected) of the utility's jurisdictional property at the close of the historical test year and the proposed test year;

See PEPCO C-3 and D-4.

(e) A statement showing the amount of depreciation reserve, at the close of the historical test year and the proposed test year, applicable to the property summarized in paragraph (d);

See PEPCO C-3 and D-4.

(f) A statement of jurisdictional operating income, setting forth the operating revenues and expenses by accounts, for the historical test year and the proposed test year;

See PEPCO C-3 and D-4.

(g) A brief description of and basis for any major change affecting the utility's operating or financial condition during the proposed test year, known as of the date of transmittal of the application, and any major change during the rate-effective period as follows:

(1) Known and measurable as of the date of transmittal of the application; or
(2) Known and which can be approximated with reasonable accuracy as of the date of transmittal of the application.

For purposes of this section, "a major change" means one which materially alters the utility's operating or financial condition from that reflected in paragraphs (a) through (f); and

N/A

(h) The most recent historic balance sheet available as of the date of filing.

See PEPCO D-9.

200.5 When a utility submits forecasted data as part of its proposed test year data, the utility's filing shall include, in addition to the information and data required by §§ 200.1 through 200.3 and §§ 201 through 213, as applicable, the following information:

(a) The basis for including forecasted data in the test year;

See PEPCO C and PEPCO D.

(b) Key assumptions which underlie the projected jurisdictional ratemaking data for the proposed test year, including but not limited to, the following:

(1) Operating Revenues;
(2) Construction Program
(3) Operating Expenses:
(A) Fuel and interchange costs, if appropriate; and
(B) Operating and maintenance expenses (excluding those expenses under § 200.5(a);

See PEPCO C; PEPCO D; PEPCO I; PEPCO K through R.

(c) Description of the procedures employed in the preparation of the projected data for the proposed test year; and

See PEPCO (C).

(d) Analyses of changes in jurisdictional rate base, jurisdictional expenses and jurisdictional operating income between the historical test year and the proposed test year.

See PEPCO (D)-2.

200.8 When a utility's historical test year and proposed test year are the same, the utility shall submit a single set of data.

Not applicable

200.9 If *pro forma* changes are included in a utility's proposed test year filing, data in that filing shall be provided for the proposed test year on an actual as well as a *pro forma* basis.

Not applicable.

200.10 In cases governed by §200.3, the information specified in §§201 through 213 shall be supplied within twenty-one (21) days after the filing of the application, unless otherwise ordered by the Commission, but shall not be regarded as part of the evidentiary record unless admitted into evidence.

To be provided in the 21-Day Compliance Filing

200.11 Any request for waiver of the filing requirement in this section shall be submitted at the time of the filing of the application for a rate change. If the request for waiver is denied, the utility shall have twenty-one (21) days after the issuance of the denial by the Commission within which to supply the information.

Application, Section V, if applicable

APPENDIX B

Statement of Estimated Costs to be Incurred

Court Reporter and Other Miscellaneous Expenses	$100,000
Outside Consultants	
Mr. Robert B. Hevert	$105,020
Brattle Group	$428,220
ScottMadden	$400,000
Outside Counsel	$923,000
Total Pepco Expenses	$1,956,240
Public Service Commission Assessment	$1,250,000
Office of People's Counsel Assessment	$1,250,0000
Total Projected Costs	$4,456,240

APPENDIX C
Proposed Procedural Schedule

May 30 2019	Pepco Application and Direct Testimony Filed
June 15, 2019	Commission issues Public Notice
June 20, 2019	21-Day Compliance Filing[23]
June 21, 2019	Petitions to Intervene
June 2019	Technical Conferences
Prior to June 28, 2019	Procedural Schedule Conference
June 28, 2019	Joint Report on Procedural Schedule Due
August 16, 2019	Direct Testimony, Exhibits and Workpapers of OPC and Intervenors
As directed by the Commission	Status and Settlement Conference(s)
October 4, 2019	Rebuttal Testimony, Exhibits and Workpapers of all Parties
November 8, 2019	Discovery Ends
Week of November 11, 2019	Settlement and Stipulation Conference(s) to develop agreed upon Joint Prehearing Statement
November 18, 2019	Joint Prehearing Statement filed
December 2, 2019	Prehearing Status Conference at which the Commission Staff will address the Joint Statement and Joint Stipulation to identify the material issues in dispute, determine the number of witnesses as well as the nature of their testimony, obtain admissions as to, or stipulations of, facts, and establish the authenticity of documents.
December 16-20, 2019	Evidentiary Hearings, if any
January 16, 2020	Initial Post-Hearing Briefs
January 31, 2020	Reply Briefs
May 1, 2020	Rates Implemented in accordance with Commission Order

Technical Conferences:

Pepco will convene 2 technical conferences. One will address the Construction Report and the other will address the CCOSS model. Commission Staff, the Office of People's Counsel (OPC), and Intervenors will be invited to attend. These technical conferences will provide the attendees the opportunity to ask questions thereby streamlining discovery regarding the Construction Report and the CCOSS model.

[23] Pepco currently anticipates that the 21-Day Compliance Filing will be submitted prior to this date.

Procedural Schedule Conference:

- Attendees: Pepco, Commission Staff, the Office of Peoples Counsel (OPC) and Intervenors.
- Purpose: Discuss: 1) procedural schedule and 2) any procedural issues.
- Process: At least three business days before the conference, parties will circulate their proposed procedural schedules.
- Product: Applicant will file and serve a Joint Report on Status Conference and any agreed upon proposed schedule or the alternate proposed procedural schedules of the Parties.

Settlement and Stipulation Conferences:

Currently Rule 121.7 of the Commission's Rules of Practice and Procedure requires that the Commission designate issues for hearing either after the pre-hearing conference or as soon thereafter as possible. Consistent with the approach the Commission has elected to follow in recent cases,[24] the Company proposes that, prior to the Evidentiary Hearings, the parties meet in one or more Settlement and Stipulation Conference to prepare a Joint Prehearing Statement identifying the material issues of fact in dispute (if any). To facilitate these discussions, the Company proposes that the Commission include at least one prior status and settlement conference in the procedural schedule.

Settlement and Stipulation Conference #1 (post- Intervenor Direct Testimony/pre-Rebuttal Testimony):

- Attendees: Pepco, Commission Staff, OPC and Intervenors.
- Purpose: Discuss: 1) settlement of issues; and 2) stipulations (fact, data requests, testimony, exhibits, etc.)
- Process: At least seven days before the conference, parties must circulate their lists of: 1) material issues in dispute; 2) facts not in dispute; and 3) stipulations.
- Product: Staff will file a Joint Report on Settlement and Stipulation Conference #1, including a master list of: 1) material issues in dispute (including parties' positions); 2) issues not in dispute; 3) agreed upon stipulations.

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[24] *See, e.g.*, Formal Case No. 1154, Order No. 19919 (May 3, 2019); Formal Case No. 1142, Order No. 19161.

Settlement and Stipulation Conference #2 (post-Rebuttal Testimony/pre-Evidentiary Hearings):

- Attendees: Pepco, Commission Staff, OPC, Intervenors.

- Purpose: Discuss: 1) settlement of issues; 2) stipulations; 3) material issues in dispute; 4) cross examination matrix 5) witness availability for cross; and, 6) witness waiver.

- Process: At least seven days before the conference, each party will circulate a list of: 1) material issues in dispute; 2) material issues not in dispute; 3) stipulations.

At the technical conference, the Parties shall first identify the material issues of fact in dispute (if any). Once the material issues of fact have been identified for the Joint Prehearing Statement, then each Party will prepares a list of witnesses that the party proposes will be called, briefly describing the purpose of the testimony (i.e., link the testimony to one or more material issues of fact), and providing an explanation as to why the witness' oral testimony will provide some meaningful insight that the written testimony does not.

In other proceedings, the Commission has found that this process aides to streamline the proceeding, so it can better determine if material issues of fact in dispute exist that require an evidentiary hearing. The Joint Prehearing Statement shall also include a Joint Stipulation signed by all Parties to the Joint Stipulation. The Joint Stipulation shall be treated as a conclusive admission by the parties to the issues in Joint Stipulation. The Commission would direct Commission Staff to convene a Prehearing Status Conference at which the Commission Staff will address the Joint Statement and Joint Stipulation to identify the material issues in dispute to be addressed at the Evidentiary Hearing, determine the number of witnesses as well as the nature of their testimony, obtain admissions as to, or stipulations of, facts, and establish the authenticity of documents. This will serve to streamline the Evidentiary Hearing process.

APPENDIX D
Glossary of Acronyms

A&G – Administrative and General
ACR – Automatic Circuit Reclosers
ADIT – Accumulated Deferred Income Taxes
AED-NCP – Average and Excess Non-coincident Peak Demand
AFUDC – Allowance for Funds Used During Construction
AIP – Annual Incentive Plan
AMI – Advanced Meter Infrastructure
AMP – Arrearage Management Program
ARAM – Average Rate Assumption Method
ASR – Automatic Sectionalizing and Restoration
ATI – Approval to Install
bps – Basis Points
BSA – Bill Stabilization Adjustment
BSC – Business Services Company
C&C – Capability and Capacity Building
CAGR – Compounded Annual Growth Rate
CAIDI – Customer Average Interruption Duration Index
CAM – Cost Allocation Manual
CAPM – Capital Asset Pricing Model
CBE – Certified Business Enterprises
CCOSS – Class Cost of Service Study
CEMI – Customers Experiencing Multiple Interruptions
CFC – Credit Facility Costs
CI – Customer Interruptions
CIAC – Contribution in Aid of Construction
CIP – Critical Infrastructure Protection
CMI – Customer Minutes of Interruptions
CT – Cooling Tower
CTA – Costs to Achieve
CTO – Costs to Optimize
CWC – Cash Working Capital
CWIP – Construction Work in Progress
DA – Distribution Automation
DCF – Discounted Cash Flow
DDIT – Deficient Deferred Income Taxes
DER – Distributed Energy Resources
DEW – Distributed Energy Workstation

EAM – Earnings Adjustment Mechanism
EDIT – Excess Deferred Income Tax
EPIS – Electric Plant in Service
EQSS – Electricity Quality of Service Standards
FinOps – Financial Operations
FP&A – Financial Planning and Analysis
GDPPI – Gross Domestic Product Price Index
GS-HV – General Service High Voltage
GS-LV – General Service Low Voltage
GT-LV – Time-Metered General Service Low Voltage
GT-HV-69KV – Time-Metered General Service High Voltage 69KV
GT-HV-OTHER – Time-Metered General Service High Voltage Other
IVR – Interactive Voice Recognition
JCOS – Jurisdictional Cost of Service Study
KPIs – Key Performance Indicators
kWh – kilowatt hours
LED – Light-Emitting Diode
LRP – Long Range Plan
MGT-LV – Time-Metered Medium General Low Voltage
MMA – Master Metered Apartments
MRP – Multiyear Rate Plan
MSOs – Major Service Outages
NOL – Net Operation Loss
O&M – Operation and Maintenance
OPEB – Other Post-Employment Benefit
PBR – Performance Based Rates
PEPCO or Pepco – Potomac Electric Power Company
PES – Pepco Energy Services, Inc.
PHI – Pepco Holdings, LLC
PHISCO – PHI Service Company
PIM – Performance Incentive Mechanism
PIV – Plug-In Vehicle
RAD – Residential Aid Discount
RMAs – Ratemaking Adjustments
RI/FS – Remedial Investigation and Feasibility Study
ROE – Return on Equity
ROR – Rate of Return
SAIDI – System Average Interruption Duration Index
SAIFI – System Average Interruption Frequency Index

SCADA – Supervisory Control and Data Acquisition
SERP – Supplemental Executive Retirement Plan
SL – Street Lighting
SLA – Service Level Agreement
T&D – Transmission and Distribution
TCJA – Tax Cut and Jobs Act of 2017

IN THE MATTER OF THE APPLICATION OF POTOMAC ELECTRIC POWER COMPANY FOR AUTHORITY TO IMPLEMENT A MULTIYEAR RATE PLAN FOR ELECTRIC DISTRIBUTION SERVICE IN THE DISTRICT OF COLUMBIA	**)**	**Formal Case No. 1156**

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

VOLUME I

DIRECT TESTIMONIES AND EXHIBITS OF

Mr. David Velazquez
Mr. Kevin M. McGowan
Mr. Tyler W. Wolverton

D.M. Velazquez
Direct Testimony
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (A)

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EXECUTIVE SUMMARY - DAVID M. VELAZQUEZ

The testimony provides an overview of Potomac Electric Power Company (Pepco or the Company) and its strategic focus. It also describes Pepco's contributions to the economy and community of the District of Columbia as well as its continued partnership with the District to help it achieve its clean energy, climate change, and resilience goals. Finally, the testimony discusses how the Company's multiyear rate plan (MRP) will address the impacts of changing energy policy and benefit District of Columbia Customers.

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF DAVID M. VELAZQUEZ
FORMAL CASE NO. 1156

I. INTRODUCTION

Q1. Please state your name and position.

A1. My name is David M. Velazquez, and I am President and Chief Executive Officer (CEO) of Pepco Holdings LLC (PHI). I am testifying on behalf of Pepco.

Q2. What are your responsibilities in your role as President and CEO of PHI?

A2. I am responsible for the leadership of PHI's overall strategy and performance associated with service reliability, grid modernization, customer satisfaction, financial management, and regulatory and external affairs. PHI serves two million customers through its three regulated utility subsidiaries: Pepco, an electric utility serving Washington, D.C. and suburban Maryland; Delmarva Power & Light Company, an electric and gas utility serving Delaware and areas of the Delmarva Peninsula; and Atlantic City Electric Company, an electric utility serving southern New Jersey. PHI employs more than 4,700 people and owns more than $16.1 billion in assets.

Q3. Please state your educational background and professional experience.

A3. I hold a bachelor's degree in engineering from Widener University in Pennsylvania. Prior to my current role, I served as executive vice president and leader of the power delivery business for PHI, managing over 95% of the business and employee base, with responsibility for all utility operations in three states and the District of Columbia, including Customer Care, Asset Management, Operations, smart grid activities, all support services (including IT), and four local unions. I was also responsible for the development of,

and led, the successful enterprise-wide strategic vision to improve reliability and customer service for the Company.

From 2006 to 2009, I served as President and CEO of Conectiv Energy, PHI's former competitive merchant energy subsidiary, leading and directing the commercial and operational activities for the Company. I served as Vice President of strategic planning and Chief Risk Officer of PHI from 2005 to 2006.

Q4. What is the purpose of your Direct Testimony?

A4. The purpose of my Direct Testimony is to

1) Provide a brief overview of the Company;
2) Describe Pepco's role and contributions to the District of Columbia, including supporting and helping meet the District of Columbia's clean energy, climate change, and resilience goals; and
3) Discuss the benefits of our proposed MRP.

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

II. OVERVIEW OF THE COMPANY

Q5. Please provide an overview of Pepco.

A5. Incorporated in 1896, Pepco is a regulated electric utility that provides electric distribution service to the District of Columbia as well as Montgomery and Prince George's Counties in Maryland. Pepco serves approximately 359,000 residential and commercial customers in the District of Columbia, including approximately 54,000

units in master-metered apartment buildings.[1] Pepco's operations include over 6,500 miles of distribution lines and 50 substations the District of Columbia. Pepco also owns approximately 1,900 total transmission miles across the District of Columbia and Maryland. Pepco is a subsidiary of Exelon Corporation.

Pepco is an integral part of the communities we serve. In addition to meeting our obligation to provide safe and reliable service, we understand that our business must support the environment and economy of the areas we serve. We work to align our policies and practices with the needs of our key stakeholders, including our customers, employees, policymakers, and regulators. Ultimately, our vision and values reflect how we conduct business, and our approach to corporate responsibility represents our vision to operate sustainably, responsibly, and in a manner that enables a brighter future for our customers and communities. Our efforts to be a good community partner range from our commitment to our environmental and sustainability goals, our local and diverse hiring, workforce development and supplier diversity, local and community engagement, and economic development. Company Witness McGowan provides more detail regarding the Company's commitments and accomplishments in these areas.

Pepco's provision of electric service also powers the homes, businesses, workplaces, retail outlets, recreation facilities, and governments offices that provide economic activity in the District of Columbia. For this reason, it is critical for the Company to stay engaged with customers, local communities, policymakers, and

[1] Pepco's Monthly Bill Stabilization Adjustment (BSA) Rider filing, Docket PEPBSAR (March 11, 2019).

regulators to fulfill the integral role that the Company plays in helping to support the economic viability of the District of Columbia.

Q6. Please briefly describe the Company's strategic focus.[2]

A6. Pepco has existed in the District of Columbia for more than 120 years, and we are committed to providing safe, reliable, affordable and sustainable electric service to our customers. The Company also recognizes its role and responsibility as the custodian of critical infrastructure that serves all eight Wards located in the Nation's Capital, meeting the modernization and reliability expectations of the District, the Commission, and District of Columbia customers.

As a subsidiary of Exelon, Pepco is also committed to delivering innovation and sustainability to the District of Columbia. Sustainability is linked to Exelon's business strategy, and it informs Pepco's decisions to deliver a more dynamic and resilient utility system with the integration of emerging technologies to meet the policy goals of the District of Columbia and evolving customer needs.

III. CHANGING ENERGY POLICY

Q7. Please describe the changes in energy policy in the District of Columbia and how they impact the Company.

A7. The District of Columbia has led the nation with its progressive approach to addressing climate action, clean energy, and sustainability. Recently, the District of Columbia enacted the Clean Energy DC Omnibus Amendment Act of 2018 ("Clean Energy Act"),[3] and the District of Columbia's Department of Energy and Environment has presented the Clean Energy DC Plan. Mayor Muriel Bowser has also appointed a

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[2] For more detail on the Company's strategic focus, see Company Witness McGowan's Direct Testimony.

[3] *CleanEnergy DC Omnibus Amendment Act of 2018*, D.C. Law 22-257, effective March 22, 2019.

Chief Resilience Officer to build a foundation for the city's resilience strategy as part of its participation in the national 100 Resilient Cities effort. The Clean Energy Act[4] mandates, among other requirements, that 100% of electricity sold in the District of Columbia come from renewable sources by 2032[5] and doubles the required amount of solar energy to be deployed in the District of Columbia.[6] The Clean Energy Act also provides energy bill assistance to low and moderate income residents, and mandates that all public transportation and privately owned fleet vehicles be emission free by 2045.[7] Consistent with the Paris Climate Accord and the District of Columbia's Clean Energy Plan, the Mayor pledged that the District of Columbia would become carbon neutral and climate resilient by 2050. The District of Columbia is committed to reducing the effects of climate change, and the Company embraces its essential role in achieving those goals. The Company looks forward to its continued partnership with the District to support this effort. Additionally, the Company is committed to working towards the efficient deployment of infrastructure that promotes the adoption of climate resilient strategies, including more prevalent distributed energy resources and the integration of transportation electrification and emerging technology, such as microgrids and battery storage.

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4 Clean Energy Act at §101(b).
5 Id.
6 Id. at § 201(c)(3).
7 Id. at §502(b)(4).

Q8. Describe the dynamic energy needs of Pepco's customers and how they use the grid differently today than in past years.

A8. Pepco places the highest priority on our customers and strives to deliver customers' needs and expectations. Customers expect their utility to help them save energy, reduce their carbon footprint, and provide them with an expanded range of choices of how they can meet their energy needs. They expect to reduce their monthly bills through energy efficiency, real-time pricing, and demand response programs. Customers want the ability to utilize solar energy even if they live in a multi-dwelling unit. Customers want choices in sources of electricity and in rate plans, and they want the ability to integrate their electricity with their other utility services. Customers and the District want to increase the number of electric vehicles in the District of Columbia and to electrify the transportation sector. Commercial customers want the ability to better control their energy costs. New technologies are in constant development for community solar, behind-the-meter generation, rooftop solar and battery storage, and other distributed energy resources

Reliability performance becomes increasingly important as these technologies are deployed, and the Company must continue to improve reliability by creating a smarter grid that can "self-heal" and minimize disruptions. The industry landscape has evolved beyond the traditional utility model, and the Company must evolve with it.

Q9. How does the Company envision technology changing the distribution grid over the next ten years?

A9. The industry is evolving and moving toward a distribution system that includes smart energy infrastructure, distributed energy resources, transportation electrification,

and storage technologies. It is essential that the electric utility grid become a platform that connects various devices, and distributed generation and renewable resources with and between customers and allows energy to flow in multiple directions. Advanced technologies and energy efficiency programs are leading to lower customer demand by empowering customers to change how they consume and purchase electricity. We envision customers adopting more distributed energy resources, including solar and storage, and ultimately transacting as prosumers in an open marketplace. These changes will require us to make substantial investments in the electric grid to deliver to our customers the connected communities of the future.

As more technology is deployed on our system, it is essential that we continue our focus on investments to secure against physical and cybersecurity threats and extreme weather events.

The Company is excited about the evolving grid and the future of connected communities. We are actively engaged in the discussions and development of policy that will advance grid modernization and connected communities to meet the policy goals of the District of Columbia and the Commission and evolving customer needs.

Consequently, further investments in the distribution grid will be required to support these types of technologies. For example, new infrastructure will be required to advance transportation electrification in the District of Columbia and to meet the mandate for electrification of the public and privately owned fleet vehicles by 2045. Certain feeders and substations are approaching their capacity to accommodate solar installations and additional investments are required to upgrade those facilities to allow new solar customers to interconnect.

IV. MULTIYEAR RATE PLAN

Q10. How does the changing energy policy in the District of Columbia impact the Company?

A10. The Company must make significant long-term investments to meet the policy goals of the District of Columbia and the changing needs of our customers. As the Company evaluates investments to improve reliability and modernize the grid, it is paramount for the Company's investments plans to align with the District of Columbia's policy goals and customer expectations. The current regulatory process in which investments are made and subsequently reviewed in a base rate case does not provide the proper alignment of the Company's investments and performance with the policy goals of the District of Columbia and customer expectations.

Q11. How does the Company's MRP proposal address these concerns?

A11. The Company's MRP proposal, as further explained by Company Witness McGowan and Company Witness Wolverton, is a three-year MRP with forecasted years 2020-2022. The MRP also includes Performance Incentive Mechanisms (PIMs), developed with input from stakeholders, that further drive operational performance and policy objectives. The Company's proposal increases transparency into the Company's future capital investment spending plans and allows stakeholders to evaluate the Company's plans and how these investments align with the District of Columbia's policy goals and customer expectations. The MRP improves the timing of cost recovery by the utility without the need to file annual rate cases. This is important as the Company invests in grid modernization and the infrastructure required to facilitate the

District of Columbia's goals of climate action, transportation electrification, and increased resilience.

While many of the investments needed to allow widespread adoption of the technologies discussed above are not in the current capital plan through 2022, we believe it is time to evaluate and adopt an MRP so that parties may start the process of aligning the Company's planned investments with the goals of the District of Columbia and expectations of customers. Adoption of the MRP now will set the framework, so as the Company continues to plan for future investments and evaluates with stakeholders future PIMs around grid modernization, a structure will be well established that facilitates a transparent discussion of investment plans with stakeholders before those investments are made.

The transition from the traditional ratemaking process, which is retrospective, to a prospective MRP will streamline the regulatory process, allow greater transparency into the Company's investments to all stakeholders, reduce the number of rate case proceedings and associated costs, and provide more rate predictability to our customers. The Company is an enthusiastic and essential partner in delivering the District of Columbia and the Commission's goals of addressing climate change. It is timely to move toward a forward-looking mechanism that aligns the Company's investment plans and performance targets with the District of Columbia's policy goals and evolving customer needs. The MRP will allow more timely recovery of the Company's investments and enable the Company to make the investments required to modernize the grid and achieve the District of Columbia and the Commission's progressive energy policy goals.

V. CONCLUSION

Q12. Does this conclude your Direct Testimony?

A12. Yes, it does.

K.M. McGowan
Direct Testimony
DC. P.S.C - - May, 2017

Introduced as:
PEPCO _____ (B)

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EXECUTIVE SUMMARY – KEVIN M. MCGOWAN

This testimony presents a general overview of Potomac Electric Power Company, (Pepco or the Company), its strategic focus, and the changing landscape in the energy industry.

The testimony provides many details about diverse and local spend in the District and achievements in economic development and philanthropy. The testimony further discusses the anticipated plans for advanced meter infrastructure (AMI) to support grid modernization and innovation.

As the testimony discusses, an alternative ratemaking mechanism is essential to deliver the grid modernization necessary to achieve the goals of the District of Columbia and the Commission as well as meet the expectations of Pepco's customers. Therefore, the testimony introduces the Company's proposed Multiyear Rate Plan (MRP) and the main drivers for the rate increase request and discusses the logistics for implementation of the MRP. It also describes Performance Incentive Mechanisms (PIMs) and their rationale.

Finally, the testimony introduces the traditional test period compliance filing and certain ratemaking adjustments.

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF KEVIN M. MCGOWAN
FORMAL CASE NO. 1156

I. INTRODUCTION

Q1. Please state your name and position.

A1. My name is Kevin M. McGowan, and I am Vice President, Regulatory Policy and Strategy of Pepco Holdings LLC (PHI). I am testifying on behalf of Pepco.

Q2. What are your responsibilities in your role as Vice President, Regulatory Policy and Strategy?

A2. I am responsible for regulatory, utility of the future, and energy acquisition matters for PHI and its three regulated utility subsidiaries: Pepco, Delmarva Power & Light Company (Delmarva Power), and Atlantic City Electric Company. In this capacity, I am responsible for regulatory affairs related to PHI's utility business before the Public Service Commission of the District of Columbia (Commission), the Delaware Public Service Commission, the New Jersey Board of Public Utilities, the Maryland Public Service Commission, and the Federal Energy Regulatory Commission. I also participate in PHI's analyses of regulatory issues and the development of positions on those issues.

Q3. Please state your educational background and professional experience.

A3. I hold a Bachelor of Business Administration degree in both Accounting and Business Data Systems from the University of Texas at San Antonio and a Master of Business Administration in Finance from the University of Chicago Booth School of Business. I am also a Certified Public Accountant.

In 1998, I joined Potomac Capital Investments, a subsidiary of Pepco, as the Vice President and Treasurer. In 2004, I transferred to the PHI Power Delivery group and eventually to PHI, where I managed various financial positions, including Strategic Planning, Financial Planning, Treasury, and Corporate Risk. In March 2009, I was promoted to Vice President and Treasurer of PHI. In November 2012, I became Vice President, Regulatory Affairs and, upon the closing of the merger between Exelon Corporation and PHI on March 23, 2016, I was named Vice President, Regulatory Policy and Strategy. Prior to joining Potomac Capital Investments, I worked for Duty Free International, an international retail company, and prior to that I worked for Ernst & Young.

Q4. What is the purpose of your Direct Testimony?

A4. My testimony will present the Company's overall case, requesting Commission approval of an MRP for the period of 2020-2022 as well as present the traditional test period compliance filing information.

To support this request and inform the Commission's decision in the matter, my testimony:

a) Provides an overview of the Company and the value to customers of the investments made by the Company;

b) Describes the rationale for the MRP;

c) Discusses the Company's proposed PIMs;

d) Discusses the traditional test period compliance filing, as required by the Commission;

1 e) Describes the importance of maintaining a reasonable Return on Equity
2 (ROE);
3 f) Discusses select ratemaking adjustments;
4 g) Provides a brief introduction of the Company's witnesses.
5 This testimony was prepared by me or under my direct supervision and control.
6 The sources for my testimony and exhibits are Company records and public documents.
7 I also rely upon my personal knowledge and experience.

8 **II. OVERVIEW OF COMPANY**

9 **Q5. Please provide a description of the Company.**

10 A5. As Company Witness Velazquez indicated, Pepco was incorporated in 1896
11 and since that time has played a vital role in the economies of the District of Columbia
12 and Maryland. Our service territory includes all of the District of Columbia and
13 portions of Montgomery County and Prince George's County. Today, Pepco provides
14 reliable electric distribution service to approximately 359,000 residential and
15 commercial customers in its District of Columbia service territory, including
16 approximately 54,000 units in Master-Metered Apartment buildings.[1] We serve our
17 District of Columbia customers through a distribution system that includes over 6,500
18 miles of distribution lines and over 50 substations.

19 Pepco also owns approximately 1,900 total transmission miles across the
20 District of Columbia and Maryland. Pepco and the PHI Service Company (PHISCO)
21 employ a workforce of approximately 1,100 people within the District of Columbia in
22 a variety of managerial and bargaining unit positions.

[1] Pepco's Monthly Bill Stabilization Adjustment (BSA) Rider filing, Docket PEPBSAR (Mar. 11, 2019).

Q6. Can you provide more detail on Company Witness Velazquez's testimony regarding of Pepco's strategic focus and how it will address the changing needs of the customers and provide sustainable electric service in the District of Columbia?

A6. Pepco's strategic focus is to provide a brighter, cleaner future for our customers and communities throughout the District of Columbia. To do that, we must provide safe, affordable, reliable, and sustainable electric service to our customers every day and serve our customers the way they want and deserve to be served. The Company is actively engaged with our customers to understand how they are changing the way they use energy; working with stakeholders on the development of policy to address environmental, resilience, societal, and economic goals important to the District of Columbia and focused on meeting customers' needs and increased expectations around climate change, sustainability and the installation of distributed energy resources. Pepco appreciates the Commission's efforts to address many of these issues through the Modernizing the Energy Delivery System for Increased Sustainability (MEDSIS)[2] proceeding, which is seen as valuable and necessary to advancing the future of sustainable electric service in the District of Columbia. As the Company has learned through MEDSIS and other initiatives, the Commission and the District of Columbia are considering several new technologies and strategies for using the electric grid to provide benefits to customers and promote clean energy, resilience, and climate action goals. Pepco is an essential partner in that process and is seeking not only to optimize the use of the grid but also to make new and innovative opportunities available to

[2] Formal Case No. 1130; In the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability.

1 customers to make the best use of the system, protect the environment, and combat
2 climate change.

3 Moreover, Pepco has been and continues to be supportive of renewable
4 generation – both broadly and within the District of Columbia - and has made
5 significant strides in streamlining the interconnection process for private and
6 community solar to move applications through the process more quickly. The Company
7 has created innovative tools to facilitate the interconnection of solar installations, such
8 as providing heat maps, hosting capacity maps, restricted circuit maps, and approved
9 equipment lists on our website. These maps are updated regularly so customers have
10 the relevant information to help them make energy decisions. In addition, the Company
11 has the Watt Plan on our website that provides information to customers about the costs
12 and projected benefits of solar specific to their address.

13 **Q7. Please describe how the Company prioritizes safety first for employees and**
14 **customers.**

15 A7. Safety is a core value at Pepco. It is a vital part of our daily work, allowing us
16 to provide a safe work environment for both our teams and the public so that we send
17 each employee home, without injury, every day. The Company has many initiatives
18 underway and has adopted best practices that promote a safety culture that drive higher
19 levels of safety performance every day. Some of these initiatives include:
20 (1) participating with the other Exelon Utilities to align on 18 safety practices that were
21 researched and benchmarked against Edison Electric Institute and American Gas
22 Association utilities; (2) sustaining Performance Assessment Programs that share
23 incidents, lessons learned, and best practices across Exelon Utilities through common

1 communication channels; and (3) leveraging the Exelon Safe Footprint program which
2 resulted in a 60% reduction in slip/trip/and fall injuries in 2017 from the prior year.
3 PHI continued to improve its practices for driver training, driver discipline, slow speed
4 maneuvering for vehicle operators, and accident avoidance technologies. As a direct
5 result of the safety programs implemented, demonstrated in Table 1, the Company's
6 overall safety performance continues to improve:

Table 1
Safety Statistics for Pepco

	2016	2017	2018
OSHA[3] Recordable	2.16	1.51	1.20
OSHA DART[4]	1.69	1.10	.96
Motor Vehicle Frequency Rate	17.36	14.89	12.71
Responsible Vehicle Accident Frequency Rate	4.50	3.68	3.71

7 To promote customer and public safety, Pepco provides information and
8 materials to customers about electric safety, including calling before digging,
9 construction safety, and safety during storms. In particular, Pepco participates annually
10 in 811 public awareness outreach to ensure consumers are safe in their neighborhoods
11 and at work. Twice a year, the Company presents at the Commission's Winter Ready
12 and Summer Ready DC Campaign and Community training events to provide District
13 of Columbia residents important tips on how to stay safe during the inclement weather.
14 The Company also provides customer education and tips for staying safe around

[3] Occupational Safety and Health Administration.
[4] DART is a safety metric for "days away, restricted or transferred." It helps the Company determine how many work injuries and illnesses required employees to miss work, perform restricted work activities or transfer to another job within a calendar year.

1 downed power lines. Pepco partners with the American Red Cross to distribute safety
2 information and discuss local hazards, such as downed wires, as well as distribute
3 smoke alarms.

4 **Q8. Discuss Pepco's focus on reliable electric service.**

5 A8. Pepco knows that electricity is indispensable to daily living and reliability is
6 paramount. As the District of Columbia's only electric distribution company, Pepco
7 recognizes that it is our job to keep the lights on. As further discussed by Company
8 Witness Clark, the reliability performance in the District of Columbia has significantly
9 improved over the past several years. The Company has improved the reliability of its
10 distribution system by, among other things, replacing aging infrastructure and investing
11 capital in new feeders, cables, equipment, and other technologies. As a result, Pepco's
12 customers in the District of Columbia have experienced 40% fewer service disruptions
13 and 58% shorter outage durations over the period 2013 through 2018, as measured by
14 the System Average Interruption Frequency Index (SAIFI) and System Average
15 Interruption Duration Index (SAIDI) metrics, respectively.[5] In the Merger Order,[6] the
16 Company committed to continue this improvement by adhering to even more stringent
17 reliability performance standards than required by the Commission's rules and has
18 achieved or exceeded those performance levels without exceeding levels of capital
19 spending set in the Merger Order.

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[5] *See* Company Witness Clark at pp. 6-7, Figures 1 and 2.

[6] Formal Case No. 1119, Order No. 18148 ("Merger Order"), Attachment B (the "Merger Commitments") at ¶54. The Commission subsequently issued Order No. 18160 correcting certain errors in the Merger Order and the Merger Commitments. References herein to the Merger Order and the Merger Commitments are to Order No. 18148 and Attachment B to Order No. 18148, respectively, as corrected by Order No. 18160.

Q9. Has the Company fulfilled all the Merger Commitments, set forth in the Merger Order, to District of Columbia customers?

A9. Yes. The Company has met all of its Merger Commitments to date, as set forth in the Merger Order, and is on track to deliver on the remaining commitments on time.

Q10. Do the MRP and the traditional test period reflect synergy savings that have been realized by customers as a result of the merger?

A10. Yes, in addition to the $78 million of upfront financial merger benefits provided to customers and the District of Columbia, the merger between Exelon and PHI is projected to bring significant merger synergy savings and operational improvements. As discussed further in Company Witness Ziminsky's Testimony, this rate case includes $11 million of merger synergy savings, in the test year, which will continue every year and will result in lower customer rates than they would have been, absent the merger.

Q11. What efforts has the Company made over the past few years to improve the customer satisfaction experience?

A11. Pepco is diligently working to transform and improve the customer experience. The Company is modernizing how we deliver energy and is working on sustainable energy solutions for customers. Pepco has made it a priority to actively engage customers by listening to them, gathering and incorporating their feedback, modifying processes, and delivering services, solutions, and tools to meet individual customer needs. The Company's goal is to offer integrated solutions to our customers, giving them more choice, convenience, and control of how they interact with us, manage their

energy use, and achieve broader affordability and sustainability goals, while continuing to maintain safe, reliable, and efficient customer service.

Q12. As a result of these efforts, have the Customer Satisfaction results improved?

A12. Yes. Pepco's overall residential customer satisfaction has improved significantly—reaching 87% in 2018, which is an improvement of three percentage points over 2017.[7] At the end of 2018, JD Power ranked Pepco second in business customer satisfaction among the East Region mid-sized utility companies, compared to fourth place in 2017. A driving factor for the improvements in customer satisfaction is the improvement in the Company's reliability performance and overall customer experience, including several enhancements to the Company's call center operations that have improved our key call center metrics over the past two years

Finally, the Company has improved the interconnection process to promote the use of solar connections, supported energy efficiency programs in the District of Columbia, and provided tools and information to customers to manage their energy usage, all for the benefit of our customers. The Company's reliability and customer satisfaction improvements reinforce its commitment to deliver high-quality service to District of Columbia customers. Although pleased with our progress to date, the Company recognizes further improvements are needed, and we are focused on achieving first quartile performance in customer satisfaction.

Q13. Briefly discuss the Company's planned reliability investments.

A13. As further detailed by Company Witness Clark in his Direct Testimony, the Company is projected to spend approximately $608.7 million over the 2018-2019

[7] Based on 2018 surveys conducted by Market Strategies Inc. with 900 District of Columbia residential customers on Market Strategies International customer survey study.

period and $957.2 million over the 2020-2022 period on upgrades and improvements to Pepco's District of Columbia distribution system.[8] These capital programs include reliability programs, load projects, and customer-driven capital projects. The reliability programs represent a significant portion of the Company's capital program and include System Performance (such as feeder reliability improvements, proactive replacement of underground residential distribution cables, equipment replacement and installation of new advanced control systems), capital corrective maintenance, automation. As a result of these and similar investments, customers have experienced significantly improved reliability performance as noted earlier. In addition, based on the most recent customer survey, residential customer satisfaction for reliability has improved to 92% for Pepco.[9]

Although these investments are made for reliability purposes, they also serve to strengthen the distribution system in ways that will enhance the system's ability to support other beneficial activities, such as increased distributed energy resources and transportation electrification.

Q14. Briefly discuss the Company's efforts to enhance its distribution system.

A14. The Company has implemented initiatives to enhance its distribution system reliability and its ability to restore customers' service faster when an outage event occurs. This includes investments in distribution automation projects, such as Automatic Sectionalizing and Restoration schemes, switches, and Automatic Circuit Reclosers, and network transformer protector RMS, that improve the Company's

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[8] *See* Company Witness Clark Direct Testimony at p. 14, Table 1.

[9] Based on 2018 surveys conducted by Market Strategies Inc. with 900 DC residential customers on Market Strategies International customer survey study.

operational performance by reducing the number of customers who experience an outage and by expediting restoration times through automatic restoration, all of which reduce costs for customers. Company Witness Clark discusses these initiatives further in his Direct Testimony.

Q15. Briefly discuss the Company's efforts to improve customer service.

A15. The Company has made several improvements to its call center operations during 2017 and 2018, including the Interactive Voice Recognition (IVR) system, which allows customers to find desired features more quickly; increased training for first-call resolution; and an enhanced customer website that provides customers with more information and flexibility and improvements in the operational processes within the Customer Care organization. These investments have resulted in improvements in our key call center metrics over the past two years, such as percent of calls answered in 30 seconds, percent of abandoned calls, and average speed to answer calls. The Company will continue to focus on improvements to the call center operations, including technology enhancements to online web tools, such as *MyAccount* that enables customers to better understand and manage their usage and select their preferred method of communications for items such as billing alerts, energy usage alerts, outage alerts, and a property management portal that allows customers and property management companies to establish and disconnect service for "move-ins and move-outs," making for a more efficient process and better overall experience. Company Witness Poncia discusses these initiatives further in his Direct Testimony. AMI, as discussed below, is key to many of these services.

Q16. Is the Company effectively using AMI to benefit customers?

A16. Yes. AMI is an integrated system of smart meters, communications networks, and data management structures that enables two-way communication between customers and Pepco. Pepco and its customers use and benefit from AMI.

Using data from the AMI meters, residential customers are better informed and empowered regarding their own usage patterns and are able to control their usage and energy costs in more efficient ways. Large commercial customers use online tools such as CEO Online and Green Button Connect to analyze, view, and manage their energy usage. In 2019, small commercial customers are able to compare and analyze their energy usage using hourly billing data, through the *MyAccount* application on the Company's website.

Using AMI, the Company can monitor outages and remotely connect and disconnect customers, while avoiding truck rolls (and associated expenses), all of which save customers money. The Company now has a better understanding and insight into customer accounts and usage patterns during inquiries, so we can provide greater assistance over the phone, the internet, and the Company's mobile application. This also has the added benefit of saving customers time and money. AMI technology provides the Company more detailed information about how energy is used on the system, which provides a foundation to facilitate investments for the grid of the future and opportunities under consideration in the MEDSIS proceeding. In addition, AMI data is used to provide greater transparency for utility operations as well as enabling consumers to make informed decisions regarding their own energy usage. Lastly, AMI

data allows for the development of potential alternative rate structures, such as off-peak rates for electric vehicle charging.

Q17. How does the Company plan to use AMI to support grid modernization and innovation?

A17. The AMI system provides detailed insight into how customers or groups of customers use energy and the grid. The AMI data provides insight on how the system is performing and where technology and distributed energy resources can be deployed throughout the distribution system to optimize its performance. The AMI system expands and enhances the different types of rate designs that can be offered and provides more detailed information for customers as they evaluate different technologies, distributed energy resources, and energy efficiency applications.

Q18. What efforts has the Company undertaken to support economic development in the District of Columbia?

A18. Pepco has invested hundreds of millions of dollars in its electric infrastructure in the District of Columbia in the past five years, which directly contributes to economic development in the District of Columbia. For example, the newly constructed $140 million Waterfront Substation, is one project that has not only improved reliability and supported the need for increased capacity, but it is also an economic driver in the District of Columbia. The new facility was completed in December 2017. The new equipment and upgraded power lines feeding the station foster and enable growth in electric demand brought on by commercial and residential development in the area. Overall, Pepco was proactive in the development of the Waterfront Substation to strengthen economic growth in the area by working with developers, regulators, local

leaders, and others to allow for the expansion and revitalization of this area in the District of Columbia. The substation also provided significant economic activity in the District of Columbia by creating employment opportunities and increasing local spending.

In addition to the economic benefits associated with infrastructure investments, Exelon and the Company, as a result of the merger, committed to provide approximately $78 million in upfront financial benefits to its District of Columbia customers and communities. These financial benefits included residential customer bill credits, funding for the MEDSIS pilot programs, energy efficiency funding, workforce development, and improving reliability performance with no increase in the capital budget. Pepco also committed to continue its support for local non-profit organizations, and as part of this commitment will provide at least $1.9 million per year for 10 years to non-profits in the District of Columbia.

Q19. Describe Pepco's focus on supporting local employment.

A19. Pepco recognizes the importance and benefits of developing and hiring a local workforce. Pepco and PHISCO employ 1,100 employees who work in the District of Columbia. The Company's employees are well-trained and well-qualified people who care about providing safe, reliable, affordable, and sustainable electric service to our customers. In support of local employment, and as part of its merger commitment, the Company hired at least 102 union employees within two years of the merger closing date. In addition, $5.2 million in Exelon contributions from the merger were used in 2017 to launch the DC Infrastructure Academy, a pipeline to infrastructure jobs for

1 District of Columbia residents.[10] Pepco also committed to contribute a total of
2 $500,000 over five years to support the DC Infrastructure Academy. Pepco has hired
3 17 graduates of the initial DC Infrastructure Academy and Quick Path to Energy
4 program for full-time positions at the Company.

5 **Q20. What role does Pepco play in employing Certified Business Enterprises in the**
6 **District of Columbia?**

7 A20. Pepco is actively engaged in hiring Certified Business Enterprises (CBE) in the
8 District of Columbia. Pepco created the Capability and Capacity Building (C&C)
9 Program to expand and develop the pool of qualified CBE construction contractors.
10 Through this innovative program, Pepco provides CBE construction contractors with
11 training and the opportunity to demonstrate their capability and capacity to perform
12 work in accordance with Pepco standards on existing Pepco projects and become
13 qualified to bid on and perform DC PLUG initiative construction projects as well as
14 other Pepco projects. Some contractors from the C&C Program are now Contractors
15 of Choice for the Pepco system, meaning that they are pre-screened and approved
16 construction contractors that are highly skilled in their assigned discipline of work. As
17 of the date of this filing, the total value of the C&C Program contracts is approximately
18 $4.2 million. Pepco is currently reviewing its upcoming projects to identify future
19 opportunities to further engage CBE firms through its C&C Program.

[10] "Mayor Bowser Launches DC Infrastructure Academy." *DCGov*, September 5, 2017, https://mayor.dc.gov/release/mayor-bowser-launches-dc-infrastructure-academy.

1 **Q21. Is diverse spending a priority for the Company? If so, why?**

2 A21. Yes. Pepco is committed to supplier diversity as a core business value that
3 reflects the customers and communities we serve and enhances our ability to remain
4 competitive while contributing to a healthier and more vibrant local economy. Pepco
5 has a long history of fostering a diverse workplace and partnering with diverse
6 businesses to supply the goods and services the Company needs. Pepco values
7 diversity not only because it produces better business decisions, but it creates an
8 inclusive culture that reflects the District of Columbia.

9 The Target 25 program initiated by Exelon's Diverse Business Empowerment
10 Group identified diverse local suppliers and provided training including how to bid on
11 projects and conduct business with larger companies. To further augment the
12 partnerships with the suppliers, Company Witness Velazquez and PHI Chief Operating
13 Officer Tyler Anthony created a diverse supplier support model, in which each supplier
14 has been assigned a PHI executive relationship owner. Depending on the maturity of
15 the relationship with the supplier, the executive's role is either a sponsor or monitor.

16 The Company is proud of its supplier diversity program that advocates for
17 procurement opportunities for women, minorities, service-disabled veterans, and
18 lesbian-, gay-, bisexual-, and transgender-owned business enterprises. As a result of
19 the Company's intentional, dedicated efforts, Pepco's diverse spending has increased
20 year after year.

21 **Q22. Discuss the Company's recent diversity spending achievements.**

22 A22. In 2018, Pepco purchased $163 million in goods and services from diversity
23 certified suppliers, or 29% of total Pepco utility spend, exceeding its 2018 goal of 28%.

1 Pepco has increased spend with diversity certified suppliers from $37.2 million in 2010
2 to $163 million in 2018, which is a significant increase over the eight-year period. The
3 2018 CBE District of Columbia plan goal, as a percentage of total spend, was 5% and
4 the Company ended the year at 9.1%, which represents $52 million.[11]

5 **Q23. Describe Pepco's philanthropic activities and engagement with non-profit**
6 **organizations in the local communities?**

7 A23. Pepco recognizes that we are part of the communities we serve. Our employees
8 live and work in our service areas, they are neighbors, family, and friends. That is why
9 we are focused on doing what we can to ensure the communities we serve are thriving,
10 healthy, and replete with opportunity. Pepco is, therefore, not only active in the District
11 of Columbia through the investments we are making to provide safe, reliable,
12 affordable, and sustainable energy every day, but we are also active through
13 investment, corporate philanthropy, volunteerism, and public policy in support of the
14 District of Columbia's energy, environmental, resilience, innovation, and inclusivity
15 goals.

16 Over 2018, Pepco donated approximately $2 million in charitable contributions
17 in District of Columbia, and employees made significant personal contributions and
18 volunteered thousands of hours of personal time to local non-profits throughout the
19 Pepco service territory that focus on the environment, health and social services,
20 community and economic development, the arts, education, and other areas.

21 The Company also works with organizations, such as United Way, Greater
22 Washington Urban League, food banks, and local agencies, to connect customers with

[11] Potomac Electric Power Company's Supplier Diversity Report ("Report") for 2018, Formal Case No. 1119 and Docket MOU-2017M (Mar. 28, 2019).

1 financial assistance that is available in the District of Columbia. The Company and our
2 employees showcased our commitment to local engagement during the recent partial
3 federal shutdown. Pepco waived late fees and proactively informed affected customers
4 that they could set up budget billing or move bill due dates. The Company established
5 a $50,000 matching grant to an emergency fund created by the United Way of the
6 National Capital Area. The Company and its employees, through our newly established
7 employee resource groups (ERGs), also partnered with Jose Andres at the World
8 Central Kitchen to support furloughed workers. Pepco employees donated food and
9 other essentials to benefit furloughed workers and volunteered time at the Resource
10 Center established by the World Central Kitchen, including staffing a booth every day
11 for two weeks, to provide affected federal workers with information about energy
12 assistance available to them and to provide help with their Pepco bill.

13 **Q24. Does Pepco consider bill affordability an issue for Pepco customers?**

14 A24. Yes. Bill affordability is important for our customers but is especially important
15 for our low- and middle-income customers. It is something we are extremely focused
16 on as we consider future investments needed to support reliability, technology, and grid
17 modernization.

18 The Company has recently supported increasing the amount of funding for the
19 District of Columbia's low-income assistance program - Residential Aid Discount
20 (RAD) - as needed to support participation growth.[12] RAD is a program that provides
21 a discount, the Residential Aid Credit, for the full energy distribution charge in addition
22 to a full discount of certain surcharges. To further assist customers, Pepco worked in

[12] *See* Pepco RAD Surcharge Filing - March 29, 2019.

concert with stakeholders to develop an Arrearage Management Program (AMP) for qualifying customers in arrears, which will include the provision of credits or matching payments for customers who make timely payments on their current bills.[13] In addition, the Company actively supports[14] and is currently working to implement an experimental rate rider that will provide assistance to senior citizen and disabled residents in the District of Columbia.[15] We also educate our customers about ways to lower their energy usage and their bills as well as the availability of important energy assistance programs offered in the District of Columbia. Pepco continues to pursue strategies to assist customers and help build a sustainable approach to affordability.

III. THE COMPANY'S MULTIYEAR RATE PLAN PROPOSAL

A. Overview

Q25. Please explain the main drivers for the Company's request for a rate increase.

A25. As explained in the testimony of Company Witness Velazquez, the business environment in which the Company is currently operating is highly dynamic, with significant changes occurring in virtually every facet of the electric distribution business. Changes in the Company's operating environment impact the Company's cost structure, and the Company cannot remain in a position to address emerging challenges on its distribution system without alignment between costs and revenues.

A rate increase is needed at this time to allow for adequate recovery of costs, which will enable the Company to continue to make significant investments in the electric distribution system, continue to improve reliability and customer service,

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[13] The AMP is scheduled to begin in the third quarter of 2019.

[14] Pepco representatives participated in all three technical workshops, including providing research materials, analysis, and comments.

[15] The Company anticipates that the rider will be initiated in the first quarter of 2020.

1 advance technologies to modernize the distribution system and provide tools to assist
2 customers in managing their energy usage. These investments are important to our
3 customers and are necessary to meet the increasing expectations of our customers and
4 the increasingly stringent merger reliability commitments, as approved by the
5 Commission. In addition, these investments in the distribution system are needed
6 today as they will make the integration of new resources more achievable in the future.

7 **Q26. Please summarize the Company's MRP Request.**

8 A26. Pepco's proposed MRP and PIMs are forms of performance-based ratemaking,
9 which is intended to explicitly reward or penalize a utility based on its performance
10 broadly or narrowly.[16] The Company is proposing a three-year MRP that incorporates
11 the forecasted years of 2020 – 2022 with rate-effective dates on May 1, 2020, January
12 1, 2021, and January 1, 2022.

13 The Company's MRP filing incorporates two primary components. First, since
14 the Company's MRP is a transition from an historic test period recovery to a future
15 three-year test period, the Company's request includes recovery of capital investments
16 since the Company's last rate case filing (Formal Case No. 1150), which was based on
17 a test period ending December 31, 2017. Second, as further detailed below, the
18 Company is proposing a three-year multiyear plan that forecasts the expected capital
19 investments and operating and maintenance costs through 2022. The three-year
20 multiyear plan incorporates three rate adjustments that have been smoothed over the
21 three-year period as well as annual reconciliations, to ensure the Company is recovering

[16] Direct Testimony of Company Witness Zakaras at p. 6.

only those costs that are prudently incurred and required to maintain and operate the business.

Q28. Why is the Company proposing an MRP?

A28. There are several important reasons why the Company is proposing an MRP. First, as noted later, the MRP provides many benefits to customers and the District of Columbia, including improved transparency, improved regulatory efficiency, lower administration costs, and increased Company accountability for managing resources and administrative costs, all of which lower the cost to the customers.

Second, it is important to align the investments the Company is making with the changing needs of our customers and the evolving energy goals of the District of Columbia. The way energy is produced, consumed, and distributed is dramatically changing. In the past, utilities designed transmission and distribution systems to connect large base load generation to customers in which electricity flowed in one way direction. Today, the industry is evolving and moving toward a distribution system that includes smart energy infrastructure, distributed energy resources, transportation electrification, and storage technologies. The utility grid is transitioning from a one-way distribution system and becoming a platform that connects various devices and generation/renewable resources with customers and allows energy to flow in multiple directions. Advanced technologies and energy efficiency programs have led to lower customer demand by empowering customers to change how they consume and purchase electricity. An MRP will allow stakeholders to review and better understand the investments the Company is planning to make to address changing customer needs

1 and evaluate the cost to make those investments relative to the goals they are designed
2 to achieve.

3 Third, given the annual level of required investments by the Company in the
4 distribution system to improve reliability, resiliency, grid modernization, and customer
5 service, the Company must file frequent annual rate cases to begin recovery of its past
6 investments. This practice is retrospective in nature, with the utility filing a rate case to
7 seek recovery of the investments it has previously made. Traditional cost-of-service
8 ratemaking needs to evolve to allow the Company to manage forward rather than
9 continuing to manage only in the past and present. Investments that drive reliability,
10 resiliency, and sustainability occur over multiple years, and it is very difficult for the
11 Company to continue to fund these investments when there is uncertainty regarding
12 what can be recovered and when. The MRP will enable the Company to reduce the
13 frequency of rate cases required to support the Company's investment plans and still
14 provide for a review of those investment plans by the Commission and other
15 stakeholders.

16 As a final note, it is critical for the Commission to balance the interests of
17 customers, energy policy, and the utility. Today, progressive energy policy goals in the
18 District of Columbia, surrounding climate change and resilience, public health, energy
19 innovation and affordability, and addressing the changing needs of our customers
20 require investments in the electric distribution system that are different from the
21 investments made in the past designed to provide safe and reliable service. The level
22 of investments needed today has outpaced the level of new revenues and, as discussed
23 further, results in ROEs significantly lower than the Company's authorized ROE, even

with frequent rate case filings. This creates a situation in which the utility does not have an opportunity to achieve its authorized ROE. An MRP provides the appropriate balance by aligning the Company's projected capital plan with the goals and expectations of the District of Columbia and our customers, while providing the opportunity for Pepco to earn its authorized ROE, but only if it also manages costs over this three-year period and meets performance metrics, as discussed later in my testimony.

Q29. Describe the overall benefits of the proposed MRP?

A29. Utilizing the proposed MRP provides many benefits to our customers, the Commission, key stakeholders, and the Company, including:

- Facilitates investments that support the District's energy policy goals;
- Provides the Commission, stakeholders, and customers with a longer-term view of future capital and operation and maintenance (O&M) investments before the utility makes those investments;
- Provides customers with rate predictability not available under the traditional ratemaking process. At the same time, it reduces regulatory costs to our customers caused by the consistent filing of traditional base rate cases required to keep up with the pace of investments;
- Provides Pepco a realistic opportunity to earn its authorized ROE and, thus, provides the right investment incentive to the Company;
- Improves the overall financial health of the utility and its credit metrics, reducing borrowing costs, which leads to lower customer rates;
- Provides the Company some revenue certainty for a period of time,

which can lead to investments that create jobs and promote economic development; and,

- Provides significant time savings and lower administrative costs, over time, due to fewer rate case filings. The Commission will determine rate adjustments for a future period, in this case through January 1, 2022. This allows for less frequent rate case filings, as the Company would not file another rate case until the early 2022-time frame, almost three years after this rate case filing was made. This will also free up time for the Commission to focus on implementing other important policy priorities related to MEDSIS, transportation electrification, and energy efficiency among others.

Q30. How does the proposed MRP create more transparency?

A30. The proposed MRP provides the Commission and other parties greater transparency into Pepco's Long-Range Plan (LRP) and planning process. As discussed further in my testimony and the testimony of others, Pepco's MRP is largely based on its forecast of costs reflected in its LRP. This represents a shift from a traditional test-year approach, wherein the Company's rate increase is primarily based on historical spending that has already occurred. An MRP allows for greater transparency of Pepco's future spending plans.

Q31. Both you and Company Witness Velazquez reference the District of Columbia's key energy priorities. Discuss these key priorities.

A31. The District of Columbia is demonstrating its focus on prioritizing energy policies through the Clean Energy Act[17] and the Department of Energy and Environment's Sustainable DC Plan with strong, steady progress toward the following energy initiatives:

- Improving energy efficiency and reducing greenhouse gas emissions by 50% by 2032 and carbon neutrality by 2050;[18]
- Increasing the District of Columbia's use of renewable energy sources to 100% by 2032;[19]
- Doubling the amount of solar energy deployed in the District of Columbia to 10% by 2041;[20]
- Providing energy-bill assistance to support low- and moderate-income residents;[21]
- Modernizing energy infrastructure for improved efficiency and reliability, reducing power outages to between zero and two events of less than 100 minute per year; and
- Requiring all public transportation and privately-owned fleet vehicles to become emissions-free by the year 2045.[22]

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[17] *CleanEnergy DC Omnibus Amendment Act of 2018, D.C. Law 22-0257, effective March 22, 2019* (Clean Energy Act).
[18] Id. at §§ 201, 301 (b)(1)(C).
[19] Id. at §101(b)(1)(A).
[20] Id. at §101(b)(1)(B).
[21] Id. at §101(b)(1)(D).
[22] Id. at §502.

In addition, the District of Columbia recently joined an unprecedented 100 Resilient Cities effort, committed to the development of strategies to address inclusive growth, climate, smart cities, health, and equity.[23]

Q32. Will Pepco's proposed MRP help facilitate these goals?

A32. Yes. An MRP is a fundamental component to enable the changes that consumers, the Commission, the Council of the District of Columbia, the Company, and other stakeholders desire in the District of Columbia, as an MRP also creates a more balanced regulatory environment that facilitates investment. The implementation of such a process will allow the Company to be better positioned to pursue the necessary framework in a transparent and collaborative way, coupled with the introduction of PIMs that promote reliability and resiliency, improved customer service, efficiency, and clean energy integration.

There has been a collective focus on harnessing clean energy integration, energy efficiency, and technological advancements nationally and in the District of Columbia. It is important for the Company to respond and prepare for this changing landscape while also focusing on safety, reliability, and resiliency and responding to customer demands regarding technology integration and optionality. The Company is becoming more innovative and proactive in not only supporting but also enabling this energy transition. The proposed MRP helps the Company to align these long-term goals with the Company's long-term planning process.

[23] http://101resilientcities.org/cities/

Q33. What are the implications the Commission should consider if the MRP is not approved?

A33. If the Commission denies the Company's MRP request, then:

1) Parties would likely return to the status quo where investments are reviewed by stakeholders after they are made;
2) The Commission, stakeholders, and the utility would lose the opportunity to improve the collaboration and transparency of the regulatory process;
3) Parties would be limited in the use of PIMs designed to align utility and stakeholder interests and support progressive District of Columbia policy;
4) Parties would be embroiled in frequent, time consuming, and costly rate case filings due to the retrospective review; and
5) Pepco would not have the opportunity to earn its authorized rate of return and would be constrained in its ability to invest in grid modernization and technology to support the District of Columbia and customer energy goals.

Further, the benefits of the proposed MRP detailed on pages 23-24 of this testimony would not manifest.

B. Authority to File an MRP and Commission Requirements

Q34. Before describing the features of the MRP, does the Company have the authority to file an alternative ratemaking plan?

A34. Yes. In Order No. 18846, the Commission recognized that "it was important to take another step forward to explore whether some form of alternative to the current system of 'cost of service' ratemaking should be implemented in the District of Columbia in a rate proceeding in the near future as a means of encouraging service

improvements, managing innovation, more operational efficiencies, and less frequent rate increases." The Commission went on to state that it was "not averse to allowing Pepco to include in its next rate case a request for a fully forecasted test year and or a multiyear rate proposal, in *addition* to a traditional test year filing…"

Q35. Why did the Company not file an MRP in its last rate case (Formal Case No. 1150)?

A35. The Company recognized that stakeholder input and engagement was important to develop a meaningful MRP. The Company did not believe adequate time was available between the July 2017, the issuance date of Order No. 18846 and the timing of the Company's next planned distribution rate case in December 2017. As such, the company filed a traditional rate case in December 2017 and took the opportunity during 2018 and early 2019, to hold four separate workshops to provide transparency into the Company's consideration of an MRP and to gain valuable feedback and input from stakeholders. The workshops were well attended by numerous stakeholders that represented approximately 13 separate groups and included robust dialogue on a wide range of issues that informed the Company's MRP process.

Q36. Related to the overall MRP proposal, did the Commission impose any conditions to making an alternative ratemaking filing?

A36. Yes. The Commission noted that such a filing must be subject to the following conditions summarized below;[24]

(1) The Commission is not averse to allowing Pepco to include in its next rate case a request for a fully forecasted test year and or a multiyear rate proposal, in addition to a traditional test year filing;

[24] In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Rates and Charges for Electric Distribution Service, Formal Case No. 1139, Order No. 18846 at p. ¶594 (July 31, 2017).

(2) There must be a baseline revenue and cost evaluation that is equivalent to an historical test year;
(3) Pepco must explain how to escalate or trend a myriad of revenues and expenses;
(4) Additional time must be allowed for the first examination of the new paradigm; thus, the schedule for any rate case that includes a fully forecasted test year for the first time will require an appropriate extension of time to ensure that the Commission and all participants have the necessary time to fully examine the new proposal;
(5) Pepco must provide a mechanism that allows parties to reconcile any forecasted components to subsequent actuals for the same test year;
(6) The Commission's focus in considering any alternative mechanism will include a review of the benefits that accrue to customers instead of solely focusing on the utility;
(7) Most multiyear rate plans feature a performance metric system that includes some performance incentive mechanisms ("PIM"). The Commission will allow Pepco to submit such a multiyear rate plan in the next rate case if Pepco believes that this should be considered in an environment of growing DERs.

Q37. How has the Company addressed these conditions?

A37. The Commission conditions are addressed in the Company's application as noted in Table 2.

Table 2

Condition	Supporting Witness
1. MRP must include a traditional test year filing	The Company's Application supports the traditional test year filing with primary support in Company Witness Ziminsky's revenue requirment testimony
2. Baseline revenue and cost evaluation which is equivalent to a historical test year	Company Witness Wolverton testimony
3. Explain how to escalate or trend a myriad of revenues and expenses	Company Witness Wolverton testimony and other Company testimonies noted in the table below
4. Appropriate extension of time to ensure that the Commission and all participants have the necessary time to fully examine any new proposal	See procedural schedule proposed in the Company's application; Four workshops conducted pre-filing to explain MRPs, PIMs and the Company's proposal
5. Mechanism which allows parties to reconcile any forecasted components to subsequent actuals for the same test year	Company Witness Wolverton and McGowan testimonies
6. Review of the benefits that accrue to customers	Company Witnesses McGowan and Zarakas testimonies
7. Include PIMs	Company Witnesses McGowan, Wolverton, Clark, and Poncia testimonies

In support of Conditions 2 and 3 above (baseline revenue and cost evaluation which is equivalent to an historical test year), the Company proffers multiple Company witnesses to describe and explain the major components of the Company's O&M and capital budget for the MRP in Table 3.

Table 3
O&M and Capital Witnesses

Company Witness	Cost Areas
Clark	Construction Report to address the Company's capital plan
Barnett	PHISCO and BSC services O&M expense
Sullivan	Electric Operations O&M expense
Ortega	Technical Services O&M Expense
Fisher	Transmission and Substations O&M expense
Maxwell	Support Services O&M expense
Poncia	Customer Care O&M expense
Calabrese	Information Technology O&M and capital expense

1 **C. Structure and Key Features of Pepco's MRP Proposal**

2 **Q38. Describe the Company's overall approach and structure of the MRP proposal.**

3 A38. The Company is proposing a three-year MRP, beginning May 2020 through
4 2022. The MRP consists of three "step" adjustments to base distribution rates for each
5 year of the MRP based on the Company's projected costs for the 2020 – 2022
6 timeframe. These step adjustments reflect a levelized annual revenue requirement
7 increase over the entire three-year term, with the specific adjustments set to occur on
8 May 1, 2020, January 1, 2021, and January 1, 2022. The testimony of Company
9 Witness Wolverton provides a discussion of the Company's proposed MRP and its
10 structure in further detail, including the Annual Reconciliation Fiiling to compare
11 projected versus actual results for each year of the MRP. A brief recap of the key
12 components of the MRP is shown in Table 4.

Table 4
Elements of the MRP

Design Element	Proposal
MRP Term	Base Year: 2018 Bridge Year: 2019 MRP: 2020 thru 2022
Rate-Effective Dates	May 1, 2020 Jan 1, 2021 Jan 1, 2022
Requested ROE	10.3%
Reconciliation	Annual Reconciliation Filing around May 15
Re-Opener	Provision to allow any party, including the Commission on its own motion, to file a petition to re-open and review the Company's MRP, if there is sufficient evidence that there is a problem that cannot be resolved through another avenue available under the plan.
Performance Incentive Mechanisms	Five PIMs (and one tracking metric) are provided to drive continued performance in the operations.

Q39. Is the Company's MRP proposal a major departure from the current system of cost-of-service ratemaking?

A39. The Company's MRP builds on the principles of cost-of-service ratemaking. The Company's proposal is still based on the traditional approach of return on rate base and recovery of expenses; however, the proposal does shift from the use of an historical or partially-forecasted test period to a forecasted multiyear period. Company Witness Zarakas from The Brattle Group provides further discussion on the use of MRPs and their foundation in traditional ratemaking principles.

Q40. What are the key features of the Company's proposed MRP?

A40. The key features of Pepco's MRP include:

- An Annual Reconciliation Filing to ensure customer rates properly reflect the cost of providing service and the expectations of the MRP, as approved by the Commission;
- Performance incentive mechanisms, which align Pepco's financial performance with the priorities of the District of Columbia, the Commission, and customers;
- Provision for deferred accounting requests for costs associated with exogenous events that could occur during the MRP; and
- Provision for a re-opener which could re-open the MRP for review or termination in the event of extreme unforeseen circumstances.

Annual Reconciliation Filing

Q41. Briefly describe the proposed Annual Reconciliation Filing.

Q41. As part of the MRP, the Company will provide an Annual Reconciliation Filing to the Commission for review. The Annual Reconciliation Filing will provide an annual side-by-side reconciliation of actual versus projected calendar year results in the MRP. As discussed in more detail by Company Witness Wolverton, Pepco is proposing the ability to adjust rates during the MRP period based on the actual earned ROE for a given annual reporting period as compared to the projected earned ROE established for the same reporting period. To the extent that the earned ROE for an annual reporting period varies from its projected earned ROE, the Company proposes the following rate adjustment at the next rate-effective date:

- No adjustment would be required if the actual earned ROE for the annual reporting period was within +/-25 basis points (bps) of the projected earned ROE for that period;
- If the actual earned ROE for the annual reporting period exceeds 25 bps of the projected earned ROE for that period, then 75% of the excess would be provided back to customers on the next rate-effective date.
- If the actual earned ROE for the annual reporting period falls below 25 bps of the projected earned ROE for that period, then the Company would file a request with the Commission to allow Pepco to collect 75% of the amount below the 25 bps from customers on the next rate-effective date. As discussed further, this adjustment is not automatic, but rather a request for Commission approval to adjust rates.

The annual reporting periods would include through May 1, 2020 and two calendar years ending 2021 and 2022.

Q42. Why is the Company proposing an Annual Reconciliation Filing?

A42. Pepco is proposing an Annual Reconciliation Filing as required by the Commission in Order No. 18846. In that Order, the Commission stated that "Pepco needs to provide a mechanism which allows parties to reconcile any forecasted components to subsequent actuals for the same test year."[25]

The proposed Annual Reconciliation Filing will ensure that customers are protected and that the rates customers pay closely reflect the actual cost of service. The design of the annual reconciliation provides a +/- 25 bps deadband around the projected

[25] Formal Case No. 1139, Order No. 18846 at ¶594.

earned ROE and a 75/25% sharing adjustment (for the portion that falls outside the deadband), which incentivizes the Company to reduce operating costs and operate more efficiently. If the Company earns less than its projected earned ROE, customers would only contribute an additional 75% of the amount that is more than 25 bps under the projected earned ROE. If the Company is earning above the projected earned ROE, the Company would lower rates (or refund) 75% of the amount that is more than 25 bps over the projected earned ROE.

This structure encourages the Company to focus on keeping its costs low. By reducing costs, the Company has the opportunity to achieve an upside ROE benefit; however, it still maintains downside risk in the event costs are higher than projected and the actual earned ROE falls short of the projected earned ROE for a particular reporting period. The Company's proposed Annual Reconciliation Filing is balanced, protects customers and provides incentive to the Company to reduce costs and improve operational efficiency. As discussed later, the Company's PIM proposal ensures O&M reductions and operational efficiencies do not come at the expense of lower operating performance.

Q43. Does the Company automatically recover its additional costs if the actual earned ROE is lower than the projected earned ROE?

A43. No. The risk of the Annual Reconciliation Filing is asymmetric. If the Company earns more than the projected earned ROE and a rate decrease is warranted, then the Company commits to provide the rate decrease to customers at the next rate-effective date. However, if the Company earns lower than the projected earned ROE, it does not automatically adjust the rates at the next rate-effective date. Rather, the Company will

1 request that the Commission approve recovery of the higher costs at the next rate-
2 effective date after a period of discovery by stakeholders and comments are received
3 from all stakeholders.

4 **Q44. Please discuss the proposed process for parties to review the Annual Reconciliation**
5 **Filing.**

6 A44. One of the objectives of the MRP is to streamline the regulatory process and
7 improve administrative efficiencies. It is important the Annual Reconciliation Filing
8 not become a time consuming "mini rate case" proceeding in which all original budgets
9 and actual costs are re-examined and challenged each year. To facilitate the annual
10 reconciliation process, the Company proposes the following standards:

11 • The annual reconciliation will include a variance report of actual versus
12 forecasted costs. The Company will provide a variance explanation and
13 supporting detail for all accounts that exceed certain dollar and percentage
14 thresholds as detailed in Table 23 of Company Witness Wolverton's Direct
15 Testimony;

16 • The current proceeding in this application is the opportunity to review,
17 challenge and approve the final MRP over the 2020-2022 period. In the
18 Annual Reconciliation Filing, the Company proposes the final Commission
19 approved MRP forecast would not be re-challenged each year;

20 • The Annual Reconciliation Filing and focus by the parties will be limited to
21 any significant annual variances included in the filing. Variances less than
22 the threshold noted in Table 23 of Company Witness Wolverton's Direct

Testimony will be deemed on budget with no further action or analysis needed; and

- A 60-day period from the date of the Annual Reconciliation Filing would be available for discovery.

Q45. Please discuss the Commission's standard of review on the Annual Reconciliation Filing.

A45. The Annual Reconciliation Filing will provide the Commission and the other parties visibility into Pepco's actual results and will enable potential sharing of under- or over-collections outside of the deadband. The Commission will have addressed the prudence of the Company's MRP projections in the order in this case.[26] The only issue before the Commission in an Annual Reconciliation Filing will be the prudence of any variance from the projections presented in the MRP. If the benefits from the MRP, in terms of administrative and regulatory cost savings, are to be realized, it is vital that the Commission make the review of the Annual Reconciliation Filing as streamlined as possible.

Q46. Are these mechanisms common among other MRPs?

A46. Yes. As discussed further by Company Witness Zarakas, 10 of the 14 states that apply MRPs to electric utilities have annual reconciliations in place as part of their MRP plans.[27] There is no common standard, and for those utilities that have an annual reconciliation filing, each jurisdiction has different variations.

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[26] Moreover, the existence of a variance does not call into question the prudence of the project in question.
[27] Direct Testimony of Witness Zarakas at p. 14.

Performance Incentive Mechanisms (PIMs)

Q47. Please provide an overview of the proposed PIMs.

A47. The Company's proposed PIMs are designed to be consistent with industry standards and are supportive of the operational performance needs of the District of Columbia and our customers. The PIMs proposed by the Company include a penalty or reward through an ROE reduction or increase, respectively, that would be addressed through the Annual Reconciliation Filing. The Company has proposed five PIMs that include a financial reward/penalty based on performance and one tracking metric that will only be tracked at this time. The financial incentives for the five PIMs are summarized in Table 5. The PIMs covering reliability measures (SAIDI and SAIFI) and customer service (Service Level and Call Abandonment Rate) include symmetric financial incentives, in that they include both a penalty and a reward for performance. The proposed distributed energy resource interconnection PIM has a symmetric financial incentive, but the potential reward is greater than the potential penalty. Company Witness Clark sponsors and further discusses the three reliability and one policy PIM as well as the reliability tracking metric. Company Witness Poncia sponsors and further discusses the two customer service PIMs.

Table 5
Proposed PIMs and Tracking Metric

Category	Goal	Metric	Target	Penalty/ Reward	Witness
Operational	Reliability	SAIFI	Extend Merger Condition 54 2020 target thru 2022 (0.58)	-10 bps / +10 bps	Clark
Operational	Reliability	SAIDI	Average of Best 3 Years Performance (69 mins)	-10 bps / +10 bps	Clark
Operational	Cust. Service	Service Level	1st Quartile performance (historical)	-2.5 bps / +2.5 bps	Poncia
Operational	Cust. Service	Abandonment Rate	1st Quartile performance (historical)	-2.5 bps / +2.5 bps	Poncia
Policy	DER	Interconnection Review Timeframe	Average ATI – 5 days	-5 bps / +10 bps	Clark
Operational	Reliability	CEMI-4	Tracking Only	N/A	Clark

Q48. Why is the Company proposing PIMs as part of the MRP?

A48. The Company has included PIMs in its MRP to further advance several operational and policy objectives that are priorities for the District of Columbia, the Commission, and Pepco's customers. The Company is proposing PIMs to ensure Company performance aligns with policy goals of the District of Columbia and customer expectations and to allow the Commission to monitor the Company's performance during the MRP period. For example, Pepco included reliability PIMs to

1 indicate its commitment to continue to provide high levels of reliability during the
2 MRP. To ensure that the utility is providing adequate levels of customer service, the
3 Company included customer service PIMs.

4 **Q49. How did the Company develop the proposed PIMs?**

5 A49. The Company identified relevant areas of utility performance that it determined
6 were important to the District of Columbia and its customers. The Company retained
7 the Brattle Group, represented by Company Witness Zarakas, to research the different
8 types of PIMs and structures that are used in other jurisdictions across the United States.
9 The Company held a series of stakeholder workshops to discuss potential PIMs and
10 various reward/penalty structures. The stakeholder workshops allowed the Company
11 to receive input on the PIMs that were most important to the stakeholders. Based upon
12 the Company's work and evaluation, the Company determined the five PIMs proposed
13 in this case were the most appropriate.

14 **Q50. Describe how the PIMs will work.**

15 A50. As further described in Company Witness Wolverton's Direct Testimony, the
16 Company is proposing PIMs with penalties/rewards as well as deadbands. Each year
17 as part of the Annual Reconciliation Filing, the Company will report the actual
18 performance of each PIM as compared to its target. If the performance of a PIM falls
19 within the deadband, then no penalty or reward would apply. If the performance of a
20 PIM falls outside of the deadband, then an ROE increase or decrease would apply and
21 would be included as an ROE adjustment in the Annual Reconciliation Filing. The
22 Company is proposing to limit the maximum reward or penalty associated with PIMs
23 implementation to plus or minus 25 points.

1 **Q51. What are the benefits of these PIMs?**

2 A51. The PIMs strongly align the Company's performance to the policies and goals
3 of the District of Columbia, stakeholders, and customers. For any specific PIM,
4 rewarding or penalizing the Company for performing outside the specified range
5 connects the Company's financial performance to operational performance and
6 encourages achievement of the specific objective. Coupled with the MRP, the
7 Company is incentivized to provide high levels of service at a reasonable cost. PIMs
8 provide specific performance incentives that are reasonable, transparent, measurable,
9 verifiable, and in accord with the District of Columbia policies and initiatives. In sum,
10 PIMs allow for an alignment of the implementation of policy goals with utility
11 operation as well as integrating broader customer benefits which could eventually
12 include energy efficiency programs, support for EV integration, or demand response
13 programs.

14 **Q52. Do PIMs improve utility performance?**

15 A52. Yes. The Company's proposal provides performance targets for each PIM over
16 the three-year MRP period. If approved by the Commission, the performance targets
17 for each PIM will be established, and the utility is incentivized to perform at or above
18 the levels established for each PIM.

19 **Q53. Describe how the proposed PIMs incentivize the Company to operate efficiently?**

20 A53. PIMs help to ensure the utility's performance does not deteriorate due to the
21 cost savings incentive over the MRP period. This incentive also provides a benefit to
22 customers through lower utility costs. As previously described and further discussed in
23 the Direct Testimony of Company Witness Wolverton, should Pepco achieve cost

1 savings that allow it to earn above the projected earned ROE deadband, these savings
2 would be shared with customers.

3 **Q54. How did the Company develop the financial risks and rewards associated with the**
4 **PIMs?**

5 A54. As there is no standard industry approach to setting PIM financial risks and
6 rewards, the Company proposed financial risks and rewards that were meaningful and
7 balanced. Under the proposal, if Pepco underperforms in all of the PIMs, then at the
8 first rate-effective date, the Company could suffer an ROE reduction as high as 25 bps,
9 which would be a significant impact for the Company. By contrast, if Pepco
10 outperforms on all of its PIMs, which will provide significant operational and customer
11 service benefits to customers, then at the first rate-effective date, the Company could
12 increase its ROE by as much as 25 basis points.

13 **Q55. Please discuss how the Company plans to support the Clean Energy Act and**
14 **develop PIMs related to Energy Efficiency and Transportation Electrification.**

15 A55. Pursuant to Title II of the Clean Energy Act, Pepco is authorized to propose
16 energy efficiency and demand response programs to the Commission for approval. The
17 legislation requires the establishment of a working group that will make
18 recommendations to the Commission within a 90-day period regarding savings metrics,
19 quantitative performance indicators, and cost-effective standards for such programs.
20 Thus, it will likely be in the latter portion of 2019 before the Commission is able to
21 establish these savings metrics, quantitative performance indicators, and cost-effective
22 standards. Pepco is excited about the opportunity to re-engage in the energy efficiency

1 efforts it has successfully implemented in the District in the past and in other PHI
2 jurisdictions.

3 The same landmark legislation recognized the importance of promoting vehicle
4 electrification and, thus, mandates that the District of Columbia establish a
5 transportation electrification program, that will require public buses, privately-owned
6 rideshare, commercial motor carriers, taxis, limousines, and privately-owned fleets
7 with more than 50 passenger seats to only operate zero-emission vehicles in the District
8 of Columbia by 2045. Implementation of this program will require the deployment of
9 electric vehicle charging stations throughout the District of Columbia.[28]

10 Pepco fully supports the Clean Energy Act. The Company is committed to
11 participating in the working group process to consider implementing energy efficiency
12 programs, demand response programs, and electric transportation in the District of
13 Columbia. Until these programs are implemented in the District of Columbia, the
14 Company cannot develop these related PIMs, and, thus, the Company decided it was
15 premature to propose such PIMs in this filing. The Company will continue to
16 participate in these initiatives throughout the year and would consider including
17 additional PIMs into this filing, or the Company's next MRP filing, once PIMs and
18 target metrics can be properly developed in alignment with the Commission's
19 approvals.

[28] On April 12, 2019, the Commission issued Order No. 19898, which approved, in part, Pepco's proposals related to transportation electrification in the District of Columbia. Pepco has applied for reconsideration and clarification of elements of Order No. 19898 and after receiving the final order in the case can determine how best to proceed to implement its program and support the District of Columbia's mandates.

Q56. Is the Company proposing any PIMs related to the Clean Energy Act?

A56. No, the Company decided not to propose PIMs in these areas at this time given the ongoing proceedings and anticipated work groups.

Deferred Accounting Treatment

Q57. Describe the Company's deferred accounting proposal.

A57. As further described in Company Witness Wolverton's Direct Testimony, the Company is proposing the ability to request deferral (regulatory asset) treatment be provided throughout the MRP period for any significant unanticipated costs incurred during the MRP-effective period (2020-2022). Common examples of significant unanticipated costs would include major storm costs and tax law changes.

Q58. How does deferred accounting treatment benefit customers?

A58. Deferring and amortizing the cost of any significant unanticipated impactful event mitigates the impact to customer rates in a given year.

Re-Opener Provision

Q59. Describe how the proposed re-opener provision will work.

A59. As described in more detail by Company Witness Wolverton, the MRP includes a re-opener provisions that will allow any party, including the Commission on its own motion, to file a petition to re-open and review the Company's MRP if there is sufficient evidence that there is a problem that cannot be resolved through another avenue available under the MRP. The re-opener provision would protect customers and the Company from impacts not originally accounted for in the MRP. The re-opener provision would allow the parties to modify the MRP to mitigate the unforeseen circumstance or exit the MRP by replacing it with a new traditional base rate case filing.

[29] If a petition is filed, the requesting party should include a recommended timeline and procedural schedule as part of its petition.

Q60. Why does the Company need a re-opener provision?

A60. The purpose of the re-opener is to protect both customers and the utility from unintended outcomes of the MRP. The Company recognizes that unforeseen factors may necessitate review, changes and/or termination of the plan in order to mitigate impact to the utility as well as customers.

Q61. How would a re-opener provision benefit customers?

A61. If it were determined that unforeseen factors were providing a significant benefit to the Company that was not properly addressed in the Annual Reconciliation Filing, then the Commission could reconsider the design and structure of the MRP. The re-opener provision provides the Commission the ability to modify the MRP to mitigate the unforeseen circumstance or approve a termination of the MRP. If the Commission decided to terminate the MRP, the rate would be frozen at current levels, and no further rate increase in the MRP would occur. The Company would have the option to file a new traditional rate case that, once approved, would replace the remaining term, if any, of the MRP.

Financial Risk to Pepco

Q62. Are there any financial risks for Pepco associated with the MRP? If so, please describe.

A62. Yes. The Company would maintain a comparable level of risk to its current risk if the proposed MRP is adopted, including:

[29] Direct Testimony of Company Witness Wolverton at 44.

- The MRP sets rates three years into the future, which is an increased risk on the Company to manage actual costs versus forecast. Any material changes in circumstances or unforeseen extraordinary events not timely corrected could present a risk to the Company.
- The ROE is set for the term of the MRP. As further discussed by Company Witness Hevert, the most dominant factor affecting utility cost of capital determinations is the level of interest rates. Because regulated utilities are capital intensive, they are highly sensitive to changes in interest rates. As interest rates increase, utility valuations decrease, driving up the required utility equity return or ROE. This represents a risk to the Company as the cost of equity to fund new investments may be higher than the level set in the MRP, and the Company would not have the ability to adjust its ROE during the MRP term.
- The Company will have the risk that prudently incurred costs may not be recoverable during the MRP term. During the term of the MRP, the Company is proposing the ability to defer certain significant unanticipated costs that may occur during the MRP and request a rate adjustment in the annual reconciliation filing, to the extent the earned ROE falls below the 25 bps deadband. To the extent the Commission does not approve the Company's request in the annual reconciliation filing, the Company may not be able to recover costs incurred over the MRP term. Also, to the extent the Company's projected earned ROE in a reporting period is less than the

target ROE but within the 25 bps deadband, the Company will not be able to recover the additional costs.

- The Company will be exposed to the risk of under recovery associated with unforeseen events that do not impact the revenue requirement by $1 million, which is the proposed minimum revenue requirement to request deferred accounting treatment.

Q63. Does the MRP reduce the Company's risk profile, such that a reduction in ROE is warranted?

A63. No. Although the MRP proposal increases the opportunity for the Company to earn the stated ROE authorized by the Commission, the Company does not believe it enhances the Company's risk profile or reduces its Cost of Equity. Company Witness Hevert further discusses this topic in his Direct Testimony.

Q64. What is the revenue requirement requested in the Company's three-year MRP proposal?

A64. The Company is requesting a rate increase of $85 million in 2020, $40 million in 2021, and $37 million in 2022. Company Witness Wolverton provides the revenue requirement schedules supporting this request.

Q65. Based on the Company's proposed MRP request, what will be the impact on the typical Residential bill?

A65. Under the proposed MRP, a typical residential customer using 692 kilowatt hours (kWh) per month will see an adjustment to their monthly bill associated with the distribution rate increases that is projected to result in the following overall net increases for customers, once all known factors over the MRP are included, specifically

lower supply prices scheduled to take effect later in 2019. Residential Aid Customers would be excluded from the monthly distribution increase but will also benefit from the lower supply prices scheduled to take effect later in 2019.

Date	Monthly Distribution Increase	Overall Net Increase	% Bill Increase
May 1, 2020	$8.57	$6.09	7.1%
Jan 1, 2021	$3.69	$3.86	4.2%
Jan 1, 2022	$3.19	$3.52	3.7%

It is important to note that if the Commission were to grant the Company's full request in this MRP proceeding, the total estimated bill for the typical residential customer in 2022 (using 692 kWh per month) is expected to be approximately 6.5% lower than it was in 2011, a period of approximately 11 years.

Q66. Discuss the Company's plan for the Customer Base Rate Credit (CBRC).

A66. The CBRC, which was established and funded by an Exelon/PHI merger commitment and later increased in Formal Case No. 1150, is projected to be fully utilized by March 2021. The CBRC has been very successful and has resulted in no residential rate increases in the District of Columbia since March 2014. The Company is proposing no changes to the CBRC as part of the filing and recommends the current monthly credit continue until the CBRC fund is fully utilized.

1 **IV. TRADITIONAL TEST PERIOD COMPLIANCE FILING**

2 **Q67. Why is the Company filing a traditional test period?**

3 A67. In Order No. 18846, the Commission directed that, should the Company choose
4 to propose a MRP, it must be filed along with a traditional test period filing.[30]

5 **Q68. Please summarize the Company's traditional test period compliance filing.**

6 A68. Company Witness Ziminsky calculates the revenue requirements using the test
7 period ending June 30, 2019 that includes six months of actual data and six months of
8 forecasted data. The revenue requirement is $88.6 million based on a return on equity
9 of 10.3%. A typical residential customer using 692 kWh per month will see a monthly
10 bill increase on average of 7.8%.

11 **Q69. Is it appropriate to simply compare the Company's proposed MRP with the**
12 **traditional test period provided in compliance with the Commission's order?**

13 A69. No. The MRP covers the three-year period 2020 through 2022. The traditional
14 test period compliance filing uses a test period ending June 30, 2019 with appropriate
15 ratemaking adjustments. To compare the two proposals, one must compare the
16 Company's MRP proposal to the traditional test period compliance filing period plus
17 the next two rate case filings the Company would make during the 2020-2022 period.
18 These two additional rate cases would seek to recover approximately $957.2 million of
19 planned capital spending through the end of 2022 that is already included in the MRP
20 but is not included in the traditional test period compliance filing due to its use of a
21 historic test period.

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[30] In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Rates and Charges for Electric Distribution Service, Formal Case No. 1139, Order No. 18846 at ¶594 (Jul. 31, 2017).

V. IMPORTANCE OF MAINTAINING A REASONABLE RETURN ON EQUITY (ROE)

Q70. What has been the Company's earned ROE over the past six years?

A70. Pepco has a well-documented history of earning less than the ROE that has been authorized by this Commission. As conveyed in Table 6, the Company has earned ROEs lower than those authorized by the Commission and, on average, has earned 2.74% less than its authorized ROE during the periods displayed.

Table 6

Period Ending	Dec. 2014	Dec. 2015	Dec. 2016[31]	Dec. 2017	Dec. 2018	Jun. 2019
Earned ROE	6.89%	6.62%	N/A	7.08%	7.27%	5.81%
Authorized ROE	9.40%	9.40%	N/A	9.50%	9.525%	9.525%
Variance	-2.51%	-2.78%	N/A	-2.42%	-2.26%	-3.72%

As noted earlier, Company Witness Ziminsky explains in his Direct Testimony that Pepco's June 30, 2019 unadjusted earned ROE is only 5.81% at the time of this filing.

Q71. Why is it important to have a competitive ROE?

A71. As supported in the testimony of Company Witness Hevert, utility companies are capital-intensive by nature, needing to finance large, sustainable projects with the help of externally generated funds. To attract external funds, utility companies must demonstrate to current and potential investors that they are able to earn a reasonable return on funds invested in the business. The Company's ROE recommendation represents a reasonable assessment of investor's required rate of return for utilities

[31] Since a rate case was pending, December 2016 was not filed with the Commission and, therefore, not included in Table 6.

similar to Pepco in today's capital market. A reasonable return should enable the Company to attract capital at a reasonable cost given the risk of the business and the industry in which the Company operates. To do so, it must compete with other firms in the capital markets, utilities and otherwise. In that sense, a reasonable return should be competitive with those available on investments of comparable risk. Investors have many choices and will favor investing in companies that offer competitive and reasonable investment returns over companies that offer less competitive or bottom-of-the range investment returns.

Q72. Why is it important that the Company earn its authorized ROE?

A72. The Company's cash flow from operations is not sufficient to fund its capital program, and, therefore, the Company must raise money in the capital markets, generally on an annual basis. Since Pepco competes with other companies when attempting to raise capital, it is important for the Company to be able to demonstrate to its investors that there is a realistic opportunity to earn a rate of return that is commensurate with the rates of return earned by the other companies of similar risks. Although the Company may have been able to raise funds in the past during periods when it was not earning its allowed rate of return, it is important for the Company to provide investors with an appropriate level of return on their investments.

Investors have provided all the funding needed to improve the system and deliver the benefits that customers and the Commission have demanded. In order to maintain the existing investor base and attract new investors to provide further funding for additional investments our customers and the Commission expect, the Company must provide the investors with an appropriate level of return on their investments. It

is important to balance the needs of the customers, the Company, and our investors. As shown in Table 6, an earned ROE that has been on average 274 bps below our authorized return on equity is certainly below investor expectations. Investors have many choices and will deploy capital towards companies that offer a competitive and reasonable investment return and will avoid investments in companies that offer less competitive or bottom-of-the range investment returns.

Q73. What is the primary cause of the Company's under earning during this period?

A73. In decades past, vertically integrated utility companies were able to cover a significant portion of their additional infrastructure spending through new load or sales growth. Today, utility companies, such as Pepco, have divested or separated their generation assets and are focused on different goals, including the promotion of energy efficiency, providing consistently high levels of service reliability, and investing in new technologies and grid modernization. However, the current ratemaking process has not kept pace with industry changes, resulting in a disconnect between when the Company makes investments and when these costs are reflected in customer rates. Currently, the traditional ratemaking process in the District of Columbia evaluates a past "test year" to set rates for the utility's cost to provide service for a future period. As such, rates do not reflect the cost to provide service in the future rate-effective period, leaving Pepco to under earn on its prudently incurred costs. In this situation, the Company is constrained and will focus on its obligation to provide safe and reliable service and will be limited in its ability to invest in grid modernization and technology to support the District of Columbia and customer energy goals.

1 These investments, coupled with a changing environment due to a necessary
2 focus on environmental and sustainability efforts, have resulted in a cost structure that
3 does not allow the appropriate alignment between costs and revenues to support
4 emerging technological and environmental opportunities. It is important that the
5 Company recover these investments in a timely manner and have the opportunity to
6 earn its authorized ROE. In light of these factors, the Company is proposing an MRP
7 that aligns the utility's capital spending plan with the interests of the District of
8 Columbia and our customers. In addition to providing transparency and additional input
9 into the Company's investments, the MRP will allow timely recovery of prudently
10 incurred costs and will reduce the time and expenses required by all parties to litigate
11 frequent rate cases.

12 **VI. SPECIFIC RATEMAKING ADJUSTMENTS**

13 **A. Benning Road Facility Environmental Remediation Costs**

14 **Q74. Is the Company requesting recovery of environmental remediation costs related**
15 **to the Benning Road facility site in this proceeding?**

16 A74. Yes, the Company is requesting recovery of costs incurred to date and
17 forecasted costs through 2020 associated with the Remedial Investigation and
18 Feasibility Study (RI/FS) related to environmental remediation at the Company's
19 Benning Road facility. The Company proposes to amortize actual RI/FS costs incurred
20 to date over a ten-year period, with the unamortized balance included in rate base.
21 Company Witness Sanford discusses the Benning Road facility environmental

1 remediation efforts in greater detail, including the historical context, current status, and
2 the actual and projected costs incurred by the Company related to the RI/FS.

3 **B. Additional Subtraction Modification Method**

4 **Q75. Please describe the Additional Subtraction Modification Method**

5 A75. Beginning January 1, 2000, in conjunction with deregulation of the utility
6 industry, Maryland public utilities were no longer subject to the Franchise Tax and only
7 became subject to the corporate income tax regime. As described below, this impacts
8 rates in both the District of Columbia and Maryland. Under the previous Franchise Tax
9 rules, Maryland corporations calculated tax based on gross revenue and beginning
10 January 1, 2000, Maryland corporations calculated tax based on taxable net income
11 (i.e.; gross income less deductible expenses). As part of the Maryland tax law change
12 on January 1, 2000, a utility company was allowed to deduct from its taxable income
13 the net book value of its assets (i.e.; the sum of its net tax value plus the excess of the
14 net book value over the net tax value provided for in the "Statutory Subtraction"
15 modification adjustment), as of January 1, 2000, when the asset is sold, retired, or
16 otherwise disposed.

17 For many years, Pepco proposed a different interpretation of the value of assets
18 Maryland utilities should be able to deduct from taxable income under the premise that
19 the legislative intent of the statute was to permit the full recovery of the asset's original
20 cost and not just the net book value as of January 1, 2000. Exelon, on behalf of Pepco,
21 Delmarva Power, and Baltimore Gas and Electric Company, requested a declaratory
22 ruling from the Office of Maryland Comptroller seeking explicit approval to use the
23 alternative methodology that provides a deduction of the full original cost of the asset

(i.e.; The Additional Subtraction Modification). In the fourth quarter of 2018, Exelon received a favorable declaratory ruling from the Office of the Maryland Comptroller approving the Company's proposal as the appropriate method.

Pepco's perseverance in pursuing this issue over the past many years, and ultimately requesting a letter ruling from the Maryland Comptroller, is a significant benefit for customers. The additional benefit from the Additional Subtraction Modification Method will save Pepco's District of Columbia customers approximately $27.6 million in state income taxes in the future as assets are sold, retired, or otherwise disposed. Company Witness Ziminsky discusses this issue in more detail in his Direct Testimony.

Q76. How does the Maryland Subtraction Modification Method impact the District of Columbia?

A76. Given that Pepco operates in multiple jurisdictions, the Company's total taxable income is allocated to each taxing jurisdiction using an apportionment formula, and then the appropriate jurisdictional income tax rate is applied to the apportioned income. This means that the starting point for Maryland income taxes is Pepco's total taxable income, which includes both District of Columbia and Maryland. As such, the Additional Subtraction Modification described is based on Pepco's total depreciation expense. This means that both Maryland and District of Columbia customers have funded the amounts for which Pepco will now be able to take additional tax deductions in Maryland. Thus, it is appropriate for a portion of this tax benefit to be allocated to District of Columbia customers. Company Witness Ziminsky's Direct Testimony elaborates more on this process.

Q77. Is this benefit similar to the benefits the Company received under the Tax Cut and Jobs Act of 2017 (TCJA)?

A77. No. The important difference between the TCJA benefits and the Additional Subtraction Modification Method is when the cash is received. Under the TCJA, Pepco had already received the federal tax benefits from the Internal Revenue Service, primarily in the form of accelerated depreciation, and was no longer required to return those benefits in the future. Under the Additional Subtraction Modification Method, the benefits will be provided to the Company in the future through lower state income taxes but only when the asset is sold, retired, or otherwise disposed. The Company is proposing to provide these benefits to customers by amortizing the total benefit over the remaining useful life of the assets. Since the cash benefits from the Additional Subtraction Modification Method will be only be received by the Company when the assets are sold, retired, or otherwise disposed, providing the benefits to customers over the remaining useful life of the assets will closely align the receipt of the cash benefits by the Company with the payment of benefits to customers.

VII. OVERVIEW OF THE COMPANY'S APPLICATION

Q78. Please describe the structure of the Company's application.

A78. This filing consists of the application for an increase in base distribution rates together with my testimony and that of 17 other witnesses:

- Mr. David M. Velazquez, President and Chief Executive Officer of Pepco Holdings LLC, provides testimony on the Company's strategic plan, changing energy policy in the District of Columbia, and support for the MRP.

- Mr. Tyler W. Wolverton, Manager, Revenue Performance, provides testimony and exhibits in support of the Company's MRP mechanics, how forecasts were developed, deferred accounting and the Annual Reconciliation Filing, re-opener procedures, and certain ratemaking adjustments relevant to the MRP.
- Mr. Jay C. Ziminsky, Director, Regulatory Strategy and Revenue Policy, provides testimony and exhibits in support of the Company's revenue requirement for the traditional test period compliance filing, the test year selection, the proposed traditional test period ratemaking adjustments, and the jurisdictional cost of service. Company Witness Ziminsky also provides testimony on the Company's capital structure.
- Mr. Lance C. Schafer, Senior Rate Analyst, provides testimony and exhibits in support of the Company's customer class cost of service.
- Mr. Peter R. Blazunas, Manager, Rate Administration, provides testimony and exhibits, in the support of the proposed rate design and tariffs.
- Mr. Robert B. Hevert, Partner, Scott Madden Inc., provides testimony and exhibits in support of the Company's proposed cost of capital and return on equity.
- Ms. Julie E. Giese, Director, Accounting, provides testimony and exhibits to support the accounting books and records.
- Mr. Bryan L. Clark, Director of Gas Operations, formerly Director, Strategy, provides testimony and exhibits on Pepco's focus on investments in reliability as well as Pepco's Construction Report and reliability PIMs.

- Mr. William Zarakas, Principal, The Brattle Group, provides an expert overview of PBR, including MRP and PIMs, as it relates to Pepco's proposal.
- Ms. Tammy D. Sanford, Manager, Environmental Management, provides a description of actual incurred and projected environmental investigation and remediation activities and costs at Pepco's Benning Road facility.
- Mr. Phillip S. Barnett, Senior Vice President, Chief Financial Officer and Treasurer, PHI, provides testimony and exhibits in support of PHISCO and BSC services.
- Mr. William Sullivan, Vice President, Electric and Gas Operations, provides testimony and exhibits in support of the Company's electric operations.
- Mr. Miguel A. Ortega, Vice President, Technical Services, PHI, provides testimony and exhibits in support of the Company's technology services.
- Ms. Sandra R. Fisher, Vice President, Transmission and Substation, provides testimony and exhibits in support of the Company's transmission and substations.
- Mr. Michael W. Maxwell, Vice President, Support Services, provides testimony and exhibits in support of Support Services operations.
- Mr. Michael S. Poncia, Vice President, Customer Operations, provides testimony and exhibits in support of Customer Care operations.

- Mr. James L. Calabrese, Vice President, IT, PHI and EU, provides testimony and exhibits in support of the Information Technology operations.

VIII. CONCLUSION

Q79. Please summarize the Company's overall position in this case.

A79. Pepco plays a vital role in the District of Columbia community as well as the regional economy and has continued to improve reliability and customer satisfaction. The Company has invested the necessary capital and resources to deliver the higher reliability performance and improved customer satisfaction, the Commission, and stakeholders have demanded. Nonetheless, there are many challenges ahead the Company must face, particularly surrounding the necessity of replacing aging infrastructure, maintaining the electric reliability improvements, and modernizing the distribution grid to address the changing needs of our customers and meeting the progressive energy policy goals of the District of Columbia. The energy environment and customer needs have changed significantly over the past decade and continue to change at a rapid pace; however, the regulatory environment is still primarily focused on an historic view of the Company's investments and costs.

The Company's MRP proposal is an opportunity to improve the collaboration and transparency of the regulatory process and more fully align the utility's interests and future investments and performance with the District of Columbia's policy goals and customer expectations. The Company's request also affords it the opportunity to continue investing in the electric distribution system to support the policy goals of the District of Columbia and the Commission to the benefit of its customers, to earn a

1 reasonable ROE, and to continue positively impacting economic and community
2 development in the District of Columbia.

3 **Q80. Does this conclude your Direct Testimony?**

4 A80. Yes, it does.

T.W. Wolverton
Direct Testimony
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (C)

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EXECUTIVE SUMMARY - TYLER W. WOLVERTON

The purpose of this testimony is to describe the proposed Multiyear Rate Plan (MRP) of Potomac Electric Power Company (Pepco or the Company). The testimony provides an overview of the Company's three-year MRP proposal; a description of the calculation of the Company's projected rate base; a description of the calculation of the Company's projected operating income; a description of the allocation of Pepco's projected costs to distribution and the District of Columbia, and a description of the ratemaking adjustments (RMAs) in the MRP.

In addition, this testimony provides a summary of the MRP revenue requirement, the proposed Annual Reconciliation Filing, the of the Company's projected proposed Deferred Accounting Mechanism, and finally, a description of the proposed Re-Opener Provision.

A summary rate base, operating income, and proposed revenue increases is shown in Table 1. This testimony and accompanying exhibits support these summary amounts.

Table 1

	Multiyear Rate Plan (Dollars in Millions)		
Plan Year	**2020**	**2021**	**2022**
Rate Base	$2,207	$2,365	$2,565
Operating Income	$95	$90	$83
Cumulative Revenue Requirement[1]	$85	$125	$162
Incremental Revenue Requirement[2]	$85	$40	$37

[1] Includes "smoothing" adjustments as discussed later in the testimony.
[2] Includes "smoothing" adjustments as discussed later in the testimony.

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF TYLER W. WOLVERTON
FORMAL CASE NO. 1156

I. INTRODUCTION AND QUALIFICATIONS

Q1. Please state your name and position.

A1. My name is Tyler W. Wolverton. I am the Manager, Revenue Performance, in the Regulatory Affairs Department of Pepco. I am testifying on behalf of Pepco.

Q2. What are your responsibilities in your role as Manager of Revenue Performance?

A2. I am responsible for the development of revenue requirements for Pepco in the District of Columbia and Maryland. In addition, I am responsible for coordinating and supporting various other regulatory compliance matters.

Q3. Please state your educational background and professional experience.

A3. I received a Bachelor of Science degree in Finance from Virginia Polytechnic Institute and State University in 2010 and a Master's in Business Administration from George Washington University in 2013.

In 2010, I joined Pepco Holdings, LLC, formerly Pepco Holdings Inc. (collectively PHI), Regulatory Affairs department as an Analyst in the Rates and Technical Services group. In 2013, I was promoted to Senior Regulatory Affairs Analyst in the Regulatory Finance department. In 2014, I was promoted to Regulatory Affairs Lead in the Regulatory Finance department. In 2016, I joined the Revenue Performance team as a Regulatory Affairs Lead. In February 2017, I was promoted to my current position as Manager, Revenue Performance.

Q4. Have you previously testified before the Public Service Commission of the District of Columbia (Commission)?

A4. Yes, I submitted testimony with respect to revenue requirements and jurisdictional allocation before the Commission in Formal Case No. 1150.

Q5. What is the purpose of your Direct Testimony?

A5. The purpose of my Direct Testimony is to support and explain the MRP portion of the Company's Performance Based Rates (PBR) proposal. Specifically, this testimony will cover:

I. Introduction and Qualifications

II. Overview of the Company's Three-Year MRP Proposal

III. Description of the Calculation of the Projected Rate Base

IV. Description of the Calculation of the Projected Operating Income

V. Allocation of Pepco Costs to Distribution and District of Columbia

VI. Description of the RMAs in the MRP

VII. Summary of the MRP Revenue Requirement Items

VIII. Annual Reconciliation Filing

IX. Deferred Accounting Mechanism

X. Re-Opener Provision

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

II. OVERVIEW OF THE COMPANY'S THREE-YEAR MULTIYEAR RATE PLAN

Q6. Please summarize the results of the MRP.

A6. As discussed by Company Witness McGowan, the Company is proposing a three-year MRP for the projected years of 2020 – 2022. A summary of the Company's projected rate base, operating income, and proposed revenue increases is included in Table 2. My testimony and accompanying exhibits support these summary amounts.

Table 2

	Multiyear Rate Plan (Dollars in Millions)		
Plan Year	**2020**	**2021**	**2022**
Rate-Effective Date	May 1, 2020	January 1, 2021	January 1, 2022
Rate Base	$2,207	$2,365	$2,565
Operating Income	$95	$90	$83
Cumulative Revenue Requirement[3]	$85	$125	$162
Incremental Revenue Requirement[4]	$85	$40	$37

Q7. What period does the MRP encompass?

A7. The MRP term includes projected costs for the calendar years 2020-2022.

[3] Includes "smoothing" adjustments as discussed later in the testimony.
[4] Includes "smoothing" adjustments as discussed later in the testimony.

Q8. Do your exhibits include any other periods in the presentation of your filing?

A8. Yes. For the purposes of the MRP, the 12-month historical period included in the filing is the calendar year for 2018. The 2019 budget is also included in the filing and is referred to as the "bridge" year throughout this testimony.

Q9. Why are 2018 actuals included as part of your presentation of MRP?

A9. In Order No. 18846,[5] the Commission noted that if Pepco were to file a multiyear rate plan, "there must be a baseline revenue and cost evaluation which is equivalent to a historical test year." The 2018 actual District of Columbia per books data is provided in PEPCO (C)-2 to satisfy that requirement.

Q10. Please explain the concept of a "bridge" year for 2019.

A10. Pepco includes 2019 as a "bridge" year between 2018 historical costs and the MRP period beginning in 2020. The "bridge" year represents the period during which this rate case application will be under review by the Commission prior to the rates becoming effective in 2020.

Q11. Why is the Company proposing an MRP term of 2020-2022?

A11. The Company expects any rate changes determined in this proceeding will go into effect during 2020, and an important aspect of alternative ratemaking in general (including MRPs) is a better matching of the timing of utility costs and rates. As such, 2020 costs will be recovered in rates going into effect in 2020, providing for such matching.

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[5] Formal Case No. 1139, Order No. 18846 at ¶594.

Q12. Why is 2019 not part of the MRP term?

A12. As previously noted, rate changes coming out of the instant proceeding are expected to be effective in 2020. If Pepco were to use 2019-2021 for its three-year MRP term and the rates going in effect in 2020 were based on 2019 costs, the rates and costs would already be misaligned. In short, Pepco would continue to experience a lag between the timing of its costs and its recovery of those costs in rates.

III. DESCRIPTION OF THE CALCULATION OF THE PROJECTED RATE BASE

Q13. Please briefly explain the concept of rate base.

A13. Generally, rate base is the value of the Company's property that is used and useful for which the Company is allowed to earn a fair rate of return.[6] Said another way, rate base represents the investor-supplied plant facilities and other investment required in supplying utility service to customers.[7] Consistent with District of Commission precedent, Pepco has calculated its MRP rate base using a 13-month average.

Rate base contains the following components that will be explained in further detail below:

- Electric Plant in Service (EPIS)
- Depreciation Reserve
- Amortization Reserve
- Materials and Supplies

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[6] Ajello, Julian. *Electric Utility Cost Allocation Manual*. National Association of Regulatory Utility Commissioners, 1992. p. 26

[7] Haine, Robert L, and Gregory E Aliff. *Accounting for Public Utilities*. Matthew Bender, 1986.

- Cash Working Capital (CWC)
- Accumulated Deferred Income Taxes (ADIT)
- Prepaid Pension Asset /OPEB Liability
- Customer Deposits
- Pepco portion of PHI Service Company (PHISCO) Assets
- Regulatory Assets
- Unamortized Credit Facility Costs (CFC)

Q14. Please describe the projection of EPIS in the MRP.

A14. EPIS makes up the largest single component of Pepco's rate base and includes the cost of electric plant owned and used in Pepco's electric utility operations and having an expected life of greater than one year from the date of installation.[8]

The projected EPIS for the years of 2020-2022 starts with the December 31, 2018 actual EPIS balances and adds projected plant additions by month, net of projected plant retirements. The Company projects its plant additions as part of its Long Range Plan (LRP).[9] The projected retirements are based on an historical average. Company Witness Barnett discusses the LRP process in detail.

Q15. How is the depreciation reserve component of the rate base projected in the MRP?

A15. The depreciation reserve represents the amount of accumulated depreciation expense on Pepco's EPIS (excluding land) as of a point in time. The 2020-2022

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[8] Pepco's EPIS is maintained in the Company's asset accounting system within the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USoA). These plant additions are included in the Construction Report and include plant additions associated with the Fredrick Douglas Bridge, which is not part of Pepco's LRP.

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depreciation reserve projection is calculated beginning with the 2018 actual depreciation reserve amounts, adding projected depreciation expense by month and subtracting projected plant retirements. The calculation of projected depreciation expense is addressed later in my testimony. As noted earlier, the projected plant retirements are based on a historical average.

Q16. How is the amortization reserve component of the rate base projected in the MRP?

A16. The amortization reserve is similar to depreciation reserve, but it represents the accumulated amortization expense on Pepco's software and other intangible assets. The amortization reserve projection is calculated beginning with the 2018 actual amortization reserve amounts and adding projected amortization expense for each of the projected years. The calculation of projected amortization expense is addressed later in my testimony.

Q17. How is the materials and supplies component of the rate base projected in the MRP?

A17. The materials and supplies category is generally made up of equipment, such as spare transformers and cables, held in stores facilities. For the purposes of the MRP projection, the materials and supplies balance has been held constant for the 2020-2022 period based on a 13-month average of actual data through February 2019.

Q18. How is the CWC component of the rate base projected in the MRP?

A18. CWC represents the amount of cash that a Company must obtain from its investors in order to provide the funds needed to operate on a day-to-day basis. Simply stated, investor funds are required in order to pay bills before cash from the sale of

utility service is received by Pepco. Inclusion of CWC in rate base provides the Company with an opportunity to recover the cost of financing these funds.

For larger companies, such as Pepco, a lead/lag study is commonly used to compute CWC. A lead/lag study is generally recognized as an accurate method of determining CWC because it is based on a detailed analysis of Company-specific data. This method estimates the timing difference between (1) when the Company renders and receives payment for its services (revenue lag) versus (2) when the Company incurs and pays its operating expenses (expense lag).

Company Witness Ziminsky presents Pepco's lead-lag study in his Direct Testimony. The lead-lag days proposed in the study are applied to Pepco's projected cash expenses for each year in the MRP period to arrive at the projected CWC allowance

Q19. How is ADIT component of the rate base projected in the MRP?

A19. ADIT represents the accumulation of deferred income taxes resulting from temporary differences between tax Internal Revenue Service (IRS) and book Generally Accepted Accounting Principles (GAAP) accounting. The projected ADIT is based on the 2018 actual ADIT balance plus the projection of monthly deferred taxes in the LRP. The projection of deferred taxes is addressed later in my testimony.

Q20. How is the prepaid pension asset/OPEB liability component of the rate base projected in the MRP?

A20. The prepaid pension asset/OPEB liability represents the net of contributions to the pension and OPEB plans versus accrued pension and OPEB expenses. These amounts are presented net of ADIT. The projected prepaid pension asset/OPEB liability

is based on the beginning balance as of 2018, less accrued pension expense, plus projected contributions to the plans. The related ADIT amounts are based on the 2018 actual balance plus the projection of monthly deferred taxes for the pension and OPEB temporary differences in the LRP.

Q21. How is the customer deposits component of the rate base projected in the MRP?

A21. Customer deposits represent funds the Company has received in advance of providing a service to a customer. For the purposes of the MRP projection, the customer deposit amounts are being held constant for the 2020-2022 period based on a three-year historical average for the years 2016 through 2018.

Q22. How is the Pepco portion of the PHISCO assets component of the rate base projected in the MRP?

A22. Pepco includes an allocated portion of net PHISCO assets in its rate base. PHISCO owns assets, such as land, structures, office furniture, computer equipment, software, and other miscellaneous equipment that are used by the PHI utilities. The same methodology used to project EPIS and depreciation/amortization reserves for Pepco assets, as described above, is used to project net PHISCO assets.

Q23. How is the regulatory assets component of the rate base projected in the MRP?

A23. Regulatory assets refer to specific costs that the Commission has permitted Pepco to defer to its balance sheet and subsequently amortize over a set period of time. The projection of regulatory assets is based on the beginning balance as of December 31, 2018, less future amortization expense based on the amortization periods approved for each individual regulatory asset.

Q24. How is the unamortized CFC component of the rate base projected in the MRP?

A24. Unamortized CFCs refer to the unamortized balance of start-up costs that Pepco incurred when it initially set up its credit facility. The projection for unamortized CFCs is based on the actual balance as of 2018 less future amortization expense based on the remaining life of the credit facility.

IV. DESCRIPTION OF THE CALCULATION OF THE PROJECTED OPERATING INCOME ITEMS

Q25. Briefly discuss operating income.

A25. Operating income represents revenues less expenses, including operations and maintenance expense, depreciation and amortization expense, other taxes, and income taxes.

Q26. What are distribution revenues, and how are they projected?

A26. Distribution revenues are the revenues collected from customers for distribution services. The projected base distribution revenues for the MRP period 2020-2022 are largely a function of projected distribution customer counts and the currently approved Bill Stabilization Adjustment revenue per customer.

Q27. How does the Company project customer counts?

A27. Generally, the Company maintains econometric models that produce sales and customer forecasts. The primary variables included in the model to explain customer growth are regional economic variables - in particular, total nonfarm employment in the District of Columbia, as published by the US Bureau of Labor Statistics. Forecasts of employment prepared by IHS Economics serve as the basis for future employment growth used in the forecast of customer counts.

Q28. What are other revenues included in operating income, and how are they calculated?

A28. Other revenues include late payment revenues, rent from electric property, interconnection fees, reconnection fees, and other miscellaneous revenues. Other revenues for the MRP period 2020-2022 are based on calendar year 2018 actuals.

Q29. Please describe operations and maintenance (O&M) expenses, and explain how they are projected in the MRP.

A29. O&M expenses include the costs of labor, materials, and other expenses necessary to operate and maintain Pepco's electric distribution system. Pepco projects its O&M expense for the planning period as part of its LRP process, as described in the testimony of Company Witness Barnett. Pepco projects its O&M expense first by department, project, and cost category. This projection is "mapped" to FERC O&M expense accounts, which are used in rate case filings including this MRP. For the MRP, Pepco is presenting 2018 actual O&M expense and 2019-2022 projected O&M expense from its LRP. The projections of Pepco's 2019-2022 O&M expenses are supported by the following Company witnesses' testimonies:

- Company Witness Barnett: PHISCO and BSC O&M expense
- Company Witness Sullivan: Electric Operations O&M expense
- Company Witness Ortega: Technical Services O&M expense
- Company Witness Fisher: Transmission and Substations O&M expense
- Company Witness Maxwell: Support Services O&M expense
- Company Witness Poncia: Customer Care O&M expense
- Company Witness Calabrese: Information Technology O&M expense

Please refer to PEPCO (C)-4, which sums the individual O&M components listed above to total projected 2019-2022 Pepco O&M expense, translates that total amount to the mapped FERC O&M expense categories, and summarizes the allocation and assignment of the total Pepco O&M expense to Pepco DC distribution.

Q30. Please explain how depreciation expense was projected in the MRP.

A30. Depreciation represents the reduction in value of a tangible, depreciable asset. Depreciation expense is the allocated portion of the cost of a fixed asset for a given accounting period. Pepco's District of Columbia depreciation expense on its accounting books is based on the depreciation rates most recently approved by the Commission in Formal Case No. 1150. Pepco's projected depreciation expense in the MRP is based on its projected monthly depreciable plant balances multiplied by the composite distribution and general depreciation rates approved by the Commission in Formal Case No. 1150. The projected monthly depreciable plant balances are based on the projections of EPIS less non-depreciable amounts, such as land.

Q31. Please explain how the amortization expense projection was developed?

A31. Amortization represents the reduction in value of an intangible asset (such as software). Amortization expense is the allocated portion of the cost of a fixed asset for a given accounting period. Pepco's projected amortization expense in the MRP is based on two factors: 1) the amortization expense and remaining useful lives on intangible assets in service as of December 31, 2018, and 2) the projected amortization expense on intangible assets expected to be placed in service during 2019-2022, based on an assumed five-year useful life (in most cases).

Pepco's amortization expense includes amortization of software, Edison Place Leasehold Improvements costs, and Pepco's Credit Facility. Pepco's amortization expense also includes the amortization of regulatory assets approved by the Commission.

Q32. Please explain how the Taxes Other Than Income Taxes were projected.

A32. Taxes Other Than Income Taxes include items such as delivery taxes, property taxes, payroll taxes, and other taxes assessed by jurisdictions or other local government authorities, except income taxes. The Company used the following methodologies to project Taxes Other Than Income Taxes for the period of the MRP: a) taxes collected through a surcharge (such as the District of Columbia delivery tax) are projected based on the Company's kWh sales projection multiplied by approved surcharge rates; b) property taxes are projected based on the projection of tax assessment values of Company-owned properties multiplied by the effective tax rate; c) payroll taxes are projected based on Pepco's labor expense projection; d) other taxes, such as District of Columbia sales and use tax, District of Columbia Commission fees, and District of Columbia business improvement taxes, are being held constant throughout the MRP period at the 2018 levels.

Q33. Please explain how District of Columbia income taxes are projected.

A33. Pepco's total projected District of Columbia income tax is calculated by multiplying the Pepco taxable income by the District of Columbia apportionment[10] percentage and then multiplying by the District corporate income tax rate of 8.25%. District of Columbia projected taxable income is a function of the revenues minus the expense items described earlier in my testimony, plus or minus Pepco's projection of permanent tax adjustments and temporary timing differences. District of Columbia income tax can be further broken down by the deferred portion that will be due in later periods and the current portion due to the District in the year in question. To calculate the deferred portion of District of Columbia income tax, the Company multiplies the District temporary timing differences by the District apportionment percentage and then by the District corporate tax rate of 8.25%. To calculate the current portion of District of Columbia income tax, the deferred portion is subtracted from the total District of Columbia income taxes.

Another component of the income tax projection is the net operation loss (NOL) that occurs when more expenses than revenues are incurred during the period, meaning the Company has no taxes due for the current period and therefore carries the tax deduction forward for future use. The Company has District of Columbia NOL carryforwards from previous years in its calculation of rate base for the MRP projection.

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[10] For state income tax purposes, companies are required to apportion their activities between jurisdictions. The apportionment calculation can differ between jurisdictions but generally includes a single factor or a combination of factors such as sales, property and payroll. District of Columbia apportionment calculation is sales only. The Company calculates its District of Columbia apportionment by taking District of Columbia sales divided by total sales.

Q34. Please explain how the Federal income taxes are projected.

A34. Pepco's total projected Federal income tax is calculated by multiplying the Federal corporate taxable income by the Federal corporate income tax rate of 21%. Federal projected taxable income is a function of the revenues minus the expense items described earlier in my testimony, including District of Columbia and Maryland income tax expense, plus or minus Pepco's projection of permanent tax adjustments and temporary timing differences. Federal income tax can be further broken down by the deferred tax portion that will be paid in later periods and the current portion due to the Federal government in the year in question. To calculate the deferred portion of Federal income tax, the Company multiplies the Federal temporary timing differences by the Federal corporate income tax rate of 21%. To calculate the current portion of Federal income tax, the deferred portion is subtracted from the total Federal income tax amount. The Company currently has no Federal NOLs to report for the MRP projection.

V. ALLOCATION OF PEPCO COSTS TO DISTRIBUTION AND TO THE DISTRICT OF COLUMBIA

Q35. How are the distribution portion of total Pepco projected costs determined in the MRP?

A35. Company Witness Ziminsky describes the process whereby the costs in the traditional test period are assigned and allocated to the distribution function (See Ziminsky PEPCO (D)-2). That process is identical in the MRP.

Q36. Have you prepared a schedule that summarizes total system and distribution-only cost-of-service elements?

A36. Yes. PEPCO (C)-2, page 1 of 3, presents a listing of the projected rate base and operating income elements on both a system- and a distribution-only level. Pages 2 and 3 of PEPCO (C)-2 provide a short description of the method used to identify the distribution-related portion of these costs. The method used to determine distribution-related cost of service is consistent with that used by the Company and accepted by the Commission in Formal Case Nos. 1103 and 1139.

Q37. How are distribution costs assigned or allocated to the District of Columbia in the MRP?

A37. Company Witness Ziminsky describes the jurisdictional allocation process whereby distribution costs are assigned and allocated to the District of Columbia jurisdiction in the traditional test period. The process is the same for the MRP.

Q38. Have you prepared a jurisdictional cost-of-service study for the MRP?

A38. Yes. PEPCO (C)-3 presents the jurisdictional allocation of Pepco's actual distribution costs for 2018, the projection of distribution costs for bridge year 2019, and the MRP projected years 2020, 2021, and 2022.

VI. DESCRIPTION OF THE RATEMAKING ADJUSTMENTS (RMAS) IN THE MRP

Q39. What are RMAs?

A39. RMAs are *pro forma* adjustments to the cost of service for reasons including (but not limited to) known and measurable changes, normalizations of volatile costs, or, in

some cases, to adjust the "per books" cost of service for past Commission practice regarding cost allowances and disallowances.

Q40. Are there any RMAs included in the MRP?

A40. Yes. The following RMAs were made to the MRP:

Table 3

RMA	RMA Description
1	Removal of supplemental executive retirement plan (SERP) costs
2	Removal of executive incentive plan (EIP) costs
3	Removal of institutional advertising/selling expenses
4	Removal of employee club costs
5	Removal of industry contributions and membership fees
6	Removal of executive perquisite expenses
7	Adjustment to BSC billed depreciation
8	Inclusion of customer deposit interest expense and credit
9	Reflection of current rate case costs
10a	Reflection of Benning regulatory asset – actual
10b	Reflection of Benning regulatory asset – forecast
11	Reflection of costs to achieve (CTA) regulatory asset
12	Reflection of PHISCO deficient deferred income taxes (DDIT)
13	Additional subtraction modification
14	Reflection of inflationary growth of O&M expense
15	Reflection of costs to optimize (CTO) regulatory asset
16	Reflection of CWC impact of ratemaking adjustments
17	Interest synchronization

Please refer to PEPCO (C)-1 page 1, which outlines the rate base and operating income inputs in the MRP period.

Q41. Do similar RMAs appear in Company Witness Ziminsky's testimony?

A41. Yes, Company Witness Ziminsky testifies to RMAs with similar names and purposes in connection with the traditional test period compliance filing. The RMAs in my testimony reflect adjustments to the MRP term of 2020-2022.

Q42. Why is there a need for RMAs in the MRP?

A42. Pepco's projected costs in its MRP include items for which the Company is not seeking recovery, and, therefore, certain items need to be removed from the MRP through an RMA. In addition, Pepco is seeking authorization to establish and recover certain regulatory assets and has added those items to its MRP.

Q43. Please describe the first RMA with respect SERP.

A43. The first RMA removes from Pepco's projected O&M expense 100% of Pepco's SERP expense and removes the capitalized portion of SERP expense from rate base for each of the projected years. Company Witness Ziminsky discusses the background for this RMA. The projected amounts are based on Pepco's LRP projection for SERP costs. Please see Table 4 for impacts on earnings of this RMA by year. Please also refer to PEPCO (C)-1, page 6.[11]

Table 4

RMA 1 Impact	**2020**	**2021**	**2022**
Rate Base	(728)	(871)	(998)
Operating Income	556	589	588

[11] Except as otherwise noted, all the amounts in Tables 4 through 21 are in thousands.

Q44. Please describe RMA 2 with respect to EIP.

A44. Consistent with Order No. 18846, RMA 2 removes the shareholder-related portion of EIP from the projected cost of service, so that only the portion of executive incentive expense associated with customer-related goals remains.[12] The projected shareholder-related EIP for the MRP term was held constant based on projected 2019 amounts.

In addition, RMA 2 removes projected costs associated with the long-term incentive plan (LTIP) expense that are not tied to customer-related goals. Company Witness Ziminsky discusses the background for this RMA. The projected amounts for non-customer-related LTIP were calculated based on the LRP projection. Please see Table 5 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 7.

Table 5

RMA 2 Impact	**2020**	**2021**	**2022**
Rate Base	(488)	(551)	(608)
Operating Income	1,128	1,055	1,090

Q45. Please describe RMA 3 with respect to institutional and promotional advertising expenses.

A45. RMA 3 removes projected expenses associated with institutional and promotional advertising, consistent with Commission precedent. Company Witness Ziminsky discusses the background for this RMA. The projected amounts were

[12] The Chief Executive Officer is the only employee of Pepco Holdings whose Annual Incentive Plan target payout is determined, at least partially, by financial goals.

calculated based on Pepco's LRP projection of FERC Account 930.1. Please see Table 6 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 8.

Table 6

RMA 3 Impact	**2020**	**2021**	**2022**
Rate Base	-	-	-
Operating Income	158	159	157

Q46. Please describe RMA 4, relating to costs associated with employee club activities.

A46. RMA 4 removes from the MRP certain employee benefit costs associated with employee association activities, as the Commission directed in Order No. 15710 in Formal Case No. 1076. Company Witness Ziminsky discusses the background for this RMA. The projected amounts were held constant based on 2018 actuals. Please see Table 7 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 9.

Table 7

RMA 4 Impact	**2020**	**2021**	**2022**
Rate Base	-	-	-
Operating Income	31	31	31

Q47. Please describe RMA 5 with respect to costs associated with industry memberships and contributions.

A47. To comply with long-standing Commission precedent, RMA 5 removes projected costs associated with industry memberships and contributions. Company Witness Ziminsky discusses the background for this RMA. The projected amounts were

calculated based on the LRP projection of these costs. Please see Table 8 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 10.

Table 8

RMA 5 Impact	**2020**	**2021**	**2022**
Rate Base	-	-	-
Operating Income	319	328	331

Q48. Please describe RMA 6 with respect to removal of executive perquisite expenses.

A48. Consistent with the Commission's decision in Formal Case No. 1139,[13] RMA 6 reflects the removal of projected executive perquisite expense from the projected cost of service. Company Witness Ziminsky discusses the background for this RMA. The projected amounts were held constant based on 2018 actuals. Please see Table 9 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 11.

Table 9

RMA 6 Impact	**2020**	**2021**	**2022**
Rate Base	-	-	-
Operating Income	20	20	20

Q49. Please describe RMA 7 with respect to BSC billed depreciation.

A49. RMA 7 adjusts projected expenses associated with BSC depreciation expense billed to Pepco, in compliance with Merger Commitment 39. Company Witness

[13] Formal Case No. 1139, Order No. 18846 at ¶171.

Ziminsky discusses the background for this RMA. The projected amounts were calculated by applying the difference in depreciation lives between BSC and Pepco to the actual BSC plant balances as of 2018. Please see Table 10 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 12.

Table 10

RMA 7 Impact	**2020**	**2021**	**2022**
Rate Base	-	-	-
Operating Income	340	340	336

Q50. Please describe RMA 8 with respect to interest expense on customer deposits and credit facility quarterly maintenance fees.

A50. In accordance with Commission precedent, RMA 8 increases projected O&M expense to reflect the interest expense related to the average level of customer deposits at the 2019 rate of 2.64%.[14] This RMA also includes the quarterly maintenance fees on Pepco's credit facility in the projected O&M expense, consistent with Commission precedent. The projected interest on customer deposits was calculated by applying the 2.64% rate to Pepco's forecasted average customer deposit balances for 2020 through 2022. The projected quarterly maintenance fees were held constant based on 2018 and 2019 Q1 actual fees. Company Witness Ziminsky discusses the background for this RMA. Please see Table 11 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 13.

[14] Formal Case No. 712, Order No. 19771 (Dec. 13, 2018).

Table 11

RMA 8 Impact	**2020**	**2021**	**2022**
Rate Base	-	-	-
Operating Income	(338)	(338)	(336)

Q51. Please describe RMA 9 with respect to current case costs.

A51. RMA 9 adjusts the cost of service to amortize incremental costs associated with this proceeding over a three-year amortization period, consistent with Commission precedent, including Formal Case No. 1139.[15]

Company Witness Ziminsky discusses the background for this RMA. The projected amounts were calculated using the current rate case cost estimates for the instant proceeding less Formal Case No. 1150 rate case costs to be refunded to customers, amortized over three years. Please see Table 12 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 14.

Table 12

RMA 9 Impact	**2020**	**2021**	**2022**
Rate Base	2,255	1,353	451
Operating Income	(229)	(902)	(902)

[15] Formal Case No. 1139, Order No. 18846 at ¶171.

Q52. Please summarize the contents of RMA 10a – Inclusion of actual Benning Road facility remedial investigation/feasibility study (RI/FS) regulatory asset.

A52. RMA 10 consist of two separate components to address the remediation efforts at the Benning Road facility: 1) actual remedial investigation costs from January 1, 2018 through March 31, 2019 and 2) actual costs to remove the cooling tower base and contaminated soil. Company Witness Ziminsky discusses the background for this RMA.[16] The projected amortization expense was calculated using a 10-year amortization period (as agreed to in the Formal Case No. 1150 settlement approved by the Commission in Order No. 19433) applied to the costs described above. Please see Table 13 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 15.

Table 13

RMA 10a Impact	**2020**	**2021**	**2022**
Rate Base	1,985	1,775	1,567
Operating Income	(209)	(209)	(209)

Q53. Please summarize the contents of RMA 10b regarding inclusion of the projected Benning Road facility RI/FS regulatory asset.

A53. RMA 10b consists of projected costs associated with the Benning Road facility RI/FS. The Company proposes that in its May 2021 Annual Reconciliation Filing (described later in this testimony) it true up these amounts with actual spending through year-end 2020 (and similarly with actual spending through 2021 in its May 2022 Annual

[16] Company Witness Ziminsky also discusses environmental efforts related to Anacostia River Sediment project, in which the Company is requesting deferral treatment for costs.

Reconciliation Filing). Company Witness Ziminsky discusses the background for this RMA. The projected amounts adjust amortization expense in the MRP term based on a ten-year amortization period of the costs projected RI/FS costs described above. Please see Table 14 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 16.

Table 14

RMA 10b Impact	**2020**	**2021**	**2022**
Rate Base	334	299	264
Operating Income	(35)	(35)	(35)

Q54. Please describe RMA 11 with respect to the CTA regulatory asset.

A54. RMA 11 adjusts the projected rate base to reflect the CTA regulatory asset (and its impact on ADIT) and adjusts projected amortization expense to reflect a five-year amortization of the CTA regulatory asset balance[17] in accordance with the Commission's decision in Formal Case No. 1119.[18] Company Witness Ziminsky discusses the background for this RMA. Please see Table 15 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 17.

[17] As of June 2018.

[18] Formal Case No. 1119, Order No. 18148 ("Merger Order"), Attachment B (the "Merger Commitments") at ¶27 (establishing a five-year amortization period). The Commission subsequently issued Order No. 18160 correcting certain errors in the Merger Order and the Merger Commitments. References herein to the Merger Order and the Merger Commitments are to Order No. 18148 and Attachment B to Order No. 18148, respectively, as corrected by Order No. 18160.

Table 15

RMA 11 Impact	**2020**	**2021**	**2022**
Rate Base	6,171	4,800	3,429
Operating Income	(1,371)	(1,371)	(1,371)

Q55. Please describe RMA 12 with respect to the PHISCO DDIT regulatory asset.

A55. RMA 12 represents the amortization of PHISCO's recoverable DDIT balances allocated to Pepco, using the amortization periods agreed to in the settlement in Formal Case Nos. 1150 and 1151,[19] Pepco proposes to amortize the property-related excess deferred income tax liability over 10 years and the non-property-related excess deferred income tax asset over a five-year period. Company Witness Ziminsky discusses the background for this RMA. Please see Table 16 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 18.

Table 16

RMA 12 Impact	**2020**	**2021**	**2022**
Rate Base	1,039	408	(223)
Operating Income	(631)	(631)	(631)

[19] Formal Case Nos. 1150 and 1151, Order No. 19433 at ¶6.

Q56. Please describe RMA 13 with respect to reflection of the additional subtraction modification.

A56. RMA 13 proposes to provide customers with the projected state income tax benefit attributable to the recognition of an incremental increase to the Maryland "Statutory Subtraction" modification. Company Witness Ziminsky discusses the background for this RMA. The projected income tax impacts were calculated using an amortization period of 36.42 years, based on the average remaining lives outlined in Pepco's most recent depreciation study filed in Formal Case No. 1150. Please see Table 17 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 19.

Table 17

RMA 13 Impact	2020	2021	2022
Rate Base	-	-	-
Operating Income	598	598	598

Q57. Please describe RMA 14 with respect to the O&M inflation adjustment.

A57. RMA 14 proposes an increase to O&M expense in MRP years 2021 and 2022 using a five-year average of the Gross Domestic Product Price Index (GDPPI) for the MRP term. As can be seen from PEPCO (C)-4, discussed earlier in my testimony, Pepco's internal LRP projections are for O&M expense growth to be relatively flat during the 2020-2022 MRP period. It is reasonable to expect that Pepco's O&M expense may increase at an inflationary rate during that time period, particularly in light of historical increases in Pepco's O&M expense. As such, Pepco has applied a five-year average of the GDPPI to its 2020 projected District of Columbia Distribution O&M

expense[20] to adjust 2021 and 2022 O&M expense versus Pepco's internal LRP projections.

The GDPPI index was selected as an escalation factor because it measures the changes in price of consumer goods and services, investment goods, government services, imports, and exports. GDPPI is measured by the U. S. Commerce Department, is readily available, and calculated on a timely basis every quarter, making it a reliable, accurate, and easy to obtain index. Please see Table 18 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 20.

Table 18

RMA 14 Impact	**2020**	**2021**	**2022**
Rate Base	-	-	-
Operating Income	-	(644)	(3,630)

Q58. Please describe RMA 15 with respect to reflection of the CTO regulatory asset.

A58. CTO represents up-front costs incurred to achieve future savings through BSC's Transformation Initiative. The BSC Transformation Initiative is a process whereby BSC has identified O&M savings in 2021 and beyond. These savings are expected to be achieved through a focus on improving efficiencies, eliminating redundancies, and leveraging innovation and technologies. In order to achieve these cost savings, BSC has and will incur certain costs, referred to as CTO.

[20] Pepco has removed depreciation and amortization included in O&M expense from these amounts.

Pepco is proposing to remove the CTO from O&M and defer it to a regulatory asset to be amortized over a five-year period to better match the recovery of CTO with the projected savings. Please refer to Table 19 for the impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 21.

Table 19

RMA 15 Impact	**2020**	**2021**	**2022**
Rate Base	1,090	848	606
Operating Income	42	(238)	(238)

Q59. Please describe RMA 16 with respect to CWC.

A59. RMA 16 adjusted the MRP CWC allowance based on the previously discussed RMAs to the extent they impact cash operating expenses. Please see Table 20 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 22.

Table 20

RMA 16 Impact	**2020**	**2021**	**2022**
Rate Base	(103)	(51)	51
Operating Income	-	-	-

Q60. Please describe RMA 17 with respect to interest synchronization.

A60. Consistent with Commission precedent, including Formal Case No. 1139, RMA 17 adjusts District of Columbia and Federal income tax expense to reflect the impact on synchronized income taxes of the ratemaking adjustments to rate base and related interest expense, as described in my testimony. Company Witness Ziminsky discusses

the background for this RMA. Please see Table 21 for impacts of this RMA by year. Please also refer to PEPCO (C)-1, page 25.

Table 21

RMA 17 Impact	**2020**	**2021**	**2022**
Rate Base	-	-	-
Operating Income	83	57	33

VII. SUMMARY OF THE MRP REVENUE REQUIREMENT ITEMS

Q61. Please summarize the MRP revenue requirement.

A61. Pepco's total MRP revenue requirement under the MRP consists of the sum of "Per Books" projected cost of service for the period of 2020-2022 and the RMAs detailed in Part VI. When summed together, these amounts represent the Pepco-Distribution-DC-adjusted MRP cost of service. Please refer to PEPCO (C)-1, which summarizes the items discussed above and provides the calculation of the revenue requirement for each year of the MRP.

Q62. Has Pepco included any "smoothing" adjustments to its revenue requirements per its Pepco-Distribution-DC-adjusted MRP cost of service?

A62. Yes. Pepco is proposing that it "smooth" its MRP rate increases in order to more evenly spread out the rate increases over the three-year MRP period and mitigate potential Year 1 rate impacts. Pepco's last rate case, Formal Case No. 1150, was based on a test period ended December 31, 2017, whereas Pepco's MRP starts with the calendar year ended December 31, 2020, representing a three-year difference in the costs on which rates are based. Over that three-year period, the Company anticipates rate base

will have grown significantly, primarily due to reliability investments and customer and load-driven investment in the District. This growth in rate base will lead to a significant revenue deficiency for the 2020 MRP year.

Pepco is proposing to utilize the MRP period to "smooth" the rate increases over the 2020-2022 timeframe, such that it will collect its entire revenue requirement for the MRP years 2020-2022 during the MRP, but the revenue increase has been shifted somewhat from 2020 to 2021-2022. Pepco is proposing that it recover 52.5% of its 2020-2022 revenue requirement in its first MRP increase, 25% in its second MRP increase, and 22.5% in its third MRP increase. Table 22 shows this shift.

Table 22
(Dollars in Millions)

		2020[21]	**2021**	**2022**
1	Cumulative Rate Increase – No Smoothing	$ 107	$131	$ 162
2	"Smoothing Adjustment"	($22)	($5)	$0
3	Cumulative Rate Increase – With Smoothing, and % of Total	$ 85	$125	$ 162
4	Incremental Revenue Requirement, with smoothing[22]	$85	$40	$37
5	Projected Earned Return on Equity (ROE)	7.10%	9.99%	10.30%

[21] The 2020 projected earned ROE assumes a May 1, 2020 rate-effective date, thus only eight months of incremental revenue will be collected in 2020.

[22] As noted in question 6 above.

Line 1 of Table 22 above shows Pepco's cumulative 2020-2022 revenue requirements at its requested 10.30% ROE. Line 2 of Table 22 above shows Pepco's proposed smoothing adjustment. Line 3 of Table 22 shows Pepco's proposed MRP rate increases including the smoothing adjustment as well as the percent of total. Line 5 shows Pepco's projected earned ROE based on the amounts in Line 3. Line 4 shows Pepco's incremental revenue requirement, including the proposed smoothing adjustment. All of the figures on Table 22 are presented on page 1 of PEPCO (C)-1. Said another way, the projected earned ROE represents the authorized ROE less the ROE impact of the smoothing adjustment.

VIII. DEFERRED ACCOUNTING MECHANISM

Q63. Pepco's MRP proposes to set customer rates through the end of 2022 using projected revenues and costs as the basis for said rates. Are there other, unforeseen costs that could arise during the MRP period?

A63. Yes. During the MRP period the Company could incur a number of unforeseen costs. These unforeseen costs could be due to internal factors at Pepco (for instance, an internal decision to increase staffing in a certain department) or due to external factors beyond Pepco's control. Externally driven costs could arise due to events such as, but not limited to, weather events, acts of God, cyber security events, changes in regulation, changes to or new legislation, or changes in GAAP. This list is not meant to be exhaustive but to provide some guidance for the types of external exogenous factors that could arise.

Q64. For unforeseen costs due to external factors beyond Pepco's control, how does Pepco propose to handle those in the MRP?

A64. Pepco proposes that for unforeseen costs due to external factors beyond Pepco's control during the term of the MRP (2020-2022), the Company would request deferral (regulatory asset) treatment, provided that the change is reasonably expected to increase or decrease the Company's District of Columbia distribution jurisdictional revenue requirement by at least $1.0 million in that year.[23] For ratemaking symmetry purposes, Pepco proposes to earn a return at the Company's authorized rate of return on this regulatory asset or accrue a return at the same rate for a regulatory liability, until which time it is reflected in customer rates.

Q65. How would customers benefit from this deferred accounting treatment?

A65. By deferring and amortizing the cost of impactful external events with a revenue requirement impact of at least $1 million, customer rates impacts in any single year are mitigated. The Commission has a history of deferring and amortizing costs associated with non-recurring items.[24]

Q66. How would Pepco request deferral treatment for these externally driven costs?

A66. In the event that Pepco experiences an external event with a revenue requirement impact of at least $1 million, Pepco proposes to submit a filing to the Commission including: a description of the unforeseen costs, a description of the external factors, and

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[23] This represents the revenue requirement prior to any amortization. For instance, if a storm occurs and Pepco incurs $1.5 million of District of Columbia-incremental O&M costs, this would be greater than $1.0 million in revenue requirement. Pepco may propose to amortize these storm costs over five years, which would equate to a $0.3 million annual amortization expense.

[24] Formal Case No. 1139, Order No. 18846 at ¶170 (RMA 31 Amortization of F.C. No. 1076 management audit costs) ¶208 (RMA 39 non-recurring billing system costs).

the amount for the unforeseen costs. The filing would include a request for regulatory asset or liability treatment of the amount(s) in question. Pepco would make this filing within 90 days of identifying the event, after which parties would have 30-days to ask discovery and provide comments. The Company proposes a Commission decision on the Company's filing within 60 days after the end of the 30 day discovery and comment period.

Q67. Relating to unforeseen storm costs specifically, what type of storm costs would Pepco propose to include?

A67. Pepco proposes that both preparation and restoration costs associated with named storms and Major Service Outages (MSOs)[25] would be included for potential regulatory asset treatment. In the event such a storm has a revenue requirement impact of at least $1 million Pepco could seek to defer incremental O&M costs related to the storm as well as any depreciation expense on incremental storm-related capital.

Q68. How would Pepco ultimately recover the regulatory asset or liability?

A68. Once the Commission authorized regulatory asset or liability treatment for the costs in question, Pepco would include these costs for recovery in its next rate case filing.

[25] The Commission's EQSS define an MSO as "customer interruption occurrences and durations during time periods when more than 10,000 of the electric utility's District of Columbia customers are without service and the restoration effort due to this major service outage takes more than twenty-four (24) hours." 15 D.C.M.R §3699.1.

Q69. How does Pepco currently recover storm costs in the District of Columbia?

A69. Pepco currently recovers storm costs using a three-year average of both major- and minor-storm related O&M expense. Storm-related capital is included in EPIS in rate base depending on the test period in the case. Under the MRP, Pepco proposes that the three-year average convention for storm-related O&M expense would no longer be used.

Q70. How does this proposal differ from Pepco's current treatment?

A70. Pepco proposes that it use its projected storm expense for the purpose of setting base distribution rates in the MRP. This projected level of storm expense would serve to cover normal storm activity. If Pepco were to incur storm costs associated with an event that rose to the level of regulatory asset treatment (named storm or MSO of at least a $1.0 million revenue requirement impact), it would seek recovery of those amounts through the regulatory asset, separately from rates set in the MRP.

IX. ANNUAL RECONCILIATION FILING

Q71. In Order No. 18846, did the Commission impose any conditions for Pepco to follow in its alternative ratemaking proposal?

A71. Yes. The Commission noted in Order No. 18846 that it was not averse to such a proposal given certain conditions, including the following: "Pepco needs to provide a mechanism which allows parties to reconcile any forecasted components to subsequent actuals for the same test year." [26]

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[26] Formal Case No. 1139, Order No. 18846 at ¶594.

Q72. Has Pepco proposed such a mechanism?

A72. Yes. Pepco is proposing an Annual Reconciliation Filing as part of its MRP.

Q73. Please explain the Annual Reconciliation Filing under the Company's proposed MRP.

A73. As discussed more fully by Company Witness McGowan, following the first calendar year (2020) and each year thereafter of the MRP period, the Company will provide a reconciliation filing to compare actual Pepco-Distribution-DC-adjusted calendar-year results versus the projected Pepco-Distribution-DC-adjusted calendar-year data provided in the MRP. The Company will provide a reconciliation of all elements of rate base and earnings, including the difference and calculation of the revenue requirement impact. The proposed reconciliation would also include a reconciliation of the projected cost of debt and capital structure to the Company's actual cost of debt and capital structure. Identical to Pepco's traditional presentation of its District of Columbia distribution cost of service, the Annual Reconciliation Filing would include a calculation of Pepco's actual earned Return on Equity (earned ROE) for the period.

The Annual Reconciliation Filing would compare Pepco's actual rate base, earnings, and earned ROE with its projected rate base, earnings, and ROE.

Q74. Please explain how the Company plans to address actual versus projected variances that will occur during the course of the MRP.

A74. Because the MRP term (years 2020-2022) is based on projected costs, it is likely that actual costs will differ somewhat from the projections. This could be due to a number of factors, such as exogenous factors, internal cost overruns or cost savings.

Pepco's Annual Reconciliation Filing will include projected versus actual variance analyses at the Pepco-DC distribution level, including a narrative description of the variance drivers for any significant annual variances. In order to streamline the Annual Reconciliation Filing, the Company proposes to provide descriptions for significant annual variances to the extent they exceed the thresholds, as defined in Table 23. An account that is below these thresholds will be deemed to be on budget, with no further action or analysis required.

Table 23

Group	Description	Basis	Threshold
1	EPIS, Accumulated Depreciation, Accumulated Deferred Income Taxes, Sale of electricity Revenues.	PEPCO (C)-1, p.1 Column 3.	At least 1% and a minimum of $500,000
2	Accumulated Amortization, Materials and Supplies, Cash Working Capital, Prepaid Pension/OPEB Liab., Customer Deposits, Pepco Portion of Servco Assets, Regulatory Assets, Unamortized Credit Facility Costs, Other Revenues, Depreciation Expense, Amortization Expense, Other Taxes, District Income Tax, Federal Income Tax.	PEPCO (C)-1, p.1 Column 3.	At least 5% and a minimum of $500,000
3	Operation and Maintenance Expense	PEPCO (C)-3, p. 4-1 through 4-9 Column 2.	At least 10% and a minimum of $500,000

The variance report and the narrative description of significant variances in the actual versus projected amounts will provide the parties and the Commission an appropriate level of information to evaluate the Company's results. The Company has

provided PEPCO (C)-5 as an example of the summary and variance analysis it would include in its Annual Reconciliation Filing.[27] Tab 1 includes the summary comparison and variances for groups 1 and 2, Tab 2 includes the O&M comparison, and variance for group 3.

Q75. How does Pepco propose that the actual earned ROE be calculated?

A75. Pepco files quarterly earned return reports with the Commission. These quarterly earned return reports are filed 30 days after the filing of Pepco's FERC Form 3Q (quarterly) and Form 1 (annual) filings and are calculated per Commission precedent in the most recent order, including unadjusted per books results, jurisdictional allocations and ratemaking adjustments per the most recent Commission order.

The filing includes a calculation of the actual earned rate of return and earned return on equity. Pepco proposes to rely on this format to reconcile its actual results with projected results per the MRP, using all the same calculation methods (e.g., 13-month average rate base,) distribution and jurisdictional allocation methods (e.g., allocation of general plant to distribution based on labor ratio, allocation of subtransmission plant to District of Columbia based on Average & Excess – Non Coincident Peak method), and ratemaking adjustments (e.g., removal of institutional and promotional advertising expense) ultimately approved by the Commission in this proceeding. Pepco would include a schedule providing side-by-side variances for each cost-of-service item,

[27] PEPCO (C)-5 provides the summary schedules Pepco would provide in its Annual Reconiliation Filing. The filing would also include the following items: 1) Jurisdictional Cost of Service Study, 2) Ratemaking Adjustments Summary (RMA Summ), 3) Revenue Requirement by RMA (Rev Req RMA), 4) Individual Ratemaking Adjustments Worksheets, 5) Capital Structure, 6) Tax Factors; 7) Performance Incentive Mechanisms actual performance versus target report.

including variance explanations. This side-by-side variance schedule would then be used to determine any sharing amounts in accordance with the Annual Reconciliation Filing mechanism for the year in question (starting with MRP year 2020). Please see PEPCO (C)-5 for an actual example of this filing.

Q76. How does the Company propose to address variances between actual results and MRP projections?

A76. Pepco proposes that there be a plus or minus 25 basis-point deadband around its projected earned ROE. [28] If Pepco's actual earned ROE falls within this deadband,[29] no adjustment to rates would be made.

Q77. What would happen if the actual earned ROE was outside this deadband?

A77. If the actual earned ROE is outside of this band, Pepco proposes a 75-25 sharing between customers and the Company. Please see Table 24, which visually portrays this mechanism, using Pepco's projected earned ROE of 7.10% for 2020:

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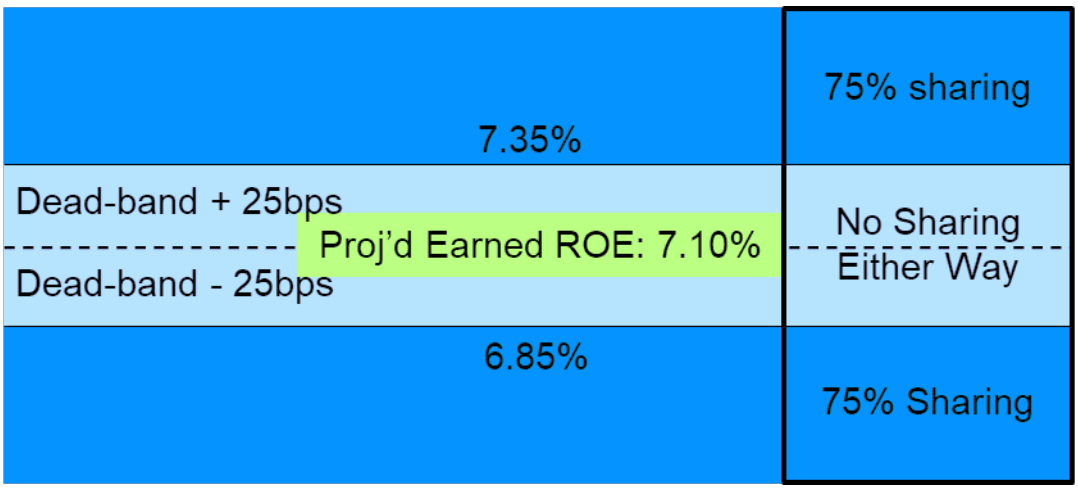
[28] The projected earned ROE is based on the ROE for 2020 and 2021 which will bring the Company to its authorized ROE in 2022. It is different than authorized ROE due to the "smoothing" adjustments in 2020 and 2022. See questionand answer 62 for more information.

[29] For the purposes of this testimony, a deadband is a defined range of basis points above and below the authorized earned ROE in which no penalty or reward will be awarded if the actual earned ROE falls within this range.

Table 24



Q78. What happens if Pepco's actual earned ROE is within the plus or minus 25 basis point deadband?

A78. Again, if Pepco's earned ROE is within the deadband surrounding its projected earned ROE (see question and answer 62 for definition), then no sharing would occur either way. This allows for variation between actual and projected costs before any rate adjustment is proposed.

Q79. How did the Company determine its deadband parameters of plus or minus 25 basis points?

A79. Pepco first reviewed other similar mechanisms throughout the industry. Pepco's proposed plus or minus 25 basis point deadband allows for a level of normal variation in which no sharing adjustment is necessary. For actual results outside the deadband, sharing would occur.

Q80. What happens if Pepco's actual earned ROE is more than 25 basis points above its projected earned ROE?

A80. In the event that Pepco exceeded its projected earned ROE by more than 25 basis points, the Company commits to return 75% of the excess above the deadband to customers in the next rate-effective date, with Pepco retaining the other 25%.

Q81. What happens if Pepco's actual earned ROE is more than 25 basis points below its projected earned ROE?

A81. In the event that Pepco under earned its projected earned ROE by more than 25 basis points, it would request the Commission to allow Pepco to collect from customers 75% of the amount below the 25 bps on the next rate-effective date.

Q82. Can you provide an example of what would happen if Pepco's actual earned ROE was 8.35% (in excess of the 7.10% projected earned ROE in Table 24)?

A82. Yes. In this scenario, customers would receive 75% of the earnings above the top of the deadband. The math would work as follows:

Actual Earned ROE:	8.35%
Vs. Projected ROE Top Deadband	7.35% (7.10%+.25%)
Difference:	1.00%
Customer Sharing Amount:	1.00% x 75% = .75%
Pepco Sharing Amount:	1.00% x 25% = 0.25%
Pepco potential to Earn:	8.35% - .75% = 7.60%

Q83. How does this address potential earnings results that exceed the projected earned ROE by the Company?

A83. This sharing mechanism provides the Company with an incentive to control and reduce its costs through the ability to retain 25% of its earnings above the edge of the deadband, while limiting the Company's potential earnings by sharing the majority (75%) with customers.

Q84. Can you provide an example of what would happen if Pepco's actual earned ROE was 5.85% (below the 7.10% projected ROE in Table 24)?

A84. Yes. In this scenario, Pepco would file a request with the Commission that customers fund 75% of the under earnings below the bottom of the deadband. The math would work as follows:

Actual Earned ROE:	5.85%
Vs. Projected ROE Bottom Deadband	6.85% (7.10%-.25%)
Difference:	-1.00%
Customer Sharing Amount:	-1.00% x 75% = -0.75%
Pepco Sharing Amount:	-1.00% x 25% = -0.25%
Pepco potential to Earn:	5.85% + 0.75% = 6.60%

Q85. How would the Annual Reconciliation Filing sharing amounts be included in customer rates?

A85. Pepco proposes that any sharing amounts be included in the next applicable rate-effective date. Any sharing amounts resulting from the May 2021 Annual Reconciliation Filing would be included in the January 1, 2022 rate-effective date as an addition or subtraction to that rate change. Any sharing amounts resulting from the May 2022

Annual Reconciliation Filing would be included in the January 1, 2023 rate-effective date as an addition or subtraction to that rate change (assuming another MRP is instituted following this one).

Q86. Will the Commission (and other parties) have an opportunity to review Pepco's actual costs versus its projection?

A86. Yes. Pepco proposes that it would make this filing around May 15th, after which there would be a 60-day discovery and comment period. After this period ends, Pepco would propose a 30-day period for the Commission to issue a decision with respect to the Company's filing and any sharing amounts necessitated by the Annual Reconciliation Filing.

Pepco's proposal is that earned ROEs above the deadband would be shared and returned to customers, whereas earned ROEs below the deadband would trigger a Pepco request for Commission approval to recover the higher costs from customers at the next rate-effective date. The other parties would have an opportunity to do due diligence and file comments on Pepco's request.

Q87. How will the performance incentive mechanisms be addressed in the Annual Reconciliation Filing?

A87. In its Annual Reconciliation Filing, Pepco will report on its performance versus the PIM targets approved by the Commission and calculate the ROE penalty or reward based on its actual performance.

If Pepco incurs a PIM penalty, it proposes that it would decrease rates on the next rate-effective date by the revenue requirement equivalent of the ROE basis point penalty. This amount would be subtracted from any sharing amount, as described above.

If Pepco incurs a PIM reward, it proposes that it would increase rates on the next rate-effective date by the revenue requirement equivalent of the ROE basis point reward. This amount would be added to any sharing amount as described above.

X. RE-OPENER PROVISION

Q88. What is a re-opener provision?

A88. Re-opener provisions allow any party, including the Commission on its own motion, to file a petition to re-open and review the Company's MRP if there is sufficient evidence that there is a problem that cannot be resolved through another avenue available under the plan. The purpose of the re-opener provision is to protect both customers and the utility from unintended outcomes of the MRP. For example, if new legislation is adopted which materially decreased Pepco's costs, it may be necessary to terminate the MRP through the re-opener and make a new rate filing. The re-opener provision would allow the parties to modify the MRP to mitigate the unforeseen circumstance or, alternatively, to exit the MRP.

Q89. Is the Company proposing to include a re-opener provision as part of its MRP?

A89. Yes; however, the Company views the re-opener provision as a last resort. The deferred accounting mechanism and the annual reconciliation filing should be sufficient to address variances in actual outcomes versus projections or other external events.

Q90. Can other parties file a re-opener petition?

A90. Yes. The Public Utilities Act[30] permits any party to petition for review of Pepco's rates. In order to ensure fairness to all parties, parties should notify the

[30] Title 34 of the District of Columbia Code

Commission of all events that they consider signal the need to utilize the re-opener provisionas soon as possible after the events have been identified.

Q91. What would happen in the case of a re-opener petition?

A91. The Commission will consider petitions to re-open and review the Company's MRP and make a determination on the merits of the request as to whether a re-opening of the plan is warranted.

Q92. Does this conclude your Direct Testimony?

A92. Yes, it does.

T.W. Wolverton
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (C) – 1

Potomac Electric Power Company

District of Columbia
Ratemaking Results - Distribution Only
Multiyear Rate Plan

(Thousands of Dollars)

Line No.		MRP 2020 Average Unadjusted (1)	MRP 2020 Ratemaking Adjustments (2)	MRP 2020 D.C. Adjusted (3)	MRP 2021 Average Unadjusted (1)	MRP 2021 Ratemaking Adjustments (2)	MRP 2021 D.C. Adjusted (3)	MRP 2022 Average Unadjusted (1)	MRP 2022 Ratemaking Adjustments (2)	MRP 2022 D.C. Adjusted (3)
	Rate Base									
1	Electric Plant in Service	$ 4,197,040	$ (1,694)	$ 4,195,346	$ 4,482,843	$ (1,992)	$ 4,480,851	$ 4,819,187	$ (2,284)	$ 4,816,903
2	Accumulated Depreciation	(1,311,476)	478	(1,310,998)	(1,422,017)	570	(1,421,447)	(1,540,707)	678	(1,540,029)
3	Accumulated Amortization	(20,322)	-	(20,322)	(27,309)	-	(27,309)	(36,209)	-	(36,209)
4	Materials and Supplies	38,116	-	38,116	38,372	-	38,372	38,582	-	38,582
5	Cash Working Capital	10,142	(103)	10,039	10,121	(51)	10,070	10,105	51	10,156
6	Accumulated Deferred Income Taxes	(824,829)	-	(824,829)	(819,153)	-	(819,153)	(806,871)	-	(806,871)
7	Prepaid Pension/OPEB Liab. (net of tax)	60,151	-	60,151	60,156	-	60,156	53,094	-	53,094
8	Customer Deposits	(9,485)	-	(9,485)	(9,485)	-	(9,485)	(9,485)	-	(9,485)
9	Pepco Portion of Servco Assets	25,300	-	25,300	20,824	-	20,824	17,231	-	17,231
10	Regulatory Assets	30,461	12,873	43,335	22,721	9,483	32,205	15,424	6,093	21,517
11	Unamortized Credit Facility Costs	246	-	246	162	-	162	77	-	77
12	Total Rate Base	$ 2,195,345	$ 11,554	$ 2,206,899	$ 2,357,234	$ 8,010	$ 2,365,245	$ 2,560,428	$ 4,538	$ 2,564,966
	Operating Revenues									
13	Sale of Electricity	$ 523,952	$ -	$ 523,952	$ 524,981	$ -	$ 524,981	$ 526,034	$ -	$ 526,034
14	Other Revenues	6,561		6,561	6,561		6,561	6,561		6,561
15	Operating Revenues	$ 530,513	$ -	$ 530,513	$ 531,542	$ -	$ 531,542	$ 532,594	$ -	$ 532,594
	Operating Expenses									
16	Operation and Maintenance	$ 174,657	$ (4,260)	$ 170,397	$ 174,002	$ (2,020)	$ 171,982	$ 171,356	$ 2,069	$ 173,425
17	Depreciation	116,102	(93)	116,009	123,321	(108)	123,213	132,402	(124)	132,278
18	Amortization	13,511	4,677	18,188	11,401	4,677	16,078	13,037	4,677	17,714
19	Other Taxes	145,818	-	145,818	145,143	-	145,143	144,323	-	144,323
20	D.C. Income Tax	(147)	(809)	(956)	1,802	(985)	817	2,109	(1,314)	796
21	Federal Income Tax	(13,504)	23	(13,481)	(15,380)	(373)	(15,753)	(17,858)	(1,140)	(18,999)
22	Total Operating Expenses	$ 436,437	$ (462)	$ 435,975	$ 440,288	$ 1,191	$ 441,479	$ 445,370	$ 4,168	$ 449,538
23	Operating Income	$ 94,076	$ 462	$ 94,538	$ 91,254	$ (1,191)	$ 90,062	$ 87,225	$ (4,168)	$ 83,057
24	**D.C. Jurisdictional Return on Rate Base**	**4.29%**		**4.28%**	**3.87%**		**3.81%**	**3.41%**		**3.24%**
25	Less Weighted Cost of Long-Term Debt	2.61%		2.61%	2.61%		2.61%	2.61%		2.61%
26	Net amount available for common equity	1.68%		1.67%	1.26%		1.20%	0.80%		0.63%
27	Common Equity ratio	50.46%		50.46%	50.46%		50.46%	50.46%		50.46%
28	**Earned D.C. Jurisdictional Return on Equity**	**3.32%**		**3.32%**	**2.50%**		**2.37%**	**1.58%**		**1.24%**
29	Requested Rate of Return			7.81%			7.81%			7.81%
30	**Cumulative Revenue Requirement**			**$ 107,364**			**$ 130,601**			**$ 161,787**
31	**Projected Earned ROE**			**10.30%**			**10.30%**			**10.30%**
32	Revenue Requirement Smoothing Adjustment			(22,426)			(5,216)			-
33	**Revenue Requirement Incl. Smoothing**			**$ 84,938**			**$ 125,385**			**$ 161,787**
34	**Projected Earned ROE Incl. Smoothing**			**7.10%** (A)			**9.99%**			**10.30%**
35	**Cumulative Revenue Requirement Incl. Smoothing**			**$ 84,938**			**$ 40,447**			**$ 36,402**
36	Percent of Total MRP Revenue Requirement			52.5%			25.0%			22.5%

(A) 2020 Projected Earned ROE reflects May 1, 2018 rate effective date, ~68% of Revenue collected May - December 2018..

Potomac Electric Power Company

District of Columbia Ratemaking Adjustments -- Distribution Only
Multiyear Rate Plan
2020

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation (4)	Amortization (5)	Other Taxes (6)	DCIT (7)	FIT (8)	Operating Income (9)
1	Removal of supplemental executive retirement plans (SERP)			(707)	(60)			63	148	556
	Electric Plant in Service	(1,090)								
	Accumulated Depreciation	362								
2	Removal of certain executive incentive plan costs			(1,502)	(33)			127	280	1,128
	Electric Plant in Service	(604)								
	Accumulated Depreciation	116								
3	Removal of institutional advertising/selling expenses			(218)				18	42	158
4	Removal of employee association costs			(42)				3	8	31
5	Removal of industry contributions and membership fees			(440)				36	85	319
6	Removal of executive perquisite expenses			(27)				2	5	20
7	Removal of BSC Billed Depreciation (Merger Commitment 39)			(469)				39	90	340
8	Reflection of customer deposit interest expense and credit facility expense and maintenance costs			466				(38)	(90)	(338)
9	Reflection of Current Case Costs			(929)		1,244		(26)	(61)	(229)
	Regulatory Assets	2,255								
10a	Reflection of Benning Regulatory Asset - Actual					288		(24)	(55)	(209)
	Regulatory Assets	1,985								
10b	Reflection of Benning Regulatory Asset - Forecast					48		(4)	(9)	(35)
	Regulatory Assets	334								
11	Reflection of CTA Regulatory Asset					1,892		(156)	(365)	(1,371)
	Regulatory Assets	6,171								
12	Reflection of PHISCO DDIT					870		(72)	(168)	(631)
	Regulatory Assets	1,039								
13	Reflection of the Additional Subtraction Modification							(757)	159	598
14	Reflection of Inflationary Growth of O&M expense			$ -				-	$ -	-
15	Reflection of CTO Regulatory Asset			$ (392)		334		5	11	42
	Regulatory Assets	1,090								
16	Reflection of CWC impact of ratemaking adjustments									-
	Cash Working Capital	(103)								
17	Interest synchronization							(25)	(58)	83
	Total Ratemaking Adjustments	$ 11,554	$ -	$ (4,260)	$ (93)	$ 4,677	$ -	$ (809)	$ 23	$ 462

Potomac Electric Power Company

District of Columbia Ratemaking Adjustments -- Distribution Only
Multiyear Rate Plan
2021

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation (4)	Amortization (5)	Other Taxes (6)	DCIT (7)	FIT (8)	Operating Income (9)
1	Removal of supplemental executive retirement plans (SERP)			(742)	(70)			67	156	589
	Electric Plant in Service	(1,293)								
	Accumulated Depreciation	422								
2	Removal of certain executive incentive plan costs			(1,417)	(38)			120	280	1,055
	Electric Plant in Service	(699)								
	Accumulated Depreciation	148								
3	Removal of institutional advertising/selling expenses			(219)				18	42	159
4	Removal of employee association costs			(42)				3	8	31
5	Removal of industry contributions and membership fees			(452)				37	87	328
6	Removal of executive perquisite expenses			(27)				2	5	20
7	Removal of BSC Billed Depreciation (Merger Commitment 39)			(469)				39	90	340
8	Reflection of customer deposit interest expense and credit facility expense and maintenance costs			466				(38)	(90)	(338)
9	Reflection of Current Case Costs					1,244		(103)	(240)	(901.93)
	Regulatory Assets	1,353								
10a	Reflection of Benning Regulatory Asset - Actual					288		(24)	(55)	(209)
	Regulatory Assets	1,775								
10b	Reflection of Benning Regulatory Asset - Forecast					48		(4)	(9)	(35)
	Regulatory Assets	299								
11	Reflection of CTA Regulatory Asset					1,892		(156)	(365)	(1,371)
	Regulatory Assets	4,800								
12	Reflection of PHISCO DDIT					870		(72)	(168)	(631)
	Regulatory Assets	408								
13	Reflection of the Additional Subtraction Modification							(757)	159	598
14	Reflection of Inflationary Growth of O&M expense			$ 888				(73)	$ (171)	(644)
15	Reflection of CTO Regulatory Asset			$ (6)		334		(27)	(63)	(238)
	Regulatory Assets	848								
16	Reflection of CWC impact of ratemaking adjustments									-
	Cash Working Capital	(51)								
17	Interest synchronization							(17)	(40)	57
	Total Ratemaking Adjustments	$ 8,010	$ -	$ (2,020)	$ (108)	$ 4,677	$ -	$ (985)	$ (373)	$ (1,191)

Potomac Electric Power Company

District of Columbia Ratemaking Adjustments -- Distribution Only
Multiyear Rate Plan
2022

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation (4)	Amortization (5)	Other Taxes (6)	DCIT (7)	FIT (8)	Operating Income (9)
1	Removal of supplemental executive retirement plans (SERP)			(730)	(81)			67	156	588
	Electric Plant in Service	(1,491)								
	Accumulated Depreciation	493								
2	Removal of certain executive incentive plan costs			(1,461)	(43)			124	290	1,090
	Electric Plant in Service	(793)								
	Accumulated Depreciation	185								
3	Removal of institutional advertising/selling expenses			(217)				18	42	157
4	Removal of employee association costs			(42)				3	8	31
5	Removal of industry contributions and membership fees			(457)				38	88	331
6	Removal of executive perquisite expenses			(27)				2	5	20
7	Removal of BSC Billed Depreciation (Merger Commitment 39)			(463)				38	89	336
8	Reflection of customer deposit interest expense and credit facility expense and maintenance costs			464				(38)	(90)	(336)
9	Reflection of Current Case Costs					1,244		(103)	(240)	(901.93)
	Regulatory Assets	451								
10a	Reflection of Benning Regulatory Asset - Actual					288		(24)	(55)	(209)
	Regulatory Assets	1,567								
10b	Reflection of Benning Regulatory Asset - Forecast					48		(4)	(9)	(35)
	Regulatory Assets	264								
11	Reflection of CTA Regulatory Asset					1,892		(156)	(365)	(1,371)
	Regulatory Assets	3,429								
12	Reflection of PHISCO DDIT					870		(72)	(168)	(631)
	Regulatory Assets	(223)								
13	Reflection of the Additional Subtraction Modification							(757)	159	598
14	Reflection of Inflationary Growth of O&M expense			$ 5,008				(413)	$ (965)	(3,630)
15	Reflection of CTO Regulatory Asset			$ (6)		334		(27)	(63)	(238)
	Regulatory Assets	606								
16	Reflection of CWC impact of ratemaking adjustments									-
	Cash Working Capital	51								
17	Interest synchronization							(10)	(23)	33
	Total Ratemaking Adjustments	$ 4,538	$ -	$ 2,069	$ (124)	$ 4,677	$ -	$ (1,314)	$ (1,140)	$ (4,168)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Analysis of Revenue Requirement -- Distribution Only
Multiyear Rate Plan

(Thousands of Dollars)		2020			2021			2022		
		Rate Base	**Operating Income**	**Revenue Requirement**	**Rate Base**	**Operating Income**	**Revenue Requirement**	**Rate Base**	**Operating Income**	**Revenue Requirement**
Unadjusted amounts based on 10.30% return on equity		$ 2,195,345	94,076	$ 106,757	$ 2,357,234	91,254	$ 128,095	$ 2,560,428	87,225	$ 155,547
Adjustments										
1	Removal of supplemental executive retirement plans (SERP)	(728)	556	(846)	(871)	589	(906)	(998)	588	(919)
2	Removal of certain executive incentive plan costs	(488)	1,128	(1,609)	(551)	1,055	(1,515)	(608)	1,090	(1,569)
3	Removal of institutional advertising/selling expenses		158	(218)		159	(219)		157	(217)
4	Removal of employee association costs		31	(43)		31	(43)		31	(43)
5	Removal of industry contributions and membership fees		319	(440)		328	(453)		331	(457)
6	Removal of executive perquisite expenses		20	(28)		20	(28)		20	(28)
7	Removal of BSC Billed Depreciation (Merger Commitment 39)		340	(469)		340	(469)		336	(464)
8	Reflection of customer deposit interest expense and credit facility expense and maintenance costs		(338)	467		(338)	467		(336)	464
9	Reflection of Current Case Costs	2,255	(229)	558	1,353	(902)	1,390	451	(902)	1,293
10a	Reflection of Benning Regulatory Asset - Actual	1,985	(209)	502	1,775	(209)	480	1,567	(209)	457
10b	Reflection of Benning Regulatory Asset - Forecast	334	(35)	84	299	(35)	81	264	(35)	77
11	Reflection of CTA Regulatory Asset	6,171	(1,371)	2,557	4,800	(1,371)	2,409	3,429	(1,371)	2,261
12	Reflection of PHISCO DDIT	1,039	(631)	982	408	(631)	914	(223)	(631)	846
13	Reflection of the Additional Subtraction Modification		598	(825)		598	(825)		598	(825)
14	Reflection of Inflationary Growth of O&M expense		-	-		(644)	888		(3,630)	5,008
15	Reflection of CTO Regulatory Asset	1,090	42	60	848	(238)	420	606	(238)	394
16	Reflection of CWC impact of ratemaking adjustments	(103)	-	(11)	(51)	-	(5)	51	-	5
17	Interest synchronization		83	(115)		57	(79)		33	(46)
	Total adjustments	**11,554**	**462**	**607**	**8,010**	**(1,191)**	**2,506**	**4,538**	**(4,168)**	**6,240**
Total revenue requirement at 7.74% rate of return based on adjusted results		**2,206,899**	**94,538**	**107,364**	**2,365,245**	**90,062**	**130,601**	**2,564,966**	**83,057**	**161,787**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Multiyear Rate Plan

(Thousands of Dollars)

Line No.	Adjustment 1 - Adjustment for Non-Qualified Supplemental Executive Retirement Plan (SERP) Costs	2020	2021	2022
	Rate Base			
1	13 month average capitalized Pepco utility SERP expense	$ 1,342	$ 1,534	$ 1,713
2	13 month average capitalized Service Company SERP expense charged to Pepco	$ 1,229	$ 1,511	$ 1,785
3	Total 13 month average capitalized SERP expense	$ 2,571	$ 3,045	$ 3,498
4	Allocation to Distribution (Plant less AFUDC ratio)	0.8175	0.8175	0.8175
5	Distribution-related capitalized SERP expense	2,102	2,489	2,860
6	Allocation to D.C. (Plant less AFUDC ratio)	0.5186	0.5194	0.5215
7	Adjustment to D.C. electric plant in service	$ (1,090)	$ (1,293)	$ (1,491)
8	13 month average accumulated depreciation on capitalized SERP	$ (932)	$ (1,071)	$ (1,234)
9	Allocation to Distribution (Depreciation less AFUDC ratio)	0.8334	0.8334	0.8334
10	Distribution-related portion of 13 month average SERP accumulated depreciation	(777)	(893)	(1,028)
11	Allocation to D.C. (Accumulated Depreciation less AFUDC ratio)	0.4654	0.4728	0.4797
12	Adjustment to D.C. accumulated depreciation	$ 362	$ 422	$ 493
	Total Rate Base	**$ (728)**	**$ (871)**	**$ (998)**
	Earnings			
13	Depreciation expense on capitalized SERP costs	$ 128	$ 151	$ 174
14	Allocation to Distribution (Depreciation less AFUDC ratio)	0.8334	0.8334	0.8334
15	Distribution-related portion of SERP depreciation expense	107	126	145
16	Allocation to D.C. (Depreciation less AFUDC ratio)	0.5562	0.5551	0.5564
17	Adjustment to D.C. depreciation expense	$ (60)	$ (70)	$ (81)
18	Total distribution SERP expense attributable to Bonus / Other Non-Qualified Benefits	1,397	1,495	1,486
19	Allocation to Distribution (Labor ratio)	0.8755	0.8755	0.8755
20	Distribution-related operation & maintenance expense	1,223	1,309	1,301
21	Direct Distribution-related operation & maintenance expense	407	400	401
22	Allocation to D.C. (O&M less A&G ratio)	0.4340	0.4341	0.4289
23	Adjustment to D.C. operations & maintenance expense	$ (707)	$ (742)	$ (730)
24	Adjustment to D.C. income tax expense	$ 63	$ 67	$ 67
25	Adjustment to Federal income tax expense	$ 148	$ 156	$ 156
	Total Earnings	**$ 556**	**$ 589**	**$ 588**

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Line No.	Adjustment 2 - Adjustment for Executive Incentive Plan Costs	AIP/Exec.total 2020	2021	2022
	Rate Base			
1	Average capitalized Exec incentive costs in electric plant in service (EPIS)	$ 1,424	$ 1,645	$ 1,860
2	Allocation to Distribution (Plant less AFUDC ratio)	0.8175	0.8175	0.8175
3	Average distribution related capitalized Exec incentive costs in EPIS	1,164	1,345	1,521
4	Allocation to D.C. (Plant less AFUDC ratio)	0.5186	0.5194	0.5215
5	Adjustment to remove average capitalized Exec incentive costs from D.C. EPIS	$ (604)	$ (699)	$ (793)
6	Average capitalized incentive costs in accumulated depreciation	$ (299)	$ (375)	$ (462)
7	Allocation to Distribution (Depreciation less AFUDC ratio)	0.8334	0.8334	0.8334
8	Average distribution related capitalized incentive costs in accumulated depreciation	(249)	(313)	(385)
9	Allocation to D.C. (Accumulated depreciation less AFUDC ratio)	0.4654	0.4728	0.4797
10	Adjustment to remove average capitalized incentive costs from D.C. accum. depreciation	$ 116	$ 148	$ 185
	Total Rate Base	**$ (488)**	**$ (551)**	**$ (608)**
	Earnings			
11	Average capitalized exec incentive costs included in depreciation expense	$ 71	$ 82	$ 93
12	Allocation to Distribution (Depreciation less AFUDC ratio)	0.8334	0.8334	0.8334
13	Average distribution related capitalized incentive costs in depreciation expense	59	68	78
14	Allocation to D.C. (Depreciation less AFUDC ratio)	0.5562	0.5551	0.5564
15	Adjustment to remove average capitalized incentive costs from D.C. depreciation	$ (33)	$ (38)	$ (43)
16	Adjustment to remove Earnings-Related CEO EIP Expense	$ 53	$ 53	$ 53
17	Adjustment to remove Non Customer-Related LTIP Expense	3,409	3,211	3,353
18	Distribution-related incentive costs in Pepco O&M expense	3,462	3,264	3,407
19	Allocation to D.C. (O&M less A&G ratio)	0.4340	0.4341	0.4289
20	Adjustment to D.C. operations and maintenance expense to remove incentive costs	$ (1,502)	$ (1,417)	$ (1,461)
21	Adjustment to D.C. income tax expense	$ 127	$ 120	$ 124
22	Adjustment to Federal income tax expense	$ 296	$ 280	$ 290
	Total Earnings	**$ 1,112**	**$ 1,055**	**$ 1,090**

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Line No.	**Adjustment 3 - Removal of Institutional Advertising and Selling Expense**			
	Earnings	**2020**	**2021**	**2022**
1	Institutional/promotional advertising, selling expenses excludable from cost of service	503	505	505
2	Allocation to D.C. (O&M less A&G ratio)	0.4340	0.4341	0.4289
3	Adjustment to D.C. operations and maintenance expense	$ (218)	$ (219)	$ (217)
4	Adjustment to D.C. income tax expense	$ 18	$ 18	$ 18
5	Adjustment to Federal income tax expense	$ 42	$ 42	$ 42
	Total Earnings	**$ 158**	**$ 159**	**$ 157**

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Line No.	Adjustment 4 - Removal of Employee Association Costs			
	Earnings	**2020**	**2021**	**2022**
1	Total employee association costs to be excluded per Formal Case 1103	$ 111	$ 111	$ 111
2	Allocation to Distribution (Labor Ratio)	0.8755	0.8755	0.8755
3	Excludable employee association costs included in distribution O&M	$ 97	$ 97	$ 97
4	Allocation to D.C. (O&M less A&G ratio)	0.4340	0.4341	0.4289
5	Adjustment to D.C. operations and maintenance expense	$ (42)	$ (42)	$ (42)
6	Adjustment to D.C. income tax expense	$ 3	$ 3	$ 3
7	Adjustment to Federal income tax expense	$ 8	$ 8	$ 8
	Total Earnings	**$ 31**	**$ 31**	**$ 31**

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Line No.	**Adjustment 5 - Removal of Industry Contributions and Membership Fees**			
	Earnings	**2020**	**2021**	**2022**
1	Industry contributions and membership fees - A&G	$ 1,148	$ 1,178	$ 1,206
2	Industry contributions and membership fees - Distribution	10	10	10
3	Allocation to Distribution (Labor Ratio)	0.8755	0.8755	0.8755
5	Excludable industry contributions & membership fees included in distribution O&M	1,015	1,041	1,066
6	Allocation to D.C. (O&M less A&G ratio)	0.4340	0.4341	0.4289
7	Adjustment to D.C. operations and maintenance expense	$ (440)	$ (452)	$ (457)
8	Adjustment to D.C. income tax expense	$ 36	$ 37	$ 38
9	Adjustment to Federal income tax expense	$ 85	$ 87	$ 88
	Total Earnings	**$ 319**	**$ 328**	**$ 331**

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Line No.	**Adjustment 6 - Removal of Executive Perquisite Expenses**			
	Earnings	**2020**	**2021**	**2022**
1	Executive Perquisite Expenses	$ 72	$ 72	$ 72
2	Allocation to Distribution (Labor Ratio)	0.8755	0.8755	0.8755
3	Executive Perquisite Expenses - Distribution	$ 63	$ 63	$ 63
4	Allocation to D.C. (O&M less A&G ratio)	0.4340	0.4341	0.4289
5	Adjustment to DC O&M Expense	$ (27)	$ (27)	$ (27)
6	Adjustment to D.C. income tax expense	$ 2	$ 2	$ 2
7	Adjustment to Federal income tax expense	$ 5	$ 5	$ 5
	Total Earnings	**$ (79)**	**$ (79)**	**$ (79)**

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Line No.	**Adjustment 7 - Adjust BSC Depreciation Expense per Merger Commitment X**			
	Earnings	**2020**	**2021**	**2022**
1	BSC Depreciation Expense Billed to Pepco Adjustment	$ 1,234	$ 1,234	$ 1,234
2	Allocation to Distribution (Labor Ratio)	0.8755	0.8755	0.8755
3	BSC Depreciation Expense included in distribution O&M	$ 1,080	$ 1,080	$ 1,080
4	Allocation to D.C. (O&M less A&G ratio)	0.4340	0.4341	0.4289
5	Adjustment to D.C. operations and maintenance expense	$ (469)	$ (469)	$ (463)
6	Adjustment to D.C. income tax expense	$ 39	$ 39	$ 38
7	Adjustment to Federal income tax expense	$ 90	$ 90	$ 89
	Total Earnings	**$ 340**	**$ 340**	**$ 336**

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Line No.	**Adjustment 8 - Inclusion of Customer Deposit Interest Expense and Credit Facility Costs**			
	Earnings	**2020**	**2021**	**2022**
1	Interest on customer deposits at 2019 rate of 2.64%	$ 249	$ 249	$ 249
2	Credit facility costs (quarterly maintenance fee)	$ 572	$ 572	$ 572
3	Allocation to Distribution (Labor ratio)	0.8755	0.8755	0.8755
4	Distribution-related credit facility costs	$ 501	$ 501	$ 501
5	Allocation factor - District of Columbia (O&M less A&G ratio)	0.4340	0.4341	0.4289
6	District of Columbia allocated credit facility costs	$ 217	$ 217	$ 215
7	Adjustment to include Commission-allowed interest charges in distribution O&M expense	$ 466	$ 466	$ 464
8	Adjustment to D.C. income tax expense	$ (38)	$ (38)	$ (38)
9	Adjustment to Federal income tax expense	$ (90)	$ (90)	$ (90)
	Total Earnings	**$ (338)**	**$ (338)**	**$ (336)**

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Line No.	**Adjustment 9 - Current Case Costs**		**2020**	**2021**	**2022**
	Earnings				
1	Current Rate Case Costs Estimate	$ 4,456			
2	Less: Refund of 1150 Rate Case Costs	(723)			
3	Subtotal Rate Case Costs Estimate	$ 3,733			
4	Less:Included in the O&M Expenses		(929)		
5	Adjustment to Amortization Expense (3 Year Amortization Period)		$ 1,244	$ 1,244	$ 1,244
6	Adjustment to DC Income Tax expense		(26)	(103)	(103)
7	Adjustment to Federal Income Tax expense		(61)	(240)	(240)
	Total Earnings		**$ (229)**	**$ (902)**	**$ (902)**
	Rate Base				
8	Test year average unamortized rate base, net of accumulated deferred taxes:				
9	Average DC regulatory asset balance	$ 3,733			
10	Decline in balance After Year 1	(622)			
11	Total average unamortized rate base balances		$ 3,111	$ 1,867	$ 622
12	Adjustment to accumulated deferred income taxes		(856)	(514)	(171)
13	Adjustment to rate base, net of accumulated deferred taxes		2,255	1,353	451
	Total Rate Base		**$ 2,255**	**$ 1,353**	**$ 451**

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Line No.	**Adjustment 10a - Actual Dollars Spent for RI/FS & CT Basins Removal**				
	Earnings		**2020**	**2021**	**2022**
1	Dollars Spent for the RI/FS from 1/1/2018 to Date - Pepco	$ 1,560			
2	CT Basins Removal Pepco	3,434			
3	Allocation to DC	57.7%			
4	Dollars Spent for the RI/FS from 1/1/2018 to Date - Pepco DC	900			
5	CT Basing Removal Pepco DC	1,981			
6	Total Benning	2,882			
7	Adjustment to Amortization Expense (10 year amortization period)		$ 288	$ 288	$ 288
8	Adjustment to DC income tax expense		(24)	(24)	(24)
9	Adjustment to federal income tax expense		(55)	(55)	(55)
	Total Earnings		**$ (209)**	**$ (209)**	**$ (209)**
	Rate Base				
10	Test year average unamortized rate base, net of accumulated deferred taxes:				
11	Average DC regulatory asset balance	$ 2,882			
12	Decline in balance After Year 1	(144)			
13	Total average unamortized rate base balances		$ 2,738	$2,450	$2,162
14	Adjustment to accumulated deferred income taxes		(753)	(674)	(595)
15	Adjustment to rate base, net of accumulated deferred taxes		1,985	1,775	1,567
	Total Rate Base		**$ 1,985**	**$1,775**	**$1,567**

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Line No.	**Adjustment 10b - Future Costs for RI/FS**				
	Earnings		**2020**	**2021**	**2022**
1	Future Costs for RI/FS - Pepco (April 2019 - December 2020)	$ 840			
2	Allocation to DC	57.7%			
3	Future Costs for RI/FS - Pepco (April 2019 - December 2020) - Pepco DC	485			
4	Adjustment to Amortization Expense (10 year amortization period)		$ 48	$ 48	$ 48
5	Adjustment to DC income tax expense		(4)	(4)	(4)
6	Adjustment to federal income tax expense		(9)	(9)	(9)
	Total Earnings		**$ (35)**	**$ (35)**	**$ (35)**
	Rate Base				
7	Test year average unamortized rate base, net of accumulated deferred taxes:				
8	Average DC regulatory asset balance	$ 485			
9	Decline in balance After Year 1	(24)			
10	Total average unamortized rate base balances		$ 461	$ 413	$ 365
11	Adjustment to accumulated deferred income taxes		(127)	(114)	(100)
12	Adjustment to rate base, net of accumulated deferred taxes		334	299	264
13	**Total Rate Base**		**$ 334**	**$ 299**	**$ 264**

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Line No.	**Adjustment 11 - Reflection of Actual Costs to Achieve (CTA)**				
	Earnings		**2020**	**2021**	**2022**
1	Actual CTA Costs	$ 9,460			
2	Adjustment to Amortization Expense (5 Year Amortization Period)		$ 1,892	$ 1,892	$ 1,892
3	Adjustment to DC Income Tax expense		(156)	(156)	(156)
4	Adjustment to Federal Income Tax expense		(365)	(365)	(365)
	Total Earnings		**$ (1,371)**	**$ (1,371)**	**$ (1,371)**
	Rate Base				
5	Test year average unamortized rate base, net of accumulated deferred taxes:				
6	Average DC regulatory asset balance	$ 9,460			
7	Decline in balance After Year 1	(946)			
8	Total average unamortized rate base balances		$ 8,514	$ 6,622	$ 4,730
9	Adjustment to accumulated deferred income taxes		(2,343)	(1,822)	(1,302)
10	Adjustment to rate base, net of accumulated deferred taxes		6,171	4,800	3,429
	Total Rate Base		**$ 6,171**	**$ 4,800**	**$ 3,429**

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Line No.	**Adjustment 12 - Amortization of PHISCO Deficient Deferred Income Tax.**				
	Earnings		**2020**	**2021**	**2022**
1	PHISCO Deficient Deferred Income Tax Balances				
2	Property-Related (10 year amortization)	$ (4,965)	$ (497)	$ (497)	$ (497)
3	Non-Property Related (5 year amortization)	6,834	1,367	1,367	1,367
4	Total	1,868	870	870	870
5	Adjustment to Amortization expense		870	870	870
6	Adjustment to DC Income Tax expense		(72)	(72)	(72)
7	Adjustment to Federal Income Tax expense		(168)	(168)	(168)
	Total Earnings		**$ (631)**	**$ (631)**	**$ (631)**
	Rate Base				
8	Average DC Regulatory Asset Balance	$ 1,868			
9	Decline in Balance After Year 1	(435)			
10	Adjustment to DC regulatory assets		$ 1,433	$ 563	$ (307)
11	Adjustment to accumulated deferred income taxes		(394)	(155)	85
	Total Rate Base		**$ 1,039**	**$ 408**	**$ (223)**

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Line No.	**Adjustment 13 - Reflection of Additional Subtraction Modification**			2020	2021	2022
	Earnings	Amount	Flow Back Period	Amortization		
1	Regulatory Liability	(27,560)	36.42 Years	$ (757)	$ (757)	$ (757)
2	Change in DC Income Tax Expense			(757)	(757)	(757)
3	Change in Federal Income Tax Expense			159	159	159
	Total Earnings			**$ 598**	**$ 598**	**$ 598**
	Rate Base					
4	Adjustment to ADIT to reflect Deferred Tax Asset			27,560	26,803	26,046
5	Adjustment to Regulatory Liability			(27,560)	(26,803)	(26,046)
	Total Rate Base			$ -	$ -	$ -

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Line No.	**Adjustment 14 - OM Inflation Adj**			
	Earnings	**2020**	**2021**	**2022**
1	DC Distribution Per Books O&M Expense	$ 174,657	$ 174,002	$ 171,356
	Remove:			
2	DC Regulatory Asset Amortization Expense included in O&M	3,363	1,848	1,292
3	PHISCO Depreciation and Amortization included in O&M	5,347	4,773	4,372
	BSC Depreciation and Amortization included in O&M	2,295	1,972	1,714
4	Total	11,006	8,592	7,377
5	DC Distribution Per Books O&M Expense (excluding D&A)	163,652	165,410	163,979
6	DC Distribution Per Books O&M Expense (excluding D&A) - 2021 and 2022 GDPPI Inflation	163,652	166,298	168,986
7	Adjustment to D.C. operations and maintenance expense		$ 888	$ 5,008
8	Adjustment to D.C. income tax expense		$ (73)	$ (413)
9	Adjustment to Federal income tax expense		$ (171)	$ (965)
	Total Earnings		**$ (644)**	**$ (3,630)**

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Line No.	**Adjustment 15 - Reflection CTO Regulatory Asset**				
	Earnings		**2020**	**2021**	**2022**
1	CTO thru December 31, 2019	$ 3,549			
2	Additional CTO in MRP		$ 903	$ 13	$ 13
3	Allocation to D.C. (O&M less A&G ratio)	43.40%	43.40%	43.41%	42.89%
4	DC Allocated CTO	$ 1,540	$ 392	$ 6	$ 6
5	Adjustment to O&M		$ (392)	$ (6)	$ (6)
5	Total Regulatory Asset (through April 30, 2020)	**1,671**			
6	Adjustment to Amortization Expense (5 Year Amortization Period)		$ 334	$ 334	$ 334
7	Adjustment to DC Income Tax expense		5	(27)	(27)
8	Adjustment to Federal Income Tax expense		11	(63)	(63)
	Total Earnings		**$ (350)**	**$ (244)**	**$ (244)**
	Rate Base				
5	Test year average unamortized rate base, net of accumulated deferred taxes:				
6	Average DC regulatory asset balance	$ 1,671			
7	Decline in balance After Year 1	(167)			
8	Total average unamortized rate base balances		$ 1,504	$ 1,170	$ 835
9	Adjustment to accumulated deferred income taxes		(414)	(322)	(230)
10	Adjustment to rate base, net of accumulated deferred taxes		1,090	848	606
	Total Rate Base		**$ 1,090**	**$ 848**	**$ 606**

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Line No.	Adjustment 16 - Reflection of Impact of Ratemaking Adjustments on Cash Working Capital			
	Rate Base	**2020**	**2021**	**2022**
1	D.C. unadjusted Cash Working Capital allowance for test year	$ 10,142	$ 10,121	$ 10,105
2	Impact of Ratemaking Adjustments on Cash Working Capital Allowance	(103)	(51)	51
3	D.C. Cash Working Capital allowance adjusted for Ratemaking Adjustments	$ 10,039	$ 10,070	$ 10,156

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Line No.	Adjustment 16-Reflect Impact of Ratemaking Adjustments on CWC	Year 2020 (1) D.C. Distribution Amount	Year 2020 (2) 2015 Study Expense Lag	Year 2020 (3) Test Year Lag Dollars (column 1 x column 2)	Year 2021 (1) D.C. Distribution Amount	Year 2021 (2) 2015 Study Expense Lag	Year 2021 (3) Test Year Lag Dollars (column 1 x column 2)	Year 2022 (1) D.C. Distribution Amount	Year 2022 (2) 2015 Study Expense Lag	Year 2022 (3) Test Year Lag Dollars (column 1 x column 2)
1	Pepco Labor	$ -	8.70	$ -	$ -	8.70	$ -	$ -	8.70	$ -
2	Pepco AIP		241.00			241.00			241.00	
3	Incremental Storm Expense	-	137.47	-	-	137.47	-	-	137.47	-
4	Control Center Lease	-	88.25	-	-	88.25	-	-	88.25	-
5	Other O&M Expense	(4,260)	35.79	(152,444)	(2,020)	35.79	(72,281)	2,069	35.79	74,056
6	Other Taxes:									
7	Property Tax - D.C.	-	97.21	-	-	97.21	-	-	97.21	-
8	Property Tax - Montgomery County	-	(4.10)	-	-	(4.10)	-	-	(4.10)	-
9	Property Tax - PG County	-	(59.76)	-	-	(59.76)	-	-	(59.76)	-
10	Property Tax - Charles County	-	(59.60)	-	-	(59.60)	-	-	(59.60)	-
11	Property Tax - Other Maryland	-	(76.77)	-	-	(76.77)	-	-	(76.77)	-
12	Property Tax - Alexandria	-	151.09	-	-	151.09	-	-	151.09	-
13	Property Tax - Arlington	-	234.50	-	-	234.50	-	-	234.50	-
14	Property Tax - Fairfax	-	0.00	-	-	0.00	-	-	0.00	-
15	Property Tax - Pr William	-	153.68	-	-	153.68	-	-	153.68	-
16	D.C. Delivery Tax	-	35.41	-	-	35.41	-	-	35.41	-
17	D.C. Public Space Occupancy Fee	-	(49.13)	-	-	(49.13)	-	-	(49.13)	-
18	D.C. RETF,SETF, EATF	-	36.27	-	-	36.27	-	-	36.27	-
19	D.C. PSC Reimbursement	-	172.50	-	-	172.50	-	-	172.50	-
20	D.C. Business Improvement Tax	-	(99.94)	-	-	(99.94)	-	-	(99.94)	-
21	D.C. Ballpark Fee	-	197.50	-	-	197.50	-	-	197.50	-
22	D.C. Sales & Use Tax	-	35.69	-	-	35.69	-	-	35.69	-
23	Montgomery County Fuel & Energy	-	45.67	-	-	45.67	-	-	45.67	-
24	Maryland Delivery Tax	-	39.26	-	-	39.26	-	-	39.26	-
25	Maryland Gross Receipts	-	44.86	-	-	44.86	-	-	44.86	-
26	Maryland Universal Surcharge	-	30.25	-	-	30.25	-	-	30.25	-
27	Maryland Environmental Surcharge	-	40.25	-	-	40.25	-	-	40.25	-
28	Maryland Sales, Use & Diesel Tax	-	35.24	-	-	35.24	-	-	35.24	-
29	Maryland PSC Reimbursement	-	(26.00)	-	-	(26.00)	-	-	(26.00)	-
30	Federal Heavy Vehicle Highway Use Tax	-	(138.50)	-	-	(138.50)	-	-	(138.50)	-
31	Payroll Tax-FICA	-	9.15	-	-	9.15	-	-	9.15	-
32	Payroll Tax-FUTA/SUTA	-	9.03	-	-	9.03	-	-	9.03	-
33	D.C. Income Tax (Current Portion)	-	59.05	-	-	59.05	-	-	59.05	-
34	Federal Income Tax (Current Portion)	-	59.05	-	-	59.05	-	-	59.05	-
35	Subtotal	$ (4,260)		$ (152,444)	$ (2,020)		$ (72,281)	$ 2,069		$ 74,056
36										
37	D.C. Composite Expense Lag		35.79			35.79			35.79	
38	D.C. Revenue Lag		44.34			44.34			44.34	
39	D.C. Net Lag		8.56			8.56			8.56	
40	D.C. Average Daily Expense			$ (12)			$ (6)			$ 6
41										
42	D.C. Impact of Ratemaking Adjustments on CWC			$ (103)			$ (51)			$ 51

	Adjustments Impacting Cash Working Capital									
1	Supplemental executive retirement plans (SERP)	(707)			(742)			(730)		
2	Pepco Incentive Payments	(1,502)			(1,417)			(1,461)		
3	Removal of institutional advertising/selling expenses	(218)			(219)			(217)		
4	Removal of employee association costs	(42)			(42)			(42)		
5	Removal of industry contributions and membership fees	(440)			(452)			(457)		
6	Removal of executive prerequisite expenses	(27)			(27)			(27)		
7	Removal of BSC Billed Depreciation (Merger Commitment 39)	(469)			(469)			(463)		
8	Inclusion of customer deposit interest expense and credit	466			466			464		
9	Current Rate Costs	(929)								
14	Reflection of Inflationary Growth of O&M expense	-			888			5,008		
15	Reflection of CTO Regulatory Asset	(392)			(6)			(6)		
			(4,260)			(2,020)			2,069	

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Ratemaking Adjustment Calculation
Multiyear Rate Plan

LINE NO.	Adjustment 16-Reflect Impact of Ratemaking Adjustments on CWC	Year 2020 (1) Test Year D.C. Distribution Amount	Year 2020 (2) 2014 Study (Lead)/Lag Days	Year 2020 (3) Test Year D.C. Distribution Lag Dollars	Year 2021 (1) Test Year D.C. Distribution Amount	Year 2021 (2) 2014 Study (Lead)/Lag Days	Year 2021 (3) Test Year D.C. Distribution Lag Dollars	Year 2022 (1) Test Year D.C. Distribution Amount	Year 2022 (2) 2014 Study (Lead)/Lag Days	Year 2022 (3) Test Year D.C. Distribution Lag Dollars
	D.C. Operating Revenues									
1	Billed Sale of Electric	$ 523,952,484	44.24	$ 23,179,657,907	$ 524,981,183	44.24	$ 23,225,167,550	$ 526,033,788	44.24	$ 23,271,734,788
2	Late Payment Penalty	1,265,146	44.24	55,970,052	1,265,146	44.24	55,970,052	1,265,146	44.24	55,970,052
3	Reconnect/Return Check	268,086	44.24	11,860,103	268,086	44.24	11,860,103	268,086	44.24	11,860,103
4	CEO Online	-	-	-	-	-	-	-	-	-
5	Rent from Electric Property	1,536,418	(46.28)	(71,098,842)	1,536,418	(46.28)	(71,098,842)	1,536,418	(46.28)	(71,098,842)
6	Billing Services	(449)	21.52	(9,664)	(449)	21.52	(9,664)	(449)	21.52	(9,664)
7	Miscellaneous Other	3,491,467	99.52	347,487,246	3,491,467	99.52	347,487,246	3,491,467	99.52	347,487,246
8	**Composite Revenue Lag - D.C.**	**$ 530,513,151**	**44.34**	**$ 23,523,866,802**	**$ 531,541,850**	**44.34**	**$ 23,569,376,445**	**$ 532,594,455**	**44.34**	**$ 23,615,943,683**
	D.C. Operating Expenses									
9	Pepco Gross Wages	$ 32,988,210	$ 8.70	$ 286,997,431	$ 33,603,546	$ 8.70	$ 292,350,852	$ 33,827,264	$ 8.70	$ 294,297,194
10	Pepco AIP	1,291,309	241.00	311,205,528	1,340,531	241.00	$ 323,067,905	1,355,664	241.00	$ 326,714,962
11	Pepco D.C. - Major Storm Expense	1,792,340	137.47	246,392,980	1,792,434	137.47	$ 246,405,902	1,578,757	137.47	$ 217,031,736
12	Control Center Lease	-	88.25	-	-	88.25	-	-	88.25	-
13	Other O&M Expense	125,519,219	35.79	4,491,830,861	125,651,747	35.79	4,496,573,504	124,990,987	35.79	4,472,927,536
14	Property tax - District of Columbia	6,628,632	97.21	644,369,284	6,827,496	97.21	663,700,852	7,032,324	97.21	683,612,229
15	Property tax - Montgomery County	1,051,344	(4.10)	(4,310,509)	1,135,799	(4.10)	(4,656,777)	1,227,022	(4.10)	(5,030,790)
16	Property tax - PG County	947,717	(59.76)	(56,635,565)	1,023,848	(59.76)	(61,185,167)	1,106,079	(59.76)	(66,099,302)
17	Property tax - Charles County	33,877	(59.60)	(2,019,075)	36,598	(59.60)	(2,181,270)	39,538	(59.60)	(2,356,460)
18	Property tax - Other MD Counties	111,788	(76.77)	(8,581,999)	120,769	(76.77)	(9,271,401)	130,468	(76.77)	(10,016,041)
19	Property tax - Alexandria	154,649	151.09	23,365,893	157,743	151.09	23,833,416	160,899	151.09	24,310,271
20	Property tax - Arlington	18,978	234.50	4,450,414	19,358	234.50	4,539,461	19,745	234.50	4,630,286
21	Property tax - Fairfax	-	-	-	-	-	-	-	-	-
22	Property tax - Pr William	3,204	153.68	492,448	3,268	153.68	502,301	3,334	153.68	512,351
23	D.C. Delivery Tax	82,210,365	35.41	2,911,069,025	81,459,867	35.41	2,884,493,890	80,636,760	35.41	2,855,347,672
24	D.C. Public Space Occupancy Fee	22,569,250	(49.13)	(1,108,827,253)	22,373,381	(49.13)	(1,099,204,209)	22,153,775	(49.13)	(1,088,414,966)
25	D.C. RETF, SETF, EATF	19,413,704	36.27	704,135,044	19,240,046	36.27	697,836,468	19,047,548	36.27	690,854,566
26	D.C. PSC Reimbursement	9,368,170	172.50	1,616,009,325	9,368,170	172.50	1,616,009,325	9,368,170	172.50	1,616,009,325
27	D.C. Business Improvement District Tax	183,824	(99.94)	(18,371,371)	183,824	(99.94)	(18,371,371)	183,822	(99.94)	(18,371,171)
28	D.C. Ball Park Fee	-	197.50	-	-	197.50	-	-	197.50	-
29	D.C. Sales & Use Tax	282,238	35.69	10,073,074	282,238	35.69	10,073,074	282,238	35.69	10,073,074
30	Federal Heavy Highway Vehicle Use Tax (FHUT)	16,698	(138.50)	(2,312,673)	16,698	(138.50)	(2,312,673)	16,698	(138.50)	(2,312,673)
31	FICA	2,802,119	9.15	25,639,391	2,871,620	9.15	26,275,325	2,892,553	9.15	26,466,861
32	FUTA/SUTA	32,809	9.03	296,262	33,622	9.03	303,610	33,867	9.03	305,823
33	DCIT currently payable	-	59.05	-	-	59.05	-	-	59.05	-
34	FIT currently payable	-	59.05	-	-	59.05	-	-	59.05	-
35	**Total D.C. Distribution Expenses**	**$ 307,420,445**		**$ 10,075,268,516**	**$ 307,542,604**		**$ 10,088,783,019**	**$ 306,087,513**		**$ 10,030,492,483**
36	**Composite Expense Lag**		**32.77**			**32.80**			**32.77**	
37	**Net Lag**		**11.57**			**11.54**			**11.57**	
38	D.C Average Daily Expenses (ln 35, col 1 ÷ 365 days)			$ 842,248			$ 842,582			$ 838,596
39	Cash Working Capital allowance before Imprest Funds			9,743,207			9,720,874			9,703,645
40	D.C. Imprest Funds			399,072			399,708			401,267
41	D.C. CWC			$ 10,142,279			$ 10,120,582			$ 10,104,912
				$ 10,142			$ 10,121			$ 10,105

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Multiyear Rate Plan

(Thousands of Dollars)

Line No.	Adjustment 17 - Interest Synchronization			
	Earnings	**2020**	**2021**	**2022**
1	Ratemaking Adjustments to Average D.C. Rate Base	$ 11,554	$ 8,010	$ 4,538
2	Weighted cost of long term debt	2.61%	2.61%	2.61%
3	Pro-forma interest on Ratemaking Adjustments to D.C. Rate Base	302	209	118
4	Adjustment to D.C. income tax expense to reflect interest synchronization per Commission Order No. 9216	$ (25)	$ (17)	$ (10)
5	Adjustment to Federal income tax expense to reflect interest synchronization per Commission Order No. 9216	$ (58)	$ (40)	$ (23)
	Total Earnings	**$ 83**	**$ 57**	**$ 33**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Interest Synchronization of Unadjusted Cost of Service
Multiyear Rate Plan

(Thousands of Dollars)

Line No.		2020	2021	2022
1	Unadjusted D.C. income tax expense for the twelve months ended December 31,	$ (374)	$ 1,589	$ 1,930
2	Unadjusted D.C. portion of Federal income tax expense for the twelve months ended December 31,	$ (14,035)	$ (15,878)	$ (18,277)
3	Unadjusted Average D.C. Rate Base	$ 2,195,345	$ 2,357,234	$ 2,560,428
4	Weighted Cost of Debt @ December 31,	2.61%	2.61%	2.61%
5	Pro-forma interest on Average D.C. Rate Base	57,298	61,524	66,827
6	less: Per Book D.C. Interest Expense	$ 60,051	$ 64,110	$ 69,000
7	Adjustment to D.C. Interest Expense for Interest Synchronization	$ (2,753)	$ (2,586)	$ (2,173)
8	Adjustment to Unadjusted D.C. Income Tax Expense for pro-forma interest expense	$ 227	$ 213	$ 179
9	Adjustment to Unadjusted D.C. Federal Income Tax Expense for pro-forma interest expense	$ 531	$ 498	$ 419
10	Unadjusted D.C. income tax reflecting synchronization of interest with unadjusted rate base (line 1 + line 8)	$ (147)	$ 1,802	$ 2,109
11	Unadjusted D.C. portion of federal income tax reflecting synchronization of interest with unadjusted rate base (line 2 + line 9)	$ (13,504)	$ (15,380)	$ (17,858)

POTOMAC ELECTRIC POWER COMPANY

Computation of District of Columbia Tax Factors
Multiyear Rate Plan

Line No.	Description	Statutory Tax Rate
1	D.C. Franchise Tax Rate	8.250%
2	Federal Income Tax Rate	21.00%

Line No.	Description	Computation	Tax Factor
3	D.C. Franchise Tax Factor	line 1	8.25000%
4	Federal Income Tax Factor	(100% - (line 3)) x line 2	19.26750%
5	Complement of Composite Tax Factor	100% - (line 3 + line 4)	72.48250%

T.W. Wolverton
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POTOMAC ELECTRIC POWER COMPANY

Functionalized Cost of Service Elements

Line No.	Item	December 2018 Total System	December 2018 Distribution Amount	December 2019 Total System	December 2019 Distribution Amount	December 2020 Total System	December 2020 Distribution Amount	December 2021 Total System	December 2021 Distribution Amount	December 2022 Total System	December 2022 Distribution Amount
	Rate Base										
1	Electric Plant in Service	$ 8,769,216,048	$ 7,155,530,317	$ 9,327,013,425	$ 7,618,343,520	$9,857,487,431	$ 8,082,083,392	$ 10,449,242,178	$ 8,617,556,590	$ 11,175,595,360	$ 9,221,903,690
2	Accumulated Depreciation	(2,992,483,034)	(2,495,674,762)	(3,162,317,039)	(2,631,913,994)	(3,376,807,572)	(2,807,843,604)	(3,605,626,162)	(2,997,944,873)	(3,850,395,242)	(3,203,733,237)
3	Accumulated Amortization	(23,947,655)	(20,966,172)	(30,697,287)	(26,875,475)	(42,839,727)	(37,506,181)	(58,153,228)	(50,913,151)	(77,430,856)	(67,790,714)
4	Materials & Supplies	81,762,941	73,227,818	87,395,556	76,791,581	84,577,904	73,227,818	84,577,904	73,416,077	84,577,904	73,416,077
5	Cash Working Capital	21,422,422	21,422,422	22,855,287	22,855,287	24,622,726	24,622,726	25,458,169	25,458,169	26,451,737	26,451,737
6	Accumulated Deferred Income Taxes	(1,783,280,143)	(1,472,154,104)	(1,811,976,954)	(1,491,161,579)	(1,816,693,713)	(1,490,268,929)	(1,829,110,985)	(1,496,691,812)	(1,864,435,047)	(1,519,998,492)
7	Net Prepaid Pension/OPEB Liability	194,279,931	170,092,080	181,119,733	158,570,326	158,319,611	138,608,819	135,528,348	138,588,716	116,685,168	123,778,300
8	Customer Deposits	(52,797,336)	(52,797,336)	(54,154,870)	(54,154,870)	(52,820,697)	(52,820,697)	(52,820,697)	(52,820,697)	(52,820,697)	(52,820,697)
9	Net Service Company Assets	62,726,735	54,917,257	64,597,319	56,554,953	55,720,595	48,783,381	45,789,510	40,088,716	37,741,719	33,042,875
10	Regulatory Assets	100,558,936	100,558,936	80,039,841	80,039,841	61,289,700	61,289,700	45,689,713	45,689,713	32,922,101	32,922,101
11	Credit Facility Costs	842,390	737,512	726,900	636,401	541,183	473,806	355,466	311,210	169,748	148,614
12	Total rate Base	$ 4,378,301,234	$ 3,534,893,968	$ 4,704,601,911	$ 3,809,685,992	$4,953,397,441	$ 4,040,650,232	$ 5,240,930,216	$ 4,342,738,657	$ 5,629,061,898	$ 4,667,320,256
13											
14											
15	Operating Income										
16	Sale of Electricity[1]	$ 1,526,938,510	$ 1,216,837,213	$ 1,575,861,054	$ 1,229,914,966	$1,571,475,454	$ 1,233,307,837	$ 1,578,587,580	$ 1,234,186,967	$ 1,588,428,228	$ 1,234,853,717
17	Other Revenues	28,346,708	17,517,104	28,346,708	17,517,104	28,346,708	17,517,104	28,346,708	17,517,104	28,346,708	17,517,104
18	Total Revenues	$ 1,555,285,218	$ 1,234,354,316	$ 1,604,207,762	$ 1,247,432,069	$1,599,822,162	$ 1,250,824,940	$ 1,606,934,288	$ 1,251,704,071	$ 1,616,774,936	$ 1,252,370,821
19											
20	O & M Expense[1]	$ 478,639,163	$ 404,861,879	$ 496,760,316	$ 419,690,814	$ 483,012,906	$ 413,199,578	$ 483,378,410	$ 412,833,393	$ 485,325,889	$ 411,472,014
21	Depreciation Expense	220,984,186	183,538,313	235,554,476	196,897,239	248,136,111	209,296,602	261,915,501	222,956,056	278,279,928	238,958,976
22	Amortization Expense	29,387,754	29,042,397	37,614,692	36,230,287	36,565,810	34,903,969	29,764,229	27,558,831	33,054,031	30,410,833
23	Taxes Other than Income Taxes	377,729,680	363,668,311	393,528,847	378,623,047	396,975,157	380,997,839	398,622,101	381,485,275	400,142,562	381,766,802
24	D.C. Income Tax	1,738,037	(3,829,323)	104,502	(6,361,296)	6,004,826	4,863,615	8,142,300	4,191,208	8,616,743	2,864,954
25	Maryland Income Tax	16,186,009	7,313,029	15,627,459	5,322,600	15,030,209	(374,205)	14,635,635	1,588,930	13,521,529	1,930,265
26	Federal Income Tax	28,629,034	3,976,240	20,391,950	(9,463,305)	16,819,048	(12,514,141)	14,828,323	(15,553,935)	10,375,156	(20,808,146)
27	Total Operating Expenses	$ 1,153,293,862	$ 988,570,846	$ 1,199,582,242	$ 1,020,939,386	$1,202,544,066	$ 1,030,373,258	$ 1,211,286,498	$ 1,035,059,756	$ 1,229,315,838	$ 1,046,595,698
28											
29	Operating Income Before AFUDC	$ 401,991,356	$ 245,783,470	$ 404,625,520	$ 226,492,683	$ 397,278,096	$ 220,451,683	$ 395,647,790	$ 216,644,315	$ 387,459,098	$ 205,775,123

[1]Excluding SOS/Purchased Power

Potomac Electric Power Company
Development of Distribution Cost of Service

Rate Base

1. **Electric Plant in Service**
   The thirteen-month average balance for distribution Electric Plant in Service is based on historical data as recorded in the financial records of the Company. Included are all balances reflected in distribution accounts, plus general and intangible plant account balances allocated to distribution based on the Distribution Labor ratio.

2. **Accumulated Depreciation**
   The thirteen-month average distribution balance for Accumulated Depreciation is based on historical data as recorded in the financial records of the Company. Included are all balances reflected in distribution accounts, plus general accumulated depreciation balances allocated to distribution based on the Distribution Labor ratio.

3. **Accumulated Amortization**
   The thirteen-month average distribution balance for Accumulated Amortization is based on historical data as recorded in the financial records of the Company. The balances are allocated to distribution based on the Distribution Labor ratio.

4. **Materials & Supplies**
   The thirteen-month average balance for Materials & Supplies is based on historical data, less amounts estimated to be related to transmission based on FERC Form 1 data.

5. **Accumulated Deferred Income Taxes**
   The thirteen-month average distribution balance for Accumulated Deferred Income Taxes is based on historical data as recorded in the financial records of the Company. Rate base deferred taxes are allocated to distribution based on Plant ratios.

6. **Net Prepaid Pension/OPEB Liability**
   The average prepaid pension asset/OPEB liability, net of associated deferred taxes, is based on historical data as recorded in the financial records of the Company. The balance is allocated to distribution based on the Distribution Labor ratio.

7. **Customer Deposits**
   Thirteen-month average Customer Deposits is based on historical data as recorded in the financial records of the Company. The balance is derived from a detailed analysis of accounting records.

8. **Pepco Portion of Service Company Assets**
   The thirteen-month average Pepco Portion of Service Company Assets is based on historical data as recorded in the financial records of the Company. The net service company assets are allocated to distribution based on the Distribution Labor ratio.

9. **Regulatory Assets**
   The thirteen-month average distribution related Regulatory Assets, net of accumulated deferred taxes, is based on historical data as recorded in the financial records of the Company.

10. **Credit Facility**
    The thirteen-month average unamortized balance of credit facility start-up costs is allocated to distribution based on the Distribution Labor ratio.

Potomac Electric Power Company
Development of Distribution Cost of Service

Operating Income

11. Sale of Electricity

Revenue is comprised of billed jurisdictional distribution revenue, based on unbundled jurisdictional distribution rates.

12. Other Revenues

Other revenues are assigned to distribution based on detailed analysis.

13. Operation & Maintenance Expense

Operation & Maintenance expense for the distribution business is based on historical data as recorded in the financial records of the Company. It reflects all distribution and customer accounts, plus a portion of the A&G accounts determined as follows: after elimination of costs in A&G accounts specifically identifiable as pertaining to the Company's Standard Offer Service business, the remaining costs are allocated to distribution based on the Distribution Labor ratio, with the exception of account 924 (property insurance), which is allocated based on plant less AFUDC, and accounts 928 (regulatory expense) and 904 (uncollectible expense), which are directly assigned based on detailed analysis.

14. Depreciation and Amortization Expense

Depreciation and amortization expense is based on historical data as recorded in the financial records of the Company. The amounts include all expenses reflected in distribution accounts, plus an allocation of expenses in general and intangible functional accounts based on the Distribution Labor ratio.

15. Other Taxes

Taxes other than income taxes is based on historical data as recorded in the financial records of the Company. Other taxes not directly assignable to distribution are allocated as follows: property taxes are allocated to distribution based on assessable plant; payroll taxes are allocated based on the Distribution Labor ratio.

16. Maryland State Income Tax

Maryland state income tax is determined by applying a Maryland apportioned income tax rate of 5.10% (based on the latest available tax return) to distribution-related system taxable income.

17. District of Columbia Income Tax

District of Columbia income tax is determined by applying a District of Columbia apportioned income tax rate 3.20% (based on the latest available tax return) to distribution-related system taxable income.

18. Federal Income Tax

Federal income tax is determined by applying the statutory rate of 21% to distribution-related system taxable income.

T.W. Wolverton
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
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28-May-19 11:52

PEPCO - DC
JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	SUMMARY OF RESULTS-1	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	RATE BASE							
1	Total System Electric Distribution		7,155,530,317	3,634,746,164	3,520,784,153	7,618,343,520	3,891,005,435	3,727,338,085
2	Less: Depreciation Reserve		2,495,674,762	1,131,593,532	1,364,081,230	2,631,913,994	1,209,631,206	1,422,282,788
3	Total Net Plant		4,659,855,555	2,503,152,633	2,156,702,923	4,986,429,526	2,681,374,228	2,305,055,298
	ADD:							
4	Construction Work in Progress		0	0	0	0	0	0
5	Working Capital		21,422,422	9,301,840	12,120,582	22,855,287	9,622,150	13,233,136
6	Plant Held for Future Use		0	0	0	0	0	0
7	Materials & Supplies		73,227,818	37,394,632	35,833,186	76,791,581	39,373,301	37,418,281
8	Regulatory Assets		100,558,936	50,112,729	50,446,207	80,039,841	40,303,447	39,736,394
9	Net Service Company Assets - Plant Related		54,917,257	27,578,828	27,338,429	56,554,953	28,814,298	27,740,655
10	Net Service Company Assets - CWIP Related		0	0	0	0	0	0
11	Net of Tax Prepaid Pension/OPEB		170,092,080	72,038,503	98,053,577	158,570,326	68,490,321	90,080,005
12	Credit Facility Costs		737,512	374,414	363,098	636,401	324,804	311,597
	DEDUCT:							
13	Accumulated Amortization		(20,966,172)	(11,489,086)	(9,477,086)	(26,875,475)	(14,565,026)	(12,310,449)
14	Customer Deposits		(52,797,336)	(8,507,321)	(44,290,015)	(54,154,870)	(9,330,243)	(44,824,626)
15	Deferred FIT		(1,265,360,905)	(702,628,929)	(562,731,976)	(1,285,649,992)	(713,597,412)	(572,052,579)
16	Deferred SIT		(206,793,199)	(115,237,207)	(91,555,992)	(205,511,587)	(109,093,791)	(96,417,796)
17	TOTAL ADIT		(1,472,154,104)	(817,866,136)	(654,287,968)	(1,491,161,579)	(822,691,203)	(668,470,376)
18	**TOTAL RATE BASE**		3,534,893,968	1,862,091,034	1,672,802,934	3,809,685,992	2,021,716,076	1,787,969,916
	DEVELOPMENT OF RETURN							
19	Revenue - Retail Sales		1,216,837,213	528,277,577	688,559,636	1,229,914,966	522,573,338	707,341,628
20	Other Operating Revenue		17,517,104	6,560,667	10,956,437	17,517,104	6,560,667	10,956,437
21	Total Electric Operating Revenue		1,234,354,316	534,838,244	699,516,073	1,247,432,069	529,134,004	718,298,065
	LESS:							
22	Operating & Maintenance Expense		404,861,879	162,573,819	242,288,060	419,690,814	177,109,697	242,581,116
23	Depreciation Expense		183,538,313	99,493,393	84,044,920	196,897,239	107,680,629	89,216,610
24	Amortization Expense		29,042,397	10,055,295	18,987,103	36,230,287	13,789,562	22,440,725
25	Other Taxes		363,668,311	147,713,081	215,955,230	378,623,047	145,970,836	232,652,212
26	State Income Taxes		3,483,706	(3,829,323)	7,313,029	(1,038,696)	(6,361,296)	5,322,600
27	Federal Income Taxes		29,380,892	14,252,343	15,128,549	22,134,712	7,851,504	14,283,208
28	Net ITC Adjustment & Excess Deferred Amortization		(25,404,652)	(13,722,673)	(11,681,979)	(31,598,017)	(18,934,189)	(12,663,828)
29	Total Federal Income Taxes		3,976,240	529,670	3,446,570	(9,463,305)	(11,082,685)	1,619,380
30	Total Operating Expenses		988,570,846	416,535,935	572,034,911	1,020,939,386	427,106,744	593,832,643
31	**OPERATING INCOME**		245,783,470	118,302,309	127,481,161	226,492,683	102,027,261	124,465,422
32	AFUDC		0	0	0	0	0	0
33	**OPERATING INCOME FOR ROR CALCULATION**		245,783,470	118,302,309	127,481,161	226,492,683	102,027,261	124,465,422
34	**RATE OF RETURN**		6.95%	6.35%	7.62%	5.95%	5.05%	6.96%
35	**RELATIVE RATE OF RETURN**		1.00	0.91	1.10	0.86	0.73	1.00

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	SUMMARY OF RESULTS-1							
	RATE BASE							
1	Total System Electric Distribution		8,082,083,392	4,197,039,916	3,885,043,477	8,617,556,590	4,482,842,590	4,134,714,000
2	Less: Depreciation Reserve		2,807,843,604	1,311,475,926	1,496,367,678	2,997,944,873	1,422,017,222	1,575,927,652
3	Total Net Plant		5,274,239,788	2,885,563,989	2,388,675,799	5,619,611,717	3,060,825,369	2,558,786,348
	ADD:							
4	Construction Work in Progress		0	0	0	0	0	0
5	Working Capital		24,622,726	10,142,314	14,480,412	25,458,169	10,120,599	15,337,570
6	Plant Held for Future Use		0	0	0	0	0	0
7	Materials & Supplies		73,227,818	38,115,874	35,111,945	73,416,077	38,372,447	35,043,630
8	Regulatory Assets		61,289,700	30,461,243	30,828,457	45,689,713	22,721,361	22,968,352
9	Net Service Company Assets - Plant Related		48,783,381	25,300,129	23,483,252	40,088,716	20,824,035	19,264,681
10	Net Service Company Assets - CWIP Related		0	0	0	0	0	0
11	Net of Tax Prepaid Pension/OPEB		138,608,819	60,151,359	78,457,460	138,588,716	60,156,374	78,432,342
12	Credit Facility Costs		473,806	245,726	228,080	311,210	161,658	149,552
	DEDUCT:							
13	Accumulated Amortization		(37,506,181)	(20,322,074)	(17,184,107)	(50,913,151)	(27,309,028)	(23,604,123)
14	Customer Deposits		(52,820,697)	(9,484,872)	(43,335,825)	(52,820,697)	(9,484,872)	(43,335,825)
15	Deferred FIT		(1,273,435,007)	(715,868,697)	(557,566,310)	(1,263,442,403)	(706,095,261)	(557,347,142)
16	Deferred SIT		(216,833,922)	(108,960,232)	(107,873,690)	(233,249,409)	(113,058,231)	(120,191,178)
17	TOTAL ADIT		(1,490,268,929)	(824,828,928)	(665,440,000)	(1,496,691,812)	(819,153,492)	(677,538,320)
18	**TOTAL RATE BASE**		4,040,650,232	2,195,344,760	1,845,305,472	4,342,738,657	2,357,234,450	1,985,504,207
	DEVELOPMENT OF RETURN							
19	Revenue - Retail Sales		1,233,307,837	523,952,484	709,355,353	1,234,186,967	524,981,183	709,205,784
20	Other Operating Revenue		17,517,104	6,560,667	10,956,437	17,517,104	6,560,667	10,956,437
21	Total Electric Operating Revenue		1,250,824,940	530,513,151	720,311,790	1,251,704,071	531,541,850	720,162,221
	LESS:							
22	Operating & Maintenance Expense		413,199,578	174,657,349	238,542,229	412,833,393	174,001,919	238,831,474
23	Depreciation Expense		209,296,602	116,102,296	93,194,306	222,956,056	123,320,925	99,635,131
24	Amortization Expense		34,903,969	13,511,078	21,392,891	27,558,831	11,401,070	16,157,760
25	Other Taxes		380,997,839	145,817,579	235,180,261	381,485,275	145,142,564	236,342,710
26	State Income Taxes		4,716,410	(147,205)	4,863,615	5,993,138	1,801,930	4,191,208
27	Federal Income Taxes		19,614,336	5,429,314	14,185,022	16,542,412	3,554,387	12,988,025
28	Net ITC Adjustment & Excess Deferred Amortization		(31,598,017)	(18,934,189)	(12,663,828)	(31,598,017)	(18,934,189)	(12,663,828)
29	Total Federal Income Taxes		(11,983,681)	(13,504,875)	1,521,194	(15,055,605)	(15,379,802)	324,197
30	Total Operating Expenses		1,031,130,718	436,436,222	594,694,496	1,035,771,086	440,288,606	595,482,480
31	**OPERATING INCOME**		219,694,223	94,076,929	125,617,294	215,932,985	91,253,244	124,679,741
32	AFUDC		0	0	0	0	0	0
33	**OPERATING INCOME FOR ROR CALCULATION**		219,694,223	94,076,929	125,617,294	215,932,985	91,253,244	124,679,741
34	**RATE OF RETURN**		5.44%	4.29%	6.81%	4.97%	3.87%	6.28%
35	**RELATIVE RATE OF RETURN**		0.78	0.62	0.98	0.72	0.56	0.90

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	SUMMARY OF RESULTS-1	ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	RATE BASE				
1	Total System Electric Distribution		9,221,903,690	4,819,186,973	4,402,716,718
2	Less: Depreciation Reserve		3,203,733,237	1,540,707,461	1,663,025,776
3	Total Net Plant		6,018,170,454	3,278,479,512	2,739,690,942
	ADD:				
4	Construction Work in Progress		0	0	0
5	Working Capital		26,451,737	10,104,920	16,346,817
6	Plant Held for Future Use		0	0	0
7	Materials & Supplies		73,416,077	38,581,693	34,834,384
8	Regulatory Assets		32,922,101	15,423,658	17,498,443
9	Net Service Company Assets - Plant Related		33,042,875	17,231,025	15,811,850
10	Net Service Company Assets - CWIP Related		0	0	0
11	Net of Tax Prepaid Pension/OPEB		123,778,300	53,094,466	70,683,834
12	Credit Facility Costs		148,614	77,498	71,116
	DEDUCT:				
13	Accumulated Amortization		(67,790,714)	(36,208,829)	(31,581,886)
14	Customer Deposits		(52,820,697)	(9,484,872)	(43,335,825)
15	Deferred FIT		(1,266,682,542)	(687,575,536)	(579,107,006)
16	Deferred SIT		(253,315,950)	(119,295,698)	(134,020,252)
17	TOTAL ADIT		(1,519,998,492)	(806,871,234)	(713,127,258)
18	**TOTAL RATE BASE**		4,667,320,256	2,560,427,839	2,106,892,417
	DEVELOPMENT OF RETURN				
19	Revenue - Retail Sales		1,234,853,717	526,033,788	708,819,929
20	Other Operating Revenue		17,517,104	6,560,667	10,956,437
21	Total Electric Operating Revenue		1,252,370,821	532,594,455	719,776,366
	LESS:				
22	Operating & Maintenance Expense		411,472,014	171,355,966	240,116,048
23	Depreciation Expense		238,958,976	132,402,164	106,556,812
24	Amortization Expense		30,410,833	13,037,433	17,373,400
25	Other Taxes		381,766,802	144,323,029	237,443,772
26	State Income Taxes		4,974,219	2,109,265	2,864,954
27	Federal Income Taxes		11,208,611	1,075,591	10,133,020
28	Net ITC Adjustment & Excess Deferred Amortization		(31,598,017)	(18,934,189)	(12,663,828)
29	Total Federal Income Taxes		(20,389,406)	(17,858,598)	(2,530,808)
30	Total Operating Expenses		1,047,193,438	445,369,259	601,824,179
31	**OPERATING INCOME**		205,177,383	87,225,195	117,952,188
32	AFUDC		0	0	0
33	**OPERATING INCOME FOR ROR CALCULATION**		205,177,383	87,225,195	117,952,188
34	**RATE OF RETURN**		4.40%	3.41%	5.60%
35	**RELATIVE RATE OF RETURN**		0.63	0.49	0.81

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	DEVELOPMENT OF RATE BASE-2	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	ELECTRIC PLANT IN SERVICE							
	SUBTRANSMISSION - CLASS							
1	3600 Land and Land Rights - Subs	STAED	2,404,237	1,010,501	1,393,736	2,404,237	1,010,501	1,393,736
2	3600 Land and Land Rights - OH Lines	STAED	0	0	0	0	0	0
3	3600 Land and Land Rights - UG Lines	STAED	0	0	0	0	0	0
4	3610 Structures and Improvements	STAED	5,794,089	2,435,256	3,358,834	5,879,614	2,471,202	3,408,412
5	3620 Station Equipment	STAED	262,268,418	110,231,416	152,037,002	258,466,498	108,633,469	149,833,029
6	3627 Station Equipment	STAED	0	0	0	1	0	1
7	3640 Poles, Towers and Fixtures	STAED	42,257,963	17,761,022	24,496,941	45,080,009	18,947,128	26,132,881
8	3650 Overhead Conductors and Devices	STAED	40,280,462	16,929,878	23,350,584	43,134,508	18,129,434	25,005,074
9	3660 Underground Conduit	STAED	131,200,048	55,143,380	76,056,668	142,116,643	59,731,625	82,385,018
10	3670 Underground Conductors and Devices	STAED	156,504,354	65,778,780	90,725,574	144,282,569	60,641,964	83,640,605
11	3680 Line Transformers	STAED	0	0	0	0	0	0
12	TOTAL SUBTRANSMISSION		640,709,572	269,290,233	371,419,339	641,364,079	269,565,322	371,798,757
	SUBTRANSMISSION - SMECO							
13	3600 Land and Land Rights - Subs	DISTROTH	45,821	0	45,821	45,821	0	45,821
14	3600 Land and Land Rights - OH Lines	DISTROTH	0	0	0	0	0	0
15	3600 Land and Land Rights - UG Lines	DISTROTH	0	0	0	0	0	0
16	3610 Structures and Improvements	DISTROTH	68,944	0	68,944	68,944	0	68,944
17	3620 Station Equipment	DISTROTH	2,606,541	0	2,606,541	2,606,541	0	2,606,541
18	3627 Station Equipment	DISTROTH	0	0	0	0	0	0
19	3640 Poles, Towers and Fixtures	DISTROTH	565,723	0	565,723	565,723	0	565,723
20	3650 Overhead Conductors and Devices	DISTROTH	228,730	0	228,730	228,730	0	228,730
21	3660 Underground Conduit	DISTROTH	484,565	0	484,565	484,565	0	484,565
22	3670 Underground Conductors and Devices	DISTROTH	0	0	0	0	0	0
23	3680 Line Transformers	DISTROTH	0	0	0	0	0	0
24	TOTAL SUBTRANSMISSION - SMECO		4,000,324	0	4,000,324	4,000,324	0	4,000,324

	DEVELOPMENT OF RATE BASE-2	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	ELECTRIC PLANT IN SERVICE							
	SUBTRANSMISSION - CLASS							
1	3600 Land and Land Rights - Subs	STAED	2,404,237	1,010,501	1,393,736	2,404,237	1,010,501	1,393,736
2	3600 Land and Land Rights - OH Lines	STAED	0	0	0	0	0	0
3	3600 Land and Land Rights - UG Lines	STAED	0	0	0	0	0	0
4	3610 Structures and Improvements	STAED	7,643,624	3,212,615	4,431,009	9,821,420	4,127,943	5,693,477
5	3620 Station Equipment	STAED	260,112,438	109,325,258	150,787,180	264,113,559	111,006,929	153,106,630
6	3627 Station Equipment	STAED	2	1	1	3	1	2
7	3640 Poles, Towers and Fixtures	STAED	45,215,339	19,004,007	26,211,332	67,628,223	28,424,142	39,204,081
8	3650 Overhead Conductors and Devices	STAED	43,303,452	18,200,441	25,103,011	64,590,023	27,147,187	37,442,837
9	3660 Underground Conduit	STAED	143,826,443	60,450,254	83,376,189	188,612,352	79,273,771	109,338,580
10	3670 Underground Conductors and Devices	STAED	144,206,023	60,609,792	83,596,232	194,852,828	81,896,643	112,956,184
11	3680 Line Transformers	STAED	0	0	0	0	0	0
12	TOTAL SUBTRANSMISSION		646,711,559	271,812,868	374,898,691	792,022,644	332,887,117	459,135,527
	SUBTRANSMISSION - SMECO							
13	3600 Land and Land Rights - Subs	DISTROTH	45,821	0	45,821	45,821	0	45,821
14	3600 Land and Land Rights - OH Lines	DISTROTH	0	0	0	0	0	0
15	3600 Land and Land Rights - UG Lines	DISTROTH	0	0	0	0	0	0
16	3610 Structures and Improvements	DISTROTH	68,944	0	68,944	68,944	0	68,944
17	3620 Station Equipment	DISTROTH	2,606,541	0	2,606,541	2,606,541	0	2,606,541
18	3627 Station Equipment	DISTROTH	0	0	0	0	0	0
19	3640 Poles, Towers and Fixtures	DISTROTH	565,723	0	565,723	565,723	0	565,723
20	3650 Overhead Conductors and Devices	DISTROTH	228,730	0	228,730	228,730	0	228,730
21	3660 Underground Conduit	DISTROTH	484,565	0	484,565	484,565	0	484,565
22	3670 Underground Conductors and Devices	DISTROTH	0	0	0	0	0	0
23	3680 Line Transformers	DISTROTH	0	0	0	0	0	0
24	TOTAL SUBTRANSMISSION - SMECO		4,000,324	0	4,000,324	4,000,324	0	4,000,324

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ELECTRIC DISTRIBUTION

DEVELOPMENT OF RATE BASE-2

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	ELECTRIC PLANT IN SERVICE				
	SUBTRANSMISSION - CLASS				
1	3600 Land and Land Rights - Subs	STAED	2,404,237	1,010,501	1,393,736
2	3600 Land and Land Rights - OH Lines	STAED	0	0	0
3	3600 Land and Land Rights - UG Lines	STAED	0	0	0
4	3610 Structures and Improvements	STAED	10,092,296	4,241,792	5,850,504
5	3620 Station Equipment	STAED	270,289,885	113,602,839	156,687,046
6	3627 Station Equipment	STAED	4	2	2
7	3640 Poles, Towers and Fixtures	STAED	84,940,862	35,700,644	49,240,218
8	3650 Overhead Conductors and Devices	STAED	81,035,046	34,059,030	46,976,016
9	3660 Underground Conduit	STAED	225,132,779	94,623,307	130,509,472
10	3670 Underground Conductors and Devices	STAED	235,180,996	98,846,573	136,334,424
11	3680 Line Transformers	STAED	0	0	0
12	TOTAL SUBTRANSMISSION		909,076,104	382,084,687	526,991,418
	SUBTRANSMISSION - SMECO				
13	3600 Land and Land Rights - Subs	DISTROTH	45,821	0	45,821
14	3600 Land and Land Rights - OH Lines	DISTROTH	0	0	0
15	3600 Land and Land Rights - UG Lines	DISTROTH	0	0	0
16	3610 Structures and Improvements	DISTROTH	68,944	0	68,944
17	3620 Station Equipment	DISTROTH	2,606,541	0	2,606,541
18	3627 Station Equipment	DISTROTH	0	0	0
19	3640 Poles, Towers and Fixtures	DISTROTH	565,723	0	565,723
20	3650 Overhead Conductors and Devices	DISTROTH	228,730	0	228,730
21	3660 Underground Conduit	DISTROTH	484,565	0	484,565
22	3670 Underground Conductors and Devices	DISTROTH	0	0	0
23	3680 Line Transformers	DISTROTH	0	0	0
24	TOTAL SUBTRANSMISSION - SMECO		4,000,324	0	4,000,324

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-3

		ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	DISTRIBUTION PLANT							
	DISTRIBUTION - DC							
1	3600 Land and Land Rights - Subs	DISTRDC	44,194,009	44,194,009	0	44,194,009	44,194,009	0
2	3600 Land and Land Rights - OH Lines	DISTRDC	243,306	243,306	0	243,306	243,306	0
3	3600 Land and Land Rights - UG Lines	DISTRDC	25,250	25,250	0	25,250	25,250	0
4	3610 Structures and Improvements	DISTRDC	61,175,023	61,175,023	0	71,077,849	71,077,849	0
5	3620 Station Equipment	DISTRDC	410,009,536	410,009,536	0	409,892,163	409,892,163	0
6	3627 Capitalize Control Ctr	DISTRDC	0	0	0	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRDC	116,455,497	116,455,497	0	125,016,421	125,016,421	0
8	3650 Overhead Conductors and Devices	DISTRDC	127,449,521	127,449,521	0	138,114,146	138,114,146	0
9	3660 Underground Conduit	DISTRDC	768,655,182	768,655,182	0	837,684,416	837,684,416	0
10	3670 Underground Conductors and Devices	DISTRDC	755,172,889	755,172,889	0	796,605,855	796,605,855	0
11	3680 Line Transformers	DISTRDC	517,249,722	517,249,722	0	568,165,942	568,165,942	0
12	3691 Services	DISTRDC	16,003,858	16,003,858	0	20,318,498	20,318,498	0
13	3692 Services	DISTRDC	114,795,422	114,795,422	0	120,194,790	120,194,790	0
14	3693 Services	DISTRDC	163,230,886	163,230,886	0	172,259,193	172,259,193	0
15	3700 Meters	DISTRDC	7,005,437	7,005,437	0	7,000,051	7,000,051	0
16	3701 AMI Meters	DISTRDC	57,125,072	57,125,072	0	61,765,290	61,765,290	0
17	3711 Installations on Customer Premises	DISTRDC	1,367,203	1,367,203	0	1,367,203	1,367,203	0
18	3731 Street Lighting and Signal Systems	DISTRDC	50,508	50,508	0	64,880	64,880	0
19	3732 Street Lighting and Signal Systems	DISTRDC	10,001,199	10,001,199	0	9,786,196	9,786,196	0
20	3734 Street Lighting and Signal Systems	DISTRDC	49,789	49,789	0	49,789	49,789	0
21	TOTAL DISTRIBUTION - DC		3,170,259,310	3,170,259,310	0	3,383,825,248	3,383,825,248	0

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ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-3

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	DISTRIBUTION PLANT							
	DISTRIBUTION - DC							
1	3600 Land and Land Rights - Subs	DISTRDC	44,194,009	44,194,009	0	44,194,009	44,194,009	0
2	3600 Land and Land Rights - OH Lines	DISTRDC	243,306	243,306	0	243,306	243,306	0
3	3600 Land and Land Rights - UG Lines	DISTRDC	25,250	25,250	0	25,250	25,250	0
4	3610 Structures and Improvements	DISTRDC	86,490,152	86,490,152	0	100,057,011	100,057,011	0
5	3620 Station Equipment	DISTRDC	409,898,329	409,898,329	0	409,898,329	409,898,329	0
6	3627 Capitalize Control Ctr	DISTRDC	0	0	0	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRDC	137,115,184	137,115,184	0	146,994,196	146,994,196	0
8	3650 Overhead Conductors and Devices	DISTRDC	153,371,639	153,371,639	0	166,243,748	166,243,748	0
9	3660 Underground Conduit	DISTRDC	928,859,886	928,859,886	0	982,379,974	982,379,974	0
10	3670 Underground Conductors and Devices	DISTRDC	829,402,760	829,402,760	0	840,767,735	840,767,735	0
11	3680 Line Transformers	DISTRDC	638,878,164	638,878,164	0	700,538,158	700,538,158	0
12	3691 Services	DISTRDC	26,559,851	26,559,851	0	32,035,296	32,035,296	0
13	3692 Services	DISTRDC	127,502,562	127,502,562	0	133,920,193	133,920,193	0
14	3693 Services	DISTRDC	185,590,817	185,590,817	0	197,245,185	197,245,185	0
15	3700 Meters	DISTRDC	6,999,983	6,999,983	0	6,999,983	6,999,983	0
16	3701 AMI Meters	DISTRDC	68,947,404	68,947,404	0	75,209,305	75,209,305	0
17	3711 Installations on Customer Premises	DISTRDC	1,367,203	1,367,203	0	1,367,203	1,367,203	0
18	3731 Street Lighting and Signal Systems	DISTRDC	91,930	91,930	0	115,744	115,744	0
19	3732 Street Lighting and Signal Systems	DISTRDC	9,752,441	9,752,441	0	9,752,441	9,752,441	0
20	3734 Street Lighting and Signal Systems	DISTRDC	49,789	49,789	0	49,789	49,789	0
21	TOTAL DISTRIBUTION - DC		3,655,340,659	3,655,340,659	0	3,848,036,855	3,848,036,855	0

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ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-3

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	DISTRIBUTION PLANT				
	DISTRIBUTION - DC				
1	3600 Land and Land Rights - Subs	DISTRDC	44,194,009	44,194,009	0
2	3600 Land and Land Rights - OH Lines	DISTRDC	243,306	243,306	0
3	3600 Land and Land Rights - UG Lines	DISTRDC	25,250	25,250	0
4	3610 Structures and Improvements	DISTRDC	115,456,296	115,456,296	0
5	3620 Station Equipment	DISTRDC	406,885,354	406,885,354	0
6	3627 Capitalize Control Ctr	DISTRDC	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRDC	158,429,379	158,429,379	0
8	3650 Overhead Conductors and Devices	DISTRDC	181,091,825	181,091,825	0
9	3660 Underground Conduit	DISTRDC	1,051,405,511	1,051,405,511	0
10	3670 Underground Conductors and Devices	DISTRDC	858,918,389	858,918,389	0
11	3680 Line Transformers	DISTRDC	770,829,266	770,829,266	0
12	3691 Services	DISTRDC	38,277,189	38,277,189	0
13	3692 Services	DISTRDC	141,236,158	141,236,158	0
14	3693 Services	DISTRDC	210,530,921	210,530,921	0
15	3700 Meters	DISTRDC	6,999,983	6,999,983	0
16	3701 AMI Meters	DISTRDC	82,347,742	82,347,742	0
17	3711 Installations on Customer Premises	DISTRDC	1,367,203	1,367,203	0
18	3731 Street Lighting and Signal Systems	DISTRDC	142,892	142,892	0
19	3732 Street Lighting and Signal Systems	DISTRDC	9,752,441	9,752,441	0
20	3734 Street Lighting and Signal Systems	DISTRDC	49,789	49,789	0
21	TOTAL DISTRIBUTION - DC		4,078,182,904	4,078,182,904	0

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ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-4

		ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	DISTRIBUTION - MARYLAND							
1	3600 Land and Land Rights - Subs	DISTRMD	11,361,081	0	11,361,081	11,558,469	0	11,558,469
2	3600 Land and Land Rights - OH Lines	DISTRMD	175,215	0	175,215	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRMD	22,173	0	22,173	0	0	0
4	3610 Structures and Improvements	DISTRMD	53,980,717	0	53,980,717	69,711,879	0	69,711,879
5	3620 Station Equipment	DISTRMD	337,149,901	0	337,149,901	387,360,215	0	387,360,215
6	3627 Capitalize Control Ctr	DISTRMD	1,893,195	0	1,893,195	(1)	0	(1)
7	3640 Poles, Towers and Fixtures	DISTRMD	283,836,395	0	283,836,395	302,242,671	0	302,242,671
8	3650 Overhead Conductors and Devices	DISTRMD	487,111,560	0	487,111,560	514,765,840	0	514,765,840
9	3660 Underground Conduit	DISTRMD	283,630,288	0	283,630,288	288,367,976	0	288,367,976
10	3670 Underground Conductors and Devices	DISTRMD	632,718,570	0	632,718,570	650,161,273	0	650,161,273
11	3680 Line Transformers	DISTRMD	503,281,956	0	503,281,956	531,111,498	0	531,111,498
12	3691 OH Services	DISTRMD	48,720,862	0	48,720,862	48,183,644	0	48,183,644
13	3692 UG Services	DISTRMD	23,385,756	0	23,385,756	23,997,572	0	23,997,572
14	3693 UG Services	DISTRMD	153,571,675	0	153,571,675	159,742,574	0	159,742,574
15	3700 Meters	DISTRMD	15,822,519	0	15,822,519	15,558,393	0	15,558,393
16	3701 AMI Meters	DISTRMD	72,051,434	0	72,051,434	73,326,666	0	73,326,666
17	3711 Installations on Customer Premises	DISTRMD	1,278,829	0	1,278,829	1,278,829	0	1,278,829
18	3731 Street Lighting and Signal Systems	DISTRMD	27,449,434	0	27,449,434	28,297,113	0	28,297,113
19	3732 Street Lighting and Signal Systems	DISTRMD	20,236,437	0	20,236,437	20,821,644	0	20,821,644
20	3734 Street Lighting and Signal Systems	DISTRMD	1,984,568	0	1,984,568	2,029,636	0	2,029,636
21	TOTAL DISTRIBUTION -MARYLAND		2,959,662,562	0	2,959,662,562	3,128,515,891	0	3,128,515,891

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ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-4

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	DISTRIBUTION - MARYLAND							
1	3600 Land and Land Rights - Subs	DISTRMD	11,558,469	0	11,558,469	11,558,469	0	11,558,469
2	3600 Land and Land Rights - OH Lines	DISTRMD	0	0	0	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRMD	0	0	0	0	0	0
4	3610 Structures and Improvements	DISTRMD	81,403,249	0	81,403,249	101,302,477	0	101,302,477
5	3620 Station Equipment	DISTRMD	427,863,510	0	427,863,510	495,576,982	0	495,576,982
6	3627 Capitalize Control Ctr	DISTRMD	(2)	0	(2)	(3)	0	(3)
7	3640 Poles, Towers and Fixtures	DISTRMD	316,169,885	0	316,169,885	317,323,295	0	317,323,295
8	3650 Overhead Conductors and Devices	DISTRMD	534,243,808	0	534,243,808	547,048,360	0	547,048,360
9	3660 Underground Conduit	DISTRMD	299,164,330	0	299,164,330	300,155,814	0	300,155,814
10	3670 Underground Conductors and Devices	DISTRMD	662,326,407	0	662,326,407	649,970,695	0	649,970,695
11	3680 Line Transformers	DISTRMD	553,073,392	0	553,073,392	589,945,028	0	589,945,028
12	3691 OH Services	DISTRMD	48,048,097	0	48,048,097	48,048,097	0	48,048,097
13	3692 UG Services	DISTRMD	24,456,764	0	24,456,764	25,239,638	0	25,239,638
14	3693 UG Services	DISTRMD	164,185,346	0	164,185,346	171,629,186	0	171,629,186
15	3700 Meters	DISTRMD	15,557,841	0	15,557,841	15,557,841	0	15,557,841
16	3701 AMI Meters	DISTRMD	74,177,519	0	74,177,519	75,575,764	0	75,575,764
17	3711 Installations on Customer Premises	DISTRMD	1,278,829	0	1,278,829	1,278,829	0	1,278,829
18	3731 Street Lighting and Signal Systems	DISTRMD	28,891,565	0	28,891,565	29,882,370	0	29,882,370
19	3732 Street Lighting and Signal Systems	DISTRMD	21,250,755	0	21,250,755	21,975,812	0	21,975,812
20	3734 Street Lighting and Signal Systems	DISTRMD	2,066,212	0	2,066,212	2,123,728	0	2,123,728
21	TOTAL DISTRIBUTION -MARYLAND		3,265,715,977	0	3,265,715,977	3,404,192,380	0	3,404,192,380

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ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-4

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	DISTRIBUTION - MARYLAND				
1	3600 Land and Land Rights - Subs	DISTRMD	11,558,469	0	11,558,469
2	3600 Land and Land Rights - OH Lines	DISTRMD	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRMD	0	0	0
4	3610 Structures and Improvements	DISTRMD	120,922,496	0	120,922,496
5	3620 Station Equipment	DISTRMD	563,058,189	0	563,058,189
6	3627 Capitalize Control Ctr	DISTRMD	(4)	0	(4)
7	3640 Poles, Towers and Fixtures	DISTRMD	323,142,919	0	323,142,919
8	3650 Overhead Conductors and Devices	DISTRMD	564,103,000	0	564,103,000
9	3660 Underground Conduit	DISTRMD	304,919,552	0	304,919,552
10	3670 Underground Conductors and Devices	DISTRMD	644,892,375	0	644,892,375
11	3680 Line Transformers	DISTRMD	626,266,512	0	626,266,512
12	3691 OH Services	DISTRMD	48,048,097	0	48,048,097
13	3692 UG Services	DISTRMD	26,010,831	0	26,010,831
14	3693 UG Services	DISTRMD	178,961,958	0	178,961,958
15	3700 Meters	DISTRMD	15,557,841	0	15,557,841
16	3701 AMI Meters	DISTRMD	76,953,145	0	76,953,145
17	3711 Installations on Customer Premises	DISTRMD	1,278,829	0	1,278,829
18	3731 Street Lighting and Signal Systems	DISTRMD	30,858,391	0	30,858,391
19	3732 Street Lighting and Signal Systems	DISTRMD	22,690,050	0	22,690,050
20	3734 Street Lighting and Signal Systems	DISTRMD	2,180,386	0	2,180,386
21	TOTAL DISTRIBUTION -MARYLAND		3,561,403,039	0	3,561,403,039

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ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-5

		ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	ELECTRIC PLANT IN SERVICE							
	DISTRIBUTION PLANT CON'T							
	DISTRIBUTION - VIRGINIA & SMECO							
1	3600 Land and Land Rights - Subs	DISTROTH	0	0	0	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTROTH	0	0	0	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTROTH	0	0	0	0	0	0
4	3610 Structures and Improvements	DISTROTH	0	0	0	0	0	0
5	3620 Station Equipment	DISTROTH	0	0	0	0	0	0
6	3627 Station Equipment	DISTROTH	0	0	0	0	0	0
7	3640 Poles, Towers and Fixtures	DISTROTH	0	0	0	0	0	0
8	3650 Overhead Conductors and Devices	DISTROTH	0	0	0	0	0	0
9	3660 Underground Conduit	DISTROTH	0	0	0	0	0	0
10	3670 Underground Conductors and Devices	DISTROTH	0	0	0	0	0	0
11	3680 Line Transformers	DISTROTH	0	0	0	0	0	0
12	3691 OH Services	DISTROTH	0	0	0	0	0	0
13	3692 UG Services	DISTROTH	0	0	0	0	0	0
14	3693 UG Services	DISTROTH	99,160	0	99,160	99,160	0	99,160
15	3700 Meters	DISTROTH	418,911	0	418,911	418,911	0	418,911
16	3701 AMI Meters	DISTROTH	0	0	0	0	0	0
17	3711 Installations on Customer Premises	DISTROTH	0	0	0	0	0	0
18	3731 Street Lighting and Signal Systems	DISTROTH	0	0	0	0	0	0
19	3732 Street Lighting and Signal Systems	DISTROTH	0	0	0	0	0	0
20	3734 Street Lighting and Signal Systems	DISTROTH	0	0	0	0	0	0
21	TOTAL DISTRIBUTION - VIRGINIA & SMECO		518,071	0	518,071	518,071	0	518,071

DEVELOP OF RATE BASE CON'T-5

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	ELECTRIC PLANT IN SERVICE							
	DISTRIBUTION PLANT CON'T							
	DISTRIBUTION - VIRGINIA & SMECO							
1	3600 Land and Land Rights - Subs	DISTROTH	0	0	0	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTROTH	0	0	0	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTROTH	0	0	0	0	0	0
4	3610 Structures and Improvements	DISTROTH	0	0	0	0	0	0
5	3620 Station Equipment	DISTROTH	0	0	0	0	0	0
6	3627 Station Equipment	DISTROTH	0	0	0	0	0	0
7	3640 Poles, Towers and Fixtures	DISTROTH	0	0	0	0	0	0
8	3650 Overhead Conductors and Devices	DISTROTH	0	0	0	0	0	0
9	3660 Underground Conduit	DISTROTH	0	0	0	0	0	0
10	3670 Underground Conductors and Devices	DISTROTH	0	0	0	0	0	0
11	3680 Line Transformers	DISTROTH	0	0	0	0	0	0
12	3691 OH Services	DISTROTH	0	0	0	0	0	0
13	3692 UG Services	DISTROTH	0	0	0	0	0	0
14	3693 UG Services	DISTROTH	99,160	0	99,160	99,160	0	99,160
15	3700 Meters	DISTROTH	418,911	0	418,911	418,911	0	418,911
16	3701 AMI Meters	DISTROTH	0	0	0	0	0	0
17	3711 Installations on Customer Premises	DISTROTH	0	0	0	0	0	0
18	3731 Street Lighting and Signal Systems	DISTROTH	0	0	0	0	0	0
19	3732 Street Lighting and Signal Systems	DISTROTH	0	0	0	0	0	0
20	3734 Street Lighting and Signal Systems	DISTROTH	0	0	0	0	0	0
21	TOTAL DISTRIBUTION - VIRGINIA & SMECO		518,071	0	518,071	518,071	0	518,071

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ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-5

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	ELECTRIC PLANT IN SERVICE				
	DISTRIBUTION PLANT CON'T				
	DISTRIBUTION - VIRGINIA & SMECO				
1	3600 Land and Land Rights - Subs	DISTROTH	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTROTH	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTROTH	0	0	0
4	3610 Structures and Improvements	DISTROTH	0	0	0
5	3620 Station Equipment	DISTROTH	0	0	0
6	3627 Station Equipment	DISTROTH	0	0	0
7	3640 Poles, Towers and Fixtures	DISTROTH	0	0	0
8	3650 Overhead Conductors and Devices	DISTROTH	0	0	0
9	3660 Underground Conduit	DISTROTH	0	0	0
10	3670 Underground Conductors and Devices	DISTROTH	0	0	0
11	3680 Line Transformers	DISTROTH	0	0	0
12	3691 OH Services	DISTROTH	0	0	0
13	3692 UG Services	DISTROTH	0	0	0
14	3693 UG Services	DISTROTH	99,160	0	99,160
15	3700 Meters	DISTROTH	418,911	0	418,911
16	3701 AMI Meters	DISTROTH	0	0	0
17	3711 Installations on Customer Premises	DISTROTH	0	0	0
18	3731 Street Lighting and Signal Systems	DISTROTH	0	0	0
19	3732 Street Lighting and Signal Systems	DISTROTH	0	0	0
20	3734 Street Lighting and Signal Systems	DISTROTH	0	0	0
21	TOTAL DISTRIBUTION - VIRGINIA & SMECO		518,071	0	518,071

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ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-6

		ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	DISTRIBUTION - SYSTEM TOTAL							
1	3600 Land and Land Rights - Subs		55,555,090	44,194,009	11,361,081	55,752,478	44,194,009	11,558,469
2	3600 Land and Land Rights - OH Lines		418,521	243,306	175,215	243,306	243,306	0
3	3600 Land and Land Rights - UG Lines		47,423	25,250	22,173	25,250	25,250	0
4	3610 Structures and Improvements		115,155,740	61,175,023	53,980,717	140,789,728	71,077,849	69,711,879
5	3620 Station Equipment		747,159,436	410,009,536	337,149,901	797,252,378	409,892,163	387,360,215
6	3627 Station Equipment		1,893,195	0	1,893,195	(1)	0	(1)
7	3640 Poles, Towers and Fixtures		400,291,892	116,455,497	283,836,395	427,259,092	125,016,421	302,242,671
8	3650 Overhead Conductors and Devices		614,561,081	127,449,521	487,111,560	652,879,986	138,114,146	514,765,840
9	3660 Underground Conduit		1,052,285,469	768,655,182	283,630,288	1,126,052,392	837,684,416	288,367,976
10	3670 Underground Conductors and Devices		1,387,891,459	755,172,889	632,718,570	1,446,767,129	796,605,855	650,161,273
11	3680 Line Transformers		1,020,531,678	517,249,722	503,281,956	1,099,277,441	568,165,942	531,111,498
12	3691 OH Services		64,724,720	16,003,858	48,720,862	68,502,141	20,318,498	48,183,644
13	3692 UG Services		138,181,178	114,795,422	23,385,756	144,192,362	120,194,790	23,997,572
14	3693 UG Services		316,901,722	163,230,886	153,670,835	332,100,928	172,259,193	159,841,734
15	3700 Meters		23,246,867	7,005,437	16,241,430	22,977,355	7,000,051	15,977,304
16	3701 AMI Meters		129,176,506	57,125,072	72,051,434	135,091,957	61,765,290	73,326,666
17	3711 Installations on Customer Premises		2,646,032	1,367,203	1,278,829	2,646,032	1,367,203	1,278,829
18	3731 Street Lighting and Signal Systems		27,499,942	50,508	27,449,434	28,361,993	64,880	28,297,113
19	3732 Street Lighting and Signal Systems		30,237,635	10,001,199	20,236,437	30,607,840	9,786,196	20,821,644
20	3734 Street Lighting and Signal Systems		2,034,356	49,789	1,984,568	2,079,424	49,789	2,029,636
21	TOTAL DISTRIBUTION - SYSTEM		6,130,439,943	3,170,259,310	2,960,180,633	6,512,859,210	3,383,825,248	3,129,033,962

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ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-6

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	DISTRIBUTION - SYSTEM TOTAL							
1	3600 Land and Land Rights - Subs		55,752,478	44,194,009	11,558,469	55,752,478	44,194,009	11,558,469
2	3600 Land and Land Rights - OH Lines		243,306	243,306	0	243,306	243,306	0
3	3600 Land and Land Rights - UG Lines		25,250	25,250	0	25,250	25,250	0
4	3610 Structures and Improvements		167,893,401	86,490,152	81,403,249	201,359,488	100,057,011	101,302,477
5	3620 Station Equipment		837,761,840	409,898,329	427,863,510	905,475,311	409,898,329	495,576,982
6	3627 Station Equipment		(2)	0	(2)	(3)	0	(3)
7	3640 Poles, Towers and Fixtures		453,285,069	137,115,184	316,169,885	464,317,490	146,994,196	317,323,295
8	3650 Overhead Conductors and Devices		687,615,447	153,371,639	534,243,808	713,292,108	166,243,748	547,048,360
9	3660 Underground Conduit		1,228,024,217	928,859,886	299,164,330	1,282,535,788	982,379,974	300,155,814
10	3670 Underground Conductors and Devices		1,491,729,167	829,402,760	662,326,407	1,490,738,430	840,767,735	649,970,695
11	3680 Line Transformers		1,191,951,556	638,878,164	553,073,392	1,290,483,186	700,538,158	589,945,028
12	3691 OH Services		74,607,949	26,559,851	48,048,097	80,083,394	32,035,296	48,048,097
13	3692 UG Services		151,959,325	127,502,562	24,456,764	159,159,830	133,920,193	25,239,638
14	3693 UG Services		349,875,322	185,590,817	164,284,506	368,973,530	197,245,185	171,728,346
15	3700 Meters		22,976,736	6,999,983	15,976,753	22,976,736	6,999,983	15,976,753
16	3701 AMI Meters		143,124,923	68,947,404	74,177,519	150,785,069	75,209,305	75,575,764
17	3711 Installations on Customer Premises		2,646,032	1,367,203	1,278,829	2,646,032	1,367,203	1,278,829
18	3731 Street Lighting and Signal Systems		28,983,495	91,930	28,891,565	29,998,114	115,744	29,882,370
19	3732 Street Lighting and Signal Systems		31,003,196	9,752,441	21,250,755	31,728,252	9,752,441	21,975,812
20	3734 Street Lighting and Signal Systems		2,116,000	49,789	2,066,212	2,173,517	49,789	2,123,728
21	TOTAL DISTRIBUTION - SYSTEM		6,921,574,706	3,655,340,659	3,266,234,048	7,252,747,307	3,848,036,855	3,404,710,451

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-6

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	DISTRIBUTION - SYSTEM TOTAL				
1	3600 Land and Land Rights - Subs		55,752,478	44,194,009	11,558,469
2	3600 Land and Land Rights - OH Lines		243,306	243,306	0
3	3600 Land and Land Rights - UG Lines		25,250	25,250	0
4	3610 Structures and Improvements		236,378,792	115,456,296	120,922,496
5	3620 Station Equipment		969,943,543	406,885,354	563,058,189
6	3627 Station Equipment		(4)	0	(4)
7	3640 Poles, Towers and Fixtures		481,572,299	158,429,379	323,142,919
8	3650 Overhead Conductors and Devices		745,194,826	181,091,825	564,103,000
9	3660 Underground Conduit		1,356,325,064	1,051,405,511	304,919,552
10	3670 Underground Conductors and Devices		1,503,810,764	858,918,389	644,892,375
11	3680 Line Transformers		1,397,095,778	770,829,266	626,266,512
12	3691 OH Services		86,325,286	38,277,189	48,048,097
13	3692 UG Services		167,246,989	141,236,158	26,010,831
14	3693 UG Services		389,592,039	210,530,921	179,061,118
15	3700 Meters		22,976,736	6,999,983	15,976,753
16	3701 AMI Meters		159,300,887	82,347,742	76,953,145
17	3711 Installations on Customer Premises		2,646,032	1,367,203	1,278,829
18	3731 Street Lighting and Signal Systems		31,001,283	142,892	30,858,391
19	3732 Street Lighting and Signal Systems		32,442,490	9,752,441	22,690,050
20	3734 Street Lighting and Signal Systems		2,230,175	49,789	2,180,386
21	TOTAL DISTRIBUTION - SYSTEM		7,640,104,014	4,078,182,904	3,561,921,110

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-7

		ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	SUBTRANSMISSION & DISTRIBUTION - TOTAL							
1	3600 Land and Land Rights - Subs		58,005,148	45,204,510	12,800,638	58,202,536	45,204,510	12,998,026
2	3600 Land and Land Rights - OH Lines		418,521	243,306	175,215	243,306	243,306	0
3	3600 Land and Land Rights - UG Lines		47,423	25,250	22,173	25,250	25,250	0
4	3610 Structures and Improvements		121,018,773	63,610,279	57,408,495	146,738,285	73,549,050	73,189,235
5	3620 Station Equipment		1,012,034,395	520,240,952	491,793,444	1,058,325,417	518,525,632	539,799,785
6	3627 Station Equipment		1,893,195	0	1,893,195	0	0	(0)
7	3640 Poles, Towers and Fixtures		443,115,578	134,216,519	308,899,059	472,904,825	143,963,549	328,941,276
8	3650 Overhead Conductors and Devices		655,070,272	144,379,399	510,690,873	696,243,224	156,243,580	539,999,644
9	3660 Underground Conduit		1,183,970,083	823,798,562	360,171,521	1,268,653,601	897,416,041	371,237,559
10	3670 Underground Conductors and Devices		1,544,395,812	820,951,669	723,444,143	1,591,049,698	857,247,819	733,801,879
11	3680 Line Transformers		1,020,531,678	517,249,722	503,281,956	1,099,277,441	568,165,942	531,111,498
12	3691 OH Services		64,724,720	16,003,858	48,720,862	68,502,141	20,318,498	48,183,644
13	3692 UG Services		138,181,178	114,795,422	23,385,756	144,192,362	120,194,790	23,997,572
14	3693 UG Services		316,901,722	163,230,886	153,670,835	332,100,928	172,259,193	159,841,734
15	3700 Meters		23,246,867	7,005,437	16,241,430	22,977,355	7,000,051	15,977,304
16	3701 AMI Meters		129,176,506	57,125,072	72,051,434	135,091,957	61,765,290	73,326,666
17	3711 Installations on Customer Premises		2,646,032	1,367,203	1,278,829	2,646,032	1,367,203	1,278,829
18	3731 Street Lighting and Signal Systems		27,499,942	50,508	27,449,434	28,361,993	64,880	28,297,113
19	3732 Street Lighting and Signal Systems		30,237,635	10,001,199	20,236,437	30,607,840	9,786,196	20,821,644
20	3734 Street Lighting and Signal Systems		2,034,356	49,789	1,984,568	2,079,424	49,789	2,029,636
21	TOTAL SUBTRANSMISSION & DISTRIBUTION - SYSTEM		6,775,149,838	3,439,549,543	3,335,600,296	7,158,223,613	3,653,390,570	3,504,833,043

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-7

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	SUBTRANSMISSION & DISTRIBUTION - TOTAL							
1	3600 Land and Land Rights - Subs		58,202,536	45,204,510	12,998,026	58,202,536	45,204,510	12,998,026
2	3600 Land and Land Rights - OH Lines		243,306	243,306	0	243,306	243,306	0
3	3600 Land and Land Rights - UG Lines		25,250	25,250	0	25,250	25,250	0
4	3610 Structures and Improvements		175,605,969	89,702,767	85,903,202	211,249,851	104,184,953	107,064,897
5	3620 Station Equipment		1,100,480,819	519,223,587	581,257,232	1,172,195,411	520,905,258	651,290,153
6	3627 Station Equipment		0	1	(1)	0	1	(1)
7	3640 Poles, Towers and Fixtures		499,066,131	156,119,191	342,946,940	532,511,437	175,418,338	357,093,099
8	3650 Overhead Conductors and Devices		731,147,629	171,572,080	559,575,549	778,110,862	193,390,935	584,719,927
9	3660 Underground Conduit		1,372,335,225	989,310,141	383,025,085	1,471,632,704	1,061,653,745	409,978,959
10	3670 Underground Conductors and Devices		1,635,935,190	890,012,551	745,922,639	1,685,591,258	922,664,379	762,926,879
11	3680 Line Transformers		1,191,951,556	638,878,164	553,073,392	1,290,483,186	700,538,158	589,945,028
12	3691 OH Services		74,607,949	26,559,851	48,048,097	80,083,394	32,035,296	48,048,097
13	3692 UG Services		151,959,325	127,502,562	24,456,764	159,159,830	133,920,193	25,239,638
14	3693 UG Services		349,875,322	185,590,817	164,284,506	368,973,530	197,245,185	171,728,346
15	3700 Meters		22,976,736	6,999,983	15,976,753	22,976,736	6,999,983	15,976,753
16	3701 AMI Meters		143,124,923	68,947,404	74,177,519	150,785,069	75,209,305	75,575,764
17	3711 Installations on Customer Premises		2,646,032	1,367,203	1,278,829	2,646,032	1,367,203	1,278,829
18	3731 Street Lighting and Signal Systems		28,983,495	91,930	28,891,565	29,998,114	115,744	29,882,370
19	3732 Street Lighting and Signal Systems		31,003,196	9,752,441	21,250,755	31,728,252	9,752,441	21,975,812
20	3734 Street Lighting and Signal Systems		2,116,000	49,789	2,066,212	2,173,517	49,789	2,123,728
21	TOTAL SUBTRANSMISSION & DISTRIBUTION - SYSTEM		7,572,286,589	3,927,153,527	3,645,133,062	8,048,770,275	4,180,923,973	3,867,846,302

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-7

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	SUBTRANSMISSION & DISTRIBUTION - TOTAL				
1	3600 Land and Land Rights - Subs		58,202,536	45,204,510	12,998,026
2	3600 Land and Land Rights - OH Lines		243,306	243,306	0
3	3600 Land and Land Rights - UG Lines		25,250	25,250	0
4	3610 Structures and Improvements		246,540,031	119,698,088	126,841,943
5	3620 Station Equipment		1,242,839,969	520,488,192	722,351,777
6	3627 Station Equipment		0	2	(2)
7	3640 Poles, Towers and Fixtures		567,078,884	194,130,024	372,948,860
8	3650 Overhead Conductors and Devices		826,458,601	215,150,855	611,307,746
9	3660 Underground Conduit		1,581,942,408	1,146,028,818	435,913,590
10	3670 Underground Conductors and Devices		1,738,991,761	957,764,962	781,226,799
11	3680 Line Transformers		1,397,095,778	770,829,266	626,266,512
12	3691 OH Services		86,325,286	38,277,189	48,048,097
13	3692 UG Services		167,246,989	141,236,158	26,010,831
14	3693 UG Services		389,592,039	210,530,921	179,061,118
15	3700 Meters		22,976,736	6,999,983	15,976,753
16	3701 AMI Meters		159,300,887	82,347,742	76,953,145
17	3711 Installations on Customer Premises		2,646,032	1,367,203	1,278,829
18	3731 Street Lighting and Signal Systems		31,001,283	142,892	30,858,391
19	3732 Street Lighting and Signal Systems		32,442,490	9,752,441	22,690,050
20	3734 Street Lighting and Signal Systems		2,230,175	49,789	2,180,386
21	TOTAL SUBTRANSMISSION & DISTRIBUTION - SYSTEM		8,553,180,442	4,460,267,590	4,092,912,852

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	DEVELOP OF RATE BASE CON'T-8	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	ELECTRIC PLANT IN SERVICE							
	GENERAL PLANT							
1	3890 Land and Land Rights	STDPLT	6,118,368	3,106,120	3,012,248	6,118,368	3,122,673	2,995,696
2	3900 Structures and Improvements	STDPLT	99,866,619	50,699,422	49,167,196	102,622,051	52,375,904	50,246,147
3	3903 Structures and Improvements	STDPLT	9,863,480	5,007,406	4,856,074	9,863,480	5,034,090	4,829,390
4	3911 Office Furniture and Equipment	STDPLT	7,926,871	4,024,245	3,902,625	6,442,815	3,288,263	3,154,552
5	3913 Office Furniture and Equipment	STDPLT	12,492,118	6,341,891	6,150,228	21,967,457	11,211,678	10,755,779
6	3915 Office Furniture and Equipment	STDPLT	0	0	0	0	0	0
7	3920 Transportation Equipment	STDPLT	0	0	0	0	0	0
8	3930 Stores Equipment	STDPLT	184,217	93,522	90,695	146,150	74,592	71,559
9	3940 Tools, Shop and Garage Equipment	STDPLT	7,958,572	4,040,339	3,918,233	10,183,912	5,197,631	4,986,280
10	3950 Laboratory Equipment	STDPLT	1,188,955	603,598	585,357	801,245	408,937	392,308
11	3960 Power Operated Equipment	STDPLT	952,665	483,641	469,024	3,177,870	1,621,911	1,555,959
12	3970 Communication Equipment	STDPLT	135,860,505	68,972,488	66,888,017	162,485,635	82,928,883	79,556,752
13	3980 Miscellaneous Equipment	STDPLT	8,310,680	4,219,094	4,091,586	9,383,804	4,789,275	4,594,529
14	3990 Other Tangible Property	STDPLT	0	0	0	0	0	0
15	TOTAL GENERAL PLANT		290,723,050	147,591,767	143,131,284	333,192,787	170,053,836	163,138,951
	INTANGIBLE PLANT							
16	3020 Franchises and Consents	DISTRMD	219	0	219	219	0	219
17	3030 Miscellaneous Intangible Plant	STDPLT	27,312,726	13,865,889	13,446,837	62,005,378	31,646,100	30,359,278
18	3030 Miscellaneous Intangible Plant Direct DC	DISTRDC	(1,880,244)	(1,880,244)	0	(1,880,244)	(1,880,244)	0
19	3030 Miscellaneous Intangible Plant Direct MD	DISTRMD	(3,959,024)	0	(3,959,024)	(3,959,024)	0	(3,959,024)
20	TOTAL INTANGIBLE PLANT		21,473,676	11,985,644	9,488,032	56,166,328	29,765,856	26,400,472

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-8

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	ELECTRIC PLANT IN SERVICE							
	GENERAL PLANT							
1	3890 Land and Land Rights	STDPLT	6,118,368	3,173,120	2,945,249	6,118,368	3,178,179	2,940,189
2	3900 Structures and Improvements	STDPLT	104,057,262	53,966,373	50,090,889	104,890,987	54,485,496	50,405,491
3	3903 Structures and Improvements	STDPLT	9,863,480	5,115,417	4,748,063	9,863,480	5,123,573	4,739,907
4	3911 Office Furniture and Equipment	STDPLT	6,443,304	3,341,639	3,101,666	6,443,304	3,346,967	3,096,338
5	3913 Office Furniture and Equipment	STDPLT	26,336,678	13,658,777	12,677,900	28,903,672	15,013,977	13,889,694
6	3915 Office Furniture and Equipment	STDPLT	0	0	0	0	0	0
7	3920 Transportation Equipment	STDPLT	0	0	0	0	0	0
8	3930 Stores Equipment	STDPLT	146,150	75,797	70,353	146,150	75,918	70,233
9	3940 Tools, Shop and Garage Equipment	STDPLT	11,658,323	6,046,261	5,612,062	12,499,436	6,492,817	6,006,619
10	3950 Laboratory Equipment	STDPLT	801,245	415,543	385,702	801,245	416,206	385,039
11	3960 Power Operated Equipment	STDPLT	4,725,206	2,450,595	2,274,611	5,639,943	2,929,661	2,710,281
12	3970 Communication Equipment	STDPLT	180,492,835	93,607,534	86,885,301	190,842,865	99,133,095	91,709,770
13	3980 Miscellaneous Equipment	STDPLT	10,181,340	5,280,266	4,901,074	10,649,837	5,532,045	5,117,792
14	3990 Other Tangible Property	STDPLT	0	0	0	0	0	0
15	TOTAL GENERAL PLANT		360,824,192	187,131,322	173,692,870	376,799,288	195,727,934	181,071,354
	INTANGIBLE PLANT							
16	3020 Franchises and Consents	DISTRMD	219	0	219	219	0	219
17	3030 Miscellaneous Intangible Plant	STDPLT	72,053,878	37,368,718	34,685,160	91,368,871	47,461,449	43,907,422
18	3030 Miscellaneous Intangible Plant Direct DC	DISTRDC	(1,880,244)	(1,880,244)	0	(1,880,244)	(1,880,244)	0
19	3030 Miscellaneous Intangible Plant Direct MD	DISTRMD	(3,959,024)	0	(3,959,024)	(3,959,024)	0	(3,959,024)
20	TOTAL INTANGIBLE PLANT		66,214,829	35,488,474	30,726,355	85,529,821	45,581,205	39,948,616

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-8

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	ELECTRIC PLANT IN SERVICE				
	GENERAL PLANT				
1	3890 Land and Land Rights	STDPLT	6,118,368	3,190,575	2,927,794
2	3900 Structures and Improvements	STDPLT	107,521,727	56,069,865	51,451,862
3	3903 Structures and Improvements	STDPLT	9,863,480	5,143,556	4,719,924
4	3911 Office Furniture and Equipment	STDPLT	6,443,304	3,360,021	3,083,284
5	3913 Office Furniture and Equipment	STDPLT	37,003,577	19,296,431	17,707,146
6	3915 Office Furniture and Equipment	STDPLT	0	0	0
7	3920 Transportation Equipment	STDPLT	0	0	0
8	3930 Stores Equipment	STDPLT	146,150	76,214	69,937
9	3940 Tools, Shop and Garage Equipment	STDPLT	15,153,487	7,902,161	7,251,326
10	3950 Laboratory Equipment	STDPLT	801,245	417,829	383,416
11	3960 Power Operated Equipment	STDPLT	8,526,308	4,446,254	4,080,054
12	3970 Communication Equipment	STDPLT	223,501,407	116,550,339	106,951,068
13	3980 Miscellaneous Equipment	STDPLT	12,128,135	6,324,516	5,803,619
14	3990 Other Tangible Property	STDPLT	0	0	0
15	TOTAL GENERAL PLANT		427,207,189	222,777,760	204,429,429
	INTANGIBLE PLANT				
16	3020 Franchises and Consents	DISTRMD	219	0	219
17	3030 Miscellaneous Intangible Plant	STDPLT	107,670,145	56,147,262	51,522,884
18	3030 Miscellaneous Intangible Plant Direct DC	DISTRDC	(1,880,244)	(1,880,244)	0
19	3030 Miscellaneous Intangible Plant Direct MD	DISTRMD	(3,959,024)	0	(3,959,024)
20	TOTAL INTANGIBLE PLANT		101,831,096	54,267,017	47,564,079

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	DEVELOP OF RATE BASE CON'T-9	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	AFUDC							
	SUBTRANSMISSION AFUDC - DC							
1	3600 Land and Land Rights - Subs	DISTRDC	0	0	0	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTRDC	0	0	0	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRDC	0	0	0	0	0	0
4	3610 Structures and Improvements	DISTRDC	0	0	0	0	0	0
5	3620 Station Equipment	DISTRDC	0	0	0	0	0	0
6	3627 Station Equipment	DISTRDC	0	0	0	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRDC	0	0	0	0	0	0
8	3650 Overhead Conductors and Devices	DISTRDC	0	0	0	0	0	0
9	3660 Underground Conduit	DISTRDC	0	0	0	0	0	0
10	3670 Underground Conductors and Devices	DISTRDC	0	0	0	0	0	0
11	TOTAL SUBTRANSMISSION AFUDC - DC		0	0	0	0	0	0
	SUBTRANSMISSION AFUDC - MD							
12	3600 Land and Land Rights - Subs	DISTRMD	0	0	0	0	0	0
13	3600 Land and Land Rights - OH Lines	DISTRMD	0	0	0	0	0	0
14	3600 Land and Land Rights - UG Lines	DISTRMD	0	0	0	0	0	0
15	3610 Structures and Improvements	DISTRMD	0	0	0	0	0	0
16	3620 Station Equipment	DISTRMD	0	0	0	0	0	0
17	3627 Station Equipment	DISTRMD	0	0	0	0	0	0
18	3640 Poles, Towers and Fixtures	DISTRMD	0	0	0	0	0	0
19	3650 Overhead Conductors and Devices	DISTRMD	0	0	0	0	0	0
20	3660 Underground Conduit	DISTRMD	0	0	0	0	0	0
21	3670 Underground Conductors and Devices	DISTRMD	0	0	0	0	0	0
22	TOTAL SUBTRANSMISSION AFUDC - MD		0	0	0	0	0	0

	DEVELOP OF RATE BASE CON'T-9	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	AFUDC							
	SUBTRANSMISSION AFUDC - DC							
1	3600 Land and Land Rights - Subs	DISTRDC	0	0	0	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTRDC	0	0	0	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRDC	0	0	0	0	0	0
4	3610 Structures and Improvements	DISTRDC	0	0	0	0	0	0
5	3620 Station Equipment	DISTRDC	0	0	0	0	0	0
6	3627 Station Equipment	DISTRDC	0	0	0	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRDC	0	0	0	0	0	0
8	3650 Overhead Conductors and Devices	DISTRDC	0	0	0	0	0	0
9	3660 Underground Conduit	DISTRDC	0	0	0	0	0	0
10	3670 Underground Conductors and Devices	DISTRDC	0	0	0	0	0	0
11	TOTAL SUBTRANSMISSION AFUDC - DC		0	0	0	0	0	0
	SUBTRANSMISSION AFUDC - MD							
12	3600 Land and Land Rights - Subs	DISTRMD	0	0	0	0	0	0
13	3600 Land and Land Rights - OH Lines	DISTRMD	0	0	0	0	0	0
14	3600 Land and Land Rights - UG Lines	DISTRMD	0	0	0	0	0	0
15	3610 Structures and Improvements	DISTRMD	0	0	0	0	0	0
16	3620 Station Equipment	DISTRMD	0	0	0	0	0	0
17	3627 Station Equipment	DISTRMD	0	0	0	0	0	0
18	3640 Poles, Towers and Fixtures	DISTRMD	0	0	0	0	0	0
19	3650 Overhead Conductors and Devices	DISTRMD	0	0	0	0	0	0
20	3660 Underground Conduit	DISTRMD	0	0	0	0	0	0
21	3670 Underground Conductors and Devices	DISTRMD	0	0	0	0	0	0
22	TOTAL SUBTRANSMISSION AFUDC - MD		0	0	0	0	0	0

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ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-9

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	AFUDC				
	SUBTRANSMISSION AFUDC - DC				
1	3600 Land and Land Rights - Subs	DISTRDC	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTRDC	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRDC	0	0	0
4	3610 Structures and Improvements	DISTRDC	0	0	0
5	3620 Station Equipment	DISTRDC	0	0	0
6	3627 Station Equipment	DISTRDC	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRDC	0	0	0
8	3650 Overhead Conductors and Devices	DISTRDC	0	0	0
9	3660 Underground Conduit	DISTRDC	0	0	0
10	3670 Underground Conductors and Devices	DISTRDC	0	0	0
11	TOTAL SUBTRANSMISSION AFUDC - DC		0	0	0
	SUBTRANSMISSION AFUDC - MD				
12	3600 Land and Land Rights - Subs	DISTRMD	0	0	0
13	3600 Land and Land Rights - OH Lines	DISTRMD	0	0	0
14	3600 Land and Land Rights - UG Lines	DISTRMD	0	0	0
15	3610 Structures and Improvements	DISTRMD	0	0	0
16	3620 Station Equipment	DISTRMD	0	0	0
17	3627 Station Equipment	DISTRMD	0	0	0
18	3640 Poles, Towers and Fixtures	DISTRMD	0	0	0
19	3650 Overhead Conductors and Devices	DISTRMD	0	0	0
20	3660 Underground Conduit	DISTRMD	0	0	0
21	3670 Underground Conductors and Devices	DISTRMD	0	0	0
22	TOTAL SUBTRANSMISSION AFUDC - MD		0	0	0

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ELECTRIC DISTRIBUTION

	DEVELOP OF RATE BASE CON'T-10	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	DISTRIBUTION AFUDC - DC							
1	3600 Land and Land Rights - Subs	DISTRDC	0	0	0	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTRDC	0	0	0	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRDC	0	0	0	0	0	0
4	3610 Structures and Improvements	DISTRDC	3,380,016	3,380,016	0	3,542,096	3,542,096	0
5	3620 Station Equipment	DISTRDC	10,024,404	10,024,404	0	10,392,702	10,392,702	0
6	3627 Station Equipment	DISTRDC	0	0	0	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRDC	403,945	403,945	0	470,647	470,647	0
8	3650 Overhead Conductors and Devices	DISTRDC	542,823	542,823	0	710,287	710,287	0
9	3660 Underground Conduit	DISTRDC	9,440,622	9,440,622	0	9,885,443	9,885,443	0
10	3670 Underground Conductors and Devices	DISTRDC	4,460,915	4,460,915	0	4,195,106	4,195,106	0
11	3680 Line Transformers	DISTRDC	108,858	108,858	0	113,066	113,066	0
12	3691 OH Services	DISTRDC	4,378	4,378	0	4,626	4,626	0
13	3692 UG Services	DISTRDC	87	87	0	295	295	0
14	3693 UG Services	DISTRDC	13,829	13,829	0	14,389	14,389	0
15	3700 Meters	DISTRDC	0	0	0	0	0	0
16	3701 AMI Meters	DISTRDC	0	0	0	0	0	0
17	3711 Installations on Customer Premises	DISTRDC	0	0	0	0	0	0
18	3731 Street Lighting and Signal Systems	DISTRDC	126	126	0	93	93	0
19	3732 Street Lighting and Signal Systems	DISTRDC	22,159	22,159	0	23,202	23,202	0
20	3734 Street Lighting and Signal Systems	DISTRDC	526	526	0	526	526	0
21	TOTAL DISTRIBUTION AFUDC - DC		28,402,691	28,402,691	0	29,352,479	29,352,479	0

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-10

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	DISTRIBUTION AFUDC - DC							
1	3600 Land and Land Rights - Subs	DISTRDC	0	0	0	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTRDC	0	0	0	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRDC	0	0	0	0	0	0
4	3610 Structures and Improvements	DISTRDC	4,568,384	4,568,384	0	5,412,515	5,412,515	0
5	3620 Station Equipment	DISTRDC	13,031,420	13,031,420	0	15,243,631	15,243,631	0
6	3627 Station Equipment	DISTRDC	0	0	0	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRDC	755,220	755,220	0	2,141,088	2,141,088	0
8	3650 Overhead Conductors and Devices	DISTRDC	1,385,948	1,385,948	0	5,368,733	5,368,733	0
9	3660 Underground Conduit	DISTRDC	12,706,921	12,706,921	0	15,028,372	15,028,372	0
10	3670 Underground Conductors and Devices	DISTRDC	5,479,381	5,479,381	0	7,322,820	7,322,820	0
11	3680 Line Transformers	DISTRDC	132,726	132,726	0	200,941	200,941	0
12	3691 OH Services	DISTRDC	5,683	5,683	0	10,562	10,562	0
13	3692 UG Services	DISTRDC	1,078	1,078	0	5,900	5,900	0
14	3693 UG Services	DISTRDC	17,954	17,954	0	21,791	21,791	0
15	3700 Meters	DISTRDC	0	0	0	0	0	0
16	3701 AMI Meters	DISTRDC	0	0	0	0	0	0
17	3711 Installations on Customer Premises	DISTRDC	0	0	0	0	0	0
18	3731 Street Lighting and Signal Systems	DISTRDC	87	87	0	87	87	0
19	3732 Street Lighting and Signal Systems	DISTRDC	29,809	29,809	0	35,242	35,242	0
20	3734 Street Lighting and Signal Systems	DISTRDC	526	526	0	526	526	0
21	TOTAL DISTRIBUTION AFUDC - DC		38,115,136	38,115,136	0	50,792,210	50,792,210	0

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-10

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	DISTRIBUTION AFUDC - DC				
1	3600 Land and Land Rights - Subs	DISTRDC	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTRDC	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRDC	0	0	0
4	3610 Structures and Improvements	DISTRDC	7,026,642	7,026,642	0
5	3620 Station Equipment	DISTRDC	19,418,419	19,418,419	0
6	3627 Station Equipment	DISTRDC	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRDC	3,380,569	3,380,569	0
8	3650 Overhead Conductors and Devices	DISTRDC	8,787,894	8,787,894	0
9	3660 Underground Conduit	DISTRDC	19,467,398	19,467,398	0
10	3670 Underground Conductors and Devices	DISTRDC	9,919,649	9,919,649	0
11	3680 Line Transformers	DISTRDC	267,670	267,670	0
12	3691 OH Services	DISTRDC	14,973	14,973	0
13	3692 UG Services	DISTRDC	9,994	9,994	0
14	3693 UG Services	DISTRDC	28,019	28,019	0
15	3700 Meters	DISTRDC	0	0	0
16	3701 AMI Meters	DISTRDC	0	0	0
17	3711 Installations on Customer Premises	DISTRDC	0	0	0
18	3731 Street Lighting and Signal Systems	DISTRDC	87	87	0
19	3732 Street Lighting and Signal Systems	DISTRDC	45,632	45,632	0
20	3734 Street Lighting and Signal Systems	DISTRDC	526	526	0
21	TOTAL DISTRIBUTION AFUDC - DC		68,367,473	68,367,473	0

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-11

		ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	DISTRIBUTION AFUDC - MD							
1	3600 Land and Land Rights - Subs	DISTRMD	0	0	0	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTRMD	0	0	0	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRMD	0	0	0	0	0	0
4	3610 Structures and Improvements	DISTRMD	1,873,383	0	1,873,383	1,873,387	0	1,873,387
5	3620 Station Equipment	DISTRMD	11,869,073	0	11,869,073	11,767,802	0	11,767,802
6	3627 Station Equipment	DISTRMD	0	0	0	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRMD	1,030,212	0	1,030,212	1,112,798	0	1,112,798
8	3650 Overhead Conductors and Devices	DISTRMD	1,592,262	0	1,592,262	1,830,193	0	1,830,193
9	3660 Underground Conduit	DISTRMD	1,948,920	0	1,948,920	1,967,267	0	1,967,267
10	3670 Underground Conductors and Devices	DISTRMD	2,568,353	0	2,568,353	1,887,039	0	1,887,039
11	3680 Line Transformers	DISTRMD	134,994	0	134,994	139,327	0	139,327
12	3691 OH Services	DISTRMD	8,387	0	8,387	8,789	0	8,789
13	3692 UG Services	DISTRMD	137	0	137	446	0	446
14	3693 UG Services	DISTRMD	24,004	0	24,004	24,978	0	24,978
15	3700 Meters	DISTRMD	0	0	0	0	0	0
16	3701 AMI Meters	DISTRMD	0	0	0	0	0	0
17	3711 Installations on Customer Premises	DISTRMD	0	0	0	0	0	0
18	3731 Street Lighting and Signal Systems	DISTRMD	189	0	189	137	0	137
19	3732 Street Lighting and Signal Systems	DISTRMD	38,600	0	38,600	40,422	0	40,422
20	3734 Street Lighting and Signal Systems	DISTRMD	1,057	0	1,057	1,057	0	1,057
21	TOTAL DISTRIBUTION AFUDC - MD		21,089,571	0	21,089,571	20,653,642	0	20,653,642

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-11

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	DISTRIBUTION AFUDC - MD							
1	3600 Land and Land Rights - Subs	DISTRMD	0	0	0	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTRMD	0	0	0	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRMD	0	0	0	0	0	0
4	3610 Structures and Improvements	DISTRMD	1,873,413	0	1,873,413	1,873,434	0	1,873,434
5	3620 Station Equipment	DISTRMD	11,943,251	0	11,943,251	12,139,390	0	12,139,390
6	3627 Station Equipment	DISTRMD	0	0	0	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRMD	1,428,823	0	1,428,823	3,422,390	0	3,422,390
8	3650 Overhead Conductors and Devices	DISTRMD	2,758,176	0	2,758,176	8,682,410	0	8,682,410
9	3660 Underground Conduit	DISTRMD	2,090,751	0	2,090,751	2,193,459	0	2,193,459
10	3670 Underground Conductors and Devices	DISTRMD	2,194,967	0	2,194,967	3,617,344	0	3,617,344
11	3680 Line Transformers	DISTRMD	156,261	0	156,261	248,960	0	248,960
12	3691 OH Services	DISTRMD	10,538	0	10,538	18,183	0	18,183
13	3692 UG Services	DISTRMD	1,612	0	1,612	8,784	0	8,784
14	3693 UG Services	DISTRMD	31,172	0	31,172	37,669	0	37,669
15	3700 Meters	DISTRMD	0	0	0	0	0	0
16	3701 AMI Meters	DISTRMD	0	0	0	0	0	0
17	3711 Installations on Customer Premises	DISTRMD	0	0	0	0	0	0
18	3731 Street Lighting and Signal Systems	DISTRMD	127	0	127	127	0	127
19	3732 Street Lighting and Signal Systems	DISTRMD	51,958	0	51,958	61,446	0	61,446
20	3734 Street Lighting and Signal Systems	DISTRMD	1,057	0	1,057	1,057	0	1,057
21	TOTAL DISTRIBUTION AFUDC - MD		22,542,107	0	22,542,107	32,304,654	0	32,304,654

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-11

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	DISTRIBUTION AFUDC - MD				
1	3600 Land and Land Rights - Subs	DISTRMD	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTRMD	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRMD	0	0	0
4	3610 Structures and Improvements	DISTRMD	1,873,475	0	1,873,475
5	3620 Station Equipment	DISTRMD	12,457,899	0	12,457,899
6	3627 Station Equipment	DISTRMD	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRMD	5,111,369	0	5,111,369
8	3650 Overhead Conductors and Devices	DISTRMD	13,690,679	0	13,690,679
9	3660 Underground Conduit	DISTRMD	2,389,854	0	2,389,854
10	3670 Underground Conductors and Devices	DISTRMD	4,959,950	0	4,959,950
11	3680 Line Transformers	DISTRMD	329,790	0	329,790
12	3691 OH Services	DISTRMD	25,188	0	25,188
13	3692 UG Services	DISTRMD	14,876	0	14,876
14	3693 UG Services	DISTRMD	48,372	0	48,372
15	3700 Meters	DISTRMD	0	0	0
16	3701 AMI Meters	DISTRMD	0	0	0
17	3711 Installations on Customer Premises	DISTRMD	0	0	0
18	3731 Street Lighting and Signal Systems	DISTRMD	127	0	127
19	3732 Street Lighting and Signal Systems	DISTRMD	79,590	0	79,590
20	3734 Street Lighting and Signal Systems	DISTRMD	1,057	0	1,057
21	TOTAL DISTRIBUTION AFUDC - MD		40,982,226	0	40,982,226

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-12

		ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	SUBTRANSMISSION AND DISTRIBUTION AFUDC - SYSTEM							
1	3600 Land and Land Rights - Subs		0	0	0	0	0	0
2	3600 Land and Land Rights - OH Lines		0	0	0	0	0	0
3	3600 Land and Land Rights - UG Lines		0	0	0	0	0	0
4	3610 Structures and Improvements		5,253,399	3,380,016	1,873,383	5,415,482	3,542,096	1,873,387
5	3620 Station Equipment		21,893,478	10,024,404	11,869,073	22,160,505	10,392,702	11,767,802
6	3627 Station Equipment		0	0	0	0	0	0
7	3640 Poles, Towers and Fixtures		1,434,158	403,945	1,030,212	1,583,445	470,647	1,112,798
8	3650 Overhead Conductors and Devices		2,135,085	542,823	1,592,262	2,540,480	710,287	1,830,193
9	3660 Underground Conduit		11,389,541	9,440,622	1,948,920	11,852,710	9,885,443	1,967,267
10	3670 Underground Conductors and Devices		7,029,268	4,460,915	2,568,353	6,082,145	4,195,106	1,887,039
11	3680 Line Transformers		243,853	108,858	134,994	252,393	113,066	139,327
12	3691 OH Services		12,765	4,378	8,387	13,415	4,626	8,789
13	3692 UG Services		224	87	137	742	295	446
14	3693 UG Services		37,833	13,829	24,004	39,366	14,389	24,978
15	3700 Meters		0	0	0	0	0	0
16	3701 AMI Meters		0	0	0	0	0	0
17	3711 Installations on Customer Premises		0	0	0	0	0	0
18	3731 Street Lighting and Signal Systems		316	126	189	230	93	137
19	3732 Street Lighting and Signal Systems		60,759	22,159	38,600	63,624	23,202	40,422
20	3734 Street Lighting and Signal Systems		1,583	526	1,057	1,583	526	1,057
21	TOTAL SUBTR. AND DISTR. AFUDC - SYSTEM		49,492,262	28,402,691	21,089,571	50,006,121	29,352,479	20,653,642

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-12

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	SUBTRANSMISSION AND DISTRIBUTION AFUDC - SYSTEM							
1	3600 Land and Land Rights - Subs		0	0	0	0	0	0
2	3600 Land and Land Rights - OH Lines		0	0	0	0	0	0
3	3600 Land and Land Rights - UG Lines		0	0	0	0	0	0
4	3610 Structures and Improvements		6,441,797	4,568,384	1,873,413	7,285,949	5,412,515	1,873,434
5	3620 Station Equipment		24,974,671	13,031,420	11,943,251	27,383,022	15,243,631	12,139,390
6	3627 Station Equipment		0	0	0	0	0	0
7	3640 Poles, Towers and Fixtures		2,184,042	755,220	1,428,823	5,563,478	2,141,088	3,422,390
8	3650 Overhead Conductors and Devices		4,144,124	1,385,948	2,758,176	14,051,143	5,368,733	8,682,410
9	3660 Underground Conduit		14,797,671	12,706,921	2,090,751	17,221,831	15,028,372	2,193,459
10	3670 Underground Conductors and Devices		7,674,348	5,479,381	2,194,967	10,940,164	7,322,820	3,617,344
11	3680 Line Transformers		288,988	132,726	156,261	449,901	200,941	248,960
12	3691 OH Services		16,221	5,683	10,538	28,745	10,562	18,183
13	3692 UG Services		2,690	1,078	1,612	14,684	5,900	8,784
14	3693 UG Services		49,126	17,954	31,172	59,460	21,791	37,669
15	3700 Meters		0	0	0	0	0	0
16	3701 AMI Meters		0	0	0	0	0	0
17	3711 Installations on Customer Premises		0	0	0	0	0	0
18	3731 Street Lighting and Signal Systems		214	87	127	214	87	127
19	3732 Street Lighting and Signal Systems		81,766	29,809	51,958	96,689	35,242	61,446
20	3734 Street Lighting and Signal Systems		1,583	526	1,057	1,583	526	1,057
21	TOTAL SUBTR. AND DISTR. AFUDC - SYSTEM		60,657,243	38,115,136	22,542,107	83,096,864	50,792,210	32,304,654

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-12

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	SUBTRANSMISSION AND DISTRIBUTION AFUDC - SYSTEM				
1	3600 Land and Land Rights - Subs		0	0	0
2	3600 Land and Land Rights - OH Lines		0	0	0
3	3600 Land and Land Rights - UG Lines		0	0	0
4	3610 Structures and Improvements		8,900,118	7,026,642	1,873,475
5	3620 Station Equipment		31,876,318	19,418,419	12,457,899
6	3627 Station Equipment		0	0	0
7	3640 Poles, Towers and Fixtures		8,491,938	3,380,569	5,111,369
8	3650 Overhead Conductors and Devices		22,478,573	8,787,894	13,690,679
9	3660 Underground Conduit		21,857,252	19,467,398	2,389,854
10	3670 Underground Conductors and Devices		14,879,599	9,919,649	4,959,950
11	3680 Line Transformers		597,460	267,670	329,790
12	3691 OH Services		40,161	14,973	25,188
13	3692 UG Services		24,870	9,994	14,876
14	3693 UG Services		76,391	28,019	48,372
15	3700 Meters		0	0	0
16	3701 AMI Meters		0	0	0
17	3711 Installations on Customer Premises		0	0	0
18	3731 Street Lighting and Signal Systems		214	87	127
19	3732 Street Lighting and Signal Systems		125,222	45,632	79,590
20	3734 Street Lighting and Signal Systems		1,583	526	1,057
21	TOTAL SUBTR. AND DISTR. AFUDC - SYSTEM		109,349,699	68,367,473	40,982,226
			8,662,530,141		

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-13

		ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	GENERAL PLANT AFUDC - DC							
1	3890 Land and Land Rights	DISTRDC	0	0	0	0	0	0
2	3900 Structures and Improvements	DISTRDC	3,356,451	3,356,451	0	3,403,725	3,403,725	0
3	3903 Structures and Improvements	DISTRDC	298,672	298,672	0	298,672	298,672	0
4	3911 Office Furniture and Equipment	DISTRDC	78	78	0	45,331	45,331	0
5	3913 Office Furniture and Equipment	DISTRDC	111,481	111,481	0	114,022	114,022	0
6	3915 Office Furniture and Equipment	DISTRDC	0	0	0	0	0	0
7	3920 Transportation Equipment	DISTRDC	0	0	0	0	0	0
8	3930 Stores Equipment	DISTRDC	0	0	0	0	0	0
9	3940 Tools, Shop and Garage Equipment	DISTRDC	69,817	69,817	0	72,315	72,315	0
10	3950 Laboratory Equipment	DISTRDC	0	0	0	0	0	0
11	3960 Power Operated Equipment	DISTRDC	0	0	0	0	0	0
12	3970 Communication Equipment	DISTRDC	2,860,522	2,860,522	0	3,595,160	3,595,160	0
13	3980 Miscellaneous Equipment	DISTRDC	63,368	63,368	0	61,896	61,896	0
14	3990 Other Tangible Property	DISTRDC	0	0	0	0	0	0
15	TOTAL GENERAL PLANT AFUDC - DC		6,760,390	6,760,390	**0**	7,591,121	7,591,121	**0**
	GENERAL PLANT AFUDC - MD							
16	3890 Land and Land Rights	DISTRMD	0	0	0	0	0	0
17	3900 Structures and Improvements	DISTRMD	0	0	4,211,770	0	0	4,223,161
18	3903 Structures and Improvements	DISTRMD	677,053	0	677,053	677,053	0	677,053
19	3911 Office Furniture and Equipment	DISTRMD	657	0	657	45,903	0	45,903
20	3913 Office Furniture and Equipment	DISTRMD	337,926	0	337,926	156,085	0	156,085
21	3915 Office Furniture and Equipment	DISTRMD	0	0	0	0	0	0
22	3920 Transportation Equipment	DISTRMD	0	0	0	0	0	0
23	3930 Stores Equipment	DISTRMD	0	0	0	0	0	0
24	3940 Tools, Shop and Garage Equipment	DISTRMD	800	0	800	3,389	0	3,389
25	3950 Laboratory Equipment	DISTRMD	0	0	0	0	0	0
26	3960 Power Operated Equipment	DISTRMD	0	0	0	0	0	0
27	3970 Communication Equipment	DISTRMD	5,061,273	0	5,061,273	5,631,220	0	5,631,220
28	3980 Miscellaneous Equipment	DISTRMD	90,759	0	90,759	89,889	0	89,889
29	3990 Other Tangible Property	DISTRMD	0	0	0	0	0	0
30	TOTAL GENERAL PLANT AFUDC - MD		10,380,237	**0**	10,380,237	10,826,699	**0**	10,826,699

DEVELOP OF RATE BASE CON'T-13

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	GENERAL PLANT AFUDC - DC							
1	3890 Land and Land Rights	DISTRDC	0	0	0	0	0	0
2	3900 Structures and Improvements	DISTRDC	3,442,556	3,442,556	0	3,483,304	3,483,304	0
3	3903 Structures and Improvements	DISTRDC	298,672	298,672	0	298,672	298,672	0
4	3911 Office Furniture and Equipment	DISTRDC	92,108	92,108	0	140,809	140,809	0
5	3913 Office Furniture and Equipment	DISTRDC	116,186	116,186	0	118,254	118,254	0
6	3915 Office Furniture and Equipment	DISTRDC	1	1	0	2	2	0
7	3920 Transportation Equipment	DISTRDC	0	0	0	0	0	0
8	3930 Stores Equipment	DISTRDC	0	0	0	0	0	0
9	3940 Tools, Shop and Garage Equipment	DISTRDC	74,304	74,304	0	76,205	76,205	0
10	3950 Laboratory Equipment	DISTRDC	0	0	0	0	0	0
11	3960 Power Operated Equipment	DISTRDC	0	0	0	0	0	0
12	3970 Communication Equipment	DISTRDC	4,159,166	4,159,166	0	4,718,704	4,718,704	0
13	3980 Miscellaneous Equipment	DISTRDC	61,765	61,765	0	61,765	61,765	0
14	3990 Other Tangible Property	DISTRDC	0	0	0	0	0	0
15	TOTAL GENERAL PLANT AFUDC - DC		8,244,757	8,244,757	**0**	8,897,715	8,897,715	**0**
	GENERAL PLANT AFUDC - MD							
16	3890 Land and Land Rights	DISTRMD	0	0	0	0	0	0
17	3900 Structures and Improvements	DISTRMD	0	0	4,222,872	0	0	4,222,872
18	3903 Structures and Improvements	DISTRMD	677,053	0	677,053	677,053	0	677,053
19	3911 Office Furniture and Equipment	DISTRMD	92,676	0	92,676	141,373	0	141,373
20	3913 Office Furniture and Equipment	DISTRMD	158,293	0	158,293	160,404	0	160,404
21	3915 Office Furniture and Equipment	DISTRMD	0	0	0	0	0	0
22	3920 Transportation Equipment	DISTRMD	0	0	0	0	0	0
23	3930 Stores Equipment	DISTRMD	0	0	0	0	0	0
24	3940 Tools, Shop and Garage Equipment	DISTRMD	5,449	0	5,449	7,418	0	7,418
25	3950 Laboratory Equipment	DISTRMD	0	0	0	0	0	0
26	3960 Power Operated Equipment	DISTRMD	0	0	0	0	0	0
27	3970 Communication Equipment	DISTRMD	6,163,197	0	6,163,197	6,691,363	0	6,691,363
28	3980 Miscellaneous Equipment	DISTRMD	90,073	0	90,073	90,380	0	90,380
29	3990 Other Tangible Property	DISTRMD	0	0	0	0	0	0
30	TOTAL GENERAL PLANT AFUDC - MD		11,409,612	**0**	11,409,612	11,990,863	**0**	11,990,863

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-13

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	GENERAL PLANT AFUDC - DC				
1	3890 Land and Land Rights	DISTRDC	0	0	0
2	3900 Structures and Improvements	DISTRDC	3,713,318	3,713,318	0
3	3903 Structures and Improvements	DISTRDC	298,672	298,672	0
4	3911 Office Furniture and Equipment	DISTRDC	415,714	415,714	0
5	3913 Office Furniture and Equipment	DISTRDC	129,929	129,929	0
6	3915 Office Furniture and Equipment	DISTRDC	3	3	0
7	3920 Transportation Equipment	DISTRDC	0	0	0
8	3930 Stores Equipment	DISTRDC	0	0	0
9	3940 Tools, Shop and Garage Equipment	DISTRDC	86,934	86,934	0
10	3950 Laboratory Equipment	DISTRDC	0	0	0
11	3960 Power Operated Equipment	DISTRDC	0	0	0
12	3970 Communication Equipment	DISTRDC	7,877,143	7,877,143	0
13	3980 Miscellaneous Equipment	DISTRDC	61,765	61,765	0
14	3990 Other Tangible Property	DISTRDC	0	0	0
15	TOTAL GENERAL PLANT AFUDC - DC		12,583,479	12,583,479	**0**
	GENERAL PLANT AFUDC - MD				
16	3890 Land and Land Rights	DISTRMD	0	0	0
17	3900 Structures and Improvements	DISTRMD	0	0	4,222,872
18	3903 Structures and Improvements	DISTRMD	677,053	0	677,053
19	3911 Office Furniture and Equipment	DISTRMD	416,255	0	416,255
20	3913 Office Furniture and Equipment	DISTRMD	172,320	0	172,320
21	3915 Office Furniture and Equipment	DISTRMD	0	0	0
22	3920 Transportation Equipment	DISTRMD	0	0	0
23	3930 Stores Equipment	DISTRMD	0	0	0
24	3940 Tools, Shop and Garage Equipment	DISTRMD	18,536	0	18,536
25	3950 Laboratory Equipment	DISTRMD	0	0	0
26	3960 Power Operated Equipment	DISTRMD	0	0	0
27	3970 Communication Equipment	DISTRMD	9,672,711	0	9,672,711
28	3980 Miscellaneous Equipment	DISTRMD	92,114	0	92,114
29	3990 Other Tangible Property	DISTRMD	0	0	0
30	TOTAL GENERAL PLANT AFUDC - MD		15,271,860	**0**	15,271,860

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	DEVELOP OF RATE BASE CON'T-14	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	GENERAL PLANT AFUDC - SMECO							
1	3890 Land and Land Rights	DISTROTH	0	0	0	0	0	0
2	3900 Structures and Improvements	DISTROTH	248,837	0	248,837	247,837	0	247,837
3	3903 Structures and Improvements	DISTROTH	35,301	0	35,301	35,301	0	35,301
4	3911 Office Furniture and Equipment	DISTROTH	0	0	0	0	0	0
5	3913 Office Furniture and Equipment	DISTROTH	3,806	0	3,806	3,807	0	3,807
6	3915 Office Furniture and Equipment	DISTROTH	0	0	0	0	0	0
7	3920 Transportation Equipment	DISTROTH	0	0	0	0	0	0
8	3930 Stores Equipment	DISTROTH	0	0	0	0	0	0
9	3940 Tools, Shop and Garage Equipment	DISTROTH	0	0	0	0	0	0
10	3950 Laboratory Equipment	DISTROTH	0	0	0	0	0	0
11	3960 Power Operated Equipment	DISTROTH	0	0	0	0	0	0
12	3970 Communication Equipment	DISTROTH	165,102	0	165,102	164,927	0	164,927
13	3980 Miscellaneous Equipment	DISTROTH	99	0	99	101	0	101
14	3990 Other Tangible Property	DISTROTH	0	0	0	0	0	0
15	TOTAL GENERAL PLANT AFUDC - SMECO		453,145	0	453,145	451,973	0	451,973
	INTANGIBLE PLANT AFUDC							
16	3030 Miscellaneous Intangible Plant DC	DISTRDC	456,130	456,130	0	851,572	851,572	0
17	3030 Miscellaneous Intangible Plant MD	DISTRMD	625,160	0	625,160	1,016,156	0	1,016,156
18	3030 Miscellaneous Intangible Plant SM	DISTROTH	16,428	0	16,428	17,149	0	17,149
19	TOTAL INTANGIBLE PLANT AFUDC		1,097,719	456,130	641,589	1,884,877	851,572	1,033,305
20	TOTAL AFUDC		68,183,752	35,619,211	32,564,542	70,760,792	37,795,172	32,965,619
21	Total Electric Plant In Service		7,155,530,317	3,634,746,164	3,520,784,153	7,618,343,520	3,891,005,435	3,727,338,085

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ELECTRIC DISTRIBUTION

	DEVELOP OF RATE BASE CON'T-14	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	GENERAL PLANT AFUDC - SMECO							
1	3890 Land and Land Rights	DISTROTH	0	0	0	0	0	0
2	3900 Structures and Improvements	DISTROTH	247,655	0	247,655	247,655	0	247,655
3	3903 Structures and Improvements	DISTROTH	35,301	0	35,301	35,301	0	35,301
4	3911 Office Furniture and Equipment	DISTROTH	0	0	0	0	0	0
5	3913 Office Furniture and Equipment	DISTROTH	3,807	0	3,807	3,807	0	3,807
6	3915 Office Furniture and Equipment	DISTROTH	0	0	0	0	0	0
7	3920 Transportation Equipment	DISTROTH	0	0	0	0	0	0
8	3930 Stores Equipment	DISTROTH	0	0	0	0	0	0
9	3940 Tools, Shop and Garage Equipment	DISTROTH	0	0	0	0	0	0
10	3950 Laboratory Equipment	DISTROTH	0	0	0	0	0	0
11	3960 Power Operated Equipment	DISTROTH	0	0	0	0	0	0
12	3970 Communication Equipment	DISTROTH	164,928	0	164,928	164,928	0	164,928
13	3980 Miscellaneous Equipment	DISTROTH	101	0	101	101	0	101
14	3990 Other Tangible Property	DISTROTH	0	0	0	0	0	0
15	TOTAL GENERAL PLANT AFUDC - SMECO		451,792	0	451,792	451,792	0	451,792
	INTANGIBLE PLANT AFUDC							
16	3030 Miscellaneous Intangible Plant DC	DISTRDC	906,700	906,700	0	919,554	919,554	0
17	3030 Miscellaneous Intangible Plant MD	DISTRMD	1,070,418	0	1,070,418	1,083,129	0	1,083,129
18	3030 Miscellaneous Intangible Plant SM	DISTROTH	17,260	0	17,260	17,290	0	17,290
19	TOTAL INTANGIBLE PLANT AFUDC		1,994,378	906,700	1,087,678	2,019,972	919,554	1,100,418
20	TOTAL AFUDC		82,757,783	47,266,593	35,491,189	106,457,207	60,609,479	45,847,727
21	Total Electric Plant In Service		8,082,083,392	4,197,039,916	3,885,043,477	8,617,556,590	4,482,842,590	4,134,714,000

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-14

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	GENERAL PLANT AFUDC - SMECO				
1	3890 Land and Land Rights	DISTROTH	0	0	0
2	3900 Structures and Improvements	DISTROTH	247,655	0	247,655
3	3903 Structures and Improvements	DISTROTH	35,301	0	35,301
4	3911 Office Furniture and Equipment	DISTROTH	0	0	0
5	3913 Office Furniture and Equipment	DISTROTH	3,807	0	3,807
6	3915 Office Furniture and Equipment	DISTROTH	0	0	0
7	3920 Transportation Equipment	DISTROTH	0	0	0
8	3930 Stores Equipment	DISTROTH	0	0	0
9	3940 Tools, Shop and Garage Equipment	DISTROTH	0	0	0
10	3950 Laboratory Equipment	DISTROTH	0	0	0
11	3960 Power Operated Equipment	DISTROTH	0	0	0
12	3970 Communication Equipment	DISTROTH	164,928	0	164,928
13	3980 Miscellaneous Equipment	DISTROTH	101	0	101
14	3990 Other Tangible Property	DISTROTH	0	0	0
15	TOTAL GENERAL PLANT AFUDC - SMECO		451,792	0	451,792
	INTANGIBLE PLANT AFUDC				
16	3030 Miscellaneous Intangible Plant DC	DISTRDC	923,653	923,653	0
17	3030 Miscellaneous Intangible Plant MD	DISTRMD	1,087,181	0	1,087,181
18	3030 Miscellaneous Intangible Plant SM	DISTROTH	17,299	0	17,299
19	TOTAL INTANGIBLE PLANT AFUDC		2,028,134	923,653	1,104,481
20	TOTAL AFUDC		139,684,964	81,874,605	57,810,359
21	Total Electric Plant In Service		9,221,903,690	4,819,186,973	4,402,716,718

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	DEVELOP OF RATE BASE CON'T-15	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	DEPRECIATION RESERVE							
1	Subtransmission - DC	DISTRDC	94,873,387	94,873,387	0	101,245,520	101,245,520	0
2	Subtransmission - MD	DISTRMD	154,050,256	0	154,050,256	159,095,147	0	159,095,147
3	Subtransmission - SM	DISTROTH	2,381,253	0	2,381,253	1,992,860	0	1,992,860
4	Distribution - DC	DISTRDC	936,775,467	936,775,467	0	998,405,705	998,405,705	0
5	Distribution - DC - Meters	DISTRDC	21,756,767	21,756,767	0	25,855,657	25,855,657	0
6	Distribution - MD	DISTRMD	1,116,845,609	0	1,116,845,609	1,161,672,588	0	1,161,672,588
7	Distribution - MD - Meters	DISTRMD	21,895,049	0	21,895,049	29,147,199	0	29,147,199
8	Distribution - VA	DISTROTH	10,335	0	10,335	5,789	0	5,789
9	Distribution - SMECO	DISTROTH	197,682	0	197,682	208,087	0	208,087
10	General - DC	DISTRDC	61,726,347	61,726,347	0	66,712,748	66,712,748	0
11	General - MD	DISTRMD	60,461,685	0	60,461,685	60,648,222	0	60,648,222
13	TOTAL DEPRECIATION RESERVE (LESS AFUDC)		2,470,973,835	1,115,131,969	1,355,841,867	2,604,989,522	1,192,219,629	1,412,769,893
14	DEPRECIATION RESERVE - AFUDC							
15	Distribution - DC	DISTRDC	12,740,147	12,740,147	0	13,399,547	13,399,547	0
16	Distribution - MD	DISTRMD	10,820,053	0	10,820,053	11,188,849	0	11,188,849
18	General - DC	DISTRDC	3,721,416	3,721,416	0	4,012,030	4,012,030	0
19	General - MD	DISTRMD	(2,805,820)	0	(2,805,820)	(1,909,762)	0	(1,909,762)
20	General - SM	DISTROTH	225,129	0	225,129	233,807	0	233,807
21	TOTAL AFUDC		24,700,927	16,461,563	8,239,363	26,924,472	17,411,577	9,512,895
22	TOTAL DEPRECIATION RESERVE		2,495,674,762	1,131,593,532	1,364,081,230	2,631,913,994	1,209,631,206	1,422,282,788
	TOTAL NET PLANT		4,659,855,555	2,503,152,633	2,156,702,923	4,986,429,526	2,681,374,228	2,305,055,298
23	**AMORTIZATION RESERVE**							
24	General	STDPLT	(6,282,649)	(3,189,521)	(3,093,128)	(6,623,680)	(3,380,572)	(3,243,108)
25	Software	STDPLT	(18,864,723)	(9,577,080)	(9,287,643)	(24,291,870)	(12,398,005)	(11,893,866)
26	AMI Software - DC	DISTRDC	1,880,244	1,880,244	0	1,880,244	1,880,244	0
27	AMI Software - MD	DISTRMD	3,959,024	0	3,959,024	3,959,024	0	3,959,024
28	AMORTIZATION RESERVE - AFUDC							
29	AFUDC DC	DISTRDC	(602,730)	(602,730)	0	(666,694)	(666,694)	0
30	AFUDC MD	DISTRMD	(1,016,139)	0	(1,016,139)	(1,092,018)	0	(1,092,018)
31	AFUDC SM	DISTROTH	(39,200)	0	(39,200)	(40,481)	0	(40,481)
32	TOTAL AMORTIZATION RESERVE		(20,966,172)	(11,489,086)	(9,477,086)	(26,875,475)	(14,565,026)	(12,310,449)

	DEVELOP OF RATE BASE CON'T-15	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	DEPRECIATION RESERVE							
1	Subtransmission - DC	DISTRDC	107,804,247	107,804,247	0	114,453,491	114,453,491	0
2	Subtransmission - MD	DISTRMD	165,797,757	0	165,797,757	172,625,934	0	172,625,934
3	Subtransmission - SM	DISTROTH	2,032,097	0	2,032,097	2,075,235	0	2,075,235
4	Distribution - DC	DISTRDC	1,081,394,375	1,081,394,375	0	1,172,323,659	1,172,323,659	0
5	Distribution - DC - Meters	DISTRDC	30,342,577	30,342,577	0	34,833,270	34,833,270	0
6	Distribution - MD	DISTRMD	1,217,557,982	0	1,217,557,982	1,278,230,279	0	1,278,230,279
7	Distribution - MD - Meters	DISTRMD	36,759,181	0	36,759,181	44,376,682	0	44,376,682
8	Distribution - VA	DISTROTH	(11,574)	0	(11,574)	(29,331)	0	(29,331)
9	Distribution - SMECO	DISTROTH	218,536	0	218,536	228,985	0	228,985
10	General - DC	DISTRDC	73,397,114	73,397,114	0	80,544,847	80,544,847	0
11	General - MD	DISTRMD	63,006,203	0	63,006,203	65,720,779	0	65,720,779
13	TOTAL DEPRECIATION RESERVE (LESS AFUDC)		2,778,298,494	1,292,938,312	1,485,360,182	2,965,383,828	1,402,155,267	1,563,228,562
14	DEPRECIATION RESERVE - AFUDC							
15	Distribution - DC	DISTRDC	14,197,368	14,197,368	0	15,185,130	15,185,130	0
16	Distribution - MD	DISTRMD	11,602,644	0	11,602,644	12,182,612	0	12,182,612
18	General - DC	DISTRDC	4,340,246	4,340,246	0	4,676,825	4,676,825	0
19	General - MD	DISTRMD	(837,602)	0	(837,602)	265,377	0	265,377
20	General - SM	DISTROTH	242,454	0	242,454	251,102	0	251,102
21	TOTAL AFUDC		29,545,110	18,537,614	11,007,496	32,561,045	19,861,955	12,699,090
22	TOTAL DEPRECIATION RESERVE		2,807,843,604	1,311,475,926	1,496,367,678	2,997,944,873	1,422,017,222	1,575,927,652
	TOTAL NET PLANT		5,274,239,788	2,885,563,989	2,388,675,799	5,619,611,717	3,060,825,369	2,558,786,348
23	**AMORTIZATION RESERVE**							
24	General	STDPLT	(6,964,711)	(3,612,052)	(3,352,660)	(7,305,743)	(3,794,959)	(3,510,784)
25	Software	STDPLT	(34,352,589)	(17,816,004)	(16,536,584)	(47,181,025)	(24,508,126)	(22,672,899)
26	AMI Software - DC	DISTRDC	1,880,244	1,880,244	0	1,880,244	1,880,244	0
27	AMI Software - MD	DISTRMD	3,959,024	0	3,959,024	3,959,024	0	3,959,024
28	AMORTIZATION RESERVE - AFUDC							
29	AFUDC DC	DISTRDC	(774,262)	(774,262)	0	(886,187)	(886,187)	0
30	AFUDC MD	DISTRMD	(1,212,047)	0	(1,212,047)	(1,336,258)	0	(1,336,258)
31	AFUDC SM	DISTROTH	(41,840)	0	(41,840)	(43,207)	0	(43,207)
32	TOTAL AMORTIZATION RESERVE		(37,506,181)	(20,322,074)	(17,184,107)	(50,913,151)	(27,309,028)	(23,604,123)

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-15

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	DEPRECIATION RESERVE				
1	Subtransmission - DC	DISTRDC	121,102,735	121,102,735	0
2	Subtransmission - MD	DISTRMD	179,454,110	0	179,454,110
3	Subtransmission - SM	DISTROTH	2,118,374	0	2,118,374
4	Distribution - DC	DISTRDC	1,270,254,440	1,270,254,440	0
5	Distribution - DC - Meters	DISTRDC	39,323,963	39,323,963	0
6	Distribution - MD	DISTRMD	1,345,002,033	0	1,345,002,033
7	Distribution - MD - Meters	DISTRMD	51,994,183	0	51,994,183
8	Distribution - VA	DISTROTH	(47,089)	0	(47,089)
9	Distribution - SMECO	DISTROTH	239,433	0	239,433
10	General - DC	DISTRDC	88,507,036	88,507,036	0
11	General - MD	DISTRMD	69,272,692	0	69,272,692
13	TOTAL DEPRECIATION RESERVE (LESS AFUDC)		3,167,221,910	1,519,188,174	1,648,033,736
14	DEPRECIATION RESERVE - AFUDC				
15	Distribution - DC	DISTRDC	16,463,207	16,463,207	0
16	Distribution - MD	DISTRMD	13,206,172	0	13,206,172
18	General - DC	DISTRDC	5,056,079	5,056,079	0
19	General - MD	DISTRMD	1,526,120	0	1,526,120
20	General - SM	DISTROTH	259,749	0	259,749
21	TOTAL AFUDC		36,511,326	21,519,286	14,992,040
22	TOTAL DEPRECIATION RESERVE		3,203,733,237	1,540,707,461	1,663,025,776
	TOTAL NET PLANT		6,018,170,454	3,278,479,512	2,739,690,942
23	**AMORTIZATION RESERVE**				
24	General	STDPLT	(7,646,774)	(3,987,600)	(3,659,175)
25	Software	STDPLT	(63,479,703)	(33,103,062)	(30,376,641)
26	AMI Software - DC	DISTRDC	1,880,244	1,880,244	0
27	AMI Software - MD	DISTRMD	3,959,024	0	3,959,024
28	AMORTIZATION RESERVE - AFUDC				
29	AFUDC DC	DISTRDC	(998,411)	(998,411)	0
30	AFUDC MD	DISTRMD	(1,460,518)	0	(1,460,518)
31	AFUDC SM	DISTROTH	(44,576)	0	(44,576)
32	TOTAL AMORTIZATION RESERVE		(67,790,714)	(36,208,829)	(31,581,886)

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ELECTRIC DISTRIBUTION

	DEVELOP OF RATE BASE CON'T-16	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
1	**CWIP**							
2	Distribution - DC	ZERO	0	0	0	0	0	0
3	Distribution - Maryland	ZERO	0	0	0	0	0	0
4	Sub-transmission	ZERO	0	0	0	0	0	0
5	General & Intangible	ZERO	0	0	0	0	0	0
7	CWIP - AFUDC							
8	CWIP AFUDC - DC Subtransmission	ZERO	0	0	0	0	0	0
9	CWIP AFUDC - DC Distribution	ZERO	0	0	0	0	0	0
10	CWIP AFUDC - MD Subtransmission	ZERO	0	0	0	0	0	0
11	CWIP AFUDC - MD Distribution	ZERO	0	0	0	0	0	0
12	CWIP AFUDC - SM General	ZERO	0	0	0	0	0	0
13	CWIP AFUDC - DC General & Intangible	ZERO	0	0	0	0	0	0
14	CWIP AFUDC - MD General & Intangible	ZERO	0	0	0	0	0	0
17	Other							
18	Total CWIP		0	0	0	0	0	0
	PLANT HELD FOR FUTURE USE							
19	Distribution - DC	ZERO	0	0	0	0	0	0
20	Distribution - Maryland	ZERO	0	0	0	0	0	0
21	PLANT HELD FOR FUTURE USE - AFUDC							
22	Distribution - DC	ZERO	0	0	0	0	0	0
23	Distribution - Maryland	ZERO	0	0	0	0	0	0
24	Total Plant Held for Future Use		0	0	0	0	0	0
25	**MATERIALS & SUPPLIES**							
26	Subtransmission	PLTSUBT	5,030,152	2,101,055	2,929,097	5,274,954	2,203,320	3,071,633
27	Distribution-Demand	PLTDEM	61,675,246	32,011,904	29,663,343	64,676,783	33,665,060	31,011,722
28	Distribution-Customer	PLTCUST	6,522,420	3,281,673	3,240,746	6,839,845	3,504,920	3,334,925
29	TOTAL MATERIALS & SUPPLIES		73,227,818	37,394,632	35,833,186	76,791,581	39,373,301	37,418,281

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	DEVELOP OF RATE BASE CON'T-16	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
1	**CWIP**							
2	Distribution - DC	ZERO	0	0	0	0	0	0
3	Distribution - Maryland	ZERO	0	0	0	0	0	0
4	Sub-transmission	ZERO	0	0	0	0	0	0
5	General & Intangible	ZERO	0	0	0	0	0	0
7	CWIP - AFUDC							
8	CWIP AFUDC - DC Subtransmission	ZERO	0	0	0	0	0	0
9	CWIP AFUDC - DC Distribution	ZERO	0	0	0	0	0	0
10	CWIP AFUDC - MD Subtransmission	ZERO	0	0	0	0	0	0
11	CWIP AFUDC - MD Distribution	ZERO	0	0	0	0	0	0
12	CWIP AFUDC - SM General	ZERO	0	0	0	0	0	0
13	CWIP AFUDC - DC General & Intangible	ZERO	0	0	0	0	0	0
14	CWIP AFUDC - MD General & Intangible	ZERO	0	0	0	0	0	0
17	Other							
18	Total CWIP		0	0	0	0	0	0
	PLANT HELD FOR FUTURE USE							
19	Distribution - DC	ZERO	0	0	0	0	0	0
20	Distribution - Maryland	ZERO	0	0	0	0	0	0
21	PLANT HELD FOR FUTURE USE - AFUDC							
22	Distribution - DC	ZERO	0	0	0	0	0	0
23	Distribution - Maryland	ZERO	0	0	0	0	0	0
24	Total Plant Held for Future Use		0	0	0	0	0	0
25	**MATERIALS & SUPPLIES**							
26	Subtransmission	PLTSUBT	5,043,084	2,106,578	2,936,506	5,043,084	2,108,956	2,934,128
27	Distribution-Demand	PLTDEM	61,833,805	32,649,644	29,184,161	61,833,805	32,743,952	29,089,853
28	Distribution-Customer	PLTCUST	6,539,188	3,457,643	3,081,545	6,539,188	3,519,539	3,019,648
29	TOTAL MATERIALS & SUPPLIES		73,416,077	38,213,864	35,202,213	73,416,077	38,372,447	35,043,630

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-16

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
1	**CWIP**				
2	Distribution - DC	ZERO	0	0	0
3	Distribution - Maryland	ZERO	0	0	0
4	Sub-transmission	ZERO	0	0	0
5	General & Intangible	ZERO	0	0	0
7	CWIP - AFUDC				
8	CWIP AFUDC - DC Subtransmission	ZERO	0	0	0
9	CWIP AFUDC - DC Distribution	ZERO	0	0	0
10	CWIP AFUDC - MD Subtransmission	ZERO	0	0	0
11	CWIP AFUDC - MD Distribution	ZERO	0	0	0
12	CWIP AFUDC - SM General	ZERO	0	0	0
13	CWIP AFUDC - DC General & Intangible	ZERO	0	0	0
14	CWIP AFUDC - MD General & Intangible	ZERO	0	0	0
17	Other				
18	Total CWIP		0	0	0
	PLANT HELD FOR FUTURE USE				
19	Distribution - DC	ZERO	0	0	0
20	Distribution - Maryland	ZERO	0	0	0
21	PLANT HELD FOR FUTURE USE - AFUDC				
22	Distribution - DC	ZERO	0	0	0
23	Distribution - Maryland	ZERO	0	0	0
24	Total Plant Held for Future Use		0	0	0
25	**MATERIALS & SUPPLIES**				
26	Subtransmission	PLTSUBT	5,043,084	2,110,322	2,932,762
27	Distribution-Demand	PLTDEM	61,833,805	32,881,145	28,952,660
28	Distribution-Customer	PLTCUST	6,539,188	3,590,227	2,948,961
29	TOTAL MATERIALS & SUPPLIES		73,416,077	38,581,693	34,834,384

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	DEVELOP OF RATE BASE CON'T-17	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
1	**MISC RATE BASE ITEMS**							
2	Net Service Company Assets - CWIP	ZERO	0	0	0	0	0	0
3	Net Service Company Assets - Plant	STDPLT	53,295,625	27,056,662	26,238,962	56,289,353	28,728,774	27,560,578
4	Net Service Company Assets - Plant Direct MD	DISTRMD	1,099,466	0	1,099,466	180,077	0	180,077
5	Net Service Company Assets - Plant Direct DC	DISTRDC	522,165	522,165	0	85,523	85,523	0
6	Net Prepaid Pension/OPEB Asset	OMLESAGS	170,092,080	72,038,503	98,053,577	158,570,326	68,490,321	90,080,005
8	Credit Facility Costs	STDPLT	737,512	374,414	363,098	636,401	324,804	311,597
9	**REGULATORY ASSETS**							
10	DC							
11	DC FC 1150 Costs	DISTRDC	1,625,325	1,625,325	0	1,179,090	1,179,090	0
12	DC FC 1139 Excess Rate Case Costs	DISTRDC	(844,404)	(844,404)	0	(612,572)	(612,572)	0
13	DC I Street Substation Rent	DISTRDC	2,986,779	2,986,779	0	2,500,352	2,500,352	0
14	DC Benning RI Costs	DISTRDC	3,265,008	3,265,008	0	3,001,383	3,001,383	0
15	DC Over-Collected Depreciation Expense	DISTRDC	(590,569)	(590,569)	0	(428,427)	(428,427)	0
16	DC AMI (FC 1076)	DISTRDC	409,783	409,783	0	349,075	349,075	0
17	DC AMI Expense (FC 1087)	DISTRDC	30,663,739	30,663,739	0	27,363,606	27,363,606	0
18	DC AMI Return (FC 1087)	DISTRDC	(40,874)	(40,874)	0	(36,475)	(36,475)	0
19	DC Formal Case 1139 Costs	DISTRDC	3,118,083	3,118,083	0	1,650,750	1,650,750	0
20	DC DLC Program Costs	DISTRDC	11,749,650	11,749,650	0	8,901,250	8,901,250	0
21	DC Interval Billing Costs	DISTRDC	3,781,800	3,781,800	0	2,865,000	2,865,000	0
22	DC AMI True Up	DISTRDC	7,047,150	7,047,150	0	5,338,750	5,338,750	0
23	DC Third Party Audit Costs	DISTRDC	75,083	75,083	0	39,750	39,750	0
24	DC 1076 Management Audit Costs	DISTRDC	1,231,083	1,231,083	0	651,750	651,750	0
25	DC CRM&B Stabilization Expense	DISTRDC	2,014,650	2,014,650	0	1,526,250	1,526,250	0
26	DC Legacy Billing System Expense	DISTRDC	246,675	246,675	0	186,875	186,875	0
27	DC Tax Prep	DISTRDC	80,850	80,850	0	61,250	61,250	0
	ADIT on DC Regulatory Assets in Rate Base	DISTRDC	(16,707,083)	(16,707,083)	0	(14,234,209)	(14,234,209)	0
28	Total DC Regulatory Assets		50,112,729	50,112,729	0	40,303,447	40,303,447	0
29	MD							
30	MD February 2010 Storm Costs	DISTRMD	139,007	0	139,007	39,207	0	39,207
31	MD January 2011 Storm	DISTRMD	535,019	0	535,019	150,903	0	150,903
32	MD 2013 Storm (Nor'easter) Prep	DISTRMD	111,325	0	111,325	14,986	0	14,986
33	MD Hurricane Irene (August 2011)	DISTRMD	596,220	0	596,220	168,165	0	168,165
34	MD Derecho	DISTRMD	1,172,162	0	1,172,162	105,555	0	105,555
35	MD Hurricane Sandy	DISTRMD	250,976	0	250,976	22,601	0	22,601
36	MD Approved AMI Costs 2	DISTRMD	2,812,410	0	2,812,410	2,510,190	0	2,510,190
37	MD Winter Storm Stella	DISTRMD	846,527	0	846,527	649,927	0	649,927
38	MD Approved AMI Costs	DISTRMD	43,055,038	0	43,055,038	37,914,138	0	37,914,138
39	MD Billing System Transition	DISTRMD	4,911,975	0	4,911,975	3,456,575	0	3,456,575
40	MD Storm Jonas Costs	DISTRMD	1,161,204	0	1,161,204	817,143	0	817,143
41	MD Storm Pax Costs	DISTRMD	459,675	0	459,675	323,475	0	323,475
42	MD Pepco CTA Costs	DISTRMD	10,945,800	0	10,945,800	7,702,600	0	7,702,600
	ADIT on MD Regulatory Assets in Rate Base	DISTRMD	(16,551,129)	0	(16,551,129)	(14,139,069)	0	(14,139,069)
43	Total MD Regulatory Assets		50,446,207	0	50,446,207	39,736,394	0	39,736,394
44	TOTAL REGULATORY ASSETS		100,558,936	50,112,729	50,446,207	80,039,841	40,303,447	39,736,394
45	**CASH WORKING CAPITAL**							
46	Operating Expenses - Other	DISTRMD	11,752,870	0	11,752,870	12,875,446	0	12,875,446
47	Operating Expenses - DC	DISTRDC	8,915,814	8,915,814	0	9,242,609	9,242,609	0
48	Plant Portion - Imprest Funds	STDPLT	779,540	395,750	383,790	769,485	392,727	376,758
49	TOTAL CASH WORKING CAPITAL		21,448,224	9,311,564	12,136,660	22,887,540	9,635,337	13,252,204
50	**CUSTOMER DEPOSITS**							
51	DC	DISTRDC	(8,507,321)	(8,507,321)	0	(9,330,243)	(9,330,243)	0
52	Maryland	DISTRMD	(44,290,015)	0	(44,290,015)	(44,824,626)	0	(44,824,626)
53	TOTAL CUSTOMER DEPOSITS		(52,797,336)	(8,507,321)	(44,290,015)	(54,154,870)	(9,330,243)	(44,824,626)

	DEVELOP OF RATE BASE CON'T-17	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
1	**MISC RATE BASE ITEMS**							
2	Net Service Company Assets - CWIP	ZERO	0	0	0	0	0	0
3	Net Service Company Assets - Plant	STDPLT	48,783,381	25,300,129	23,483,252	40,088,716	20,824,035	19,264,681
4	Net Service Company Assets - Plant Direct MD	DISTRMD	0	0	0	0	0	0
5	Net Service Company Assets - Plant Direct DC	DISTRDC	0	0	0	0	0	0
6	Net Prepaid Pension/OPEB Asset	OMLESAGS	138,608,819	60,151,359	78,457,460	138,588,716	60,156,374	78,432,342
8	Credit Facility Costs	STDPLT	473,806	245,726	228,080	311,210	161,658	149,552
9	**REGULATORY ASSETS**							
10	DC							
11	DC FC 1150 Costs	DISTRDC	621,756	621,756	0	111,098	111,098	0
12	DC FC 1139 Excess Rate Case Costs	DISTRDC	(323,021)	(323,021)	0	(57,719)	(57,719)	0
13	DC I Street Substation Rent	DISTRDC	1,892,820	1,892,820	0	1,285,288	1,285,288	0
14	DC Benning RI Costs	DISTRDC	2,672,125	2,672,125	0	2,342,867	2,342,867	0
15	DC Over-Collected Depreciation Expense	DISTRDC	(225,918)	(225,918)	0	(40,368)	(40,368)	0
16	DC AMI (FC 1076)	DISTRDC	288,366	288,366	0	227,658	227,658	0
17	DC AMI Expense (FC 1087)	DISTRDC	24,063,472	24,063,472	0	20,763,339	20,763,339	0
18	DC AMI Return (FC 1087)	DISTRDC	(32,076)	(32,076)	0	(27,677)	(27,677)	0
19	DC Formal Case 1139 Costs	DISTRDC	300,991	300,991	0	0	0	0
20	DC DLC Program Costs	DISTRDC	6,052,850	6,052,850	0	3,204,450	3,204,450	0
21	DC Interval Billing Costs	DISTRDC	1,948,200	1,948,200	0	1,031,400	1,031,400	0
22	DC AMI True Up	DISTRDC	3,630,350	3,630,350	0	1,921,950	1,921,950	0
23	DC Third Party Audit Costs	DISTRDC	7,248	7,248	0	0	0	0
24	DC 1076 Management Audit Costs	DISTRDC	118,838	118,838	0	0	0	0
25	DC CRM&B Stabilization Expense	DISTRDC	1,037,850	1,037,850	0	549,450	549,450	0
26	DC Legacy Billing System Expense	DISTRDC	127,075	127,075	0	67,275	67,275	0
27	DC Tax Prep	DISTRDC	41,650	41,650	0	22,050	22,050	0
	ADIT on DC Regulatory Assets in Rate Base	DISTRDC	(11,761,334)	(11,761,334)	0	(8,679,701)	(8,679,701)	0
28	Total DC Regulatory Assets		30,461,243	30,461,243	0	22,721,361	22,721,361	0
29	MD							
30	MD February 2010 Storm Costs	DISTRMD	0	0	0	0	0	0
31	MD January 2011 Storm	DISTRMD	0	0	0	0	0	0
32	MD 2013 Storm (Nor'easter) Prep	DISTRMD	0	0	0	0	0	0
33	MD Hurricane Irene (August 2011)	DISTRMD	0	0	0	0	0	0
34	MD Derecho	DISTRMD	0	0	0	0	0	0
35	MD Hurricane Sandy	DISTRMD	0	0	0	0	0	0
36	MD Approved AMI Costs 2	DISTRMD	2,207,970	0	2,207,970	1,905,749	0	1,905,749
37	MD Winter Storm Stella	DISTRMD	453,327	0	453,327	256,727	0	256,727
38	MD Approved AMI Costs	DISTRMD	32,773,238	0	32,773,238	27,632,338	0	27,632,338
39	MD Billing System Transition	DISTRMD	2,001,175	0	2,001,175	564,434	0	564,434
40	MD Storm Jonas Costs	DISTRMD	473,083	0	473,083	133,434	0	133,434
41	MD Storm Pax Costs	DISTRMD	187,275	0	187,275	52,821	0	52,821
42	MD Pepco CTA Costs	DISTRMD	4,459,400	0	4,459,400	1,257,779	0	1,257,779
	ADIT on MD Regulatory Assets in Rate Base	DISTRMD	(11,727,010)	0	(11,727,010)	(8,834,930)	0	(8,834,930)
43	Total MD Regulatory Assets		30,828,457	0	30,828,457	22,968,352	0	22,968,352
44	TOTAL REGULATORY ASSETS		61,289,700	30,461,243	30,828,457	45,689,713	22,721,361	22,968,352
45	**CASH WORKING CAPITAL**							
46	Operating Expenses - Other	DISTRMD	14,129,412	0	14,129,412	14,987,650	0	14,987,650
47	Operating Expenses - DC	DISTRDC	9,756,678	9,756,678	0	9,734,660	9,734,660	0
48	Plant Portion - Imprest Funds	STDPLT	769,485	399,072	370,413	769,485	399,708	369,777
49	TOTAL CASH WORKING CAPITAL		24,655,575	10,155,750	14,499,825	25,491,795	10,134,368	15,357,427
50	**CUSTOMER DEPOSITS**							
51	DC	DISTRDC	(9,484,872)	(9,484,872)	0	(9,484,872)	(9,484,872)	0
52	Maryland	DISTRMD	(43,335,825)	0	(43,335,825)	(43,335,825)	0	(43,335,825)
53	TOTAL CUSTOMER DEPOSITS		(52,820,697)	(9,484,872)	(43,335,825)	(52,820,697)	(9,484,872)	(43,335,825)

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-17

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
1	**MISC RATE BASE ITEMS**				
2	Net Service Company Assets - CWIP	ZERO	0	0	0
3	Net Service Company Assets - Plant	STDPLT	33,042,875	17,231,025	15,811,850
4	Net Service Company Assets - Plant Direct MD	DISTRMD	0	0	0
5	Net Service Company Assets - Plant Direct DC	DISTRDC	0	0	0
6	Net Prepaid Pension/OPEB Asset	OMLESAGS	123,778,300	53,094,466	70,683,834
8	Credit Facility Costs	STDPLT	148,614	77,498	71,116
9	**REGULATORY ASSETS**				
10	DC				
11	DC FC 1150 Costs	DISTRDC	0	0	0
12	DC FC 1139 Excess Rate Case Costs	DISTRDC	0	0	0
13	DC I Street Substation Rent	DISTRDC	677,757	677,757	0
14	DC Benning RI Costs	DISTRDC	2,013,609	2,013,609	0
15	DC Over-Collected Depreciation Expense	DISTRDC	0	0	0
16	DC AMI (FC 1076)	DISTRDC	166,949	166,949	0
17	DC AMI Expense (FC 1087)	DISTRDC	17,463,206	17,463,206	0
18	DC AMI Return (FC 1087)	DISTRDC	(23,278)	(23,278)	0
19	DC Formal Case 1139 Costs	DISTRDC	0	0	0
20	DC DLC Program Costs	DISTRDC	584,287	584,287	0
21	DC Interval Billing Costs	DISTRDC	188,062	188,062	0
22	DC AMI True Up	DISTRDC	350,441	350,441	0
23	DC Third Party Audit Costs	DISTRDC	0	0	0
24	DC 1076 Management Audit Costs	DISTRDC	0	0	0
25	DC CRM&B Stabilization Expense	DISTRDC	100,185	100,185	0
26	DC Legacy Billing System Expense	DISTRDC	12,267	12,267	0
27	DC Tax Prep	DISTRDC	4,021	4,021	0
	ADIT on DC Regulatory Assets in Rate Base	DISTRDC	(6,113,846)	(6,113,846)	0
28	Total DC Regulatory Assets		15,423,658	15,423,658	0
29	MD				
30	MD February 2010 Storm Costs	DISTRMD	0	0	0
31	MD January 2011 Storm	DISTRMD	0	0	0
32	MD 2013 Storm (Nor'easter) Prep	DISTRMD	0	0	0
33	MD Hurricane Irene (August 2011)	DISTRMD	0	0	0
34	MD Derecho	DISTRMD	0	0	0
35	MD Hurricane Sandy	DISTRMD	0	0	0
36	MD Approved AMI Costs 2	DISTRMD	1,603,529	0	1,603,529
37	MD Winter Storm Stella	DISTRMD	65,155	0	65,155
38	MD Approved AMI Costs	DISTRMD	22,491,438	0	22,491,438
39	MD Billing System Transition	DISTRMD	0	0	0
40	MD Storm Jonas Costs	DISTRMD	0	0	0
41	MD Storm Pax Costs	DISTRMD	0	0	0
42	MD Pepco CTA Costs	DISTRMD	0	0	0
	ADIT on MD Regulatory Assets in Rate Base	DISTRMD	(6,661,679)	0	(6,661,679)
43	Total MD Regulatory Assets		17,498,443	0	17,498,443
44	TOTAL REGULATORY ASSETS		32,922,101	15,423,658	17,498,443
45	**CASH WORKING CAPITAL**				
46	Operating Expenses - Other	DISTRMD	15,998,811	0	15,998,811
47	Operating Expenses - DC	DISTRDC	9,717,522	9,717,522	0
48	Plant Portion - Imprest Funds	STDPLT	769,485	401,267	368,218
49	TOTAL CASH WORKING CAPITAL		26,485,818	10,118,789	16,367,029
50	**CUSTOMER DEPOSITS**				
51	DC	DISTRDC	(9,484,872)	(9,484,872)	0
52	Maryland	DISTRMD	(43,335,825)	0	(43,335,825)
53	TOTAL CUSTOMER DEPOSITS		(52,820,697)	(9,484,872)	(43,335,825)

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-18

		ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
1	**DEFERRED TAXES**							
2	**Plant Related**							
3	DCIT @ 21%	STDPLT	21,778,177	11,056,157	10,722,020	21,476,979	10,961,350	10,515,629
4	MDIT @ 21%	STDPLT	21,751,899	11,042,816	10,709,083	24,394,723	12,450,498	11,944,225
5	FIT	STDPLT	738,515,085	374,922,959	363,592,126	780,303,662	398,248,811	382,054,851
6	Adjusted FIT		782,045,162	397,021,932	385,023,230	826,175,365	421,660,659	404,514,706
7	LESS: DCIT @ 21%	DISTRDC	21,778,177	21,778,177	0	21,476,979	21,476,979	0
8	LESS: MDIT @ 21%	DISTRMD	21,751,899	0	21,751,899	24,394,723	0	24,394,723
9	FIT		738,515,085	375,243,755	363,271,331	780,303,662	400,183,680	380,119,982
10	NOVA FIT - Direct	DISTROTH	0	0	0	0	0	0
11	DCIT	DISTRDC	103,705,607	103,705,607	0	102,271,330	102,271,330	0
12	MDIT	DISTRMD	103,580,472	0	103,580,472	116,165,349	0	116,165,349
13	NOVA Related Deferred DCIT	DISTRDC	0	0	0	0	0	0
14	Total Depreciation Related		945,801,164	478,949,361	466,851,803	998,740,341	502,455,010	496,285,332
15	Total Plant Less CIAC		7,155,530,317	3,634,746,164	3,520,784,153	7,618,343,520	3,891,005,435	3,727,338,085
16	Total Depre Reserve		2,495,674,762	1,131,593,532	1,364,081,230	2,631,913,994	1,209,631,206	1,422,282,788
17	Average		0.348775653	0.311326701	0.387436767	0.345470638	0.310878827	0.381581374
18	Difference			(0.037448953)	0.038661114		(0.034591810)	0.036110736
19	Adjustment			(136,117,437)	136,117,437		(134,596,922)	134,596,922
20	Tax			47,641,103	(47,641,103)		47,108,923	(47,108,923)
21	Total Plant Related		945,801,164	526,590,464	419,210,700	998,740,341	549,563,932	449,176,409

	DEVELOP OF RATE BASE CON'T-18	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
1	**DEFERRED TAXES**							
2	**Plant Related**							
3	DCIT @ 21%	STDPLT	22,491,211	11,664,434	10,826,777	23,568,875	12,242,824	11,326,052
4	MDIT @ 21%	STDPLT	26,259,826	13,618,920	12,640,906	28,224,077	14,660,962	13,563,114
5	FIT	STDPLT	801,643,987	415,750,114	385,893,873	823,360,210	427,693,464	395,666,746
6	Adjusted FIT		850,395,024	441,033,468	409,361,556	875,153,163	454,597,251	420,555,912
7	LESS: DCIT @ 21%	DISTRDC	22,491,211	22,491,211	0	23,568,875	23,568,875	0
8	LESS: MDIT @ 21%	DISTRMD	26,259,826	0	26,259,826	28,224,077	0	28,224,077
9	FIT		801,643,987	418,542,257	383,101,729	823,360,210	431,028,375	392,331,835
10	NOVA FIT - Direct	DISTROTH	0	0	0	0	0	0
11	DCIT	DISTRDC	107,101,004	107,101,004	0	112,232,740	112,232,740	0
12	MDIT	DISTRMD	125,046,791	0	125,046,791	134,400,365	0	134,400,365
13	NOVA Related Deferred DCIT	DISTRDC	0	0	0	0	0	0
14	Total Depreciation Related		1,033,791,782	525,643,261	508,148,521	1,069,993,316	543,261,115	526,732,201
15	Total Plant Less CIAC		8,082,083,392	4,197,039,916	3,885,043,477	8,617,556,590	4,482,842,590	4,134,714,000
16	Total Depre Reserve		2,807,843,604	1,311,475,926	1,496,367,678	2,997,944,873	1,422,017,222	1,575,927,652
17	Average		0.347415817	0.312476401	0.385161115	0.347888040	0.317213284	0.381145504
18	Difference			(0.034939416)	0.037745298		(0.030674756)	0.033257464
19	Adjustment			(146,642,125)	146,642,125		(137,510,102)	137,510,102
20	Tax			51,324,744	(51,324,744)		48,128,536	(48,128,536)
21	Total Plant Related		1,033,791,782	576,968,005	456,823,777	1,069,993,316	591,389,650	478,603,665

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-18

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
1	**DEFERRED TAXES**				
2	**Plant Related**				
3	DCIT @ 21%	STDPLT	25,010,688	13,042,442	11,968,246
4	MDIT @ 21%	STDPLT	30,785,497	16,053,859	14,731,638
5	FIT	STDPLT	857,721,696	447,280,203	410,441,493
6	Adjusted FIT		913,517,881	476,376,504	437,141,377
7	LESS: DCIT @ 21%	DISTRDC	25,010,688	25,010,688	0
8	LESS: MDIT @ 21%	DISTRMD	30,785,497	0	30,785,497
9	FIT		857,721,696	451,365,816	406,355,880
10	NOVA FIT - Direct	DISTROTH	0	0	0
11	DCIT	DISTRDC	119,098,516	119,098,516	0
12	MDIT	DISTRMD	146,597,604	0	146,597,604
13	NOVA Related Deferred DCIT	DISTRDC	0	0	0
14	Total Depreciation Related		1,123,417,816	570,464,332	552,953,484
15	Total Plant Less CIAC		9,221,903,690	4,819,186,973	4,402,716,718
16	Total Depre Reserve		3,203,733,237	1,540,707,461	1,663,025,776
17	Average		0.347404760	0.319702778	0.377727181
18	Difference			(0.027701982)	0.030322422
19	Adjustment			(133,501,032)	133,501,032
20	Tax			28,035,217	(28,035,217)
21	Total Plant Related		1,123,417,816	598,499,548	524,918,267

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	DEVELOP OF RATE BASE CON'T-19	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
1	**Loss on Debt Reacquisition**							
2	DCIT @ 21%	STDPLT	77,108	39,146	37,963	69,052	35,243	33,809
3	MDIT @ 21%	STDPLT	116,382	59,084	57,298	110,052	56,168	53,884
4	FIT	STDPLT	2,265,169	1,149,961	1,115,208	1,978,773	1,009,920	968,853
5	Adjusted FIT		2,458,659	1,248,191	1,210,468	2,157,877	1,101,330	1,056,547
6	LESS: DCIT @ 21%	DISTRDC	77,108	77,108	0	69,052	69,052	0
7	LESS: MDIT @ 21%	DISTRMD	116,382	0	116,382	110,052	0	110,052
8	FIT		2,265,169	1,171,083	1,094,086	1,978,773	1,032,278	946,495
9	DCIT	DISTRDC	367,183	367,183	0	0	0	0
10	MDIT	DISTRMD	554,200	0	554,200	328,819	0	328,819
11	Total Loss on Debt Reacquisition		3,186,552	1,538,265	1,648,286	2,307,592	1,032,278	1,275,314

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-19

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
1	**Loss on Debt Reacquisition**							
2	DCIT @ 21%	STDPLT	59,218	30,712	28,506	50,137	26,043	24,093
3	MDIT @ 21%	STDPLT	94,379	48,947	45,432	79,905	41,507	38,399
4	FIT	STDPLT	1,696,977	880,089	816,888	1,436,732	746,309	690,423
5	Adjusted FIT		1,850,575	959,749	890,826	1,566,774	813,859	752,915
6	LESS: DCIT @ 21%	DISTRDC	59,218	59,218	0	50,137	50,137	0
7	LESS: MDIT @ 21%	DISTRMD	94,379	0	94,379	79,905	0	79,905
8	FIT		1,696,977	900,530	796,447	1,436,732	763,722	673,010
9	DCIT	DISTRDC	281,992	281,992	0	238,747	238,747	0
10	MDIT	DISTRMD	449,425	0	449,425	380,502	0	380,502
11	Total Loss on Debt Reacquisition		2,428,395	1,182,523	1,245,872	2,055,981	1,002,469	1,053,512

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-19

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
1	**Loss on Debt Reacquisition**				
2	DCIT @ 21%	STDPLT	41,408	21,593	19,815
3	MDIT @ 21%	STDPLT	65,994	34,414	31,580
4	FIT	STDPLT	1,186,603	618,783	567,819
5	Adjusted FIT		1,294,005	674,791	619,214
6	LESS: DCIT @ 21%	DISTRDC	41,408	41,408	0
7	LESS: MDIT @ 21%	DISTRMD	65,994	0	65,994
8	FIT		1,186,603	633,383	553,220
9	DCIT	DISTRDC	197,182	197,182	0
10	MDIT	DISTRMD	314,258	0	314,258
11	Total Loss on Debt Reacquisition		1,698,043	830,565	867,478

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	DEVELOP OF RATE BASE CON'T-20	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
1	**Def Inc. Tax Asset Federal NOL**							
2	DCIT @ 21%	STDPLT	0	0	0	0	0	0
3	MDIT @ 21%	STDPLT	0	0	0	0	0	0
4	FIT	STDPLT	(5,740,460)	(2,914,267)	(2,826,193)	(0)	(0)	(0)
5	Adjusted FIT		(5,740,460)	(2,914,267)	(2,826,193)	(0)	(0)	(0)
6	LESS: DCIT @ 21%	DISTRDC	0	0	0	0	0	0
7	LESS: MDIT @ 21%	DISTRMD	0	0	0	0	0	0
8	FIT		(5,740,460)	(2,914,267)	(2,826,193)	(0)	(0)	(0)
9	DCIT	DISTRDC	0	0	0	0	0	0
10	MDIT	DISTRMD	0	0	0	0	0	0
11	Total Def Inc. Tax Asset Federal NOL		(5,740,460)	(2,914,267)	(2,826,193)	(0)	(0)	(0)
12	**Def Inc. Tax Asset State NOL**							
13	DCIT @ 21%	STDPLT	0	0	0	0	0	0
14	MDIT @ 21%	STDPLT	0	0	0	0	0	0
15	FIT	STDPLT	0	0	0	0	0	0
16	Adjusted FIT		0	0	0	0	0	0
17	LESS: DCIT @ 21%	DISTRDC	0	0	0	0	0	0
18	LESS: MDIT @ 21%	DISTRMD	0	0	0	0	0	0
19	FIT		0	0	0	0	0	0
20	DCIT	DISTRDC	0	0	0	0	0	0
21	MDIT	DISTRMD	0	0	0	0	0	0
22	Total Def Inc. Tax Asset State NOL		0	0	0	0	0	0
24	**DIRECTS**							
25	Federal Excess DIT - DC Protected Property	DISTRDC	138,883,528	138,883,528	0	139,311,595	139,311,595	0
26	Federal Excess DIT - DC Non-Protected Property	DISTRDC	120,035,172	120,035,172	0	107,976,327	107,976,327	0
27	Federal Excess DIT - DC Non-Protected Non-Property	DISTRDC	20,912,910	20,912,910	0	17,237,013	17,237,013	0
28	Federal Excess DIT - MD Protected Property	DISTRMD	118,297,254	0	118,297,254	118,340,281	0	118,340,281
29	Federal Excess DIT - MD Non-Protected Property	DISTRMD	99,812,995	0	99,812,995	93,262,341	0	93,262,341
30	Federal Excess DIT - MD Non-Protected Non-Property	DISTRMD	28,934,012	0	28,934,012	24,974,330	0	24,974,330
31	DC Excess DIT - Order No. 188446	DISTRDC	13,692,932	13,692,932	0	6,074,733	6,074,733	0
32	DC Excess DIT - Order No. 19247	DISTRDC	5,448,490	5,448,490	0	4,136,381	4,136,381	0
33	MD Excess DIT	DISTRMD	(3,966,649)	0	(3,966,649)	(12,891,610)	0	(12,891,610)
34	MD NOL MDIT	DISTRMD	(8,612,031)	0	(8,612,031)	(7,379,998)	0	(7,379,998)
35	MD NOL FIT	DISTRMD	1,808,527	0	1,808,527	1,549,800	0	1,549,800
36	Benefit DC NOL DCIT	DISTRDC	(7,977,005)	(7,977,005)	0	(3,717,472)	(3,717,472)	0
37	Benefit DC NOL FIT	DISTRDC	1,675,171	1,675,171	0	780,669	780,669	0
38	ITC	ZERO	0	0	0	0	0	0
39	DEFERRED STATE TAXES		206,793,199	115,237,207	91,555,992	204,987,532	108,764,972	96,222,560
40	DEFERRED FEDERAL INCOME TAXES		1,265,399,363	702,648,453	562,750,910	1,285,714,791	713,630,484	572,084,306
41	TOTAL DEFERRED TAXES		1,472,192,561	817,885,660	654,306,901	1,490,702,322	822,395,456	668,306,866
42	**TOTAL RATE BASE**		3,534,881,312	1,862,081,235	1,672,800,077	3,810,177,502	2,022,025,009	1,788,152,493

	DEVELOP OF RATE BASE CON'T-20	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
1	**Def Inc. Tax Asset Federal NOL**							
2	DCIT @ 21%	STDPLT	0	0	0	0	0	0
3	MDIT @ 21%	STDPLT	0	0	0	0	0	0
4	FIT	STDPLT	0	0	0	0	0	0
5	Adjusted FIT		0	0	0	0	0	0
6	LESS: DCIT @ 21%	DISTRDC	0	0	0	0	0	0
7	LESS: MDIT @ 21%	DISTRMD	0	0	0	0	0	0
8	FIT		0	0	0	0	0	0
9	DCIT	DISTRDC	0	0	0	0	0	0
10	MDIT	DISTRMD	0	0	0	0	0	0
11	Total Def Inc. Tax Asset Federal NOL		0	0	0	0	0	0
12	**Def Inc. Tax Asset State NOL**							
13	DCIT @ 21%	STDPLT	0	0	0	0	0	0
14	MDIT @ 21%	STDPLT	0	0	0	0	0	0
15	FIT	STDPLT	0	0	0	0	0	0
16	Adjusted FIT		0	0	0	0	0	0
17	LESS: DCIT @ 21%	DISTRDC	0	0	0	0	0	0
18	LESS: MDIT @ 21%	DISTRMD	0	0	0	0	0	0
19	FIT		0	0	0	0	0	0
20	DCIT	DISTRDC	0	0	0	0	0	0
21	MDIT	DISTRMD	0	0	0	0	0	0
22	Total Def Inc. Tax Asset State NOL		0	0	0	0	0	0
24	**DIRECTS**							
25	Federal Excess DIT - DC Protected Property	DISTRDC	137,420,284	137,420,284	0	135,629,978	135,629,978	0
26	Federal Excess DIT - DC Non-Protected Property	DISTRDC	94,896,113	94,896,113	0	82,514,447	82,514,447	0
27	Federal Excess DIT - DC Non-Protected Non-Property	DISTRDC	12,525,189	12,525,189	0	8,065,000	8,065,000	0
28	Federal Excess DIT - MD Protected Property	DISTRMD	115,923,131	0	115,923,131	113,635,069	0	113,635,069
29	Federal Excess DIT - MD Non-Protected Property	DISTRMD	87,772,895	0	87,772,895	82,576,612	0	82,576,612
30	Federal Excess DIT - MD Non-Protected Non-Property	DISTRMD	20,330,537	0	20,330,537	15,934,745	0	15,934,745
31	DC Excess DIT - Order No. 188446	DISTRDC	827,439	827,439	0	0	0	0
32	DC Excess DIT - Order No. 19247	DISTRDC	2,125,320	2,125,320	0	586,745	586,745	0
33	MD Excess DIT	DISTRMD	(12,891,610)	0	(12,891,610)	(12,891,610)	0	(12,891,610)
34	MD NOL MDIT	DISTRMD	(4,730,916)	0	(4,730,916)	(1,698,080)	0	(1,698,080)
35	MD NOL FIT	DISTRMD	993,492	0	993,492	356,597	0	356,597
36	Benefit DC NOL DCIT	DISTRDC	(1,375,523)	(1,375,523)	0	(0)	(0)	0
37	Benefit DC NOL FIT	DISTRDC	288,860	288,860	0	0	0	0
38	ITC	ZERO	0	0	0	0	0	0
39	DEFERRED STATE TAXES		216,833,922	108,960,232	107,873,690	233,249,409	113,058,231	120,191,178
40	DEFERRED FEDERAL INCOME TAXES		1,273,491,466	715,897,977	557,593,488	1,263,509,390	706,130,058	557,379,332
41	TOTAL DEFERRED TAXES		1,490,325,387	824,858,209	665,467,178	1,496,758,799	819,188,289	677,570,510
42	**TOTAL RATE BASE**		4,040,814,881	2,195,426,905	1,845,387,976	4,342,705,296	2,357,213,422	1,985,491,874

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-20

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
1	**Def Inc. Tax Asset Federal NOL**				
2	DCIT @ 21%	STDPLT	0	0	0
3	MDIT @ 21%	STDPLT	0	0	0
4	FIT	STDPLT	0	0	0
5	Adjusted FIT		0	0	0
6	LESS: DCIT @ 21%	DISTRDC	0	0	0
7	LESS: MDIT @ 21%	DISTRMD	0	0	0
8	FIT		0	0	0
9	DCIT	DISTRDC	0	0	0
10	MDIT	DISTRMD	0	0	0
11	Total Def Inc. Tax Asset Federal NOL		0	0	0
12	**Def Inc. Tax Asset State NOL**				
13	DCIT @ 21%	STDPLT	0	0	0
14	MDIT @ 21%	STDPLT	0	0	0
15	FIT	STDPLT	0	0	0
16	Adjusted FIT		0	0	0
17	LESS: DCIT @ 21%	DISTRDC	0	0	0
18	LESS: MDIT @ 21%	DISTRMD	0	0	0
19	FIT		0	0	0
20	DCIT	DISTRDC	0	0	0
21	MDIT	DISTRMD	0	0	0
22	Total Def Inc. Tax Asset State NOL		0	0	0
24	**DIRECTS**				
25	Federal Excess DIT - DC Protected Property	DISTRDC	133,839,672	133,839,672	0
26	Federal Excess DIT - DC Non-Protected Property	DISTRDC	70,132,781	70,132,781	0
27	Federal Excess DIT - DC Non-Protected Non-Property	DISTRDC	3,604,810	3,604,810	0
28	Federal Excess DIT - MD Protected Property	DISTRMD	111,347,007	0	111,347,007
29	Federal Excess DIT - MD Non-Protected Property	DISTRMD	77,380,329	0	77,380,329
30	Federal Excess DIT - MD Non-Protected Non-Property	DISTRMD	11,538,954	0	11,538,954
31	DC Excess DIT - Order No. 188446	DISTRDC	0	0	0
32	DC Excess DIT - Order No. 19247	DISTRDC	0	0	0
33	MD Excess DIT	DISTRMD	(12,891,610)	0	(12,891,610)
34	MD NOL MDIT	DISTRMD	0	0	0
35	MD NOL FIT	DISTRMD	0	0	0
36	Benefit DC NOL DCIT	DISTRDC	(0)	(0)	0
37	Benefit DC NOL FIT	DISTRDC	0	0	0
38	ITC	ZERO	0	0	0
39	DEFERRED STATE TAXES		253,315,950	119,295,698	134,020,252
40	DEFERRED FEDERAL INCOME TAXES		1,266,751,852	687,611,679	579,140,173
41	TOTAL DEFERRED TAXES		1,520,067,801	806,907,377	713,160,425
42	**TOTAL RATE BASE**		4,667,285,027	2,560,405,565	2,106,879,462

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	OPERATING REVENUES-21	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	ELECTRIC SALES REVENUES							
	Revenue - Retail Sales							
1	DC - Retail Sales	DISTRDC	528,277,577	528,277,577	0	522,573,338	522,573,338	0
2	MD - Retail Sales	DISTRMD	688,559,636	0	688,559,636	707,341,628	0	707,341,628
3	Retail Total		1,216,837,213	528,277,577	688,559,636	1,229,914,966	522,573,338	707,341,628
	REVENUE - OTHER							
4	Late Payment Revenue DC	DISTRDC	1,265,146	1,265,146	0	1,265,146	1,265,146	0
5	Late Payment Revenue MD	DISTRMD	2,663,807	0	2,663,807	2,663,807	0	2,663,807
6	Miscellaneous Service Revenue DC	DISTRDC	(449)	(449)	0	(449)	(449)	0
7	Miscellaneous Service Revenue MD	DISTRMD	(8,849)	0	(8,849)	(8,849)	0	(8,849)
8	MD Opt Out Fees	DISTRMD	274,819	0	274,819	274,819	0	274,819
9	Rent from Electric Property DC	DISTRDC	1,536,418	1,536,418	0	1,536,418	1,536,418	0
10	Rent from Electric Property MD	DISTRMD	3,249,524	0	3,249,524	3,249,524	0	3,249,524
11	Rents - Customer Related DC	DISTRDC	0	0	0	0	0	0
12	Rents - Customer Related MD	DISTRMD	0	0	0	0	0	0
13	Other DC	DISTRDC	3,759,552	3,759,552	0	3,759,552	3,759,552	0
14	Other MD	DISTRMD	4,777,137	0	4,777,137	4,777,137	0	4,777,137
15	TOTAL OTHER REVENUE		17,517,104	6,560,667	10,956,437	17,517,104	6,560,667	10,956,437
16	TOTAL REVENUE		**1,234,354,316**	**534,838,244**	**699,516,073**	**1,247,432,069**	**529,134,004**	**718,298,065**

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

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	OPERATING REVENUES-21	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	ELECTRIC SALES REVENUES							
	Revenue - Retail Sales							
1	DC - Retail Sales	DISTRDC	523,952,484	523,952,484	0	524,981,183	524,981,183	0
2	MD - Retail Sales	DISTRMD	709,355,353	0	709,355,353	709,205,784	0	709,205,784
3	Retail Total		1,233,307,837	523,952,484	709,355,353	1,234,186,967	524,981,183	709,205,784
	REVENUE - OTHER							
4	Late Payment Revenue DC	DISTRDC	1,265,146	1,265,146	0	1,265,146	1,265,146	0
5	Late Payment Revenue MD	DISTRMD	2,663,807	0	2,663,807	2,663,807	0	2,663,807
6	Miscellaneous Service Revenue DC	DISTRDC	(449)	(449)	0	(449)	(449)	0
7	Miscellaneous Service Revenue MD	DISTRMD	(8,849)	0	(8,849)	(8,849)	0	(8,849)
8	MD Opt Out Fees	DISTRMD	274,819	0	274,819	274,819	0	274,819
9	Rent from Electric Property DC	DISTRDC	1,536,418	1,536,418	0	1,536,418	1,536,418	0
10	Rent from Electric Property MD	DISTRMD	3,249,524	0	3,249,524	3,249,524	0	3,249,524
11	Rents - Customer Related DC	DISTRDC	0	0	0	0	0	0
12	Rents - Customer Related MD	DISTRMD	0	0	0	0	0	0
13	Other DC	DISTRDC	3,759,552	3,759,552	0	3,759,552	3,759,552	0
14	Other MD	DISTRMD	4,777,137	0	4,777,137	4,777,137	0	4,777,137
15	TOTAL OTHER REVENUE		17,517,104	6,560,667	10,956,437	17,517,104	6,560,667	10,956,437
16	TOTAL REVENUE		**1,250,824,940**	**530,513,151**	**720,311,790**	**1,251,704,071**	**531,541,850**	**720,162,221**

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lultiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	OPERATING REVENUES-21	ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	ELECTRIC SALES REVENUES				
	Revenue - Retail Sales				
1	DC - Retail Sales	DISTRDC	526,033,788	526,033,788	0
2	MD - Retail Sales	DISTRMD	708,819,929	0	708,819,929
3	Retail Total		1,234,853,717	526,033,788	708,819,929
	REVENUE - OTHER				
4	Late Payment Revenue DC	DISTRDC	1,265,146	1,265,146	0
5	Late Payment Revenue MD	DISTRMD	2,663,807	0	2,663,807
6	Miscellaneous Service Revenue DC	DISTRDC	(449)	(449)	0
7	Miscellaneous Service Revenue MD	DISTRMD	(8,849)	0	(8,849)
8	MD Opt Out Fees	DISTRMD	274,819	0	274,819
9	Rent from Electric Property DC	DISTRDC	1,536,418	1,536,418	0
10	Rent from Electric Property MD	DISTRMD	3,249,524	0	3,249,524
11	Rents - Customer Related DC	DISTRDC	0	0	0
12	Rents - Customer Related MD	DISTRMD	0	0	0
13	Other DC	DISTRDC	3,759,552	3,759,552	0
14	Other MD	DISTRMD	4,777,137	0	4,777,137
15	TOTAL OTHER REVENUE		17,517,104	6,560,667	10,956,437
16	TOTAL REVENUE		**1,252,370,821**	**532,594,455**	**719,776,366**

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	OPERATION & MAINT EXP-22	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	DISTRIBUTION EXPENSES							
	OPERATION							
1	958000 Operation Supervision & Engineering	OMEXP580	3,708,109	1,720,406	1,987,702	4,043,758	2,437,637	1,606,121
2	958100 Load dispatching	OMEXP581	5,625,435	2,858,015	2,767,420	7,539,999	3,844,834	3,695,165
3	958200 Station expenses	OMEXP582	1,292,337	672,186	620,151	2,065,386	1,197,792	867,594
4	958300 Overhead line expenses	OMEXP583	1,048,048	226,111	821,937	4,141,126	2,886,863	1,254,263
5	958400 Underground line expenses	OMEXP584	5,674,402	3,293,671	2,380,730	14,856,200	11,847,966	3,008,234
6	958500 Street lighting	OMEXP585	634,821	0	634,821	775,000	0	775,000
7	958600 Meter expenses	OMEXP586	6,951,837	3,104,157	3,847,680	6,922,651	3,514,417	3,408,234
8	958700 Customer installations expenses	OMEXP587	8,438,964	3,432,725	5,006,239	8,046,894	3,142,439	4,904,455
9	958800 Miscellaneous distribution expenses	OMEXP588	9,179,511	2,884,680	6,294,830	7,156,153	4,485,419	2,670,735
10	958900 Rents Control Center	OMEXP589	9,440,399	5,494,753	3,945,646	11,947,480	7,740,450	4,207,030
11	TOTAL OPERATION		51,993,862	23,686,705	28,307,157	67,494,647	41,097,816	26,396,831
	MAINTENANCE							
12	959000 Maintenance Supervision & Engineering	OMEXP590	782,810	233,415	549,395	735,108	288,091	447,017
13	959100 Maintenance Structures	OMEXP591	13,536	7,585	5,951	218,839	115,644	103,195
14	959200 Maintain equipment	OMEXP592	16,992,873	8,893,163	8,099,710	18,950,950	8,849,946	10,101,004
15	959300 Maintain overhead lines	OMEXP593	42,382,829	7,553,298	34,829,532	40,184,302	7,881,105	32,303,197
16	959400 Maintain underground line	OMEXP594	22,698,059	13,908,851	8,789,208	14,483,883	8,559,036	5,924,847
17	959500 Maintain line transformers	OMEXP595	6,445,668	3,983,312	2,462,356	1,955,350	883,342	1,072,008
18	959600 Maintain street lighting & signal sys	OMEXP596	4,878,991	1,340	4,877,651	3,997,808	13,151	3,984,657
19	959700 Maintain meters	OMEXP597	842,418	342,858	499,561	814,413	314,733	499,680
20	959800 Maintain distribution plant	OMEXP598	2,262,553	1,192,968	1,069,584	4,757,669	1,876,124	2,881,545
21	TOTAL MAINTENANCE		97,299,738	36,116,790	61,182,948	86,098,321	28,781,171	57,317,151
22	TOTAL DISTRIBUTION EXPENSES		149,293,601	59,803,495	89,490,105	153,592,968	69,878,987	83,713,981

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

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	OPERATION & MAINT EXP-22	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	DISTRIBUTION EXPENSES							
	OPERATION							
1	958000 Operation Supervision & Engineering	OMEXP580	4,124,435	2,575,745	1,548,690	4,147,287	2,600,843	1,546,444
2	958100 Load dispatching	OMEXP581	7,986,162	4,131,982	3,854,180	7,919,806	4,096,412	3,823,394
3	958200 Station expenses	OMEXP582	2,283,333	1,292,647	990,686	1,809,024	860,077	948,947
4	958300 Overhead line expenses	OMEXP583	4,296,232	2,987,941	1,308,291	4,571,870	3,148,462	1,423,408
5	958400 Underground line expenses	OMEXP584	14,676,515	11,659,303	3,017,212	15,220,352	12,227,323	2,993,029
6	958500 Street lighting	OMEXP585	776,500	0	776,500	776,500	0	776,500
7	958600 Meter expenses	OMEXP586	6,968,485	3,603,416	3,365,069	7,061,005	3,687,439	3,373,566
8	958700 Customer installations expenses	OMEXP587	7,739,884	3,275,161	4,464,723	7,880,653	3,344,932	4,535,721
9	958800 Miscellaneous distribution expenses	OMEXP588	8,969,827	5,714,214	3,255,613	7,624,557	4,946,028	2,678,529
10	958900 Rents Control Center	OMEXP589	4,251,779	3,865,225	386,554	4,347,204	3,958,487	388,717
11	TOTAL OPERATION		62,073,152	39,105,634	22,967,517	61,358,258	38,870,002	22,488,256
	MAINTENANCE							
12	959000 Maintenance Supervision & Engineering	OMEXP590	734,780	287,868	446,912	682,597	266,293	416,304
13	959100 Maintenance Structures	OMEXP591	262,875	133,884	128,991	252,584	120,395	132,189
14	959200 Maintain equipment	OMEXP592	17,969,701	8,355,955	9,613,746	19,327,483	8,844,027	10,483,456
15	959300 Maintain overhead lines	OMEXP593	42,489,150	7,909,012	34,580,139	42,343,485	7,609,339	34,734,146
16	959400 Maintain underground line	OMEXP594	14,521,798	8,715,049	5,806,749	15,103,166	9,140,013	5,963,153
17	959500 Maintain line transformers	OMEXP595	1,600,690	950,625	650,065	1,640,757	987,996	652,761
18	959600 Maintain street lighting & signal sys	OMEXP596	3,359,061	13,184	3,345,877	3,369,183	13,204	3,355,979
19	959700 Maintain meters	OMEXP597	637,732	248,179	389,553	651,106	262,244	388,862
20	959800 Maintain distribution plant	OMEXP598	5,255,922	2,070,858	3,185,064	5,350,591	2,099,269	3,251,322
21	TOTAL MAINTENANCE		86,831,709	28,684,615	58,147,095	88,720,952	29,342,779	59,378,173
22	TOTAL DISTRIBUTION EXPENSES		148,904,861	67,790,249	81,114,612	150,079,209	68,212,781	81,866,429

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lultiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	OPERATION & MAINT EXP-22	ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	DISTRIBUTION EXPENSES				
	OPERATION				
1	958000 Operation Supervision & Engineering	OMEXP580	4,209,171	2,633,553	1,575,618
2	958100 Load dispatching	OMEXP581	8,036,886	4,165,189	3,871,697
3	958200 Station expenses	OMEXP582	1,853,792	860,904	992,888
4	958300 Overhead line expenses	OMEXP583	4,828,904	3,315,321	1,513,583
5	958400 Underground line expenses	OMEXP584	15,199,289	12,182,753	3,016,536
6	958500 Street lighting	OMEXP585	776,500	0	776,500
7	958600 Meter expenses	OMEXP586	7,062,952	3,667,412	3,395,540
8	958700 Customer installations expenses	OMEXP587	8,039,314	3,416,578	4,622,736
9	958800 Miscellaneous distribution expenses	OMEXP588	6,035,420	4,100,282	1,935,138
10	958900 Rents Control Center	OMEXP589	4,447,829	4,056,349	391,479
11	TOTAL OPERATION		60,490,057	38,398,342	22,091,715
	MAINTENANCE				
12	959000 Maintenance Supervision & Engineering	OMEXP590	687,944	261,786	426,158
13	959100 Maintenance Structures	OMEXP591	262,495	117,832	144,663
14	959200 Maintain equipment	OMEXP592	19,636,933	8,666,517	10,970,416
15	959300 Maintain overhead lines	OMEXP593	43,256,261	7,500,429	35,755,832
16	959400 Maintain underground line	OMEXP594	15,393,840	9,378,227	6,015,613
17	959500 Maintain line transformers	OMEXP595	1,669,725	1,015,926	653,799
18	959600 Maintain street lighting & signal sys	OMEXP596	3,372,417	13,225	3,359,192
19	959700 Maintain meters	OMEXP597	665,538	277,762	387,776
20	959800 Maintain distribution plant	OMEXP598	5,498,464	2,105,281	3,393,183
21	TOTAL MAINTENANCE		90,443,617	29,336,984	61,106,632
22	TOTAL DISTRIBUTION EXPENSES		150,933,674	67,735,326	83,198,347

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	OPERATION & MAINT EXP CON'T-23	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	CUSTOMER ACCOUNTS EXPENSE							
1	990200 Meter reading expenses	OMEXP902	989,971	357,955	632,016	1,012,249	366,010	646,239
2	990300 Cust records and collection exp	OMEXP903	77,888,559	26,505,088	51,383,471	87,130,361	29,423,643	57,706,718
3	990500 Miscellaneous cust accounts exp	OMEXP905	0	0	0	0	0	0
4	990400 Uncollectible accounts	OMEXP904	6,328,224	2,183,470	4,144,754	7,261,367	2,801,792	4,459,575
5	TOTAL CUSTOMER ACCOUNTS EXPENSE		85,206,754	29,046,512	56,160,242	95,403,977	32,591,445	62,812,532
	CUSTOMER SERVICE EXPENSE							
6	990700 Supervision	OMEXP907	0	0	0	0	0	0
7	990800 Customer assistance expenses	OMEXP908	4,616,928	1,369,819	3,247,110	5,538,289	1,644,426	3,893,863
8	990900 Informational & instructional adv	OMEXP909	2,099,119	691,501	1,407,618	773,046	264,725	508,321
9	991000 Miscellaneous customer service & informational exp	OMEXP910	0	0	0	0	0	0
10	TOTAL CUSTOMER SERVICE EXPENSE		6,716,048	2,061,320	4,654,728	6,311,335	1,909,151	4,402,184
	SALES EXPENSE							
11	991200 Demonstrating & selling expenses	OMEXP912	0	0	0	0	0	0
12	991300 Advertising expense	OMEXP913	0	0	0	0	0	0
13	TOTAL SALES EXPENSE		0	0	0	0	0	0
14	**OPERATIONS & MAINTENANCE LESS A&G**		241,216,402	90,911,327	150,305,075	255,308,281	104,379,582	150,928,698

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

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	OPERATION & MAINT EXP CON'T-23	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	CUSTOMER ACCOUNTS EXPENSE							
1	990200 Meter reading expenses	OMEXP902	1,043,755	377,402	666,353	1,052,010	380,387	671,623
2	990300 Cust records and collection exp	OMEXP903	89,815,091	30,510,467	59,304,624	88,274,929	30,011,278	58,263,651
3	990500 Miscellaneous cust accounts exp	OMEXP905	0	0	0	0	0	0
4	990400 Uncollectible accounts	OMEXP904	7,303,216	3,054,786	4,248,430	8,116,951	3,443,012	4,673,939
5	TOTAL CUSTOMER ACCOUNTS EXPENSE		98,162,062	33,942,655	64,219,407	97,443,890	33,834,677	63,609,213
	CUSTOMER SERVICE EXPENSE							
6	990700 Supervision	OMEXP907	0	0	0	0	0	0
7	990800 Customer assistance expenses	OMEXP908	5,563,216	1,645,095	3,918,120	5,603,770	1,650,898	3,952,873
8	990900 Informational & instructional adv	OMEXP909	777,751	266,336	511,415	781,247	267,533	513,714
9	991000 Miscellaneous customer service & informational exp	OMEXP910	0	0	0	0	0	0
10	TOTAL CUSTOMER SERVICE EXPENSE		6,340,967	1,911,432	4,429,535	6,385,017	1,918,431	4,466,586
	SALES EXPENSE							
11	991200 Demonstrating & selling expenses	OMEXP912	0	0	0	0	0	0
12	991300 Advertising expense	OMEXP913	0	0	0	0	0	0
13	TOTAL SALES EXPENSE		0	0	0	0	0	0
14	**OPERATIONS & MAINTENANCE LESS A&G**		253,407,890	103,644,336	149,763,554	253,908,117	103,965,888	149,942,228

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ELECTRIC DISTRIBUTION

	OPERATION & MAINT EXP CON'T-23	ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	CUSTOMER ACCOUNTS EXPENSE				
1	990200 Meter reading expenses	OMEXP902	1,061,146	383,690	677,456
2	990300 Cust records and collection exp	OMEXP903	87,473,202	30,105,737	57,367,464
3	990500 Miscellaneous cust accounts exp	OMEXP905	0	0	0
4	990400 Uncollectible accounts	OMEXP904	8,042,946	3,182,522	4,860,424
5	TOTAL CUSTOMER ACCOUNTS EXPENSE		96,577,294	33,671,949	62,905,344
	CUSTOMER SERVICE EXPENSE				
6	990700 Supervision	OMEXP907	0	0	0
7	990800 Customer assistance expenses	OMEXP908	5,637,200	1,660,299	3,976,901
8	990900 Informational & instructional adv	OMEXP909	781,657	267,674	513,983
9	991000 Miscellaneous customer service & informational exp	OMEXP910	0	0	0
10	TOTAL CUSTOMER SERVICE EXPENSE		6,418,857	1,927,973	4,490,884
	SALES EXPENSE				
11	991200 Demonstrating & selling expenses	OMEXP912	0	0	0
12	991300 Advertising expense	OMEXP913	0	0	0
13	TOTAL SALES EXPENSE		0	0	0
14	**OPERATIONS & MAINTENANCE LESS A&G**		253,929,824	103,335,249	150,594,576

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ELECTRIC DISTRIBUTION

	OPERATION & MAINT EXP CON'T-24	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	ADMINISTRATIVE & GENERAL EXPENSE							
	OPERATION							
1	992000 Administrative & General salaries	OMLESAGS	4,079,180	1,727,641	2,351,539	6,028,310	2,603,771	3,424,538
2	992000 Administrative & General salaries Direct MD	DISTRMD	577,053	0	577,053	869,030	0	869,030
3	992000 Administrative & General salaries Direct DC	DISTRDC	795,677	795,677	0	657,096	657,096	0
4	992100 Office supplies & expenses	OMLESAGS	6,169,305	2,612,864	3,556,441	1,768,790	763,983	1,004,807
5	992100 Office supplies & expenses -DC	DISTRDC	173,615	173,615	0	0	0	0
6	992100 Office supplies & expenses -MD	DISTRMD	158,345	0	158,345	0	0	0
7	992300 Outside services employed	OMLESAGS	122,416,007	51,846,423	70,569,584	117,809,759	50,884,856	66,924,903
8	992300 Outside services employed - MD	DISTRMD	(414,574)	0	(414,574)	215,747	0	215,747
9	992300 Outside services employed - DC	DISTRDC	1,657,790	1,657,790	0	905,811	905,811	0
10	992400 Property insurance	STDPLT	1,007,429	511,443	495,986	989,175	504,852	484,323
11	992500 Injuries & damages	OMLESAGS	4,068,003	1,722,907	2,345,096	3,329,106	1,437,921	1,891,186
12	992600 Employee pensions & benefits	OMLESAGS	10,041,343	4,252,775	5,788,568	24,480,803	10,573,845	13,906,958
13	992600 Distr-direct empl pensions & benefits- DC	DISTRDC	2,461,556	2,461,556	0	0	0	0
14	992600 Distr-direct empl pensions & benefits- MD	DISTRMD	3,985,837	0	3,985,837	0	0	0
15	992800 Regulatory commission expenses	OMLESAGS	20,430	8,652	11,777	150,361	64,945	85,416
16	Regulatory commission exp - DC	DISTRDC	2,813,955	2,813,955	0	3,779,079	3,779,079	0
17	Regulatory commission exp - MD	DISTRMD	1,091,134	0	1,091,134	2,116,933	0	2,116,933
18	992900 Duplicate charges-Credit	OMLESAGS	0	0	0	0	0	0
19	993010 General ad expenses	OMLESAGS	873,677	370,026	503,652	501,288	216,518	284,770
20	993020 Miscellaneous general expenses	OMLESAGS	1,604,816	679,682	925,134	781,245	337,439	443,807
21	993100 Rents	OMLESAGS	0	0	0	0	0	0
22	TOTAL OPERATION		163,580,579	71,635,006	91,945,573	164,382,533	72,730,115	91,652,418
23	**MAINTENANCE**							
24	993500 Maintenance of general plant	OMLESAGS	64,898	27,486	37,412	0	0	0
25	TOTAL MAINTENANCE		64,898	27,486	37,412	0	0	0
26	TOTAL ADMINISTRATIVE & GENERAL EXPENSE		163,645,477	71,662,492	91,982,985	164,382,533	72,730,115	91,652,418
27	**TOTAL OPERATION & MAINTENANCE EXPENSE**		404,861,879	162,573,819	242,288,060	419,690,814	177,109,697	242,581,116

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ELECTRIC DISTRIBUTION

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	OPERATION & MAINT EXP CON'T-24	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	ADMINISTRATIVE & GENERAL EXPENSE							
	OPERATION							
1	992000 Administrative & General salaries	OMLESAGS	7,414,703	3,217,721	4,196,982	8,964,698	3,891,253	5,073,445
2	992000 Administrative & General salaries Direct MD	DISTRMD	900,573	0	900,573	927,688	0	927,688
3	992000 Administrative & General salaries Direct DC	DISTRDC	677,013	677,013	0	693,596	693,596	0
4	992100 Office supplies & expenses	OMLESAGS	1,866,990	810,208	1,056,782	1,964,800	852,849	1,111,951
5	992100 Office supplies & expenses -DC	DISTRDC	0	0	0	0	0	0
6	992100 Office supplies & expenses -MD	DISTRMD	0	0	0	0	0	0
7	992300 Outside services employed	OMLESAGS	112,242,795	48,709,431	63,533,364	111,381,204	48,346,572	63,034,632
8	992300 Outside services employed - MD	DISTRMD	220,636	0	220,636	224,242	0	224,242
9	992300 Outside services employed - DC	DISTRDC	692,832	692,832	0	267,016	267,016	0
10	992400 Property insurance	STDPLT	989,175	513,008	476,167	82,431	42,819	39,612
11	992500 Injuries & damages	OMLESAGS	3,437,003	1,491,538	1,945,464	3,608,052	1,566,126	2,041,927
12	992600 Employee pensions & benefits	OMLESAGS	23,981,360	10,407,068	13,574,292	23,889,267	10,369,471	13,519,796
13	992600 Distr-direct empl pensions & benefits- DC	DISTRDC	0	0	0	0	0	0
14	992600 Distr-direct empl pensions & benefits- MD	DISTRMD	0	0	0	0	0	0
15	992800 Regulatory commission expenses	OMLESAGS	153,763	66,728	87,035	156,469	67,918	88,551
16	Regulatory commission exp - DC	DISTRDC	3,843,781	3,843,781	0	3,324,559	3,324,559	0
17	Regulatory commission exp - MD	DISTRMD	2,026,059	0	2,026,059	2,027,056	0	2,027,056
18	992900 Duplicate charges-Credit	OMLESAGS	0	0	0	0	0	0
19	993010 General ad expenses	OMLESAGS	503,159	218,353	284,806	505,062	219,229	285,833
20	993020 Miscellaneous general expenses	OMLESAGS	841,848	365,332	476,515	909,137	394,624	514,513
21	993100 Rents	OMLESAGS	0	0	0	0	0	0
22	TOTAL OPERATION		159,791,688	71,013,013	88,778,676	158,925,276	70,036,030	88,889,246
23	**MAINTENANCE**							
24	993500 Maintenance of general plant	OMLESAGS	0	0	0	0	0	0
25	TOTAL MAINTENANCE		0	0	0	0	0	0
26	TOTAL ADMINISTRATIVE & GENERAL EXPENSE		159,791,688	71,013,013	88,778,676	158,925,276	70,036,030	88,889,246
27	**TOTAL OPERATION & MAINTENANCE EXPENSE**		413,199,578	174,657,349	238,542,229	412,833,393	174,001,919	238,831,474

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ELECTRIC DISTRIBUTION

	OPERATION & MAINT EXP CON'T-24	ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	ADMINISTRATIVE & GENERAL EXPENSE				
	OPERATION				
1	992000 Administrative & General salaries	OMLESAGS	10,683,964	4,582,866	6,101,098
2	992000 Administrative & General salaries Direct MD	DISTRMD	943,561	0	943,561
3	992000 Administrative & General salaries Direct DC	DISTRDC	704,901	704,901	0
4	992100 Office supplies & expenses	OMLESAGS	1,884,366	808,295	1,076,071
5	992100 Office supplies & expenses -DC	DISTRDC	0	0	0
6	992100 Office supplies & expenses -MD	DISTRMD	0	0	0
7	992300 Outside services employed	OMLESAGS	109,778,935	47,089,465	62,689,470
8	992300 Outside services employed - MD	DISTRMD	228,835	0	228,835
9	992300 Outside services employed - DC	DISTRDC	272,456	272,456	0
10	992400 Property insurance	STDPLT	82,431	42,986	39,445
11	992500 Injuries & damages	OMLESAGS	3,743,271	1,605,669	2,137,602
12	992600 Employee pensions & benefits	OMLESAGS	23,280,092	9,985,951	13,294,141
13	992600 Distr-direct empl pensions & benefits- DC	DISTRDC	0	0	0
14	992600 Distr-direct empl pensions & benefits- MD	DISTRMD	0	0	0
15	992800 Regulatory commission expenses	OMLESAGS	159,612	68,465	91,147
16	Regulatory commission exp - DC	DISTRDC	2,220,909	2,220,909	0
17	Regulatory commission exp - MD	DISTRMD	2,069,740	0	2,069,740
18	992900 Duplicate charges-Credit	OMLESAGS	0	0	0
19	993010 General ad expenses	OMLESAGS	505,062	216,645	288,417
20	993020 Miscellaneous general expenses	OMLESAGS	984,055	422,109	561,946
21	993100 Rents	OMLESAGS	0	0	0
22	TOTAL OPERATION		157,542,190	68,020,717	89,521,473
23	**MAINTENANCE**				
24	993500 Maintenance of general plant	OMLESAGS	0	0	0
25	TOTAL MAINTENANCE		0	0	0
26	TOTAL ADMINISTRATIVE & GENERAL EXPENSE		157,542,190	68,020,717	89,521,473
27	**TOTAL OPERATION & MAINTENANCE EXPENSE**		411,472,014	171,355,966	240,116,048

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

			2018			2019		
		ALLOC	TOTAL DISTRIBUTION (1)	DC DISTRIBUTION (2)	OTHER DISTRIBUTION (3)	Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	DEPRECIATION & AMORT EXP-25							
	DEPRECIATION EXPENSE							
1	Distribution - DC	DISTRDC	82,280,435	82,280,435	0	88,178,746	88,178,746	0
2	Distribution - Maryland	DISTRMD	62,677,089	0	62,677,089	66,434,700	0	66,434,700
3	Distribution - VA	DISTROTH	2,763	0	2,763	2,763	0	2,763
4	Distribution - SM	DISTROTH	0	0	0	0	0	0
5	Meters DC	DISTRDC	4,109,198	4,109,198	0	4,488,394	4,488,394	0
6	Meters MD	DISTRMD	7,525,517	0	7,525,517	7,616,213	0	7,616,213
7	Meters SM	DISTROTH	10,449	0	10,449	10,449	0	10,449
8	Subtransmission - DC	DISTRDC	6,720,774	6,720,774	0	6,651,074	6,651,074	0
9	Subtransmission - MD	DISTRMD	6,828,048	0	6,828,048	6,829,849	0	6,829,849
10	Subtransmission - SM	DISTROTH	39,017	0	39,017	43,109	0	43,109
11	General DC	DISTRDC	5,466,757	5,466,757	0	7,362,868	7,362,868	0
12	General MD	DISTRMD	5,544,924	0	5,544,924	6,832,685	0	6,832,685
13	TOTAL DEPRECIATION EXPENSE (LESS AFUDC)		181,204,969	98,577,163	82,627,806	194,450,848	106,681,082	87,769,766
14	DEPRECIATION EXPENSE - AFUDC							
15	Distribution - DC	DISTRDC	672,757	672,757	0	677,733	677,733	0
16	Distribution - Maryland	DISTRMD	392,690	0	392,690	388,522	0	388,522
17	General MD	DISTRMD	1,015,673	0	1,015,673	1,049,675	0	1,049,675
18	General DC	DISTRDC	243,473	243,473	0	321,814	321,814	0
19	General SM	DISTROTH	8,751	0	8,751	8,647	0	8,647
20	TOTAL DEPRECIATION EXPENSE - AFUDC		2,333,344	916,230	1,417,115	2,446,391	999,547	1,446,844
21	TOTAL DEPRECIATION EXPENSE		183,538,313	99,493,393	84,044,920	196,897,239	107,680,629	89,216,610
	AMORTIZATION EXPENSE							
22	Software	STDPLT	1,867,565	948,109	919,456	9,013,098	4,600,075	4,413,023
23	AMI Software - DC	DISTRDC	0	0	0	0	0	0
24	AMI Software - MD	DISTRMD	0	0	0	0	0	0
25	General	STDPLT	341,031	173,132	167,900	341,031	174,055	166,977
26	Credit Facility	STDPLT	163,244	82,875	80,370	162,596	82,985	79,611
27	Regulatory Assets - DC							
28	DC AMI (2008)	DISTRDC	60,708	60,708	0	60,708	60,708	0
29	DC AMI Expense	DISTRDC	3,295,734	3,295,734	0	3,295,734	3,295,734	0
30	DC DLC Program Costs	DISTRDC	2,848,400	2,848,400	0	2,848,400	2,848,400	0
31	DC Interval Billing Costs	DISTRDC	916,800	916,800	0	916,800	916,800	0
32	DC AMI True Up	DISTRDC	1,708,400	1,708,400	0	1,708,400	1,708,400	0
33	Total Regulatory Assets - DC		8,830,043	8,830,043	0	8,830,043	8,830,043	0
34	Regulatory Assets - MD							
35	MD Hurricane Irene (August 2011)	DISTRMD	433,614	0	433,614	379,412	0	379,412
36	MD Approved AMI Costs 2	DISTRMD	302,220	0	302,220	302,220	0	302,220
37	MD Local 1900 Ratification Bonus	DISTRMD	45,750	0	45,750	0	0	0
38	EV Pilot Costs	DISTRMD	151,000	0	151,000	132,125	0	132,125
39	Approved AMI Costs	DISTRMD	5,140,900	0	5,140,900	5,140,900	0	5,140,900
40	MD Legacy Meters	DISTRMD	8,467,077	0	8,467,077	8,467,077	0	8,467,077
41	MD Tax Compensation Carrying Costs	DISTRMD	0	0	0	0	0	0
42	Pepco CTAs	DISTRMD	3,243,200	0	3,243,200	3,243,200	0	3,243,200
43	Total Regulatory Assets - MD		17,783,761	0	17,783,761	17,664,934	0	17,664,934
44	TOTAL AMORTIZATION EXPENSE (LESS AFUDC)		28,985,645	10,034,159	18,951,486	36,011,703	13,687,158	22,324,545
45	AMORIZATION EXPENSE - AFUDC							
46	AFUDC DC	DISTRDC	21,136	21,136	0	102,405	102,405	0
47	AFUDC MD	DISTRMD	34,412	0	34,412	114,830	0	114,830
48	AFUDC SM	DISTROTH	1,204	0	1,204	1,350	0	1,350
49	TOTAL AMORTIZATION EXPENSE - AFUDC		56,752	21,136	35,616	218,584	102,405	116,180
50	TOTAL AMORTIZATION EXPENSE		29,042,397	10,055,295	18,987,103	36,230,287	13,789,562	22,440,725
51	**TOTAL DEPRECIATION & AMORTIZATION**		212,580,710	109,548,688	103,032,023	233,127,526	121,470,191	111,657,335

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ELECTRIC DISTRIBUTION

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		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	DEPRECIATION & AMORT EXP-25							
	DEPRECIATION EXPENSE							
1	Distribution - DC	DISTRDC	95,744,538	95,744,538	0	102,347,655	102,347,655	0
2	Distribution - Maryland	DISTRMD	69,706,473	0	69,706,473	75,339,427	0	75,339,427
3	Distribution - VA	DISTROTH	2,763	0	2,763	2,763	0	2,763
4	Distribution - SM	DISTROTH	0	0	0	0	0	0
5	Meters DC	DISTRDC	4,490,693	4,490,693	0	4,490,693	4,490,693	0
6	Meters MD	DISTRMD	7,617,501	0	7,617,501	7,617,501	0	7,617,501
7	Meters SM	DISTROTH	10,449	0	10,449	10,449	0	10,449
8	Subtransmission - DC	DISTRDC	6,649,244	6,649,244	0	6,649,244	6,649,244	0
9	Subtransmission - MD	DISTRMD	6,828,176	0	6,828,176	6,828,176	0	6,828,176
10	Subtransmission - SM	DISTROTH	43,138	0	43,138	43,138	0	43,138
11	General DC	DISTRDC	7,976,057	7,976,057	0	8,383,715	8,383,715	0
12	General MD	DISTRMD	7,442,629	0	7,442,629	7,823,407	0	7,823,407
13	TOTAL DEPRECIATION EXPENSE (LESS AFUDC)		206,511,662	114,860,533	91,651,129	219,536,168	121,871,306	97,664,861
14	DEPRECIATION EXPENSE - AFUDC							
15	Distribution - DC	DISTRDC	908,716	908,716	0	1,104,867	1,104,867	0
16	Distribution - Maryland	DISTRMD	444,607	0	444,607	828,431	0	828,431
17	General MD	DISTRMD	1,089,923	0	1,089,923	1,133,192	0	1,133,192
18	General DC	DISTRDC	333,047	333,047	0	344,752	344,752	0
19	General SM	DISTROTH	8,647	0	8,647	8,647	0	8,647
20	TOTAL DEPRECIATION EXPENSE - AFUDC		2,784,940	1,241,763	1,543,177	3,419,888	1,449,618	1,970,270
21	TOTAL DEPRECIATION EXPENSE		209,296,602	116,102,296	93,194,306	222,956,056	123,320,925	99,635,131
	AMORTIZATION EXPENSE							
22	Software	STDPLT	10,946,966	5,677,336	5,269,630	14,767,868	7,671,151	7,096,717
23	AMI Software - DC	DISTRDC	0	0	0	0	0	0
24	AMI Software - MD	DISTRMD	0	0	0	0	0	0
25	General	STDPLT	341,031	176,866	164,165	341,031	177,148	163,883
26	Credit Facility	STDPLT	162,596	84,326	78,270	162,596	84,460	78,135
27	Regulatory Assets - DC							
28	DC AMI (2008)	DISTRDC	60,708	60,708	0	60,708	60,708	0
29	DC AMI Expense	DISTRDC	3,295,734	3,295,734	0	3,295,734	3,295,734	0
30	DC DLC Program Costs	DISTRDC	2,136,300	2,136,300	0	0	0	0
31	DC Interval Billing Costs	DISTRDC	687,600	687,600	0	0	0	0
32	DC AMI True Up	DISTRDC	1,281,300	1,281,300	0	0	0	0
33	Total Regulatory Assets - DC		7,461,643	7,461,643	0	3,356,443	3,356,443	0
34	Regulatory Assets - MD							
35	MD Hurricane Irene (August 2011)	DISTRMD	0	0	0	0	0	0
36	MD Approved AMI Costs 2	DISTRMD	302,220	0	302,220	226,665	0	226,665
37	MD Local 1900 Ratification Bonus	DISTRMD	0	0	0	0	0	0
38	EV Pilot Costs	DISTRMD	0	0	0	0	0	0
39	Approved AMI Costs	DISTRMD	4,284,083	0	4,284,083	0	0	0
40	MD Legacy Meters	DISTRMD	8,467,077	0	8,467,077	8,467,077	0	8,467,077
41	MD Tax Compensation Carrying Costs	DISTRMD	0	0	0	0	0	0
42	Pepco CTAs	DISTRMD	2,702,667	0	2,702,667	0	0	0
43	Total Regulatory Assets - MD		15,756,047	0	15,756,047	8,693,742	0	8,693,742
44	TOTAL AMORTIZATION EXPENSE (LESS AFUDC)		34,668,282	13,400,171	21,268,112	27,321,679	11,289,202	16,032,477
45	AMORIZATION EXPENSE - AFUDC							
46	AFUDC DC	DISTRDC	110,907	110,907	0	111,868	111,868	0
47	AFUDC MD	DISTRMD	123,415	0	123,415	123,915	0	123,915
48	AFUDC SM	DISTROTH	1,364	0	1,364	1,368	0	1,368
49	TOTAL AMORTIZATION EXPENSE - AFUDC		235,687	110,907	124,779	237,151	111,868	125,283
50	TOTAL AMORTIZATION EXPENSE		34,903,969	13,511,078	21,392,891	27,558,831	11,401,070	16,157,760
51	**TOTAL DEPRECIATION & AMORTIZATION**		244,200,571	129,613,374	114,587,197	250,514,886	134,721,995	115,792,891

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ELECTRIC DISTRIBUTION

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	DEPRECIATION & AMORT EXP-25				
	DEPRECIATION EXPENSE				
1	Distribution - DC	DISTRDC	109,904,748	109,904,748	0
2	Distribution - Maryland	DISTRMD	80,595,474	0	80,595,474
3	Distribution - VA	DISTROTH	2,763	0	2,763
4	Distribution - SM	DISTROTH	0	0	0
5	Meters DC	DISTRDC	4,490,693	4,490,693	0
6	Meters MD	DISTRMD	7,617,501	0	7,617,501
7	Meters SM	DISTROTH	10,449	0	10,449
8	Subtransmission - DC	DISTRDC	6,649,244	6,649,244	0
9	Subtransmission - MD	DISTRMD	6,828,176	0	6,828,176
10	Subtransmission - SM	DISTROTH	43,138	0	43,138
11	General DC	DISTRDC	9,475,869	9,475,869	0
12	General MD	DISTRMD	8,972,411	0	8,972,411
13	TOTAL DEPRECIATION EXPENSE (LESS AFUDC)		234,590,466	130,520,554	104,069,912
14	DEPRECIATION EXPENSE - AFUDC				
15	Distribution - DC	DISTRDC	1,472,773	1,472,773	0
16	Distribution - Maryland	DISTRMD	1,108,141	0	1,108,141
17	General MD	DISTRMD	1,370,112	0	1,370,112
18	General DC	DISTRDC	408,838	408,838	0
19	General SM	DISTROTH	8,647	0	8,647
20	TOTAL DEPRECIATION EXPENSE - AFUDC		4,368,511	1,881,611	2,486,900
21	TOTAL DEPRECIATION EXPENSE		238,958,976	132,402,164	106,556,812
	AMORTIZATION EXPENSE				
22	Software	STDPLT	17,845,177	9,305,809	8,539,368
23	AMI Software - DC	DISTRDC	0	0	0
24	AMI Software - MD	DISTRMD	0	0	0
25	General	STDPLT	341,031	177,839	163,192
26	Credit Facility	STDPLT	162,596	84,789	77,806
27	Regulatory Assets - DC				
28	DC AMI (2008)	DISTRDC	60,708	60,708	0
29	DC AMI Expense	DISTRDC	3,295,734	3,295,734	0
30	DC DLC Program Costs	DISTRDC	0	0	0
31	DC Interval Billing Costs	DISTRDC	0	0	0
32	DC AMI True Up	DISTRDC	0	0	0
33	Total Regulatory Assets - DC		3,356,443	3,356,443	0
34	Regulatory Assets - MD				
35	MD Hurricane Irene (August 2011)	DISTRMD	0	0	0
36	MD Approved AMI Costs 2	DISTRMD	0	0	0
37	MD Local 1900 Ratification Bonus	DISTRMD	0	0	0
38	EV Pilot Costs	DISTRMD	0	0	0
39	Approved AMI Costs	DISTRMD	0	0	0
40	MD Legacy Meters	DISTRMD	8,467,077	0	8,467,077
41	MD Tax Compensation Carrying Costs	DISTRMD	0	0	0
42	Pepco CTAs	DISTRMD	0	0	0
43	Total Regulatory Assets - MD		8,467,077	0	8,467,077
44	TOTAL AMORTIZATION EXPENSE (LESS AFUDC)		30,172,323	12,924,881	17,247,443
45	AMORIZATION EXPENSE - AFUDC				
46	AFUDC DC	DISTRDC	112,552	112,552	0
47	AFUDC MD	DISTRMD	124,588	0	124,588
48	AFUDC SM	DISTROTH	1,370	0	1,370
49	TOTAL AMORTIZATION EXPENSE - AFUDC		238,509	112,552	125,957
50	TOTAL AMORTIZATION EXPENSE		30,410,833	13,037,433	17,373,400
51	**TOTAL DEPRECIATION & AMORTIZATION**		269,369,809	145,439,597	123,930,212

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ELECTRIC DISTRIBUTION

	OTHER TAXES & EXPENSES-26	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	OTHER TAXES							
1	Payroll Taxes - FICA	OMLESAG	5,444,308	2,051,889	3,392,419	6,805,718	2,782,432	4,023,285
2	Payroll Taxes - MD EE/EA & Storm	DISTRMD	88,549	0	88,549	0	0	0
3	MD Property Tax - Subtransmission	STAED	4,292,125	1,803,980	2,488,145	4,723,339	1,985,219	2,738,120
4	DC Property Tax - Subtransmission	STAED	56,607	23,792	32,815	73,522	30,901	42,621
5	VA Property Tax - Subtransmission	STAED	404,611	170,058	234,553	412,484	173,367	239,117
6	Property Taxes - DC	DISTRDC	4,931,174	4,931,174	0	6,404,663	6,404,663	0
7	Property Taxes - Maryland	DISTRMD	34,409,104	0	34,409,104	37,866,057	0	37,866,057
8	Property Taxes - SMECO	DISTROTH	51,378	0	51,378	56,540	0	56,540
9	Property Taxes - VA	DISTROTH	733	0	733	748	0	748
10	Total Property Taxes		44,145,732	6,929,004	37,216,728	49,537,353	8,594,151	40,943,202
11	Federal Highway Use Tax	OMLESAG	11,992	4,520	7,473	12,004	4,908	7,096
12	DC							
13	Delivery Tax	DISTRDC	84,839,386	84,839,386	0	82,595,527	82,595,527	0
14	PSOS	DISTRDC	23,308,898	23,308,898	0	22,661,334	22,661,334	0
15	Use	DISTRDC	282,238	282,238	0	282,238	282,238	0
16	PSC	DISTRDC	9,368,172	9,368,172	0	9,368,170	9,368,170	0
17	RETF/EATF/SETF	DISTRDC	20,745,150	20,745,150	0	19,498,251	19,498,251	0
18	Ballpark	DISTRDC	183,825	183,825	0	183,825	183,825	0
19	Bus Improvement	DISTRDC	0	0	0	0	0	0
20	MD							
21	Environ Surch	DISTRMD	1,998,457	0	1,998,457	2,018,230	0	2,018,230
22	PSC	DISTRMD	2,431,906	0	2,431,906	2,431,910	0	2,431,910
23	Delivery Tax	DISTRMD	8,906,598	0	8,906,598	8,811,986	0	8,811,986
24	Univ Svc	DISTRMD	9,250,569	0	9,250,569	9,210,706	0	9,210,706
25	Montgomery County Surcharge	DISTRMD	139,503,520	0	139,503,520	154,473,519	0	154,473,519
26	Sales, Use, & Diesel Fuel Tax	DISTRMD	51,277	0	51,277	51,276	0	51,276
27	Gross Receipts	DISTRMD	13,103,043	0	13,103,043	10,676,309	0	10,676,309
28	VA							
29	Use	DISTROTH	4,692	0	4,692	4,692	0	4,692
30	TOTAL OTHER TAXES		363,668,311	147,713,081	215,955,230	378,623,047	145,970,836	232,652,212

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

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	OTHER TAXES & EXPENSES-26	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	OTHER TAXES							
1	Payroll Taxes - FICA	OMLESAG	6,931,330	2,834,928	4,096,402	7,095,257	2,905,243	4,190,014
2	Payroll Taxes - MD EE/EA & Storm	DISTRMD	0	0	0	0	0	0
3	MD Property Tax - Subtransmission	STAED	5,102,846	2,144,726	2,958,120	5,512,763	2,317,014	3,195,749
4	DC Property Tax - Subtransmission	STAED	75,728	31,828	43,899	78,000	32,783	45,216
5	VA Property Tax - Subtransmission	STAED	420,727	176,832	243,895	429,145	180,370	248,775
6	Property Taxes - DC	DISTRDC	6,596,803	6,596,803	0	6,794,712	6,794,712	0
7	Property Taxes - Maryland	DISTRMD	40,908,487	0	40,908,487	44,194,714	0	44,194,714
8	Property Taxes - SMECO	DISTROTH	61,083	0	61,083	65,990	0	65,990
9	Property Taxes - VA	DISTROTH	763	0	763	778	0	778
10	Total Property Taxes		53,166,436	8,950,189	44,216,247	57,076,102	9,324,880	47,751,222
11	Federal Highway Use Tax	OMLESAG	12,006	4,910	7,096	12,006	4,916	7,090
12	DC							
13	Delivery Tax	DISTRDC	82,210,365	82,210,365	0	81,459,867	81,459,867	0
14	PSOS	DISTRDC	22,569,250	22,569,250	0	22,373,381	22,373,381	0
15	Use	DISTRDC	282,238	282,238	0	282,238	282,238	0
16	PSC	DISTRDC	9,368,170	9,368,170	0	9,368,170	9,368,170	0
17	RETF/EATF/SETF	DISTRDC	19,413,704	19,413,704	0	19,240,046	19,240,046	0
18	Ballpark	DISTRDC	183,824	183,824	0	183,824	183,824	0
19	Bus Improvement	DISTRDC	0	0	0	0	0	0
20	MD							
21	Environ Surch	DISTRMD	2,007,209	0	2,007,209	1,978,056	0	1,978,056
22	PSC	DISTRMD	2,431,909	0	2,431,909	2,431,909	0	2,431,909
23	Delivery Tax	DISTRMD	8,763,871	0	8,763,871	8,636,581	0	8,636,581
24	Univ Svc	DISTRMD	9,210,702	0	9,210,702	9,210,702	0	9,210,702
25	Montgomery County Surcharge	DISTRMD	153,656,756	0	153,656,756	151,299,790	0	151,299,790
26	Sales, Use, & Diesel Fuel Tax	DISTRMD	51,276	0	51,276	51,277	0	51,277
27	Gross Receipts	DISTRMD	10,734,101	0	10,734,101	10,781,377	0	10,781,377
28	VA							
29	Use	DISTROTH	4,692	0	4,692	4,692	0	4,692
30	TOTAL OTHER TAXES		380,997,839	145,817,579	235,180,261	381,485,275	145,142,564	236,342,710

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ELECTRIC DISTRIBUTION

	OTHER TAXES & EXPENSES-26	ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	OTHER TAXES				
1	Payroll Taxes - FICA	OMLESAG	7,191,210	2,926,421	4,264,789
2	Payroll Taxes - MD EE/EA & Storm	DISTRMD	0	0	0
3	MD Property Tax - Subtransmission	STAED	5,955,525	2,503,107	3,452,418
4	DC Property Tax - Subtransmission	STAED	80,340	33,767	46,573
5	VA Property Tax - Subtransmission	STAED	437,731	183,979	253,753
6	Property Taxes - DC	DISTRDC	6,998,557	6,998,557	0
7	Property Taxes - Maryland	DISTRMD	47,744,248	0	47,744,248
8	Property Taxes - SMECO	DISTROTH	71,290	0	71,290
9	Property Taxes - VA	DISTROTH	793	0	793
10	Total Property Taxes		61,288,485	9,719,410	51,569,075
11	Federal Highway Use Tax	OMLESAG	12,006	4,886	7,120
12	DC				
13	Delivery Tax	DISTRDC	80,636,760	80,636,760	0
14	PSOS	DISTRDC	22,153,775	22,153,775	0
15	Use	DISTRDC	282,238	282,238	0
16	PSC	DISTRDC	9,368,170	9,368,170	0
17	RETF/EATF/SETF	DISTRDC	19,047,548	19,047,548	0
18	Ballpark	DISTRDC	183,822	183,822	0
19	Bus Improvement	DISTRDC	0	0	0
20	MD				
21	Environ Surch	DISTRMD	1,942,377	0	1,942,377
22	PSC	DISTRMD	2,431,909	0	2,431,909
23	Delivery Tax	DISTRMD	8,480,806	0	8,480,806
24	Univ Svc	DISTRMD	9,210,702	0	9,210,702
25	Montgomery County Surcharge	DISTRMD	148,650,547	0	148,650,547
26	Sales, Use, & Diesel Fuel Tax	DISTRMD	51,277	0	51,277
27	Gross Receipts	DISTRMD	10,830,478	0	10,830,478
28	VA				
29	Use	DISTROTH	4,692	0	4,692
30	TOTAL OTHER TAXES		381,766,802	144,323,029	237,443,772

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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

			2018			2019		
		ALLOC	TOTAL DISTRIBUTION (1)	DC DISTRIBUTION (2)	OTHER DISTRIBUTION (3)	Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	DEVELOPMENT OF INCOME TAXES-27							
	FEDERAL & STATE TAX CALCULATION							
1	**OPERATING REVENUES**		1,234,354,316	534,838,244	699,516,073	1,247,432,069	529,134,004	718,298,065
2	**OPERATING EXPENSES**							
3	Operation & Maintenance Expense		404,861,879	162,573,819	242,288,060	419,690,814	177,109,697	242,581,116
4	Depreciation and Amortization		212,580,710	109,548,688	103,032,023	233,127,526	121,470,191	111,657,335
5	Taxes Other than Income Tax		363,668,311	147,713,081	215,955,230	378,623,047	145,970,836	232,652,212
6	OPER INC PRE STATE TAX, INTEREST AND FED TAX		253,243,416	115,002,656	138,240,760	215,990,682	84,583,280	131,407,402
7	Less: Interest Expense	STDPLT	105,467,357	53,542,757	51,924,600	109,530,300	55,901,713	53,628,586
8	Int On Cust Deps - DC	DISTRDC	117,241	117,241	0	246,680	246,680	0
9	Int On Cust Deps - MD	DISTRMD	619,847	0	619,847	1,176,256	0	1,176,256
10	Total Interest Expense		106,204,445	53,659,998	52,544,447	110,953,236	56,148,394	54,804,842
11	**FIT ADJUSTMENTS (SCHEDULE M)**							
12	MD Prop Tax Adjustment - MD	DISTRMD	924,254	0	924,254	917,297	0	917,297
13	MD Prop Tax Adjustment Subt	STAED	115,290	48,456	66,833	114,422	48,091	66,330
14	MD Prop Tax Adjustment SMECO	DISTROTH	1,380	0	1,380	1,370	0	1,370
15	MD Prop Tax Adjustment - DC	DISTRDC	0	0	0	0	0	0
16	blank	DISTRMD	0	0	0	0	0	0
17	Pre-81 Removal Cost Flow-Through for Md	DISTRMD	7,990,382	0	7,990,382	4,565,886	0	4,565,886
18	blank	DISTRMD	0	0	0	0	0	0
19	Excess Tax/Book Depreciation (Pre-75)	DEPRE	(4,279,622)	(2,328,154)	(1,951,468)	(4,478,143)	(2,456,832)	(2,021,311)
20	Non-Deductible Meal Exp	OMLESAG	(1,105,428)	(416,621)	(688,807)	(448,081)	(183,192)	(264,889)
21	OPEB Medicare Subsidy	OMLESAGS	0	0	0	0	0	0
22	Control Center AFUDC DC	DISTROTH	0	0	0	0	0	0
23	Control Center AFUDC MD	DISTRMD	0	0	0	0	0	0
24	TOTAL FIT ADJUSTMENTS (SCHEDULE M)		3,646,256	(2,696,319)	6,342,575	672,750	(2,591,933)	3,264,683
25	TAXABLE INCOME FOR STATE		143,392,715	64,038,977	79,353,739	104,364,696	31,026,820	73,337,877
26	**STATE INCOME TAXES**		3,483,706	(3,829,323)	7,313,029	(1,038,696)	(6,361,296)	5,322,600
27	TAXABLE INCOME FOR FED		139,909,009	67,868,300	72,040,710	105,403,392	37,388,116	68,015,277
28	**FEDERAL INCOME TAXES**		29,380,892	14,252,343	15,128,549	22,134,712	7,851,504	14,283,208
29	**FEDERAL EXCESS DEFERRED AMORTIZATION**							
30	Excess Deferred Amortization-Federal (MD Distr)	DISTRMD	(11,627,163)	0	(11,627,163)	(12,609,012)	0	(12,609,012)
31	Excess Deferred Amortization-Federal (DC Distr)	DISTRDC	(13,652,616)	(13,652,616)	0	(18,864,132)	(18,864,132)	0
32	**ITC ADJUSTMENT**							
33	4% + 6% (Post 81) - DC	DISTRDC	(70,057)	(70,057)	0	(70,057)	(70,057)	0
34	4% + 6% (Post 81) - MD	DISTRMD	(54,816)	0	(54,816)	(54,816)	0	(54,816)
35	TOTAL ITC ADJUSTMENT		(124,873)	(70,057)	(54,816)	(124,873)	(70,057)	(54,816)
36	**TOTAL FEDERAL INCOME TAXES**		3,976,240	529,670	3,446,570	(9,463,305)	(11,082,685)	1,619,380
37	**TOTAL INCOME TAXES**		7,459,946	(3,299,653)	10,759,599	(10,502,001)	(17,443,981)	6,941,980
38	**TOTAL EXPENSES**		988,570,846	416,535,935	572,034,911	1,020,939,386	427,106,744	593,832,643
39	**NET OPERATING INCOME**		245,783,470	118,302,309	127,481,161	226,492,683	102,027,261	124,465,422
40	**AFUDC**	ZERO	0	0	0	0	0	0
41	**NET OPERATING INCOME FOR ROR CALCULATION**		245,783,470	118,302,309	127,481,161	226,492,683	102,027,261	124,465,422

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ELECTRIC DISTRIBUTION

	DEVELOPMENT OF INCOME TAXES-27	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	FEDERAL & STATE TAX CALCULATION							
1	**OPERATING REVENUES**		1,250,824,940	530,513,151	720,311,790	1,251,704,071	531,541,850	720,162,221
2	**OPERATING EXPENSES**							
3	Operation & Maintenance Expense		413,199,578	174,657,349	238,542,229	412,833,393	174,001,919	238,831,474
4	Depreciation and Amortization		244,200,571	129,613,374	114,587,197	250,514,886	134,721,995	115,792,891
5	Taxes Other than Income Tax		380,997,839	145,817,579	235,180,261	381,485,275	145,142,564	236,342,710
6	OPER INC PRE STATE TAX, INTEREST AND FED TAX		212,426,952	80,424,849	132,002,103	206,870,517	77,675,372	129,195,146
7	Less: Interest Expense	STDPLT	112,556,431	57,048,994	55,507,437	120,354,006	61,275,037	59,078,969
8	Int On Cust Deps - DC	DISTRDC	249,372	249,372	0	249,372	249,372	0
9	Int On Cust Deps - MD	DISTRMD	1,139,388	0	1,139,388	1,139,388	0	1,139,388
10	Total Interest Expense		113,945,191	57,298,366	56,646,825	121,742,766	61,524,409	60,218,357
11	**FIT ADJUSTMENTS (SCHEDULE M)**							
12	MD Prop Tax Adjustment - MD	DISTRMD	917,297	0	917,297	917,300	0	917,300
13	MD Prop Tax Adjustment Subt	STAED	114,422	48,091	66,330	114,422	48,092	66,331
14	MD Prop Tax Adjustment SMECO	DISTROTH	1,370	0	1,370	1,370	0	1,370
15	MD Prop Tax Adjustment - DC	DISTRDC	0	0	0	0	0	0
16	blank	DISTRMD	0	0	0	0	0	0
17	Pre-81 Removal Cost Flow-Through for Md	DISTRMD	4,145,150	0	4,145,150	4,145,148	0	4,145,148
18	blank	DISTRMD	0	0	0	0	0	0
19	Excess Tax/Book Depreciation (Pre-75)	DEPRE	(4,478,140)	(2,490,714)	(1,987,426)	(4,478,136)	(2,485,952)	(1,992,184)
20	Non-Deductible Meal Exp	OMLESAG	(336,348)	(137,567)	(198,781)	(338,880)	(138,759)	(200,121)
21	OPEB Medicare Subsidy	OMLESAGS	0	0	0	0	0	0
22	Control Center AFUDC DC	DISTROTH	0	0	0	0	0	0
23	Control Center AFUDC MD	DISTRMD	0	0	0	0	0	0
24	TOTAL FIT ADJUSTMENTS (SCHEDULE M)		363,750	(2,580,190)	2,943,940	361,224	(2,576,619)	2,937,843
25	TAXABLE INCOME FOR STATE		98,118,011	25,706,673	72,411,338	84,766,527	18,727,581	66,038,947
26	**STATE INCOME TAXES**		4,716,410	(147,205)	4,863,615	5,993,138	1,801,930	4,191,208
27	TAXABLE INCOME FOR FED		93,401,601	25,853,878	67,547,723	78,773,389	16,925,651	61,847,739
28	**FEDERAL INCOME TAXES**		19,614,336	5,429,314	14,185,022	16,542,412	3,554,387	12,988,025
29	**FEDERAL EXCESS DEFERRED AMORTIZATION**							
30	Excess Deferred Amortization-Federal (MD Distr)	DISTRMD	(12,609,012)	0	(12,609,012)	(12,609,012)	0	(12,609,012)
31	Excess Deferred Amortization-Federal (DC Distr)	DISTRDC	(18,864,132)	(18,864,132)	0	(18,864,132)	(18,864,132)	0
32	**ITC ADJUSTMENT**							
33	4% + 6% (Post 81) - DC	DISTRDC	(70,057)	(70,057)	0	(70,057)	(70,057)	0
34	4% + 6% (Post 81) - MD	DISTRMD	(54,816)	0	(54,816)	(54,816)	0	(54,816)
35	TOTAL ITC ADJUSTMENT		(124,873)	(70,057)	(54,816)	(124,873)	(70,057)	(54,816)
36	**TOTAL FEDERAL INCOME TAXES**		(11,983,681)	(13,504,875)	1,521,194	(15,055,605)	(15,379,802)	324,197
37	**TOTAL INCOME TAXES**		(7,267,271)	(13,652,080)	6,384,809	(9,062,467)	(13,577,872)	4,515,405
38	**TOTAL EXPENSES**		1,031,130,718	436,436,222	594,694,496	1,035,771,086	440,288,606	595,482,480
39	**NET OPERATING INCOME**		219,694,223	94,076,929	125,617,294	215,932,985	91,253,244	124,679,741
40	**AFUDC**	ZERO	0	0	0	0	0	0
41	**NET OPERATING INCOME FOR ROR CALCULATION**		219,694,223	94,076,929	125,617,294	215,932,985	91,253,244	124,679,741

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	DEVELOPMENT OF INCOME TAXES-27	ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	FEDERAL & STATE TAX CALCULATION				
1	**OPERATING REVENUES**		1,252,370,821	532,594,455	719,776,366
2	**OPERATING EXPENSES**				
3	Operation & Maintenance Expense		411,472,014	171,355,966	240,116,048
4	Depreciation and Amortization		269,369,809	145,439,597	123,930,212
5	Taxes Other than Income Tax		381,766,802	144,323,029	237,443,772
6	OPER INC PRE STATE TAX, INTEREST AND FED TAX		189,762,196	71,475,862	118,286,334
7	Less: Interest Expense	STDPLT	129,665,575	66,577,487	63,088,088
8	Int On Cust Deps - DC	DISTRDC	249,372	249,372	0
9	Int On Cust Deps - MD	DISTRMD	1,139,388	0	1,139,388
10	Total Interest Expense		131,054,335	66,826,859	64,227,476
11	**FIT ADJUSTMENTS (SCHEDULE M)**				
12	MD Prop Tax Adjustment - MD	DISTRMD	917,300	0	917,300
13	MD Prop Tax Adjustment Subt	STAED	114,422	48,092	66,331
14	MD Prop Tax Adjustment SMECO	DISTROTH	1,370	0	1,370
15	MD Prop Tax Adjustment - DC	DISTRDC	0	0	0
16	blank	DISTRMD	0	0	0
17	Pre-81 Removal Cost Flow-Through for Md	DISTRMD	4,145,148	0	4,145,148
18	blank	DISTRMD	0	0	0
19	Excess Tax/Book Depreciation (Pre-75)	DEPRE	(4,478,136)	(2,491,528)	(1,986,608)
20	Non-Deductible Meal Exp	OMLESAG	(340,800)	(138,687)	(202,113)
21	OPEB Medicare Subsidy	OMLESAGS	0	0	0
22	Control Center AFUDC DC	DISTROTH	0	0	0
23	Control Center AFUDC MD	DISTRMD	0	0	0
24	TOTAL FIT ADJUSTMENTS (SCHEDULE M)		359,304	(2,582,123)	2,941,427
25	TAXABLE INCOME FOR STATE		58,348,557	7,231,126	51,117,431
26	**STATE INCOME TAXES**		4,974,219	2,109,265	2,864,954
27	TAXABLE INCOME FOR FED		53,374,338	5,121,861	48,252,477
28	**FEDERAL INCOME TAXES**		11,208,611	1,075,591	10,133,020
29	**FEDERAL EXCESS DEFERRED AMORTIZATION**				
30	Excess Deferred Amortization-Federal (MD Distr)	DISTRMD	(12,609,012)	0	(12,609,012)
31	Excess Deferred Amortization-Federal (DC Distr)	DISTRDC	(18,864,132)	(18,864,132)	0
32	**ITC ADJUSTMENT**				
33	4% + 6% (Post 81) - DC	DISTRDC	(70,057)	(70,057)	0
34	4% + 6% (Post 81) - MD	DISTRMD	(54,816)	0	(54,816)
35	TOTAL ITC ADJUSTMENT		(124,873)	(70,057)	(54,816)
36	**TOTAL FEDERAL INCOME TAXES**		(20,389,406)	(17,858,598)	(2,530,808)
37	**TOTAL INCOME TAXES**		(15,415,187)	(15,749,333)	334,146
38	**TOTAL EXPENSES**		1,047,193,438	445,369,259	601,824,179
39	**NET OPERATING INCOME**		205,177,383	87,225,195	117,952,188
40	**AFUDC**	ZERO	0	0	0
41	**NET OPERATING INCOME FOR ROR CALCULATION**		205,177,383	87,225,195	117,952,188

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	OPERATION & MAINTENANCE EXP-28	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	DEVELOPMENT OF OPERATION & MAINTENANCE							
	DISTRIBUTION EXPENSES							
	Storm Costs - Direct DC							
	OPERATION							
1	958100 Load dispatching	DISTRDC	0	0	0	0	0	0
1	958200 Station Expenses	DISTRDC	0	0	0	0	0	0
2	589 rents	DISTRDC	233,540	233,540	0	607,532	607,532	0
3	958800 Miscellaneous distribution expenses	DISTRDC	(3,166,012)	(3,166,012)	0	329,258	329,258	0
4	TOTAL OPERATION		233,540	233,540	0	607,532	607,532	0
	MAINTENANCE							
5	959200 Station expenses	DISTRDC	0	0	0	0	0	0
6	959300 Maintain overhead lines	DISTRDC	3,270,517	3,270,517	0	4,325,251	4,325,251	0
7	TOTAL MAINTENANCE		3,270,517	3,270,517	0	4,325,251	4,325,251	0
	Storm Costs - Direct MD							
	OPERATION							
8	958100 Load dispatching	DISTRMD	3,650	0	3,650	3,042	0	3,042
9	958200 Station expenses	DISTRMD	0	0	0	0	0	0
10	958300 Overhead line expenses	DISTRMD	0	0	0	0	0	0
11	958800 Miscellaneous distribution expenses	DISTRMD	374,684	0	374,684	319,022	0	319,022
12	TOTAL OPERATION		3,650	0	3,650	3,042	0	3,042
	MAINTENANCE							
13	959200 Station expenses	DISTRMD	30,422	0	30,422	28,344	0	28,344
14	959300 Maintain overhead lines	DISTRMD	25,579,008	0	25,579,008	19,371,337	0	19,371,337
15	TOTAL MAINTENANCE		25,609,430	0	25,609,430	19,399,681	0	19,399,681

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

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	OPERATION & MAINTENANCE EXP-28	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	DEVELOPMENT OF OPERATION & MAINTENANCE							
	DISTRIBUTION EXPENSES							
	Storm Costs - Direct DC							
	OPERATION							
1	958100 Load dispatching	DISTRDC	0	0	0	0	0	0
1	958200 Station Expenses	DISTRDC	0	0	0	0	0	0
2	589 rents	DISTRDC	607,532	607,532	0	607,532	607,532	0
3	958800 Miscellaneous distribution expenses	DISTRDC	329,258	329,258	0	329,258	329,258	0
4	TOTAL OPERATION		607,532	607,532	0	607,532	607,532	0
	MAINTENANCE							
5	959200 Station expenses	DISTRDC	0	0	0	0	0	0
6	959300 Maintain overhead lines	DISTRDC	4,493,824	4,493,824	0	4,558,692	4,558,692	0
7	TOTAL MAINTENANCE		4,493,824	4,493,824	0	4,558,692	4,558,692	0
	Storm Costs - Direct MD							
	OPERATION							
8	958100 Load dispatching	DISTRMD	304	0	304	0	0	0
9	958200 Station expenses	DISTRMD	0	0	0	0	0	0
10	958300 Overhead line expenses	DISTRMD	0	0	0	0	0	0
11	958800 Miscellaneous distribution expenses	DISTRMD	263,360	0	263,360	241,413	0	241,413
12	TOTAL OPERATION		304	0	304	0	0	0
	MAINTENANCE							
13	959200 Station expenses	DISTRMD	28,344	0	28,344	27,360	0	27,360
14	959300 Maintain overhead lines	DISTRMD	20,592,818	0	20,592,818	20,635,564	0	20,635,564
15	TOTAL MAINTENANCE		20,621,162	0	20,621,162	20,662,924	0	20,662,924

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lultiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	OPERATION & MAINTENANCE EXP-28	ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	DEVELOPMENT OF OPERATION & MAINTENANCE				
	DISTRIBUTION EXPENSES				
	Storm Costs - Direct DC				
	OPERATION				
1	958100 Load dispatching	DISTRDC	0	0	0
1	958200 Station Expenses	DISTRDC	0	0	0
2	589 rents	DISTRDC	607,532	607,532	0
3	958800 Miscellaneous distribution expenses	DISTRDC	329,258	329,258	0
4	TOTAL OPERATION		607,532	607,532	0
	MAINTENANCE				
5	959200 Station expenses	DISTRDC	0	0	0
6	959300 Maintain overhead lines	DISTRDC	4,637,575	4,637,575	0
7	TOTAL MAINTENANCE		4,637,575	4,637,575	0
	Storm Costs - Direct MD				
	OPERATION				
8	958100 Load dispatching	DISTRMD	0	0	0
9	958200 Station expenses	DISTRMD	0	0	0
10	958300 Overhead line expenses	DISTRMD	0	0	0
11	958800 Miscellaneous distribution expenses	DISTRMD	0	0	0
12	TOTAL OPERATION		0	0	0
	MAINTENANCE				
13	959200 Station expenses	DISTRMD	13,778	0	13,778
14	959300 Maintain overhead lines	DISTRMD	20,918,886	0	20,918,886
15	TOTAL MAINTENANCE		20,932,664	0	20,932,664

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

			2018			2019		
		ALLOC	TOTAL DISTRIBUTION (1)	DC DISTRIBUTION (2)	OTHER DISTRIBUTION (3)	Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	OPERATION & MAINTENANCE EXP-29							
	DISTRIBUTION EXPENSES LESS STORM COSTS							
	OPERATION							
1	958000 Operation Supervision & Engineering	OMOPER	3,407,994	1,652,578	1,755,416	4,043,758	2,437,637	1,606,121
2	Direct to Maryland	DISTRMD	232,286	0	232,286	0	0	0
3	Direct to DC	DISTRDC	67,828	67,828	0	0	0	0
4	Total 958000		3,708,109	1,720,406	1,987,702	4,043,758	2,437,637	1,606,121
5	958100 Load dispatching							
6	Allocable	PLTDACTS	5,621,785	2,858,015	2,763,770	7,536,957	3,844,834	3,692,123
7	Direct to Maryland	DISTRMD	0	0	0	0	0	0
8	Total 958100		5,621,785	2,858,015	2,763,770	7,536,957	3,844,834	3,692,123
9	958200 Station expenses							
10	Subtransmission	PLTSUBT	335,732	140,233	195,499	293,212	122,473	170,739
11	Substations	PLTSUBS	947,033	530,659	416,374	827,094	437,072	390,022
12	Direct to Maryland	DISTRMD	8,278	0	8,278	306,833	0	306,833
13	Direct to DC	DISTRDC	1,295	1,295	0	638,247	638,247	0
14	Total 958200		1,292,337	672,186	620,151	2,065,386	1,197,792	867,594
15	958300 Overhead line expenses							
16	Direct to DC	DISTRDC	1,675	1,675	0	2,785,033	2,785,033	0
17	Direct to Maryland	DISTRMD	162,129	0	162,129	959,665	0	959,665
18	Subtransmission	STAED	66,459	27,933	38,526	29,795	12,523	17,272
19	Subtransmission - SMECO	DISTROTH	640	0	640	287	0	287
20	OH Lines	PLTOH	817,146	196,504	620,642	366,346	89,307	277,039
21	Total 958300		1,048,048	226,111	821,937	4,141,126	2,886,863	1,254,263
22	958400 Underground line expenses							
23	Subtransmission	STAED	98,657	41,465	57,191	75,325	31,659	43,666
24	Subtransmission - SMECO	DISTROTH	166	0	166	127	0	127
25	UG Lines	PLTUG	836,761	522,534	314,227	638,874	405,824	233,050
26	UG Services	PLTUGS	156,052	95,338	60,714	119,147	73,159	45,988
27	UG Line expenses- DC	DISTRDC	2,634,334	2,634,334	0	11,337,324	11,337,324	0
28	UG Line expenses- MD	DISTRMD	1,948,432	0	1,948,432	2,685,403	0	2,685,403
29	Total 958400		5,674,402	3,293,671	2,380,730	14,856,200	11,847,966	3,008,234
30	958500 Street lighting - MD	DISTRMD	634,821	0	634,821	775,000	0	775,000
31	958600 Meter expenses	PLANT370	1,963,677	826,196	1,137,481	2,368,708	1,030,466	1,338,242
32	958600 Meter expenses - MD	DISTRMD	2,710,199	0	2,710,199	2,069,992	0	2,069,992
33	958600 Meter expenses - DC	DISTRDC	2,277,960	2,277,960	0	2,483,951	2,483,951	0
34	Total 958600		6,951,837	3,104,157	3,847,680	6,922,651	3,514,417	3,408,234
35	958700 Customer installations expenses	PLANT371	92,056	47,565	44,491	151,034	78,039	72,995
36	958700 Customer installations expenses -MD	DISTRMD	4,961,749	0	4,961,749	4,831,460	0	4,831,460
37	958700 Customer installations expenses -DC	DISTRDC	3,385,160	3,385,160	0	3,064,400	3,064,400	0
38	Total 958700		8,438,964	3,432,725	5,006,239	8,046,894	3,142,439	4,904,455
39	958800 Miscellaneous distribution expenses	OMOPER	7,089,091	3,437,587	3,651,504	4,421,572	2,665,388	1,756,184
40	958801 Miscellaneous dist- MD- debit/credit	DISTRMD	0	0	0	0	0	0
41	958800 Miscellaneous distr - Maryland	DISTRMD	2,268,641	0	2,268,641	595,529	0	595,529
42	958800 Miscellaneous distr - DC	DISTRDC	2,613,106	2,613,106	0	1,490,772	1,490,772	0
43	Total 958800		11,970,838	6,050,693	5,920,146	6,507,873	4,156,160	2,351,713
44	958900 Rents							
45	Distribution	STDPLT	7,612,847	3,864,824	3,748,022	7,809,085	3,985,575	3,823,510
46	Substations	DISTRDC	1,275,028	1,275,028	0	2,882,436	2,882,436	0
47	95890C Rents- DC	DISTRDC	121,361	121,361	0	264,907	264,907	0
48	95890M Rents- MD	DISTRMD	197,623	0	197,623	383,520	0	383,520
49	Total 958900		9,206,858	5,261,213	3,945,646	11,339,948	7,132,918	4,207,030
50	TOTAL OPERATION		54,548,000	26,619,177	27,928,822	66,235,793	40,161,026	26,074,767

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ELECTRIC DISTRIBUTION

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	OPERATION & MAINTENANCE EXP-29							
	DISTRIBUTION EXPENSES LESS STORM COSTS							
	OPERATION							
1	958000 Operation Supervision & Engineering	OMOPER	4,124,435	2,575,745	1,548,690	4,147,287	2,600,843	1,546,444
2	Direct to Maryland	DISTRMD	0	0	0	0	0	0
3	Direct to DC	DISTRDC	0	0	0	0	0	0
4	Total 958000		4,124,435	2,575,745	1,548,690	4,147,287	2,600,843	1,546,444
5	958100 Load dispatching							
6	Allocable	PLTDACTS	7,985,858	4,131,982	3,853,876	7,919,806	4,096,412	3,823,394
7	Direct to Maryland	DISTRMD	0	0	0	0	0	0
8	Total 958100		7,985,858	4,131,982	3,853,876	7,919,806	4,096,412	3,823,394
9	958200 Station expenses							
10	Subtransmission	PLTSUBT	330,913	138,228	192,685	300,368	125,610	174,758
11	Substations	PLTSUBS	933,438	475,407	458,032	847,280	403,857	443,422
12	Direct to Maryland	DISTRMD	339,969	0	339,969	330,767	0	330,767
13	Direct to DC	DISTRDC	679,013	679,013	0	330,609	330,609	0
14	Total 958200		2,283,333	1,292,647	990,686	1,809,024	860,077	948,947
15	958300 Overhead line expenses							
16	Direct to DC	DISTRDC	2,895,505	2,895,505	0	3,054,698	3,054,698	0
17	Direct to Maryland	DISTRMD	1,054,562	0	1,054,562	1,179,334	0	1,179,334
18	Subtransmission	STAED	26,017	10,935	15,082	25,392	10,672	14,719
19	Subtransmission - SMECO	DISTROTH	250	0	250	244	0	244
20	OH Lines	PLTOH	319,897	81,500	238,397	312,202	83,091	229,111
21	Total 958300		4,296,232	2,987,941	1,308,291	4,571,870	3,148,462	1,423,408
22	958400 Underground line expenses							
23	Subtransmission	STAED	72,123	30,313	41,810	71,709	30,139	41,570
24	Subtransmission - SMECO	DISTROTH	121	0	121	121	0	121
25	UG Lines	PLTUG	611,714	395,462	216,252	608,201	399,833	208,368
26	UG Services	PLTUGS	114,082	71,176	42,907	113,427	71,124	42,303
27	UG Line expenses- DC	DISTRDC	11,162,352	11,162,352	0	11,726,227	11,726,227	0
28	UG Line expenses- MD	DISTRMD	2,716,122	0	2,716,122	2,700,667	0	2,700,667
29	Total 958400		14,676,515	11,659,303	3,017,212	15,220,352	12,227,323	2,993,029
30	958500 Street lighting - MD	DISTRMD	776,500	0	776,500	776,500	0	776,500
31	958600 Meter expenses	PLANT370	2,470,217	1,129,468	1,340,749	2,521,491	1,192,955	1,328,536
32	958600 Meter expenses - MD	DISTRMD	2,024,320	0	2,024,320	2,045,030	0	2,045,030
33	958600 Meter expenses - DC	DISTRDC	2,473,948	2,473,948	0	2,494,484	2,494,484	0
34	Total 958600		6,968,485	3,603,416	3,365,069	7,061,005	3,687,439	3,373,566
35	958700 Customer installations expenses	PLANT371	155,313	80,250	75,063	154,749	79,959	74,790
36	958700 Customer installations expenses -MD	DISTRMD	4,389,660	0	4,389,660	4,460,931	0	4,460,931
37	958700 Customer installations expenses -DC	DISTRDC	3,194,911	3,194,911	0	3,264,973	3,264,973	0
38	Total 958700		7,739,884	3,275,161	4,464,723	7,880,653	3,344,932	4,535,721
39	958800 Miscellaneous distribution expenses	OMOPER	6,335,151	3,956,357	2,378,794	4,863,444	3,049,959	1,813,485
40	958801 Miscellaneous dist- MD- debit/credit	DISTRMD	0	0	0	0	0	0
41	958800 Miscellaneous distr - Maryland	DISTRMD	613,459	0	613,459	623,631	0	623,631
42	958800 Miscellaneous distr - DC	DISTRDC	1,428,599	1,428,599	0	1,566,811	1,566,811	0
43	Total 958800		8,377,209	5,384,956	2,992,253	7,053,886	4,616,770	2,437,116
44	958900 Rents							
45	Distribution	STDPLT	0	0	0	0	0	0
46	Substations	DISTRDC	2,975,199	2,975,199	0	3,065,425	3,065,425	0
47	95890C Rents- DC	DISTRDC	282,494	282,494	0	285,530	285,530	0
48	95890M Rents- MD	DISTRMD	386,554	0	386,554	388,717	0	388,717
49	Total 958900		3,644,247	3,257,693	386,554	3,739,672	3,350,955	388,717
50	TOTAL OPERATION		60,872,698	38,168,845	22,703,853	60,180,055	37,933,212	22,246,843

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Iultiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	OPERATION & MAINTENANCE EXP-29				
	DISTRIBUTION EXPENSES LESS STORM COSTS				
	OPERATION				
1	958000 Operation Supervision & Engineering	OMOPER	4,209,171	2,633,553	1,575,618
2	Direct to Maryland	DISTRMD	0	0	0
3	Direct to DC	DISTRDC	0	0	0
4	Total 958000		4,209,171	2,633,553	1,575,618
5	958100 Load dispatching				
6	Allocable	PLTDACTS	8,036,886	4,165,189	3,871,697
7	Direct to Maryland	DISTRMD	0	0	0
8	Total 958100		8,036,886	4,165,189	3,871,697
9	958200 Station expenses				
10	Subtransmission	PLTSUBT	304,476	127,411	177,066
11	Substations	PLTSUBS	858,867	385,539	473,328
12	Direct to Maryland	DISTRMD	342,494	0	342,494
13	Direct to DC	DISTRDC	347,955	347,955	0
14	Total 958200		1,853,792	860,904	992,888
15	958300 Overhead line expenses				
16	Direct to DC	DISTRDC	3,214,736	3,214,736	0
17	Direct to Maryland	DISTRMD	1,264,286	0	1,264,286
18	Subtransmission	STAED	26,297	11,053	15,244
19	Subtransmission - SMECO	DISTROTH	253	0	253
20	OH Lines	PLTOH	323,332	89,532	233,800
21	Total 958300		4,828,904	3,315,321	1,513,583
22	958400 Underground line expenses				
23	Subtransmission	STAED	73,841	31,035	42,806
24	Subtransmission - SMECO	DISTROTH	124	0	124
25	UG Lines	PLTUG	626,285	418,306	207,979
26	UG Services	PLTUGS	116,800	73,785	43,015
27	UG Line expenses- DC	DISTRDC	11,659,627	11,659,627	0
28	UG Line expenses- MD	DISTRMD	2,722,612	0	2,722,612
29	Total 958400		15,199,289	12,182,753	3,016,536
30	958500 Street lighting - MD	DISTRMD	776,500	0	776,500
31	958600 Meter expenses	PLANT370	2,576,345	1,262,857	1,313,488
32	958600 Meter expenses - MD	DISTRMD	2,082,052	0	2,082,052
33	958600 Meter expenses - DC	DISTRDC	2,404,555	2,404,555	0
34	Total 958600		7,062,952	3,667,412	3,395,540
35	958700 Customer installations expenses	PLANT371	158,040	81,659	76,381
36	958700 Customer installations expenses -MD	DISTRMD	4,546,355	0	4,546,355
37	958700 Customer installations expenses -DC	DISTRDC	3,334,919	3,334,919	0
38	Total 958700		8,039,314	3,416,578	4,622,736
39	958800 Miscellaneous distribution expenses	OMOPER	3,480,453	2,177,616	1,302,837
40	958801 Miscellaneous dist- MD- debit/credit	DISTRMD	0	0	0
41	958800 Miscellaneous distr - Maryland	DISTRMD	632,301	0	632,301
42	958800 Miscellaneous distr - DC	DISTRDC	1,593,408	1,593,408	0
43	Total 958800		5,706,162	3,771,024	1,935,138
44	958900 Rents				
45	Distribution	STDPLT	0	0	0
46	Substations	DISTRDC	3,159,389	3,159,389	0
47	95890C Rents- DC	DISTRDC	289,428	289,428	0
48	95890M Rents- MD	DISTRMD	391,479	0	391,479
49	Total 958900		3,840,296	3,448,817	391,479
50	TOTAL OPERATION		59,553,266	37,461,551	22,091,715

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ELECTRIC DISTRIBUTION

	OPERATION & MAINTENANCE EXP-30	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	MAINTENANCE							
1	959000 Maintenance Supervision & Engineering	OMMAINTN	485,659	233,415	252,244	735,108	288,091	447,017
2	Direct to Maryland	DISTRMD	297,151	0	297,151	0	0	0
3	959100 Maintain Structures	PLTSUBS	13,536	7,585	5,951	218,839	115,644	103,195
4	959200 Station expenses							
5	Subtransmission	PLTSUBT	1,148,698	479,802	668,896	3,578,849	1,494,867	2,083,983
6	Substations	PLTSUBS	3,240,247	1,815,634	1,424,613	10,095,221	5,334,751	4,760,470
7	Direct to Maryland	DISTRMD	5,975,780	0	5,975,780	3,228,208	0	3,228,208
8	Direct to DC	DISTRDC	6,597,727	6,597,727	0	2,020,328	2,020,328	0
9	Total 959200		16,962,451	8,893,163	8,069,288	18,922,606	8,849,946	10,072,660
	959300 Maintain overhead lines							
10	Subtransmission	STAED	177,658	74,670	102,988	100,689	42,319	58,369
11	Subtransmission - SMECO	DISTROTH	1,710	0	1,710	969	0	969
12	OH Lines	PLTOH	2,184,401	525,296	1,659,105	1,238,019	301,802	936,217
13	OH Services	PLTOHS	139,315	34,447	104,868	78,958	23,420	55,538
14	Direct to Maryland	DISTRMD	7,381,852	0	7,381,852	11,880,766	0	11,880,766
15	Direct to DC	DISTRDC	3,648,368	3,648,368	0	3,188,312	3,188,312	0
16	Total 959300		13,533,305	4,282,780	9,250,524	16,487,713	3,555,854	12,931,860
	959400 Maintain underground line							
17	Subtransmission	STAED	547,579	230,147	317,432	687,617	289,005	398,612
18	Subtransmission - SMECO	DISTROTH	922	0	922	1,158	0	1,158
19	UG Lines	PLTUG	4,644,314	2,900,247	1,744,067	5,832,054	3,704,622	2,127,432
20	UG Services	PLTUGS	866,145	529,159	336,986	1,087,654	667,842	419,812
21	Direct to Maryland	DISTRMD	6,389,800	0	6,389,800	2,977,833	0	2,977,833
22	Direct to DC	DISTRDC	10,249,298	10,249,298	0	3,897,567	3,897,567	0
23	Total 959400		22,698,059	13,908,851	8,789,208	14,483,883	8,559,036	5,924,847
	959500 Maintain line transformers							
24	Allocable	PLANT368	2,933,730	1,486,941	1,446,788	1,249,171	645,639	603,532
25	Direct to Maryland	DISTRMD	1,015,568	0	1,015,568	468,476	0	468,476
26	Direct to DC	DISTRDC	2,496,370	2,496,370	0	237,703	237,703	0
27	Total 959500		6,445,668	3,983,312	2,462,356	1,955,350	883,342	1,072,008
	959600 Maintain street lighting & signal systems							
28	Allocable	OM596SL	(144)	(8)	(136)	239,063	13,151	225,912
29	Direct to Maryland	DISTRMD	4,877,787	0	4,877,787	3,758,745	0	3,758,745
30	Direct to DC	DISTRDC	1,348	1,348	0	0	0	0
31	Total 959600		4,878,991	1,340	4,877,651	3,997,808	13,151	3,984,657
32	959700 Maintain meters	PLANT370	804,317	338,408	465,909	723,469	314,733	408,736
33	Direct to Maryland	DISTRMD	33,651	0	33,651	90,944	0	90,944
34	Direct to DC	DISTRDC	4,450	4,450	0	0	0	0
35	Total 959700		842,418	342,858	499,561	814,413	314,733	499,680
36	959800 Maintain distribution plant	OMMAINTN	1,199,907	576,692	623,214	4,650,571	1,822,575	2,827,996
37	95980M Maintain distribution plant- MD	DISTRMD	446,370	0	446,370	53,549	0	53,549
38	95980C Maintain distribution plant- DC	DISTRDC	616,276	616,276	0	53,549	53,549	0
39	95980Y Maintain Distribution Plant-Acctg Policy Harmon	OMMAINTN	0	0	0	0	0	0
40	Total 959800		2,262,553	1,192,968	1,069,584	4,757,669	1,876,124	2,881,545
41	TOTAL MAINTENANCE		68,419,791	32,846,273	35,573,518	62,373,389	24,455,920	37,917,470
42	TOTAL DISTR. EXPENSE LESS STORM & TREE		122,967,791	59,465,450	63,502,341	128,609,182	64,616,946	63,992,236

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ELECTRIC DISTRIBUTION

	OPERATION & MAINTENANCE EXP-30	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	MAINTENANCE							
1	959000 Maintenance Supervision & Engineering	OMMAINTN	734,780	287,868	446,912	682,597	266,293	416,304
2	Direct to Maryland	DISTRMD	0	0	0	0	0	0
3	959100 Maintain Structures	PLTSUBS	262,875	133,884	128,991	252,584	120,395	132,189
4	959200 Station expenses							
5	Subtransmission	PLTSUBT	3,485,867	1,456,103	2,029,764	3,664,597	1,532,490	2,132,107
6	Substations	PLTSUBS	9,832,935	5,007,984	4,824,951	10,337,098	4,927,197	5,409,901
7	Direct to Maryland	DISTRMD	2,730,687	0	2,730,687	2,914,088	0	2,914,088
8	Direct to DC	DISTRDC	1,891,868	1,891,868	0	2,384,340	2,384,340	0
9	Total 959200		17,941,357	8,355,955	9,585,402	19,300,123	8,844,027	10,456,096
	959300 Maintain overhead lines							
10	Subtransmission	STAED	101,160	42,518	58,643	101,289	42,572	58,717
11	Subtransmission - SMECO	DISTROTH	974	0	974	975	0	975
12	OH Lines	PLTOH	1,243,817	316,888	926,929	1,245,403	331,460	913,944
13	OH Services	PLTOHS	79,327	28,240	51,087	79,429	31,773	47,655
14	Direct to Maryland	DISTRMD	12,949,689	0	12,949,689	13,077,291	0	13,077,291
15	Direct to DC	DISTRDC	3,027,542	3,027,542	0	2,644,842	2,644,842	0
16	Total 959300		17,402,509	3,415,188	13,987,321	17,149,229	3,050,647	14,098,582
	959400 Maintain underground line							
17	Subtransmission	STAED	686,207	288,413	397,794	724,388	304,460	419,928
18	Subtransmission - SMECO	DISTROTH	1,156	0	1,156	1,220	0	1,220
19	UG Lines	PLTUG	5,820,093	3,762,585	2,057,508	6,143,924	4,039,029	2,104,895
20	UG Services	PLTUGS	1,085,423	677,193	408,230	1,145,816	718,483	427,334
21	Direct to Maryland	DISTRMD	2,942,061	0	2,942,061	3,009,777	0	3,009,777
22	Direct to DC	DISTRDC	3,986,858	3,986,858	0	4,078,041	4,078,041	0
23	Total 959400		14,521,798	8,715,049	5,806,749	15,103,166	9,140,013	5,963,153
	959500 Maintain line transformers							
24	Allocable	PLANT368	1,317,239	706,031	611,208	1,350,578	733,161	617,417
25	Direct to Maryland	DISTRMD	38,857	0	38,857	35,344	0	35,344
26	Direct to DC	DISTRDC	244,594	244,594	0	254,835	254,835	0
27	Total 959500		1,600,690	950,625	650,065	1,640,757	987,996	652,761
	959600 Maintain street lighting & signal systems							
28	Allocable	OM596SL	239,670	13,184	226,486	240,039	13,204	226,835
29	Direct to Maryland	DISTRMD	3,119,391	0	3,119,391	3,129,144	0	3,129,144
30	Direct to DC	DISTRDC	0	0	0	0	0	0
31	Total 959600		3,359,061	13,184	3,345,877	3,369,183	13,204	3,355,979
32	959700 Maintain meters	PLANT370	542,784	248,179	294,605	554,293	262,244	292,049
33	Direct to Maryland	DISTRMD	94,948	0	94,948	96,813	0	96,813
34	Direct to DC	DISTRDC	0	0	0	0	0	0
35	Total 959700		637,732	248,179	389,553	651,106	262,244	388,862
36	959800 Maintain distribution plant	OMMAINTN	5,147,640	2,016,717	3,130,923	5,242,181	2,045,064	3,197,117
37	95980M Maintain distribution plant- MD	DISTRMD	54,141	0	54,141	54,205	0	54,205
38	95980C Maintain distribution plant- DC	DISTRDC	54,141	54,141	0	54,205	54,205	0
39	95980Y Maintain Distribution Plant-Acctg Policy Harmon	OMMAINTN	0	0	0	0	0	0
40	Total 959800		5,255,922	2,070,858	3,185,064	5,350,591	2,099,269	3,251,322
41	TOTAL MAINTENANCE		61,716,724	24,190,791	37,525,933	63,499,336	24,784,087	38,715,249
42	TOTAL DISTR. EXPENSE LESS STORM & TREE		122,589,422	62,359,635	60,229,787	123,679,391	62,717,299	60,962,092

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ELECTRIC DISTRIBUTION

	OPERATION & MAINTENANCE EXP-30	ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	MAINTENANCE				
1	959000 Maintenance Supervision & Engineering	OMMAINTN	687,944	261,786	426,158
2	Direct to Maryland	DISTRMD	0	0	0
3	959100 Maintain Structures	PLTSUBS	262,495	117,832	144,663
4	959200 Station expenses				
5	Subtransmission	PLTSUBT	3,754,278	1,571,010	2,183,268
6	Substations	PLTSUBS	10,590,071	4,753,801	5,836,269
7	Direct to Maryland	DISTRMD	2,937,100	0	2,937,100
8	Direct to DC	DISTRDC	2,341,706	2,341,706	0
9	Total 959200		19,623,155	8,666,517	10,956,638
	959300 Maintain overhead lines				
10	Subtransmission	STAED	101,421	42,627	58,794
11	Subtransmission - SMECO	DISTROTH	976	0	976
12	OH Lines	PLTOH	1,247,028	345,308	901,721
13	OH Services	PLTOHS	79,532	35,265	44,267
14	Direct to Maryland	DISTRMD	13,831,188	0	13,831,188
15	Direct to DC	DISTRDC	2,439,654	2,439,654	0
16	Total 959300		17,699,800	2,862,854	14,836,946
	959400 Maintain underground line				
17	Subtransmission	STAED	736,704	309,637	427,067
18	Subtransmission - SMECO	DISTROTH	1,241	0	1,241
19	UG Lines	PLTUG	6,248,386	4,173,401	2,074,985
20	UG Services	PLTUGS	1,165,298	736,144	429,154
21	Direct to Maryland	DISTRMD	3,083,165	0	3,083,165
22	Direct to DC	DISTRDC	4,159,046	4,159,046	0
23	Total 959400		15,393,840	9,378,227	6,015,613
	959500 Maintain line transformers				
24	Allocable	PLANT368	1,379,771	761,271	618,500
25	Direct to Maryland	DISTRMD	35,299	0	35,299
26	Direct to DC	DISTRDC	254,655	254,655	0
27	Total 959500		1,669,725	1,015,926	653,799
	959600 Maintain street lighting & signal systems				
28	Allocable	OM596SL	240,406	13,225	227,181
29	Direct to Maryland	DISTRMD	3,132,011	0	3,132,011
30	Direct to DC	DISTRDC	0	0	0
31	Total 959600		3,372,417	13,225	3,359,192
32	959700 Maintain meters	PLANT370	566,661	277,762	288,899
33	Direct to Maryland	DISTRMD	98,877	0	98,877
34	Direct to DC	DISTRDC	0	0	0
35	Total 959700		665,538	277,762	387,776
36	959800 Maintain distribution plant	OMMAINTN	5,390,212	2,051,155	3,339,057
37	95980M Maintain distribution plant- MD	DISTRMD	54,126	0	54,126
38	95980C Maintain distribution plant- DC	DISTRDC	54,126	54,126	0
39	95980Y Maintain Distribution Plant-Acctg Policy Harmon	OMMAINTN	0	0	0
40	Total 959800		5,498,464	2,105,281	3,393,183
41	TOTAL MAINTENANCE		64,873,378	24,699,409	40,173,968
42	TOTAL DISTR. EXPENSE LESS STORM & TREE		124,426,644	62,160,961	62,265,683

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ELECTRIC DISTRIBUTION

	OPERATION & MAINTENANCE EXP-31	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	DISTRIBUTION EXPENSES - TOTAL							
	OPERATION							
1	958000 Operation Supervision & Engineering		3,708,109	1,720,406	1,987,702	4,043,758	2,437,637	1,606,121
2	958100 Load dispatching		5,625,435	2,858,015	2,767,420	7,539,999	3,844,834	3,695,165
3	958200 Station expenses		1,292,337	672,186	620,151	2,065,386	1,197,792	867,594
4	958300 Overhead line expenses		1,048,048	226,111	821,937	4,141,126	2,886,863	1,254,263
5	958400 Underground line expenses		5,674,402	3,293,671	2,380,730	14,856,200	11,847,966	3,008,234
6	958500 Street lighting		634,821	0	634,821	775,000	0	775,000
7	958600 Meter expenses		6,951,837	3,104,157	3,847,680	6,922,651	3,514,417	3,408,234
8	958700 Customer installations expenses		8,438,964	3,432,725	5,006,239	8,046,894	3,142,439	4,904,455
9	958800 Miscellaneous distribution expenses		9,179,511	2,884,680	6,294,830	7,156,153	4,485,419	2,670,735
10	958900 Rents Control Center		9,440,399	5,494,753	3,945,646	11,947,480	7,740,450	4,207,030
11	TOTAL OPERATION		51,993,862	23,686,705	28,307,157	67,494,647	41,097,816	26,396,831
12	**MAINTENANCE**							
13	959000 Maintenance Supervision & Engineering		782,810	233,415	549,395	735,108	288,091	447,017
14	959100 Maintenance Structures		13,536	7,585	5,951	218,839	115,644	103,195
15	959200 Maintain equipment		16,992,873	8,893,163	8,099,710	18,950,950	8,849,946	10,101,004
16	959300 Maintain overhead lines		42,382,829	7,553,298	34,829,532	40,184,302	7,881,105	32,303,197
17	959400 Maintain underground line		22,698,059	13,908,851	8,789,208	14,483,883	8,559,036	5,924,847
18	959500 Maintain line transformers		6,445,668	3,983,312	2,462,356	1,955,350	883,342	1,072,008
19	959600 Maintain street lighting & signal sys		4,878,991	1,340	4,877,651	3,997,808	13,151	3,984,657
20	959700 Maintain meters		842,418	342,858	499,561	814,413	314,733	499,680
21	959800 Maintain distribution plant		2,262,553	1,192,968	1,069,584	4,757,669	1,876,124	2,881,545
22	TOTAL MAINTENANCE		97,299,738	36,116,790	61,182,948	86,098,321	28,781,171	57,317,151
23	TOTAL DISTRIBUTION EXPENSES		149,293,601	59,803,495	89,490,105	153,592,968	69,878,987	83,713,981

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ELECTRIC DISTRIBUTION

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	OPERATION & MAINTENANCE EXP-31	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	DISTRIBUTION EXPENSES - TOTAL							
	OPERATION							
1	958000 Operation Supervision & Engineering		4,124,435	2,575,745	1,548,690	4,147,287	2,600,843	1,546,444
2	958100 Load dispatching		7,986,162	4,131,982	3,854,180	7,919,806	4,096,412	3,823,394
3	958200 Station expenses		2,283,333	1,292,647	990,686	1,809,024	860,077	948,947
4	958300 Overhead line expenses		4,296,232	2,987,941	1,308,291	4,571,870	3,148,462	1,423,408
5	958400 Underground line expenses		14,676,515	11,659,303	3,017,212	15,220,352	12,227,323	2,993,029
6	958500 Street lighting		776,500	0	776,500	776,500	0	776,500
7	958600 Meter expenses		6,968,485	3,603,416	3,365,069	7,061,005	3,687,439	3,373,566
8	958700 Customer installations expenses		7,739,884	3,275,161	4,464,723	7,880,653	3,344,932	4,535,721
9	958800 Miscellaneous distribution expenses		8,969,827	5,714,214	3,255,613	7,624,557	4,946,028	2,678,529
10	958900 Rents Control Center		4,251,779	3,865,225	386,554	4,347,204	3,958,487	388,717
11	TOTAL OPERATION		62,073,152	39,105,634	22,967,517	61,358,258	38,870,002	22,488,256
12	**MAINTENANCE**							
13	959000 Maintenance Supervision & Engineering		734,780	287,868	446,912	682,597	266,293	416,304
14	959100 Maintenance Structures		262,875	133,884	128,991	252,584	120,395	132,189
15	959200 Maintain equipment		17,969,701	8,355,955	9,613,746	19,327,483	8,844,027	10,483,456
16	959300 Maintain overhead lines		42,489,150	7,909,012	34,580,139	42,343,485	7,609,339	34,734,146
17	959400 Maintain underground line		14,521,798	8,715,049	5,806,749	15,103,166	9,140,013	5,963,153
18	959500 Maintain line transformers		1,600,690	950,625	650,065	1,640,757	987,996	652,761
19	959600 Maintain street lighting & signal sys		3,359,061	13,184	3,345,877	3,369,183	13,204	3,355,979
20	959700 Maintain meters		637,732	248,179	389,553	651,106	262,244	388,862
21	959800 Maintain distribution plant		5,255,922	2,070,858	3,185,064	5,350,591	2,099,269	3,251,322
22	TOTAL MAINTENANCE		86,831,709	28,684,615	58,147,095	88,720,952	29,342,779	59,378,173
23	TOTAL DISTRIBUTION EXPENSES		148,904,861	67,790,249	81,114,612	150,079,209	68,212,781	81,866,429

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	OPERATION & MAINTENANCE EXP-31	ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	DISTRIBUTION EXPENSES - TOTAL				
	OPERATION				
1	958000 Operation Supervision & Engineering		4,209,171	2,633,553	1,575,618
2	958100 Load dispatching		8,036,886	4,165,189	3,871,697
3	958200 Station expenses		1,853,792	860,904	992,888
4	958300 Overhead line expenses		4,828,904	3,315,321	1,513,583
5	958400 Underground line expenses		15,199,289	12,182,753	3,016,536
6	958500 Street lighting		776,500	0	776,500
7	958600 Meter expenses		7,062,952	3,667,412	3,395,540
8	958700 Customer installations expenses		8,039,314	3,416,578	4,622,736
9	958800 Miscellaneous distribution expenses		6,035,420	4,100,282	1,935,138
10	958900 Rents Control Center		4,447,828	4,056,349	391,479
11	TOTAL OPERATION		60,490,056	38,398,341	22,091,715
12	**MAINTENANCE**				
13	959000 Maintenance Supervision & Engineering		687,944	261,786	426,158
14	959100 Maintenance Structures		262,495	117,832	144,663
15	959200 Maintain equipment		19,636,933	8,666,517	10,970,416
16	959300 Maintain overhead lines		43,256,261	7,500,429	35,755,832
17	959400 Maintain underground line		15,393,840	9,378,227	6,015,613
18	959500 Maintain line transformers		1,669,725	1,015,926	653,799
19	959600 Maintain street lighting & signal sys		3,372,417	13,225	3,359,192
20	959700 Maintain meters		665,538	277,762	387,776
21	959800 Maintain distribution plant		5,498,464	2,105,281	3,393,183
22	TOTAL MAINTENANCE		90,443,617	29,336,984	61,106,632
23	TOTAL DISTRIBUTION EXPENSES		150,933,673	67,735,325	83,198,347

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OPERATION & MAINTENANCE EXP-32
CUSTOMER ACCOUNTS & SALES EXP - STORM COSTS DIRECTS

		ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	CUSTOMER ACCOUNTS EXPENSE							
	990300 Cust records and collection exp							
1	DC	DISTRDC	572,341	572,341	0	548,200	548,200	0
2	MD	DISTRMD	1,786,501	0	1,786,501	1,548,780	0	1,548,780
3	TOTAL CUSTOMER ACCOUNTS EXPENSE		2,358,843	572,341	1,786,501	2,096,980	548,200	1,548,780
	CUSTOMER SERVICE EXPENSE							
	990800 Customer assistance expenses							
4	DC	DISTRDC	0	0	0	0	0	0
5	MD	DISTRMD	28,066	0	28,066	17,564	0	17,564
6	TOTAL CUSTOMER SERVICE EXPENSE		28,066	0	28,066	17,564	0	17,564

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ELECTRIC DISTRIBUTION

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OPERATION & MAINTENANCE EXP-32

CUSTOMER ACCOUNTS & SALES EXP - STORM COSTS DIRECTS

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	CUSTOMER ACCOUNTS EXPENSE							
	990300 Cust records and collection exp							
1	DC	DISTRDC	548,200	548,200	0	548,200	548,200	0
2	MD	DISTRMD	1,479,382	0	1,479,382	1,356,191	0	1,356,191
3	TOTAL CUSTOMER ACCOUNTS EXPENSE		2,027,582	548,200	1,479,382	1,904,391	548,200	1,356,191
	CUSTOMER SERVICE EXPENSE							
	990800 Customer assistance expenses							
4	DC	DISTRDC	0	0	0	0	0	0
5	MD	DISTRMD	10,890	0	10,890	9,975	0	9,975
6	TOTAL CUSTOMER SERVICE EXPENSE		10,890	0	10,890	9,975	0	9,975

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		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	OPERATION & MAINTENANCE EXP-32				
	CUSTOMER ACCOUNTS & SALES EXP - STORM COSTS DIRECTS				
	CUSTOMER ACCOUNTS EXPENSE				
	990300 Cust records and collection exp				
1	DC	DISTRDC	365,467	365,467	0
2	MD	DISTRMD	915	0	915
3	TOTAL CUSTOMER ACCOUNTS EXPENSE		366,381	365,467	915
	CUSTOMER SERVICE EXPENSE				
	990800 Customer assistance expenses				
4	DC	DISTRDC	0	0	0
5	MD	DISTRMD	0	0	0
6	TOTAL CUSTOMER SERVICE EXPENSE		0	0	0

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ELECTRIC DISTRIBUTION

OPERATION & MAINTENANCE EXP-33
CUSTOMER ACCOUNTS & SALES EXPENSE LESS STORM COSTS

		ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	CUSTOMER ACCOUNTS EXPENSE							
	990200 Meter reading expenses							
1	DC	DISTRDC	357,955	357,955	0	366,010	366,010	0
2	MD	DISTRMD	632,009	0	632,009	646,231	0	646,231
3	Other	DISTROTH	8	0	8	8	0	8
	990300 Cust records and collection exp							
4	DC	DISTRDC	25,932,747	25,932,747	0	28,875,443	28,875,443	0
5	MD	DISTRMD	49,596,929	0	49,596,929	56,157,893	0	56,157,893
6	Other	DISTROTH	40	0	40	45	0	45
	990500 Miscellaneous cust accounts exp							
	990400 Uncollectible accounts							
7	DC	DISTRDC	2,183,470	2,183,470	0	2,801,792	2,801,792	0
8	MD	DISTRMD	4,144,754	0	4,144,754	4,459,575	0	4,459,575
9	Total Account 990400		6,328,224	2,183,470	4,144,754	7,261,367	2,801,792	4,459,575
10	TOTAL CUSTOMER ACCOUNTS EXPENSE		82,847,911	28,474,171	54,373,740	93,306,997	32,043,245	61,263,752
	CUSTOMER SERVICE EXPENSE							
	990700 Supervision							
11	DC	DISTRDC	0	0	0	0	0	0
12	MD	DISTRMD	0	0	0	0	0	0
	990800 Customer assistance expenses							
13	DC	DISTRDC	1,369,819	1,369,819	0	1,644,426	1,644,426	0
14	MD	DISTRMD	3,219,043	0	3,219,043	3,876,299	0	3,876,299
15	Other	DISTROTH	0	0	0	0	0	0
	990900 Informational & instructional adv							
16	DC	DISTRDC	691,500	691,500	0	264,725	264,725	0
17	MD	DISTRMD	1,407,618	0	1,407,618	508,321	0	508,321
	991000 Miscellaneous customer service & informational exp							
18	DC	DISTRDC	0	0	0	0	0	0
19	MD	DISTRMD	0	0	0	0	0	0
20	TOTAL CUSTOMER SERVICE EXPENSE		6,687,980	2,061,319	4,626,661	6,293,771	1,909,151	4,384,620
	SALES EXPENSE							
21	991200 Demonstrating & selling expenses							
	991300 Advertising expense							
22	DC	DISTRDC	0	0	0	0	0	0
23	MD	DISTRMD	0	0	0	0	0	0
24	TOTAL SALES EXPENSE		0	0	0	0	0	0

OPERATION & MAINTENANCE EXP-33

CUSTOMER ACCOUNTS & SALES EXPENSE LESS STORM COSTS

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	CUSTOMER ACCOUNTS EXPENSE							
	990200 Meter reading expenses							
1	DC	DISTRDC	377,402	377,402	0	380,387	380,387	0
2	MD	DISTRMD	666,345	0	666,345	671,615	0	671,615
3	Other	DISTROTH	8	0	8	8	0	8
	990300 Cust records and collection exp							
4	DC	DISTRDC	29,962,267	29,962,267	0	29,463,078	29,463,078	0
5	MD	DISTRMD	57,825,195	0	57,825,195	56,907,413	0	56,907,413
6	Other	DISTROTH	47	0	47	46	0	46
	990500 Miscellaneous cust accounts exp							
	990400 Uncollectible accounts							
7	DC	DISTRDC	3,054,786	3,054,786	0	3,443,012	3,443,012	0
8	MD	DISTRMD	4,248,430	0	4,248,430	4,673,939	0	4,673,939
9	Total Account 990400		7,303,216	3,054,786	4,248,430	8,116,951	3,443,012	4,673,939
10	TOTAL CUSTOMER ACCOUNTS EXPENSE		96,134,480	33,394,455	62,740,025	95,539,499	33,286,477	62,253,022
	CUSTOMER SERVICE EXPENSE							
	990700 Supervision							
11	DC	DISTRDC	0	0	0	0	0	0
12	MD	DISTRMD	0	0	0	0	0	0
	990800 Customer assistance expenses							
13	DC	DISTRDC	1,645,095	1,645,095	0	1,650,897	1,650,897	0
14	MD	DISTRMD	3,907,230	0	3,907,230	3,942,897	0	3,942,897
15	Other	DISTROTH	0	0	0	0	0	0
	990900 Informational & instructional adv							
16	DC	DISTRDC	266,336	266,336	0	267,533	267,533	0
17	MD	DISTRMD	511,415	0	511,415	513,713	0	513,713
	991000 Miscellaneous customer service & informational exp							
18	DC	DISTRDC	0	0	0	0	0	0
19	MD	DISTRMD	0	0	0	0	0	0
20	TOTAL CUSTOMER SERVICE EXPENSE		6,330,077	1,911,431	4,418,645	6,375,042	1,918,431	4,456,611
	SALES EXPENSE							
21	991200 Demonstrating & selling expenses							
	991300 Advertising expense							
22	DC	DISTRDC	0	0	0	0	0	0
23	MD	DISTRMD	0	0	0	0	0	0
24	TOTAL SALES EXPENSE		0	0	0	0	0	0

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OPERATION & MAINTENANCE EXP-33

CUSTOMER ACCOUNTS & SALES EXPENSE LESS STORM COSTS

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	CUSTOMER ACCOUNTS EXPENSE				
	990200 Meter reading expenses				
1	DC	DISTRDC	383,690	383,690	0
2	MD	DISTRMD	677,448	0	677,448
3	Other	DISTROTH	8	0	8
	990300 Cust records and collection exp				
4	DC	DISTRDC	29,740,271	29,740,271	0
5	MD	DISTRMD	57,366,503	0	57,366,503
6	Other	DISTROTH	47	0	47
	990500 Miscellaneous cust accounts exp				
	990400 Uncollectible accounts				
7	DC	DISTRDC	3,182,522	3,182,522	0
8	MD	DISTRMD	4,860,424	0	4,860,424
9	Total Account 990400		8,042,946	3,182,522	4,860,424
10	TOTAL CUSTOMER ACCOUNTS EXPENSE		96,210,913	33,306,483	62,904,430
	CUSTOMER SERVICE EXPENSE				
	990700 Supervision				
11	DC	DISTRDC	0	0	0
12	MD	DISTRMD	0	0	0
	990800 Customer assistance expenses				
13	DC	DISTRDC	1,660,299	1,660,299	0
14	MD	DISTRMD	3,976,900	0	3,976,900
15	Other	DISTROTH	0	0	0
	990900 Informational & instructional adv				
16	DC	DISTRDC	267,674	267,674	0
17	MD	DISTRMD	513,983	0	513,983
	991000 Miscellaneous customer service & informational exp				
18	DC	DISTRDC	0	0	0
19	MD	DISTRMD	0	0	0
20	TOTAL CUSTOMER SERVICE EXPENSE		6,418,857	1,927,973	4,490,884
	SALES EXPENSE				
21	991200 Demonstrating & selling expenses				
	991300 Advertising expense				
22	DC	DISTRDC	0	0	0
23	MD	DISTRMD	0	0	0
24	TOTAL SALES EXPENSE		0	0	0

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OPERATION & MAINTENANCE EXP-34
TOTAL CUSTOMER ACCOUNTS & SALES EXPENSE

		ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	CUSTOMER ACCOUNTS EXPENSE							
	990200 Meter reading expenses							
1	DC		357,955	357,955	0	366,010	366,010	0
2	MD		632,009	0	632,009	646,231	0	646,231
3	Other		8	0	8	8	0	8
	990300 Cust records and collection exp							
4	DC		26,505,088	26,505,088	0	29,423,643	29,423,643	0
5	MD		51,383,431	0	51,383,431	57,706,673	0	57,706,673
6	Other		40	0	40	45	0	45
	990500 Miscellaneous cust accounts exp							
	990400 Uncollectible accounts							
7	DC		2,183,470	2,183,470	0	2,801,792	2,801,792	0
8	MD		4,144,754	0	4,144,754	4,459,575	0	4,459,575
9	Total Account 990400		6,328,224	2,183,470	4,144,754	7,261,367	2,801,792	4,459,575
10	TOTAL CUSTOMER ACCOUNTS EXPENSE		85,206,754	29,046,512	56,160,242	95,403,977	32,591,445	62,812,532
			85,206,754			95,403,977		
	CUSTOMER SERVICE EXPENSE							
	990700 Supervision							
11	DC		0	0	0	0	0	0
12	MD		0	0	0	0	0	0
	990800 Customer assistance expenses							
13	DC		1,369,819	1,369,819	0	1,644,426	1,644,426	0
14	MD		3,247,109	0	3,247,109	3,893,863	0	3,893,863
15	Other		0	0	0	0	0	0
	990900 Informational & instructional adv							
16	DC		691,500	691,500	0	264,725	264,725	0
17	MD		1,407,618	0	1,407,618	508,321	0	508,321
	991000 Miscellaneous customer service & informational exp							
18	DC		0	0	0	0	0	0
19	MD		0	0	0	0	0	0
20	TOTAL CUSTOMER SERVICE EXPENSE		6,716,046	2,061,319	4,654,727	6,311,335	1,909,151	4,402,184
			6,716,048			6,311,335		
	SALES EXPENSE							
21	991200 Demonstrating & selling expenses							
	991300 Advertising expense							
22	DC		0	0	0	0	0	0
23	MD		0	0	0	0	0	0
24	TOTAL SALES EXPENSE		0	0	0	0	0	0
25	**Total Storm Costs**		31,504,046	4,076,399	27,427,647	26,450,050	5,480,983	20,969,068
26	**O&M Less A&G & Storm Costs**		212,503,682	90,000,940	122,502,742	228,209,950	98,569,342	129,640,608
27	**O&M Less A&G**		241,216,401	90,911,327	150,305,074	255,308,280	104,379,582	150,928,698

OPERATION & MAINTENANCE EXP-34

TOTAL CUSTOMER ACCOUNTS & SALES EXPENSE

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	CUSTOMER ACCOUNTS EXPENSE							
	990200 Meter reading expenses							
1	DC		377,402	377,402	0	380,387	380,387	0
2	MD		666,345	0	666,345	671,615	0	671,615
3	Other		8	0	8	8	0	8
	990300 Cust records and collection exp							
4	DC		30,510,467	30,510,467	0	30,011,278	30,011,278	0
5	MD		59,304,577	0	59,304,577	58,263,605	0	58,263,605
6	Other		47	0	47	46	0	46
	990500 Miscellaneous cust accounts exp							
	990400 Uncollectible accounts							
7	DC		3,054,786	3,054,786	0	3,443,012	3,443,012	0
8	MD		4,248,430	0	4,248,430	4,673,939	0	4,673,939
9	Total Account 990400		7,303,216	3,054,786	4,248,430	8,116,951	3,443,012	4,673,939
10	TOTAL CUSTOMER ACCOUNTS EXPENSE		98,162,062	33,942,655	64,219,407	97,443,890	33,834,677	63,609,213
			98,162,062			97,443,890		
	CUSTOMER SERVICE EXPENSE							
	990700 Supervision							
11	DC		0	0	0	0	0	0
12	MD		0	0	0	0	0	0
	990800 Customer assistance expenses							
13	DC		1,645,095	1,645,095	0	1,650,897	1,650,897	0
14	MD		3,918,120	0	3,918,120	3,952,872	0	3,952,872
15	Other		0	0	0	0	0	0
	990900 Informational & instructional adv							
16	DC		266,336	266,336	0	267,533	267,533	0
17	MD		511,415	0	511,415	513,713	0	513,713
	991000 Miscellaneous customer service & informational exp							
18	DC		0	0	0	0	0	0
19	MD		0	0	0	0	0	0
20	TOTAL CUSTOMER SERVICE EXPENSE		6,340,966	1,911,431	4,429,535	6,385,017	1,918,431	4,466,586
			6,340,967			6,385,017		
	SALES EXPENSE							
21	991200 Demonstrating & selling expenses							
	991300 Advertising expense							
22	DC		0	0	0	0	0	0
23	MD		0	0	0	0	0	0
24	TOTAL SALES EXPENSE		0	0	0	0	0	0
25	**Total Storm Costs**		27,761,292	5,649,556	22,111,737	27,743,514	5,714,424	22,029,090
26	**O&M Less A&G & Storm Costs**		225,053,979	97,665,522	127,388,457	225,593,931	97,922,206	127,671,724
27	**O&M Less A&G**		253,407,889	103,644,336	149,763,554	253,908,116	103,965,888	149,942,228

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OPERATION & MAINTENANCE EXP-34
TOTAL CUSTOMER ACCOUNTS & SALES EXPENSE

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	CUSTOMER ACCOUNTS EXPENSE				
	990200 Meter reading expenses				
1	DC		383,690	383,690	0
2	MD		677,448	0	677,448
3	Other		8	0	8
	990300 Cust records and collection exp				
4	DC		30,105,737	30,105,737	0
5	MD		57,367,418	0	57,367,418
6	Other		47	0	47
	990500 Miscellaneous cust accounts exp				
	990400 Uncollectible accounts				
7	DC		3,182,522	3,182,522	0
8	MD		4,860,424	0	4,860,424
9	Total Account 990400		8,042,946	3,182,522	4,860,424
10	TOTAL CUSTOMER ACCOUNTS EXPENSE		96,577,294	33,671,949	62,905,344
			96,577,294		
	CUSTOMER SERVICE EXPENSE				
	990700 Supervision				
11	DC		0	0	0
12	MD		0	0	0
	990800 Customer assistance expenses				
13	DC		1,660,299	1,660,299	0
14	MD		3,976,900	0	3,976,900
15	Other		0	0	0
	990900 Informational & instructional adv				
16	DC		267,674	267,674	0
17	MD		513,983	0	513,983
	991000 Miscellaneous customer service & informational exp				
18	DC		0	0	0
19	MD		0	0	0
20	TOTAL CUSTOMER SERVICE EXPENSE		6,418,857	1,927,973	4,490,884
			6,418,857		
	SALES EXPENSE				
21	991200 Demonstrating & selling expenses				
	991300 Advertising expense				
22	DC		0	0	0
23	MD		0	0	0
24	TOTAL SALES EXPENSE		0	0	0
25	**Total Storm Costs**		26,544,152	5,610,573	20,933,579
26	**O&M Less A&G & Storm Costs**		227,056,413	97,395,416	129,660,997
27	**O&M Less A&G**		253,929,823	103,335,248	150,594,575

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	ALLOCATION FACTOR TABLE-35 CAPACITY-DISTRIBUTION RELATED	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
1	Direct Maryland Distribution	DISTRMD	1	0	1	1	0	1
2	Direct Other Distribution	DISTROTH	1	0	1	1	0	1
3								
4	Direct DC Distribution	DISTRDC	1	1	0	1	1	0
5	ZERO ALLOCATION	ZERO	0	0	0	0	0	0
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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

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	ALLOCATION FACTOR TABLE-35 CAPACITY-DISTRIBUTION RELATED	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
1	Direct Maryland Distribution	DISTRMD	1	0	1	1	0	1
2	Direct Other Distribution	DISTROTH	1	0	1	1	0	1
3								
4	Direct DC Distribution	DISTRDC	1	1	0	1	1	0
5	ZERO ALLOCATION	ZERO	0	0	0	0	0	0
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28-May-19 12:26 JURISDICTIONAL COST OF SERVICE STUDY
lultiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	ALLOCATION FACTOR TABLE-35 CAPACITY-DISTRIBUTION RELATED	ALLOC	2022 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
1	Direct Maryland Distribution	DISTRMD	1	0	1
2	Direct Other Distribution	DISTROTH	1	0	1
3					
4	Direct DC Distribution	DISTRDC	1	1	0
5	ZERO ALLOCATION	ZERO	0	0	0
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PEPCO - DC
JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

		2018			2019		
	ALLOC	TOTAL DISTRIBUTION (1)	DC DISTRIBUTION (2)	OTHER DISTRIBUTION (3)	Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
ALLOCATION FACTOR TABLE-36 CAPACITY-DISTR RELATED CON'T							
ENERGY RELATED							

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

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		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	ALLOCATION FACTOR TABLE-36 CAPACITY-DISTR RELATED CON'T							
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lultiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	ALLOCATION FACTOR TABLE-36 CAPACITY-DISTR RELATED CON'T				
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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

		ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	ALLOCATION FACTOR TABLE-37 CUSTOMER RELATED							
2	596 Street Lights -Aug 17	OM596SL	1,864,031	102,539	1,761,492	1,864,031	102,539	1,761,492
6	OTHER ALLOCATORS							

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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

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		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	ALLOCATION FACTOR TABLE-37 CUSTOMER RELATED							
1								
2	596 Street Lights -Aug 17	OM596SL	1,864,031	102,539	1,761,492	1,864,031	102,539	1,761,492
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6	OTHER ALLOCATORS							
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lultiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	ALLOCATION FACTOR TABLE-37 CUSTOMER RELATED				
1					
2	596 Street Lights -Aug 17	OM596SL	1,864,031	102,539	1,761,492
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6	OTHER ALLOCATORS				
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PEPCO - DC
JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

			2018			2019		
		ALLOC	TOTAL DISTRIBUTION (1)	DC DISTRIBUTION (2)	OTHER DISTRIBUTION (3)	Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	ALLOCATION FACTOR TABLE-38 INTERNALLY DEVELOPED							
1	Plant Subtransmission	PLTSUBT	644,709,895	269,290,233	375,419,662	645,364,403	269,565,322	375,799,080
2	Subt & Distr Total	STDPLT	6,775,149,838	3,439,549,543	3,335,600,296	7,158,223,613	3,653,390,570	3,504,833,043
3	OM Less A&G	OMLESAG	241,216,402	90,911,327	150,305,075	255,308,281	104,379,582	150,928,698
4	Depre Exp Less AFUDC	DEPRE	181,204,969	98,577,163	82,627,806	194,450,848	106,681,082	87,769,766
5								
	INTERNALLY DEVELOPED CON'T							
6	Plant - MD & Other Only (NO DC)	PLTMDOTH	2,991,430,335	26,929,023	2,964,501,312	3,160,283,664	26,929,023	3,133,354,641
7	CWIP ST&D LESS AFUDC	CWIPSTD	0	0	0	0	0	0
8	Demand Plant (Dist Only)	PLTDEM	5,395,790,984	2,800,629,935	2,595,161,049	5,746,299,178	2,991,019,357	2,755,279,821
9	Customer Plant (Dist Only)	PLTCUST	734,648,959	369,629,374	365,019,584	766,560,032	392,805,890	373,754,142
10	Plant 360-368 (ST&D) (Excl. 3627 Control Center)	PLTDACTS	6,038,607,685	3,069,920,168	2,968,687,517	6,391,663,581	3,260,584,679	3,131,078,901
11	Plant 368	PLANT368	1,020,531,678	517,249,722	503,281,956	1,099,277,441	568,165,942	531,111,498
12	Plant 370	PLANT370	152,423,373	64,130,509	88,292,864	158,069,311	68,765,341	89,303,970
13	Plant 371	PLANT371	2,646,032	1,367,203	1,278,829	2,646,032	1,367,203	1,278,829
14	OM Operations	OMOPER	38,869,053	18,848,078	20,020,974	55,684,162	33,567,229	22,116,933
15	Substations (Dist Only)	PLTSUBS	919,763,462	515,378,568	404,384,894	993,794,583	525,164,021	468,630,562
16	OM Maintenance	OMMAINTN	65,374,429	31,419,890	33,954,539	56,880,612	22,291,705	34,588,907
17	Customer Deposits	CDEP	(52,797,336)	(8,507,321)	(44,290,015)	(54,154,870)	(9,330,243)	(44,824,626)
18	Depre Related Def Tax	PLTDEF	738,515,085	422,884,857	315,630,228	780,303,662	447,292,603	333,011,060
19	O&M Less A&G and Storm Costs	OMLESAGS	212,503,682	90,000,940	122,502,742	228,209,950	98,569,342	129,640,608
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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

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		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	ALLOCATION FACTOR TABLE-38 INTERNALLY DEVELOPED							
1	Plant Subtransmission	PLTSUBT	650,711,882	271,812,868	378,899,014	796,022,968	332,887,117	463,135,850
2	Subt & Distr Total	STDPLT	7,572,286,589	3,927,153,527	3,645,133,062	8,048,770,275	4,180,923,973	3,867,846,302
3	OM Less A&G	OMLESAG	253,407,890	103,644,336	149,763,554	253,908,117	103,965,888	149,942,228
4	Depre Exp Less AFUDC	DEPRE	206,511,662	114,860,533	91,651,129	219,536,168	121,871,306	97,664,861
5								
	INTERNALLY DEVELOPED CON'T							
6	Plant - MD & Other Only (NO DC)	PLTMDOTH	3,297,483,749	26,929,023	3,270,554,726	3,435,960,153	26,929,023	3,409,031,130
7	CWIP ST&D LESS AFUDC	CWIPSTD	0	0	0	0	0	0
8	Demand Plant (Dist Only)	PLTDEM	6,114,281,728	3,228,478,680	2,885,803,048	6,404,222,833	3,391,341,717	3,012,881,116
9	Customer Plant (Dist Only)	PLTCUST	807,292,979	426,861,979	380,431,000	848,524,474	456,695,138	391,829,336
10	Plant 360-368 (ST&D) (Excl. 3627 Control Center)	PLTDACTS	6,764,993,610	3,500,291,547	3,264,702,063	7,200,245,800	3,724,228,833	3,476,016,967
11	Plant 368	PLANT368	1,191,951,556	638,878,164	553,073,392	1,290,483,186	700,538,158	589,945,028
12	Plant 370	PLANT370	166,101,659	75,947,387	90,154,272	173,761,805	82,209,288	91,552,516
13	Plant 371	PLANT371	2,646,032	1,367,203	1,278,829	2,646,032	1,367,203	1,278,829
14	OM Operations	OMOPER	48,371,054	30,208,143	18,162,911	48,978,882	30,715,599	18,263,283
15	Substations (Dist Only)	PLTSUBS	1,061,407,717	540,582,491	520,825,226	1,162,587,274	554,149,350	608,437,924
16	OM Maintenance	OMMAINTN	55,726,022	21,832,064	33,893,957	57,466,148	22,418,525	35,047,623
17	Customer Deposits	CDEP	(52,820,697)	(9,484,872)	(43,335,825)	(52,820,697)	(9,484,872)	(43,335,825)
18	Depre Related Def Tax	PLTDEF	801,643,987	469,867,001	331,776,986	823,360,210	479,156,911	344,203,300
19	O&M Less A&G and Storm Costs	OMLESAGS	225,053,979	97,665,522	127,388,457	225,593,931	97,922,206	127,671,724
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lultiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	ALLOCATION FACTOR TABLE-38 INTERNALLY DEVELOPED	ALLOC	2022 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
1	Plant Subtransmission	PLTSUBT	913,076,428	382,084,687	530,991,741
2	Subt & Distr Total	STDPLT	8,553,180,442	4,460,267,590	4,092,912,852
3	OM Less A&G	OMLESAG	253,929,824	103,335,249	150,594,576
4	Depre Exp Less AFUDC	DEPRE	234,590,466	130,520,554	104,069,912
5					
	INTERNALLY DEVELOPED CON'T				
6	Plant - MD & Other Only (NO DC)	PLTMDOTH	3,593,170,812	26,929,023	3,566,241,789
7	CWIP ST&D LESS AFUDC	CWIPSTD	0	0	0
8	Demand Plant (Dist Only)	PLTDEM	6,746,342,096	3,587,478,586	3,158,863,510
9	Customer Plant (Dist Only)	PLTCUST	893,761,918	490,704,318	403,057,600
10	Plant 360-368 (ST&D) (Excl. 3627 Control Center)	PLTDACTS	7,659,418,524	3,969,563,271	3,689,855,253
11	Plant 368	PLANT368	1,397,095,778	770,829,266	626,266,512
12	Plant 370	PLANT370	182,277,623	89,347,725	92,929,898
13	Plant 371	PLANT371	2,646,032	1,367,203	1,278,829
14	OM Operations	OMOPER	49,637,933	31,056,975	18,580,958
15	Substations (Dist Only)	PLTSUBS	1,262,074,809	566,535,659	695,539,150
16	OM Maintenance	OMMAINTN	58,686,970	22,332,343	36,354,627
17	Customer Deposits	CDEP	(52,820,697)	(9,484,872)	(43,335,825)
18	Depre Related Def Tax	PLTDEF	857,721,696	479,401,032	378,320,663
19	O&M Less A&G and Storm Costs	OMLESAGS	227,056,413	97,395,416	129,660,997
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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	ALLOCATION FACTOR TABLE-39 INTERNALLY DEVELOPED CON'T	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
1	PLT OH Lines (Dist Only)	PLTOH	1,015,271,493	244,148,324	771,123,170	1,080,382,384	263,373,873	817,008,511
2	PLT UG Lines (Dist Only)	PLTUG	2,440,224,351	1,523,853,321	916,371,030	2,572,844,771	1,634,315,521	938,529,249
3	PLT OH Services (Dist Only)	PLTOHS	64,724,720	16,003,858	48,720,862	68,502,141	20,318,498	48,183,644
4	PLT UG Services (Dist Only)	PLTUGS	455,082,900	278,026,308	177,056,592	476,293,290	292,453,983	183,839,306
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11	958000 Operation Supervision & Engineering	OMEXP580	3,708,109	1,720,406	1,987,702	4,043,758	2,437,637	1,606,121
12	958100 Load dispatching	OMEXP581	5,625,435	2,858,015	2,767,420	7,539,999	3,844,834	3,695,165
13	958200 Station expenses	OMEXP582	1,292,337	672,186	620,151	2,065,386	1,197,792	867,594
14	958300 Overhead line expenses	OMEXP583	1,048,048	226,111	821,937	4,141,126	2,886,863	1,254,263
15	958400 Underground line expenses	OMEXP584	5,674,402	3,293,671	2,380,730	14,856,200	11,847,966	3,008,234
16	958500 Street lighting	OMEXP585	634,821	0	634,821	775,000	0	775,000
17	958600 Meter expenses	OMEXP586	6,951,837	3,104,157	3,847,680	6,922,651	3,514,417	3,408,234
18	958700 Customer installations expenses	OMEXP587	8,438,964	3,432,725	5,006,239	8,046,894	3,142,439	4,904,455
19	958800 Miscellaneous distribution expenses	OMEXP588	9,179,511	2,884,680	6,294,830	7,156,153	4,485,419	2,670,735
23	958900 Rents Control Center	OMEXP589	9,440,399	5,494,753	3,945,646	11,947,480	7,740,450	4,207,030
24	959000 Maintenance Supervision & Engineering	OMEXP590	782,810	233,415	549,395	735,108	288,091	447,017
25	959100 Maintenance Structures	OMEXP591	13,536	7,585	5,951	218,839	115,644	103,195
26	959200 Maintain equipment	OMEXP592	16,992,873	8,893,163	8,099,710	18,950,950	8,849,946	10,101,004
27	959300 Maintain overhead lines	OMEXP593	42,382,829	7,553,298	34,829,532	40,184,302	7,881,105	32,303,197
28	959400 Maintain underground line	OMEXP594	22,698,059	13,908,851	8,789,208	14,483,883	8,559,036	5,924,847
29	959500 Maintain line transformers	OMEXP595	6,445,668	3,983,312	2,462,356	1,955,350	883,342	1,072,008
30	959600 Maintain street lighting & signal sys	OMEXP596	4,878,991	1,340	4,877,651	3,997,808	13,151	3,984,657
31	959700 Maintain meters	OMEXP597	842,418	342,858	499,561	814,413	314,733	499,680
32	959800 Maintain distribution plant	OMEXP598	2,262,553	1,192,968	1,069,584	4,757,669	1,876,124	2,881,545
33	990200 Meter reading expenses	OMEXP902	989,971	357,955	632,016	1,012,249	366,010	646,239
34	990300 Cust records and collection exp	OMEXP903	77,888,559	26,505,088	51,383,471	87,130,361	29,423,643	57,706,718
35	990500 Miscellaneous cust accounts exp	OMEXP905	0	0	0	0	0	0
36	990400 Uncollectible accounts	OMEXP904	6,328,224	2,183,470	4,144,754	7,261,367	2,801,792	4,459,575
37	990700 Supervision	OMEXP907	0	0	0	0	0	0
38	990800 Customer assistance expenses	OMEXP908	4,616,928	1,369,819	3,247,109	5,538,289	1,644,426	3,893,863
39	990900 Informational & instructional adv	OMEXP909	2,099,118	691,500	1,407,618	773,046	264,725	508,321
40	991000 Miscellaneous customer service & informational exp	OMEXP910	0	0	0	0	0	0
41	991200 Demonstrating & selling expenses	OMEXP912	0	0	0	0	0	0
42	991300 Advertising expense	OMEXP913	0	0	0	0	0	0
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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	ALLOCATION FACTOR TABLE-39 INTERNALLY DEVELOPED CON'T	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
1	PLT OH Lines (Dist Only)	PLTOH	1,141,143,821	290,730,128	850,413,693	1,177,852,905	313,481,250	864,371,655
2	PLT UG Lines (Dist Only)	PLTUG	2,719,778,634	1,758,287,896	961,490,737	2,773,299,468	1,823,172,959	950,126,509
3	PLT OH Services (Dist Only)	PLTOHS	74,607,949	26,559,851	48,048,097	80,083,394	32,035,296	48,048,097
4	PLT UG Services (Dist Only)	PLTUGS	501,834,648	313,093,378	188,741,269	528,133,361	331,165,377	196,967,984
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11	958000 Operation Supervision & Engineering	OMEXP580	4,124,435	2,575,745	1,548,690	4,147,287	2,600,843	1,546,444
12	958100 Load dispatching	OMEXP581	7,986,162	4,131,982	3,854,180	7,919,806	4,096,412	3,823,394
13	958200 Station expenses	OMEXP582	2,283,333	1,292,647	990,686	1,809,024	860,077	948,947
14	958300 Overhead line expenses	OMEXP583	4,296,232	2,987,941	1,308,291	4,571,870	3,148,462	1,423,408
15	958400 Underground line expenses	OMEXP584	14,676,515	11,659,303	3,017,212	15,220,352	12,227,323	2,993,029
16	958500 Street lighting	OMEXP585	776,500	0	776,500	776,500	0	776,500
17	958600 Meter expenses	OMEXP586	6,968,485	3,603,416	3,365,069	7,061,005	3,687,439	3,373,566
18	958700 Customer installations expenses	OMEXP587	7,739,884	3,275,161	4,464,723	7,880,653	3,344,932	4,535,721
19	958800 Miscellaneous distribution expenses	OMEXP588	8,969,827	5,714,214	3,255,613	7,624,557	4,946,028	2,678,529
23	958900 Rents Control Center	OMEXP589	4,251,779	3,865,225	386,554	4,347,204	3,958,487	388,717
24	959000 Maintenance Supervision & Engineering	OMEXP590	734,780	287,868	446,912	682,597	266,293	416,304
25	959100 Maintenance Structures	OMEXP591	262,875	133,884	128,991	252,584	120,395	132,189
26	959200 Maintain equipment	OMEXP592	17,969,701	8,355,955	9,613,746	19,327,483	8,844,027	10,483,456
27	959300 Maintain overhead lines	OMEXP593	42,489,150	7,909,012	34,580,139	42,343,485	7,609,339	34,734,146
28	959400 Maintain underground line	OMEXP594	14,521,798	8,715,049	5,806,749	15,103,166	9,140,013	5,963,153
29	959500 Maintain line transformers	OMEXP595	1,600,690	950,625	650,065	1,640,757	987,996	652,761
30	959600 Maintain street lighting & signal sys	OMEXP596	3,359,061	13,184	3,345,877	3,369,183	13,204	3,355,979
31	959700 Maintain meters	OMEXP597	637,732	248,179	389,553	651,106	262,244	388,862
32	959800 Maintain distribution plant	OMEXP598	5,255,922	2,070,858	3,185,064	5,350,591	2,099,269	3,251,322
33	990200 Meter reading expenses	OMEXP902	1,043,755	377,402	666,353	1,052,010	380,387	671,623
34	990300 Cust records and collection exp	OMEXP903	89,815,091	30,510,467	59,304,624	88,274,929	30,011,278	58,263,651
35	990500 Miscellaneous cust accounts exp	OMEXP905	0	0	0	0	0	0
36	990400 Uncollectible accounts	OMEXP904	7,303,216	3,054,786	4,248,430	8,116,951	3,443,012	4,673,939
37	990700 Supervision	OMEXP907	0	0	0	0	0	0
38	990800 Customer assistance expenses	OMEXP908	5,563,215	1,645,095	3,918,120	5,603,770	1,650,897	3,952,872
39	990900 Informational & instructional adv	OMEXP909	777,751	266,336	511,415	781,247	267,533	513,713
40	991000 Miscellaneous customer service & informational exp	OMEXP910	0	0	0	0	0	0
41	991200 Demonstrating & selling expenses	OMEXP912	0	0	0	0	0	0
42	991300 Advertising expense	OMEXP913	0	0	0	0	0	0
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lultiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	ALLOCATION FACTOR TABLE-39 INTERNALLY DEVELOPED CON'T	ALLOC	2022 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
1	PLT OH Lines (Dist Only)	PLTOH	1,227,010,431	339,764,511	887,245,920
2	PLT UG Lines (Dist Only)	PLTUG	2,860,161,078	1,910,349,150	949,811,928
3	PLT OH Services (Dist Only)	PLTOHS	86,325,286	38,277,189	48,048,097
4	PLT UG Services (Dist Only)	PLTUGS	556,839,028	351,767,079	205,071,949
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11	958000 Operation Supervision & Engineering	OMEXP580	4,209,171	2,633,553	1,575,618
12	958100 Load dispatching	OMEXP581	8,036,886	4,165,189	3,871,697
13	958200 Station expenses	OMEXP582	1,853,792	860,904	992,888
14	958300 Overhead line expenses	OMEXP583	4,828,904	3,315,321	1,513,583
15	958400 Underground line expenses	OMEXP584	15,199,289	12,182,753	3,016,536
16	958500 Street lighting	OMEXP585	776,500	0	776,500
17	958600 Meter expenses	OMEXP586	7,062,952	3,667,412	3,395,540
18	958700 Customer installations expenses	OMEXP587	8,039,314	3,416,578	4,622,736
19	958800 Miscellaneous distribution expenses	OMEXP588	6,035,420	4,100,282	1,935,138
23	958900 Rents Control Center	OMEXP589	4,447,828	4,056,349	391,479
24	959000 Maintenance Supervision & Engineering	OMEXP590	687,944	261,786	426,158
25	959100 Maintenance Structures	OMEXP591	262,495	117,832	144,663
26	959200 Maintain equipment	OMEXP592	19,636,933	8,666,517	10,970,416
27	959300 Maintain overhead lines	OMEXP593	43,256,261	7,500,429	35,755,832
28	959400 Maintain underground line	OMEXP594	15,393,840	9,378,227	6,015,613
29	959500 Maintain line transformers	OMEXP595	1,669,725	1,015,926	653,799
30	959600 Maintain street lighting & signal sys	OMEXP596	3,372,417	13,225	3,359,192
31	959700 Maintain meters	OMEXP597	665,538	277,762	387,776
32	959800 Maintain distribution plant	OMEXP598	5,498,464	2,105,281	3,393,183
33	990200 Meter reading expenses	OMEXP902	1,061,146	383,690	677,456
34	990300 Cust records and collection exp	OMEXP903	87,473,202	30,105,737	57,367,464
35	990500 Miscellaneous cust accounts exp	OMEXP905	0	0	0
36	990400 Uncollectible accounts	OMEXP904	8,042,946	3,182,522	4,860,424
37	990700 Supervision	OMEXP907	0	0	0
38	990800 Customer assistance expenses	OMEXP908	5,637,200	1,660,299	3,976,900
39	990900 Informational & instructional adv	OMEXP909	781,657	267,674	513,983
40	991000 Miscellaneous customer service & informational exp	OMEXP910	0	0	0
41	991200 Demonstrating & selling expenses	OMEXP912	0	0	0
42	991300 Advertising expense	OMEXP913	0	0	0
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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

			2018			2019		
		ALLOC	TOTAL DISTRIBUTION (1)	DC DISTRIBUTION (2)	OTHER DISTRIBUTION (3)	Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	RATIO TABLE-40 CAPACITY-DISTRIBUTION RELATED							
1	Direct Maryland Distribution	DISTRMD	1.000000	0.000000	1.000000	1.000000	0.000000	1.000000
2	Direct Other Distribution	DISTROTH	1.000000	0.000000	1.000000	1.000000	0.000000	1.000000
3	Subtransmission Average & Excess (NCP)	STAED	1.000000	0.420300	0.579700	1.000000	0.420300	0.579700
4	Subtransmission Average & Excess (NCP) - VA	STAEDOTH	0.042530	0.042030	0.000500	0.042530	0.042030	0.000500
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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

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RATIO TABLE-40
CAPACITY-DISTRIBUTION RELATED

		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
1	Direct Maryland Distribution	DISTRMD	1.000000	0.000000	1.000000	1.000000	0.000000	1.000000
2	Direct Other Distribution	DISTROTH	1.000000	0.000000	1.000000	1.000000	0.000000	1.000000
3	Subtransmission Average & Excess (NCP)	STAED	1.000000	0.420300	0.579700	1.000000	0.420300	0.579700
4	Subtransmission Average & Excess (NCP) - VA	STAEDOTH	0.042530	0.042030	0.000500	0.042530	0.042030	0.000500
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lultiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	RATIO TABLE-40 CAPACITY-DISTRIBUTION RELATED				
1	Direct Maryland Distribution	DISTRMD	1.000000	0.000000	1.000000
2	Direct Other Distribution	DISTROTH	1.000000	0.000000	1.000000
3	Subtransmission Average & Excess (NCP)	STAED	1.000000	0.420300	0.579700
4	Subtransmission Average & Excess (NCP) - VA	STAEDOTH	0.042530	0.042030	0.000500
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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

		2018			2019		
	ALLOC	TOTAL DISTRIBUTION (1)	DC DISTRIBUTION (2)	OTHER DISTRIBUTION (3)	Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

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		2020			2021		
	ALLOC	Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)	Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
RATIO TABLE-41							
CAPACITY-DISTR RELATED CON'T-							
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lultiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

		2022		
		Total DISTRIBUTION	DC DISTRIBUTION	Other DISTRIBUTION
	ALLOC	(1)	(2)	(3)
RATIO TABLE-41				
CAPACITY-DISTR RELATED CON'T-				
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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

		ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
	RATIO TABLE-42 CUSTOMER RELATED-25							
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2	596 Street Lights	OM596SL	1.000000	0.055009	0.944991	1.000000	0.055009	0.944991
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JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

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		ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
	RATIO TABLE-42 CUSTOMER RELATED-25							
1								
2	596 Street Lights	OM596SL	1.000000	0.055009	0.944991	1.000000	0.055009	0.944991
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lultiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
	RATIO TABLE-42 CUSTOMER RELATED-25				
1					
2	596 Street Lights	OM596SL	1.000000	0.055009	0.944991
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Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	RATIO TABLE-43 INTERNALLY DEVELOPED	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
1	Plant Subtransmission	PLTSUBT	1.000000	0.417692	0.582308	1.000000	0.417695	0.582305
2	Subt & Distr Total	STDPLT	1.000000	0.507671	0.492329	1.000000	0.510377	0.489623
3	OM Less A&G	OMLESAG	1.000000	0.376887	0.623113	1.000000	0.408837	0.591163
4	Depre Exp Less AFUDC	DEPRE	1.000000	0.544009	0.455991	1.000000	0.548627	0.451373
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	INTERNALLY DEVELOPED CON'T							
6	Plant MD & Other Only NO DC	PLTMDOTH	1.000000	0.009002	0.990998	1.000000	0.008521	0.991479
7	CWIP ST&D LESS AFUDC	CWIPSTD	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
8	Demand Plant	PLTDEM	1.000000	0.519040	0.480960	1.000000	0.520512	0.479488
9	Customer Plant	PLTCUST	1.000000	0.503137	0.496863	1.000000	0.512427	0.487573
10	Plant 360-368	PLTDACTS	1.000000	0.508382	0.491618	1.000000	0.510131	0.489869
11	Plant 368	PLANT368	1.000000	0.506843	0.493157	1.000000	0.516854	0.483146
12	Plant 370	PLANT370	1.000000	0.420739	0.579261	1.000000	0.435033	0.564967
13	Plant 371	PLANT371	1.000000	0.516699	0.483301	1.000000	0.516699	0.483301
14	OM Operations	OMOPER	1.000000	0.484912	0.515088	1.000000	0.602815	0.397185
15	Plant Substations	PLTSUBS	1.000000	0.560338	0.439662	1.000000	0.528443	0.471557
16	OM Maintenance	OMMAINTN	1.000000	0.480614	0.519386	1.000000	0.391903	0.608097
17	Customer Deposits	CDEP	1.000000	0.161132	0.838868	1.000000	0.172288	0.827712
18	Depre Related Def Tax	PLTDEF	1.000000	0.572615	0.427385	1.000000	0.573229	0.426771
19	O&M Less A&G and Storm Costs	OMLESAGS	1.000000	0.423526	0.576474	1.000000	0.431924	0.568076
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ELECTRIC DISTRIBUTION

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	RATIO TABLE-43 INTERNALLY DEVELOPED	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
1	Plant Subtransmission	PLTSUBT	1.000000	0.417716	0.582284	1.000000	0.418188	0.581812
2	Subt & Distr Total	STDPLT	1.000000	0.518622	0.481378	1.000000	0.519449	0.480551
3	OM Less A&G	OMLESAG	1.000000	0.409002	0.590998	1.000000	0.409463	0.590537
4	Depre Exp Less AFUDC	DEPRE	1.000000	0.556194	0.443806	1.000000	0.555131	0.444869
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	INTERNALLY DEVELOPED CON'T							
6	Plant MD & Other Only NO DC	PLTMDOTH	1.000000	0.008167	0.991833	1.000000	0.007837	0.992163
7	CWIP ST&D LESS AFUDC	CWIPSTD	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
8	Demand Plant	PLTDEM	1.000000	0.528023	0.471977	1.000000	0.529548	0.470452
9	Customer Plant	PLTCUST	1.000000	0.528757	0.471243	1.000000	0.538223	0.461777
10	Plant 360-368	PLTDACTS	1.000000	0.517412	0.482588	1.000000	0.517236	0.482764
11	Plant 368	PLANT368	1.000000	0.535993	0.464007	1.000000	0.542850	0.457150
12	Plant 370	PLANT370	1.000000	0.457234	0.542766	1.000000	0.473115	0.526885
13	Plant 371	PLANT371	1.000000	0.516699	0.483301	1.000000	0.516699	0.483301
14	OM Operations	OMOPER	1.000000	0.624509	0.375491	1.000000	0.627119	0.372881
15	Plant Substations	PLTSUBS	1.000000	0.509307	0.490693	1.000000	0.476652	0.523348
16	OM Maintenance	OMMAINTN	1.000000	0.391775	0.608225	1.000000	0.390117	0.609883
17	Customer Deposits	CDEP	1.000000	0.179567	0.820433	1.000000	0.179567	0.820433
18	Depre Related Def Tax	PLTDEF	1.000000	0.586129	0.413871	1.000000	0.581953	0.418047
19	O&M Less A&G and Storm Costs	OMLESAGS	1.000000	0.433965	0.566035	1.000000	0.434064	0.565936
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ELECTRIC DISTRIBUTION

	RATIO TABLE-43 INTERNALLY DEVELOPED	ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
1	Plant Subtransmission	PLTSUBT	1.000000	0.418459	0.581541
2	Subt & Distr Total	STDPLT	1.000000	0.521475	0.478525
3	OM Less A&G	OMLESAG	1.000000	0.406944	0.593056
4	Depre Exp Less AFUDC	DEPRE	1.000000	0.556376	0.443624
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	INTERNALLY DEVELOPED CON'T				
6	Plant MD & Other Only NO DC	PLTMDOTH	1.000000	0.007495	0.992505
7	CWIP ST&D LESS AFUDC	CWIPSTD	0.000000	0.000000	0.000000
8	Demand Plant	PLTDEM	1.000000	0.531766	0.468234
9	Customer Plant	PLTCUST	1.000000	0.549032	0.450968
10	Plant 360-368	PLTDACTS	1.000000	0.518259	0.481741
11	Plant 368	PLANT368	1.000000	0.551737	0.448263
12	Plant 370	PLANT370	1.000000	0.490174	0.509826
13	Plant 371	PLANT371	1.000000	0.516699	0.483301
14	OM Operations	OMOPER	1.000000	0.625670	0.374330
15	Plant Substations	PLTSUBS	1.000000	0.448892	0.551108
16	OM Maintenance	OMMAINTN	1.000000	0.380533	0.619467
17	Customer Deposits	CDEP	1.000000	0.179567	0.820433
18	Depre Related Def Tax	PLTDEF	1.000000	0.558924	0.441076
19	O&M Less A&G and Storm Costs	OMLESAGS	1.000000	0.428948	0.571052
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PEPCO - DC
JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

	RATIO TABLE-44 INTERNALLY DEVELOPED CON'T-	ALLOC	2018 TOTAL DISTRIBUTION (1)	2018 DC DISTRIBUTION (2)	2018 OTHER DISTRIBUTION (3)	2019 Total DISTRIBUTION (1)	2019 DC DISTRIBUTION (2)	2019 Other DISTRIBUTION (3)
1	PLT OH Lines	PLTOH	1.000000	0.240476	0.759524	1.000000	0.243778	0.756222
2	PLT UG Lines	PLTUG	1.000000	0.624473	0.375527	1.000000	0.635217	0.364783
3	PLT OH Services	PLTOHS	1.000000	0.247260	0.752740	1.000000	0.296611	0.703389
4	PLT UG Services	PLTUGS	1.000000	0.610936	0.389064	1.000000	0.614021	0.385979
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11	958000 Operation Supervision & Engineering	OMEXP580	1.000000	0.463958	0.536042	1.000000	0.602815	0.397185
12	958100 Load dispatching	OMEXP581	1.000000	0.508052	0.491948	1.000000	0.509925	0.490075
13	958200 Station expenses	OMEXP582	1.000000	0.520132	0.479868	1.000000	0.579936	0.420064
14	958300 Overhead line expenses	OMEXP583	1.000000	0.215745	0.784255	1.000000	0.697120	0.302880
15	958400 Underground line expenses	OMEXP584	1.000000	0.580444	0.419556	1.000000	0.797510	0.202490
16	958500 Street lighting	OMEXP585	1.000000	0.000000	1.000000	1.000000	0.000000	1.000000
17	958600 Meter expenses	OMEXP586	1.000000	0.446523	0.553477	1.000000	0.507669	0.492331
18	958700 Customer installations expenses	OMEXP587	1.000000	0.406771	0.593229	1.000000	0.390516	0.609484
19	958800 Miscellaneous distribution expenses	OMEXP588	1.000000	0.314252	0.685748	1.000000	0.626792	0.373208
23	958900 Rents Control Center	OMEXP589	1.000000	0.582047	0.417953	1.000000	0.647873	0.352127
24	959000 Maintenance Supervision & Engineering	OMEXP590	1.000000	0.298176	0.701824	1.000000	0.391903	0.608097
25	959100 Maintenance Structures	OMEXP591	1.000000	0.560338	0.439662	1.000000	0.528443	0.471557
26	959200 Maintain equipment	OMEXP592	1.000000	0.523347	0.476653	1.000000	0.466992	0.533008
27	959300 Maintain overhead lines	OMEXP593	1.000000	0.178216	0.821784	1.000000	0.196124	0.803876
28	959400 Maintain underground line	OMEXP594	1.000000	0.612777	0.387223	1.000000	0.590935	0.409065
29	959500 Maintain line transformers	OMEXP595	1.000000	0.617983	0.382017	1.000000	0.451756	0.548244
30	959600 Maintain street lighting & signal sys	OMEXP596	1.000000	0.000275	0.999725	1.000000	0.003289	0.996711
31	959700 Maintain meters	OMEXP597	1.000000	0.406992	0.593008	1.000000	0.386454	0.613546
32	959800 Maintain distribution plant	OMEXP598	1.000000	0.527267	0.472733	1.000000	0.394337	0.605663
33	990200 Meter reading expenses	OMEXP902	1.000000	0.361581	0.638419	1.000000	0.361581	0.638419
34	990300 Cust records and collection exp	OMEXP903	1.000000	0.340295	0.659705	1.000000	0.337697	0.662303
35	990500 Miscellaneous cust accounts exp	OMEXP905	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
36	990400 Uncollectible accounts	OMEXP904	1.000000	0.345037	0.654963	1.000000	0.385849	0.614151
37	990700 Supervision	OMEXP907	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
38	990800 Customer assistance expenses	OMEXP908	1.000000	0.296695	0.703305	1.000000	0.296920	0.703080
39	990900 Informational & instructional adv	OMEXP909	1.000000	0.329424	0.670576	1.000000	0.342444	0.657556
40	991000 Miscellaneous customer service & informational exp	OMEXP910	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
41	991200 Demonstrating & selling expenses	OMEXP912	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
42	991300 Advertising expense	OMEXP913	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
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PEPCO - DC
JURISDICTIONAL COST OF SERVICE STUDY
Multiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

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	RATIO TABLE-44 INTERNALLY DEVELOPED CON'T-	ALLOC	2020 Total DISTRIBUTION (1)	2020 DC DISTRIBUTION (2)	2020 Other DISTRIBUTION (3)	2021 Total DISTRIBUTION (1)	2021 DC DISTRIBUTION (2)	2021 Other DISTRIBUTION (3)
1	PLT OH Lines	PLTOH	1.000000	0.254771	0.745229	1.000000	0.266146	0.733854
2	PLT UG Lines	PLTUG	1.000000	0.646482	0.353518	1.000000	0.657402	0.342598
3	PLT OH Services	PLTOHS	1.000000	0.355992	0.644008	1.000000	0.400024	0.599976
4	PLT UG Services	PLTUGS	1.000000	0.623897	0.376103	1.000000	0.627049	0.372951
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11	958000 Operation Supervision & Engineering	OMEXP580	1.000000	0.624509	0.375491	1.000000	0.627119	0.372881
12	958100 Load dispatching	OMEXP581	1.000000	0.517393	0.482607	1.000000	0.517236	0.482764
13	958200 Station expenses	OMEXP582	1.000000	0.566123	0.433877	1.000000	0.475437	0.524563
14	958300 Overhead line expenses	OMEXP583	1.000000	0.695479	0.304521	1.000000	0.688659	0.311341
15	958400 Underground line expenses	OMEXP584	1.000000	0.794419	0.205581	1.000000	0.803354	0.196646
16	958500 Street lighting	OMEXP585	1.000000	0.000000	1.000000	1.000000	0.000000	1.000000
17	958600 Meter expenses	OMEXP586	1.000000	0.517102	0.482898	1.000000	0.522226	0.477774
18	958700 Customer installations expenses	OMEXP587	1.000000	0.423154	0.576846	1.000000	0.424449	0.575551
19	958800 Miscellaneous distribution expenses	OMEXP588	1.000000	0.637048	0.362952	1.000000	0.648697	0.351303
23	958900 Rents Control Center	OMEXP589	1.000000	0.909084	0.090916	1.000000	0.910582	0.089418
24	959000 Maintenance Supervision & Engineering	OMEXP590	1.000000	0.391775	0.608225	1.000000	0.390117	0.609883
25	959100 Maintenance Structures	OMEXP591	1.000000	0.509307	0.490693	1.000000	0.476652	0.523348
26	959200 Maintain equipment	OMEXP592	1.000000	0.465002	0.534998	1.000000	0.457588	0.542412
27	959300 Maintain overhead lines	OMEXP593	1.000000	0.186142	0.813858	1.000000	0.179705	0.820295
28	959400 Maintain underground line	OMEXP594	1.000000	0.600136	0.399864	1.000000	0.605172	0.394828
29	959500 Maintain line transformers	OMEXP595	1.000000	0.593885	0.406115	1.000000	0.602158	0.397842
30	959600 Maintain street lighting & signal sys	OMEXP596	1.000000	0.003925	0.996075	1.000000	0.003919	0.996081
31	959700 Maintain meters	OMEXP597	1.000000	0.389160	0.610840	1.000000	0.402767	0.597233
32	959800 Maintain distribution plant	OMEXP598	1.000000	0.394005	0.605995	1.000000	0.392343	0.607657
33	990200 Meter reading expenses	OMEXP902	1.000000	0.361581	0.638419	1.000000	0.361581	0.638419
34	990300 Cust records and collection exp	OMEXP903	1.000000	0.339703	0.660297	1.000000	0.339975	0.660025
35	990500 Miscellaneous cust accounts exp	OMEXP905	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
36	990400 Uncollectible accounts	OMEXP904	1.000000	0.418280	0.581720	1.000000	0.424176	0.575824
37	990700 Supervision	OMEXP907	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
38	990800 Customer assistance expenses	OMEXP908	1.000000	0.295709	0.704291	1.000000	0.294605	0.705395
39	990900 Informational & instructional adv	OMEXP909	1.000000	0.342444	0.657556	1.000000	0.342444	0.657556
40	991000 Miscellaneous customer service & informational exp	OMEXP910	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
41	991200 Demonstrating & selling expenses	OMEXP912	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
42	991300 Advertising expense	OMEXP913	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
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PEPCO - DC
28-May-19 12:27 JURISDICTIONAL COST OF SERVICE STUDY
lultiyear Rate Plan (2018 Base, 2019 Bridge, 2020-2022 Projection)
ELECTRIC DISTRIBUTION

RATIO TABLE-44
INTERNALLY DEVELOPED CON'T-

		ALLOC	2022 Total DISTRIBUTION (1)	2022 DC DISTRIBUTION (2)	2022 Other DISTRIBUTION (3)
1	PLT OH Lines	PLTOH	1.000000	0.276904	0.723096
2	PLT UG Lines	PLTUG	1.000000	0.667917	0.332083
3	PLT OH Services	PLTOHS	1.000000	0.443406	0.556594
4	PLT UG Services	PLTUGS	1.000000	0.631721	0.368279
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11	958000 Operation Supervision & Engineering	OMEXP580	1.000000	0.625670	0.374330
12	958100 Load dispatching	OMEXP581	1.000000	0.518259	0.481741
13	958200 Station expenses	OMEXP582	1.000000	0.464402	0.535598
14	958300 Overhead line expenses	OMEXP583	1.000000	0.686558	0.313442
15	958400 Underground line expenses	OMEXP584	1.000000	0.801534	0.198466
16	958500 Street lighting	OMEXP585	1.000000	0.000000	1.000000
17	958600 Meter expenses	OMEXP586	1.000000	0.519246	0.480754
18	958700 Customer installations expenses	OMEXP587	1.000000	0.424984	0.575016
19	958800 Miscellaneous distribution expenses	OMEXP588	1.000000	0.679370	0.320630
23	958900 Rents Control Center	OMEXP589	1.000000	0.911984	0.088016
24	959000 Maintenance Supervision & Engineering	OMEXP590	1.000000	0.380533	0.619467
25	959100 Maintenance Structures	OMEXP591	1.000000	0.448892	0.551108
26	959200 Maintain equipment	OMEXP592	1.000000	0.441338	0.558662
27	959300 Maintain overhead lines	OMEXP593	1.000000	0.173395	0.826605
28	959400 Maintain underground line	OMEXP594	1.000000	0.609219	0.390781
29	959500 Maintain line transformers	OMEXP595	1.000000	0.608439	0.391561
30	959600 Maintain street lighting & signal sys	OMEXP596	1.000000	0.003921	0.996079
31	959700 Maintain meters	OMEXP597	1.000000	0.417350	0.582650
32	959800 Maintain distribution plant	OMEXP598	1.000000	0.382885	0.617115
33	990200 Meter reading expenses	OMEXP902	1.000000	0.361581	0.638419
34	990300 Cust records and collection exp	OMEXP903	1.000000	0.344171	0.655829
35	990500 Miscellaneous cust accounts exp	OMEXP905	0.000000	0.000000	0.000000
36	990400 Uncollectible accounts	OMEXP904	1.000000	0.395691	0.604309
37	990700 Supervision	OMEXP907	0.000000	0.000000	0.000000
38	990800 Customer assistance expenses	OMEXP908	1.000000	0.294526	0.705474
39	990900 Informational & instructional adv	OMEXP909	1.000000	0.342444	0.657556
40	991000 Miscellaneous customer service & informational exp	OMEXP910	0.000000	0.000000	0.000000
41	991200 Demonstrating & selling expenses	OMEXP912	0.000000	0.000000	0.000000
42	991300 Advertising expense	OMEXP913	0.000000	0.000000	0.000000
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T.W. Wolverton
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (C) – 4

Pepco
Multiyear Rate Plan O&M Summary
($ Thousands)

Responsibility Area	Witness	2018	2019	2020	2021	2022
Customer Operations	Poncia	$ 62,859	$ 76,511	$ 76,689	$ 77,463	$ 78,163
Electric Operations	Sullivan	101,604	99,877	87,154	87,030	87,227
Technical Services	Ortega	48,378	51,185	53,960	54,357	55,976
Transmission and Substations	Fisher	44,514	53,029	52,685	52,658	53,594
Support Services	Maxwell	28,140	20,699	21,612	22,097	22,436
Communications	Barnett	4,672	3,374	3,422	3,460	3,497
Executive Management	Barnett	2,313	2,633	2,655	2,691	2,743
Controller	Barnett	5,632	5,339	5,163	5,065	5,226
Finance	Barnett	5,801	4,672	4,689	4,783	4,873
Treasury (Bank Fees)	Barnett	495	1,411	1,455	1,462	1,469
Government Affairs	Barnett	11,344	12,477	12,688	12,889	13,005
Human Resources	Barnett	3,220	3,146	3,246	3,233	3,281
Legal	Barnett	5,635	4,646	4,635	4,652	4,677
PHISCO Depreciation and Amortization	Barnett	17,005	16,339	14,075	12,559	11,640
Regulatory Affairs	Barnett	13,557	16,035	16,342	16,586	16,902
Supply	Barnett	2,529	1,597	1,496	1,592	1,610
Non-Embedded EBSC - Non IT	Barnett	56,661	50,732	49,005	48,480	48,106
Non-Embedded EBSC - IT	Calabrese	48,567	50,209	51,324	49,276	47,829
Project Management		6,971	3,465	2,903	2,954	2,837
Bad Debt Expense		10,752	11,163	10,910	11,836	11,666
Other		(2,012)	8,221	6,904	8,255	8,569
Total		$ 478,639	$ 496,760	$ 483,013	$ 483,378	$ 485,326
Total by FERC:						
Transmission/SOS		41,634	46,284	38,548	37,963	38,064
Distribution		145,754	151,136	147,334	148,560	149,983
Customer		97,306	108,828	111,421	111,013	111,687
Administrative & General		184,105	184,262	179,406	179,525	179,261
Below the Line/Other		9,840	6,251	6,304	6,318	6,332
Total		$ 478,639	$ 496,760	$ 483,013	$ 483,378	$ 485,326
Reconciliation to Distribution O&M						
Remove Transmission/SOS		(41,634)	(46,284)	(38,548)	(37,963)	(38,064)
Remove Below the Line/Other		(9,840)	(6,251)	(6,304)	(6,318)	(6,332)
Remove SOS Bad Debt Expense		(4,102)	(3,902)	(3,607)	(3,719)	(3,623)
Remove Empower MD Costs		(3,415)	(3,245)	(3,199)	(3,170)	(3,155)
Remove Empower MD Costs - Deferred		-	(2,080)	(2,150)	(2,210)	(2,279)
Remove Transmission Allocation of A&G		(22,475)	(22,435)	(21,815)	(21,751)	(21,705)
Remove Other		(346)	(12)	(13)	(13)	(13)
Add Reg Asset Amortizations		8,034	7,139	5,823	4,598	1,317
Total Distribution O&M		$ 404,862	$ 419,691	$ 413,200	$ 412,833	$ 411,472
DC Distribution O&M (per PEPCO C-3)		$ 162,574	$ 177,110	$ 174,657	$ 174,002	$ 171,356

T.W. Wolverton
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (C) – 5

Potomac Electric Power Company

District of Columbia
Ratemaking Results - Distribution Only
Annual Reconciliation Filing Example (For Illustrative Purposes Only)

(Thousands of Dollars)

Line No.		MRP 2020 - PROJECTION Average Unadjusted (1)	Ratemaking Adjustments (2)	D.C. Adjusted (3)	MRP 2020 - ACTUAL Average Unadjusted (4)	Ratemaking Adjustments (5)	D.C. Adjusted (6)	Adjusted Results Variance $ (6) vs. (3)	Adjusted Results Variance %	Variance Group / Threshold	Threshold Met? (Y/N)	Variance Description
	Rate Base											
1	Electric Plant in Service	$ 4,197,040	$ (1,694)	$ 4,195,346	$ 4,150,000	$ (1,694)	$ 4,148,306	$ (47,040)	-1.1%	G1: >1% & min $500K	Y	Provide Description of Variance
2	Accumulated Depreciation	(1,311,476)	478	(1,310,998)	(1,310,000)	478	(1,309,522)	1,476	-0.1%	G1: >1% & min $500K	N	
3	Accumulated Amortization	(20,322)	-	(20,322)	(20,300)	-	(20,300)	22	-0.1%	G2: >5% & min $500K	N	
4	Materials and Supplies	38,116	-	38,116	42,000	-	42,000	3,884	10.2%	G2: >5% & min $500K	Y	Provide Description of Variance
5	Cash Working Capital	10,142	(103)	10,039	10,142	(103)	10,039	-	0.0%	G2: >5% & min $500K	N	
6	Accumulated Deferred Income Taxes	(824,829)	-	(824,829)	(824,829)	-	(824,829)	-	0.0%	G1: >1% & min $500K	N	
7	Prepaid Pension/OPEB Liab. (net of tax)	60,151	-	60,151	60,151	-	60,151	-	0.0%	G2: >5% & min $500K	N	
8	Customer Deposits	(9,485)	-	(9,485)	(9,485)	-	(9,485)	-	0.0%	G2: >5% & min $500K	N	
9	Pepco Portion of Servco Assets	25,300	-	25,300	25,300	-	25,300	-	0.0%	G2: >5% & min $500K	N	
10	Regulatory Assets	30,461	12,873	43,335	30,461	12,873	43,335	-	0.0%	G2: >5% & min $500K	N	
11	Unamortized Credit Facility Costs	246	-	246	246	-	246	-	0.0%	G2: >5% & min $500K	N	
12	Total Rate Base	$ 2,195,345	$ 11,554	$ 2,206,899	$ 2,153,687	$ 11,554	$ 2,165,241	$ (41,658)				
	Operating Revenues											
13	Sale of Electricity	$ 523,952	$ 58,085 (a)	$ 582,037	$ 523,952	$ 58,085	$ 582,037	$ -	0.0%	G1: >1% & min $500K	N	
14	Other Revenues	6,561		6,561	6,561		6,561	-	0.0%	G2: >5% & min $500K	N	
15	Operating Revenues	$ 530,513	$ 58,085	$ 588,598	$ 530,513	$ 58,085	$ 588,598	$ -				
	Operating Expenses											
16	Operation and Maintenance	$ 174,657	$ (4,260)	$ 170,397	$ 172,657	$ (4,917)	$ 167,740	$ (2,657)	-1.6%	G3: See Tab 2	N/A	
17	Depreciation	116,102	(93)	116,009	116,102	(93)	116,009	-	0.0%	G2: >5% & min $500K	N	
18	Amortization	13,511	4,677	18,188	13,511	4,677	18,188	-	0.0%	G2: >5% & min $500K	N	
19	Other Taxes	145,818	-	145,818	145,818	-	145,818	-	0.0%	G2: >5% & min $500K	N	
20	D.C. Income Tax	(147)	3,983	3,836	18	4,037	4,055	219	5.7%	G2: >5% & min $500K	N	
21	Federal Income Tax	(13,504)	11,215	(2,290)	(13,119)	11,341	(1,778)	512	-22.4%	G2: >5% & min $500K	Y	Provide Description of Variance
22	Total Operating Expenses	$ 436,437	$ 15,521	$ 451,958	$ 434,987	$ 15,045	$ 450,032	$ (1,926)				
23	Operating Income	$ 94,076	$ 42,563	$ 136,640	$ 95,526	$ 43,040	$ 138,566	$ 1,926				
24	**D.C. Jurisdictional Return on Rate Base**	**4.29%**		**6.19%**	**4.44%**		**6.40%**	**0.21%**				
25	Less Weighted Cost of Long-Term Debt	2.61%		2.61%	2.65%		2.65%	0.04%				
26	Net amount available for common equity	1.68%		3.58%	1.79%		3.75%					
27	Common Equity ratio	50.46%		50.46%	50.50%		50.50%	0.04%				
28	**Earned D.C. Jurisdictional Return on Equity**	**3.32%**		**7.10%**	**3.54%**		**7.42%**	**0.33%**				

(a) 58,085 = 84,938 x 68%

Dead-band Low	6.85%		
Dead-band High	7.35%		
Actual ROE within Dead-band? (Y/N)	N		
Amount Outside of Dead-band	-0.08%	Plus/Minus PIMS Factor	Total Rate Adjustment
Customer %	75%		
Customer ROE Sharing	-0.06%	-0.10%	-0.16%
Customer Revenue Sharing	$ (874)	$ (1,509)	$ (2,382)
Utility %	25%		
Utility ROE Sharing	-0.02%		
Utility Revenue Sharing	$ (291)		

Potomac Electric Power Company

District of Columbia
Ratemaking Results - Distribution Only
Annual Reconciliation Filing Example (For Illustrative Purposes Only)

		MRP 2020 - PROJECTION	MRP 2020 - ACTUAL	Adjusted Results Variance $	Adjusted Results Variance %	Variance Group / Threshold	Threshold Met? (Y/N)	Variance Description
	DISTRIBUTION EXPENSES							
	OPERATION							
1	958000 Operation Supervision & Engineering	2,575,745	1,350,000	(1,225,745)	-47.6%	G3: >10% & min $500K	Y	Provide Description of Variance
2	958100 Load dispatching	4,131,982	4,000,000	(131,982)	-3.2%	G3: >10% & min $500K	N	
3	958200 Station expenses	1,292,647	1,292,647	-	0.0%	G3: >10% & min $500K	N	
4	958300 Overhead line expenses	2,987,941	2,987,941	-	0.0%	G3: >10% & min $500K	N	
5	958400 Underground line expenses	11,659,303	11,017,031	(642,273)	-5.5%	G3: >10% & min $500K	N	
6	958500 Street lighting	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
7	958600 Meter expenses	3,603,416	3,603,416	-	0.0%	G3: >10% & min $500K	N	
8	958700 Customer installations expenses	3,275,161	3,275,161	-	0.0%	G3: >10% & min $500K	N	
9	958800 Miscellaneous distribution expenses	5,714,214	5,714,214	-	0.0%	G3: >10% & min $500K	N	
10	958900 Rents Control Center	3,865,225	3,865,225	-	0.0%	G3: >10% & min $500K	N	
11	TOTAL OPERATION	39,105,634	37,105,634	(2,000,000)				
	MAINTENANCE							
12	959000 Maintenance Supervision & Engineering	287,868	287,868	-	0.0%	G3: >10% & min $500K	N	
13	959100 Maintenance Structures	133,884	133,884	-	0.0%	G3: >10% & min $500K	N	
14	959200 Maintain equipment	8,355,955	8,355,955	-	0.0%	G3: >10% & min $500K	N	
15	959300 Maintain overhead lines	7,909,012	7,909,012	-	0.0%	G3: >10% & min $500K	N	
16	959400 Maintain underground line	8,715,049	8,715,049	-	0.0%	G3: >10% & min $500K	N	
17	959500 Maintain line transformers	950,625	950,625	-	0.0%	G3: >10% & min $500K	N	
18	959600 Maintain street lighting & signal sys	13,184	13,184	-	0.0%	G3: >10% & min $500K	N	
19	959700 Maintain meters	248,179	248,179	-	0.0%	G3: >10% & min $500K	N	
20	959800 Maintain distribution plant	2,070,858	2,070,858	-	0.0%	G3: >10% & min $500K	N	
21	TOTAL MAINTENANCE	28,684,615	28,684,615	-	0.0%	G3: >10% & min $500K	N	
22	TOTAL DISTRIBUTION EXPENSES	67,790,249	65,790,249	(2,000,000)				
	OPERATION & MAINT EXP CON'T-23							
	CUSTOMER ACCOUNTS EXPENSE							
1	990200 Meter reading expenses	377,402	377,402	-	0.0%	G3: >10% & min $500K	N	
2	990300 Cust records and collection exp	30,510,467	30,510,467	-	0.0%	G3: >10% & min $500K	N	
3	990500 Miscellaneous cust accounts exp	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
4	990400 Uncollectible accounts	3,054,786	3,054,786	-	0.0%	G3: >10% & min $500K	N	
5	TOTAL CUSTOMER ACCOUNTS EXPENSE	33,942,655	33,942,655	-				
	CUSTOMER SERVICE EXPENSE							
6	990700 Supervision	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
7	990800 Customer assistance expenses	1,645,095	1,645,095	-	0.0%	G3: >10% & min $500K	N	
8	990900 Informational & instructional adv	266,336	266,336	-	0.0%	G3: >10% & min $500K	N	
9	991000 Miscellaneous customer service & informational exp	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
10	TOTAL CUSTOMER SERVICE EXPENSE	1,911,432	1,911,432	-				
	SALES EXPENSE							
11	991200 Demonstrating & selling expenses	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
12	991300 Advertising expense	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
13	TOTAL SALES EXPENSE	-	-	-				
14	OPERATIONS & MAINTENANCE LESS A&G	103,644,336	101,644,336	(2,000,000)				

Potomac Electric Power Company

District of Columbia
Ratemaking Results - Distribution Only
Annual Reconciliation Filing Example (For Illustrative Purposes Only)

		MRP 2020 - PROJECTION	MRP 2020 - ACTUAL	Adjusted Results Variance $	Adjusted Results Variance %	Variance Group / Threshold	Threshold Met? (Y/N)	Variance Description
	OPERATION & MAINT EXP CON'T-24							
	ADMINISTRATIVE & GENERAL EXPENSE							
	OPERATION							
1	992000 Administrative & General salaries	3,217,721	3,217,721	-	0.0%	G3: >10% & min $500K	N	
2	992000 Administrative & General salaries Direct MD	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
3	992000 Administrative & General salaries Direct DC	677,013	677,013	-	0.0%	G3: >10% & min $500K	N	
4	992100 Office supplies & expenses	810,208	810,208	-	0.0%	G3: >10% & min $500K	N	
5	992100 Office supplies & expenses -DC	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
6	992100 Office supplies & expenses -MD	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
7	992300 Outside services employed	48,709,431	48,709,431	-	0.0%	G3: >10% & min $500K	N	
8	992300 Outside services employed - MD	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
9	992300 Outside services employed - DC	692,832	692,832	-	0.0%	G3: >10% & min $500K	N	
10	992400 Property insurance	513,008	513,008	-	0.0%	G3: >10% & min $500K	N	
11	992500 Injuries & damages	1,491,538	1,491,538	-	0.0%	G3: >10% & min $500K	N	
12	992600 Employee pensions & benefits	10,407,068	10,407,068	-	0.0%	G3: >10% & min $500K	N	
13	992600 Distr-direct empl pensions & benefits- DC	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
14	992600 Distr-direct empl pensions & benefits- MD	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
15	992800 Regulatory commission expenses	66,728	66,728	-	0.0%	G3: >10% & min $500K	N	
16	Regulatory commission exp - DC	3,843,781	3,843,781	-	0.0%	G3: >10% & min $500K	N	
17	Regulatory commission exp - MD	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
18	992900 Duplicate charges-Credit	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
19	993010 General ad expenses	218,353	218,353	-	0.0%	G3: >10% & min $500K	N	
20	993020 Miscellaneous general expenses	365,332	365,332	-	0.0%	G3: >10% & min $500K	N	
21	993100 Rents	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
22	TOTAL OPERATION	71,013,013	71,013,013	-				
23	MAINTENANCE							
24	993500 Maintenance of general plant	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
25	TOTAL MAINTENANCE	-	-	-				
26	TOTAL ADMINISTRATIVE & GENERAL EXPENSE	71,013,013	71,013,013	-				
27	TOTAL DC DISTR OPERATION & MAINTENANCE EXPENSE - UNADJUSTED	174,657,349	172,657,349	(2,000,000)				
	Ratemaking Adjustments							
1	Removal of supplemental executive retirement plans (SERP)	(707,000)	(707,000)	-	0.0%	G3: >10% & min $500K	N	
2	Removal of certain executive incentive plan costs	(1,502,000)	(1,502,000)	-	0.0%	G3: >10% & min $500K	N	
3	Removal of institutional advertising/selling expenses	(218,000)	(218,000)	-	0.0%	G3: >10% & min $500K	N	
4	Removal of employee association costs	(42,000)	(42,000)	-	0.0%	G3: >10% & min $500K	N	
5	Removal of industry contributions and membership fees	(440,000)	(440,000)	-	0.0%	G3: >10% & min $500K	N	
6	Removal of executive perquisite expenses	(27,277)	(27,277)	-	0.0%	G3: >10% & min $500K	N	
7	Removal of BSC Billed Depreciation (Merger Commitment 39)	(469,000)	(1,126,000)	(657,000)	140.1%	G3: >10% & min $500K	Y	Provide Description of Variance
8	Reflection of customer deposit interest expense and credit facilit	466,372	466,372	-	0.0%	G3: >10% & min $500K	N	
9	Reflection of Current Case Costs	(929,000)	(929,000)	-	0.0%	G3: >10% & min $500K	N	
14	Reflection of Inflationary Growth of O&M expense	-	-	-	#DIV/0!	G3: >10% & min $500K	N	
15	Reflection of CTO Regulatory Asset	(391,982)	(391,982)	-	0.0%	G3: >10% & min $500K	N	
		(4,259,887)	(4,916,887)	(657,000)				
	Total DC Distribution O&M Expense - Adjusted	170,397,461	167,740,461	(2,657,000)				

IN THE MATTER OF THE APPLICATION OF POTOMAC ELECTRIC POWER COMPANY FOR AUTHORITY TO IMPLEMENT A MULTIYEAR RATE PLAN FOR ELECTRIC DISTRIBUTION SERVICE IN THE DISTRICT OF COLUMBIA	**)**	**Formal Case No. 1156**

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

VOLUME II

DIRECT TESTIMONIES AND EXHIBITS OF

Mr. Jay C. Ziminsky
Mr. Lance Schafer

J.C. Ziminsky
Direct Testimony
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (D)

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EXECUTIVE SUMMARY - JAY C. ZIMINSKY

To comply with the Public Service Commission of the District of Columbia's (Commission) directive in Formal Case No. 1139 that if the Potomac Electric Power Company (Pepco or the Company) presents an alternative ratemaking proposal Pepco was also to submit a traditional test year filing, this testimony presents the Company's traditional test period compliance filing revenue requirement study including Electric Distribution Cost of Service, Ratemaking Adjustments and Jurisdictional Cost of Service. The traditional test period compliance filing revenue requirement study supports a $88.6 million increase in annual District of Columbia distribution revenues. The testimony also addresses items such as the Company's capital structure and Cash Working Capital/2017 Lead-Lag Study that support both the Company's Multiyear Rate Plan (MRP) and the traditional test period compliance filing. Finally, the testimony addresses several merger commitments from Formal Case No. 1119 as well as other Commission directives**.**

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF JAY C. ZIMINSKY
FORMAL CASE NO. 1156

I. INTRODUCTION AND QUALIFICATIONS

Q1. Please state your name and position.

A1. My name is Jay C. Ziminsky. I am Director, Regulatory Strategy and Revenue Policy, in the Regulatory Affairs Department of Pepco Holdings LLC (PHI). I am testifying on behalf of Pepco or the Company.

Q2. What are your responsibilities in your role as Director of Regulatory Strategy and Revenue Policy?

A2. I am responsible for the coordination of revenue requirement, cost allocation, and rate determinations in PHI's distribution jurisdictions of the District of Columbia, Maryland, Delaware, and New Jersey, as well as PHI's transmission filings with the Federal Energy Regulatory Commission (FERC). In addition, I am responsible for coordinating and supporting regulatory strategy, revenue policy, and various other regulatory compliance matters.

Q3. Please state your educational background and professional experience.

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

In 1988, I joined Price Waterhouse as a Tax Associate. In 1991, I joined Delmarva Power & Light Company (Delmarva Power) as a Staff Accountant in the General Accounting section of the Controller's Department. In 1994, I joined the Management Information Process Redesign team as a Senior Accountant. In 1995, I joined the Conectiv Enterprises Business and Financial Management team as a Senior Financial Analyst. In 1996, I was promoted to Finance and Accounting Manager of Conectiv Communications, where I was later promoted to Finance and Accounting Director (in 1999) and Vice President – Finance (in 2000). In 2002, I joined the PHI Treasury Department as Finance Manager. In 2006, I joined the PHI Regulatory Department and was later promoted to Manager of Revenue Requirements in October 2008, where my responsibilities included the coordination of revenue requirement determinations in New Jersey, Delaware and Maryland as well as coordinating various other regulatory compliance matters. With the consummation of the merger between PHI and Exelon Corporation (Exelon), I was promoted to my current position in April 2016.

Q4. What is the scope of your Direct Testimony in this proceeding?

A4. I present the Company's traditional test period compliance filing revenue requirement study which presents the $88.6 million increase in annual District of Columbia distribution revenues, which the Company is presenting in compliance with the requirement that Pepco file a traditional test year filing in addition to an alternative ratemaking proposal.

This testimony and the accompanying exhibits were prepared by me or under my direct supervision. The sources for my testimony are Company records, public documents, and my personal knowledge and experience. My testimony is separated into three sections:

- Section A covers items that only address the traditional test period compliance filing such as: Electric Distribution Cost of Service, Ratemaking Adjustments (RMAs), and Jurisdictional Cost of Service;
- Section B covers items that support both the MRP and the traditional test period compliance filing such as Capital Structure and Cash Working Capital/2017 Lead-Lag Study; and
- Section C covers merger commitments and other directives.

Q5. Why is Pepco filing a traditional test year along with its MRP filing?

A5. Pepco is filing a traditional test year in compliance with the following Commission directive in Order No. 18846 in Formal Case No. 1139:

> The Commission is not averse to allowing Pepco to include in its next rate case a request for a fully forecasted test year and or a multi-year rate proposal, in addition to a traditional test year filing, subject to the following conditions in addition to those stated in Commission Rules 200.1, 200.2, 200.3, and 200.5.[1]

Q6. Please list all the exhibits provided in support of your Direct Testimony along with a brief description.

A6. Please see Table 1 for a description of the exhibits presented in support of my Direct Testimony:

[1] Formal Case No. 1139, Order No. 18846 at ¶594.

Table 1

PEPCO (D)-1	Presents Company's unadjusted and adjusted District of Columbia jurisdictional results of operation for the provision of distribution service for the 12 months ended June 30, 2019.
PEPCO (D)-2	Presents listing of rate base and operating income elements on both a system and a distribution-only level.
PEPCO (D)-3	Jurisdictional Cost of Service Study (JCOS)
PEPCO (D)-4	Commission Rule 200.5: Analysis of Changes in Average Unadjusted District of Columbia Jurisdictional Rate Base and Operating Income
PEPCO (D)-5	Capital Structure
PEPCO (D)-6	Calculation of the District of Columbia recordation fees for the December 2018 long-term debt issuance.
PEPCO (D)-7	Cash Working Capital (CWC) Lead Lag Study
PEPCO (D)-8	Provides a quantification of the test period synergies (labor vs. non-labor, PHI Service Company (PHISCO) vs. Exelon Business Service Company (EBSC))
PEPCO (D)-9	Presents most recent historic balance sheet available as of the date of the filing
PEPCO (D)-10	Presents Company's regulatory expense related to matters before the Commission for the 12 months ended December 31, 2018.

II. ELECTRIC DISTRIBUTION COST OF SERVICE

Q7. Is the Company's proposal in this proceeding consistent with Commission precedent as it relates to the inclusion of projected data in the proposed test year?

A7. Yes. Commission Rule 200.4 states that "…the proposed test year may include forecasted data; provided, that the proposed test year does not include more than six (6) months of forecasted data."[2] The Company has chosen a partially projected test year because it provides a more current test period that will be more predictive of the rate-effective period than would a fully historical test year. Further, the use of a partially projected test year is consistent with the Company's presentation in previous rate cases. In

[2] 15 D.C.M.R. § 200.4.

that regard, the Company's applications in Formal Case Nos. 1053 and 1087 were based on six months actual, six months projected test year, which the Commission found to be appropriate in both cases.[3]

Q8. Have you prepared an exhibit that supports the Company's test year used in the traditional test period compliance filing?

A8. Yes. PEPCO (D)-1 presents the financial and accounting data for the test year ended June 30, 2019, which support the Company's presented increase in annual revenues.

Q9. Please summarize the contents of PEPCO (D)-1.

A9. PEPCO (D)-1 includes the following contents:

- Page 1 presents the Company's unadjusted and adjusted[4] District of Columbia jurisdictional results of operation for the provision of distribution service for the 12 months ended June 30, 2019. Page 1 also presents the $88.6 million revenue requirement recommended to achieve the 10.30% rate of return on equity supported by the Direct Testimony of Company Witness Hevert;
- Page 2 presents a summary of the ratemaking adjustments;
- Page 3 presents the revenue requirement associated with each individual ratemaking adjustment;
- Pages 4 through 44 present the detailed derivation of each of the ratemaking

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[3] Formal Case No. 1053, Order No. 14712 at ¶13; Formal Case No. 1087, Order No. 16930 at ¶20.

[4] Unadjusted (or per books) jurisdictional results reflect the test period rate base and earnings results, based on data in the Company's accounting records. Adjusted jurisdictional results reflect ratemaking adjustments for "known and measurable" changes to the unadjusted jurisdictional results. Ratemaking adjustments and their purpose of making the test period results more reflective of the rate-effective period are further discussed in Section IV of my Direct Testimony.

adjustments which I sponsor, along with any associated tax effect;

- Page 45 presents the per books interest synchronization calculation; and
- Page 46 presents the statutory tax rates and associated gross-up factors used in determining the Company's revenue requirement.

The Company's December 31, 2018 capital structure and associated cost rates that were used in deriving the District of Columbia revenue requirement presented at page 1 of PEPCO (D)-1 (line 15, column 4). These items are discussed in the capital structure section of my Direct Testimony and the Direct Testimony of Company Witness Hevert.

III. TRADITIONAL TEST PERIOD COMPLIANCE FILING

Q10. Please describe the procedures employed in the preparation of the projected data.

A10. The six months of projected data were based on the Company's 2019 budgeted data. The projected data were combined with six months of actual data, then directly assigned and/or allocated first to the Company's distribution business and then to the District of Columbia jurisdiction. This method is consistent with the procedure employed in Formal Case Nos. 1053, 1087, 1103 and 1139, all of which the Commission accepted.

Q11. What test year is the Company proposing for use as part of its traditional test period compliance filing, and why was it chosen?

A11. The proposed traditional test year is the 12-month period ended June 30, 2019, comprised of historical data for the six-month period ended December 31, 2018 and forecasted data for the six-month period ended June 30, 2019. The level of return in this test year is representative of the level of return that the Company's current rates are producing on its distribution cost of service. Under current traditional ratemaking, the adjusted test period is reflective of conditions expected to prevail during the period that the

rates set in this proceeding are likely to be in effect, which represents the rate-effective period.

Q12. Please summarize the results of your traditional test compliance period compliance revenue requirements study.

A12. As shown at PEPCO (D)-1, page 1, the Company is earning a rate of return of only 4.87% on its fully adjusted rate base for the 12 months ended June 30, 2019. This translates to an adjusted return on equity of 4.48%.

Q13. Please discuss how Pepco's distribution-only cost of service was developed.

A13. Amounts presented in this proceeding relate only to Pepco's regulated distribution operations. The financial records of the Company are not presented on a distribution-only basis; rather, they consist of costs associated with the Standard Offer Service, Transmission, and Distribution lines of business. The basis for developing Pepco's distribution-only cost of service from the Company's financial records is the distribution accounts as specified in the FERC Uniform System of Accounts. The majority of costs, on both the plant side and the expense side, are contained in FERC accounts that are specific to function.

Distribution plant costs are those costs contained in the FERC distribution accounts numbers 360 to 373. Distribution expense costs are those costs contained in the FERC distribution accounts (inclusive of Customer Accounts Expenses, Customer Service and Informational Expenses, and Sales Expenses) numbers 580 through 916. The exception to this is Account 904, Uncollectible Accounts, which must be functionalized between distribution and supply. Transmission plant costs are contained in FERC transmission

accounts numbers 350 to 359. Transmission expense costs are those costs contained in the FERC transmission accounts numbers 560 through 573.

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

Q14. Have you prepared an exhibit that summarizes total system and distribution-only cost of service elements?

A14. Yes. PEPCO (D)-2, page 1 of 3, presents a listing of rate base and operating income elements on both a system and a distribution-only level. Pages 2 through 3 of PEPCO (D)-2 provide a short description of the method used to identify the distribution-related portion of these costs. The method used to determine distribution-related cost of service is consistent with that used by the Company and accepted by the Commission in Formal Case Nos. 1087, 1103, and 1139.

Q15. Is the revenue requirement and cost of service reflected in your Direct Testimony in conformance with past Commission ratemaking determinations?

A15. Yes. The operating results presented in my Direct Testimony and the accompanying exhibits are generally based upon past Commission ratemaking determinations. Unadjusted rate base is presented on a 13-month-average basis. Rate base has been reduced by the amount of customer deposits in Account 235. Plant Held for Future Use was also excluded from rate base, consistent with the Commission's decision

in Formal Case No. 929.[5] Rate base includes plant materials and operating supplies, net of related accounts payable, as approved in Formal Case No. 905.[6] Also included is the net average balance of the Company's prepaid pension asset and other post-employment benefit (OPEB) liability, net of associated accumulated deferred income taxes (ADIT), which the Commission determined to be "consistent with Commission precedent" in Formal Case No. 1053 (Order No. 14712 at p. 48) and which has consistently been accepted by the Commission in each case since that time, including Pepco's most recent fully litigated base rate case, Formal Case No. 1139.[7]

IV. RATEMAKING ADJUSTMENTS

Q16. What are ratemaking adjustments (RMAs) and why are they necessary?

A16. A component of the ratemaking process is the proposed RMAs. RMAs are generally adjustments to the per books/unadjusted rate base and operating income to adjust for "known and measurable" changes in order to make the test period results more reflective of the rate-effective period, which represents the first 12 months in which the new rates will actually be in effect.

Q17. Please list the RMAs detailed in your Direct Testimony.

A17. See Table 2 for a list of all the Company's proposed RMAs in this case. My Direct Testimony contains details for each of these RMAs.

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[5] Formal Case No. 929, Order No. 10837 at page 46.
[6] Formal Case No. 905, Order No. 9868.
[7] Formal Case No. 1139, Order No. 18846 at ¶171.

Table 2

RMA	RMA Description
1	Annualization of test year reliability closings
2	Inclusion of post-test year reliability plant closings from July 2019 through December 2019
3	Inclusion of post-test year reliability plant closings (based on Construction Work in Progress (CWIP) balance at December 31, 2019) from January 2020 through June 2020
4	Removal of DC Power Line Undergrounding (DC PLUG) initiative costs
5	Annualization of regulatory assets
6	Annualization of Formal Case No. 1150 base revenues
7	Reflection of three-year average overtime level
8	Annualization of wage increases
9	Annualization of employee health and welfare costs
10	Reflection of 2019 pension and Other Post-Employment Benefits (OPEB) expense
11	Removal of supplemental executive retirement plan (SERP) costs
12	Adjustment for executive incentive plan costs
13	Removal of adjustments to deferred compensation balances
14	Reflection of three-year average regulatory expense
15	Reflection of three-year average storm costs
16	Removal of employee club costs
17	Removal of industry contributions and membership fees
18	Removal of institutional advertising/selling expenses
19	Reflection of increase in DC Water and Sewer Authority (DC Water) rates
20a	Reflection of Benning Road Facility environmental remediation effort costs
20b	Inclusion of Benning Road Facility future costs to complete the Remedial Investigation & Feasibility Study (RI/FS)
21	Inclusion of customer deposit interest expense and credit
22	Annualization of software amortization
23	Removal of executive perquisite expenses
24	Annualization of Formal Case No. 1150 depreciation rates
25	Reflection of 8.25% DC income tax rate change
26	Annualization of federal excess deferred income tax liability amortization
27	Removal of Tax Cuts and Jobs Act of 2017 (TCJA) revenue debit
28	Inclusion of Frederick Douglass Memorial Bridge project costs
29	Amortization of PHI Service Company (PHISCO) deficient deferred income tax
30	Reflection of Control Center capital lease expiration
31	Reflection of Maryland Additional Subtraction Modification Method
32	Inclusion of Exelon Merger Commitment adjustment related to Exelon Business Service Company (EBSC) depreciation billed to Pepco

33	Reflection of current rate case costs
34	Inclusion of costs to achieve (CTA) regulatory asset
35	Inclusion of non-labor operation and maintenance (O&M) inflation adjustment
36	Reflection of cost to optimize (CTO) regulatory asset
37	Reflection of cash working capital (CWC) impact of ratemaking adjustments
38	Reflection of interest synchronization

Q18. Please describe RMA 1 with respect to the annualization of test year reliability closings.

A18. RMA 1 adjusts the cost of service to annualize the impact of reliability projects placed in service during the 12 months ended June 30, 2019. As discussed by Company Witness Clark in his Direct Testimony, achievement of the reliability performance standards to which the Company has committed, continued investment in reliability initiatives is required. This adjustment was approved by the Commission in Order No. 18846 in Formal Case No. 1139, following the Commission's precedent set in earlier cases on this adjustment.

This adjustment reflects in Electric Plant in Service (EPIS) the full value of reliability projects placed in service during the test year and are serving customers. The adjustment also removes actual retirements from both EPIS and accumulated depreciation. In addition, it includes the impact on depreciation (both expense and accumulated) and reflects the estimated impact on ADIT.

RMA 1 increases rate base by $43,431,000 and decreases operating income by $805,000 (PEPCO (D)-1, page 4 of 46).

Q19. Please describe RMA 2 with respect to projected reliability plant closings up to evidentiary hearings.

A19. RMA 2 reflects the effect of reliability projects that will be closed to EPIS from July 1, 2019 through December 31, 2019 and for which actual data will be made available prior to the evidentiary hearings in this proceeding (based on the anticipated procedural schedule). These projects also do not generate any new revenue and the associated construction costs will be expended before the rate-effective period commences. Like RMA 1, this adjustment reflects the full value of projects placed into service in EPIS and removes retirements from both EPIS and accumulated depreciation. It also annualizes the associated depreciation (both expense and reserve) and also reflects the estimated impact on ADIT.

RMA 2 increases rate base by $104,796,000 and decreases operating income by $2,079,000 (PEPCO (D)-1, page 5 of 46).

Q20. Has the Commission approved a similar adjustment in prior cases?

A20. Yes. In Formal Case No. 1139, the Commission evaluated and approved a similar adjustment (RMA 24) for reliability closings through the ninth post-test year month. In so doing, the Commission found that "(1) the projects [included in RMA 24] represented "known and certain changes that can be calculated with precision;" (2) the projects were placed in service at a point not "too remote" from the end of the test year; and (3) the projects were needed, reasonable, and beneficial to ratepayers during the rate-effective period."[8] The Commission also accepted a portion of the Company's proposed RMA 25

[8] Formal Case No. 1139, Order No. 18846 at ¶76.

in Formal Case No. 1139, allowing an adjustment for reliability plant closings that occurred up to February 2017, the month prior to evidentiary hearings. The Commission noted that these "costs, represent known and measurable dollars that were expended by the Company and the projects placed into service in January 2017 and February 2017 will be used and useful in providing service to Pepco's customers throughout the entirety of the rate-effective period."[9]

The Company will follow the same procedure as in Formal Case No. 1139 in terms of updating RMA 2 to actual information in time for the parties to conduct discovery and cross examine witnesses. The reliability projects included in RMA 2 will be completed within five months of the test year and will serve customers throughout the projected rate-effective period. As such, RMA 2 clearly meets the Commission's "three prong test" the Commission followed in Formal Case No. 1139.

Q21. Please discuss RMA 3, which proposes to include in rate base reliability projects in CWIP as of December 31, 2019 and expected to be closed to plant in service from January 1, 2019 through June 30, 2020.

A21. RMA 3 reflects the impact of reliability projects in CWIP as of December 31, 2019 and that are forecasted to be placed into service from December 2019 to June 2020. The projects included in RMA 3 will represent known and certain costs that will have already been expended by the Company as of the date of the evidentiary hearings and will reside in CWIP. As such, none of the dollars included in RMA 3 will represent "budgeted" or "estimated" spending by the Company. These projects do not generate any new revenue

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[9] *Id*. at ¶94.

and the associated construction costs will be expended before the rate-effective period commences. The projects are expected to be completed, providing service to customers and placed into service during the rate-effective period in this proceeding.

RMA 3 increases rate base by $59,687,000 and decreases operating income by $1,149,000 (PEPCO (D)-1, page 6 of 46).

Q22. Please describe RMA 4 with respect to the DC PLUG initiative.

A22. RMA 4 removes from cost of service all Electric Company Infrastructure Improvement Costs[10] that are eligible for recovery through the Underground Project Charge,[11] as authorized by the Electric Company Infrastructure Improvement Financing Act of 2014, as amended.[12]

RMA 4 decreases rate base by $197,000 and increases operating income by $5,000 (PEPCO (D)-1, page 7 of 46).

Q23. Please describe RMA 5 with respect to the annualization of regulatory asset amortization.

A23. RMA 5 annualizes amortization expense to reflect the regulatory assets approved by the Commission in Order No. 19433 in Formal Case Nos. 1150 and 1151, as these amortizations began part way through the test year on August 13, 2018. This RMA makes the following adjustments:

- Adjustment to amortization expense:
    - Adjusts amortization expense for the excess rate case costs collected from

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[10] D.C. Code § 34-1311.01(21).
[11] D.C. Code § 34-1311.01(42).
[12] D.C. Code §§ 34-1311.01 *et seq*.

Formal Case No. 1139; and

- Adjusts amortization expense for the over-collected depreciation regulatory liability.

- Adjustment to O&M Expense:
  - Adjusts O&M expense for the amortization of the rate case costs related to Formal Case No. 1150;
  - I Street Substation lease regulatory asset. This RMA will annualize new amortization expense and adjusts the I Street lease expense; and
  - Regulatory asset for the Remedial Investigation (R/I) costs associated with the environmental issues at the Benning Road facility. This RMA will annualize new amortization expense.

RMA 5 decreases rate base by $51,000 and decreases operating income by $360,000 (PEPCO (D)-1, page 8 of 46).

Q24. Please describe RMA 6 with respect to the annualization of the Formal Case Nos. 1150 and 1151 rate decrease.

A24. RMA 6 annualizes the billed distribution revenues to levels set in Order No. 19433 in Formal Case Nos. 1150 and 1151. The rate decrease, authorized by the Commission in Order No. 19433, went into effect on August 13, 2018, part way through the 12 months ended June 30, 2019, which aligns with the Company's traditional test period compliance filing in this proceeding. As such, this RMA is necessary to reflect a full annual amount of distribution revenues at the levels set in Order No. 19433 in Formal Case No. 1150.

RMA 6 decreases operating income by $3,639,000 (PEPCO (D)-1, page 9 of 46).

Q25. Please describe RMA 7 with respect to average overtime levels.

A25. RMA 7 adjusts O&M expense to reflect the three-year average for overtime expenses so that the adjusted test period reflects a normalized level of expense. In Order No. 18846 in Formal Case No. 1139, the Commission approved a similar uncontested adjustment to reflect average overtime expense.[13]

RMA 7 decreases operating income by $905,000 (PEPCO (D)-1, page 10 of 46).

Q26. Please describe RMA 8 with respect to wage increases.

A26. RMA 8 adjusts operation and maintenance expense and payroll tax to annualize employee salary and wage increases that occurred or will occur during the test year (March 1, 2019 for management employees and June 1, 2019 for union/bargaining unit employees). Also included are increases for management (2.5% projected at March 1, 2020) and union employees (2.5% anticipated increase effective June 1, 2020). The wage increases have been adjusted to take into account changes in employee levels, consistent with the treatment approved in each of the Company's base rate proceedings since Formal Case No. 1053.

RMA 8 decreases operating income by $1,770,000 (PEPCO (D)-1, page 11 of 46).

Q27. Please describe RMA 9 with respect to the annualization of employee health and welfare costs.

A27. RMA 9 adjusts O&M expense to reflect changes in employee health and welfare costs in the rate-effective period, consistent with the ratemaking concept approved in Formal Case Nos. 1076, 1087, 1103, and 1139 (Order Nos. 15710, 16930, 17424, and

[13] Formal Case No. 1139, Order No. 18846 at ¶171.

18846, respectively). Costs associated with medical, dental, and vision plans are adjusted to reflect anticipated percentage increases based on an analysis of historical increases in these costs experienced by Pepco in the last three years. The Commission approved a similar uncontested adjustment in Formal Case No. 1139.[14] RMA 9 increases operating income by $67,000 (PEPCO (D)-1, page 12 of 46).

Q28. Please describe RMA 10 with respect to pension and OPEB costs.

A28. RMA 10 adjusts the cost of service to reflect the 2019 level of pension and OPEB expense based on data from the Company's independent actuary, Willis Towers Watson. Consistent with treatment approved in Formal Case No. 1087 (Order No. 16930), Formal Case No. 1103 (Order No. 17424), and Formal Case No. 1139 (Order No. 18846), Pepco's rate base is adjusted to reflect the 2019 level of distribution-related, District of Columbia allocated portion of the net of tax prepaid pension asset and OPEB liability. Also, consistent with treatment approved in Formal Case Nos. 1087, 1103, and 1139, RMA 10 adjusts operating income to reflect the 2019 pension and OPEB expense projected to be incurred by Pepco, including both expense direct to Pepco and the Pepco-allocated portion of such expense related to PHISCO employees and EBSC employees.

RMA 10 decreases rate base by $3,880,000 and decreases operating income by $841,000 (PEPCO (D)-1, page 13 of 46).

Q29. Please describe RMA 11 with respect to the SERP costs.

A29. SERP is a Pepco-sponsored non-qualified retirement program for certain executives that supplements retirement benefits in addition to the normal retirement

[14] Formal Case No. 1139, Order No. 18846 at ¶171.

program (pension) provided by the Company in its Internal Revenue Service-qualified retirement plan.

RMA 11 removes from Pepco's O&M expense 100% of Pepco's SERP expense and removes the formerly capitalized portion of SERP expense from rate base. This treatment of SERP expense in RMA 11 is consistent with Order No. 18846 in Formal Case No. 1139, in which the Commission "disallowed[ed] 100% of SERP expense."[15] However, Pepco continues to believe that recovery of SERP expense is warranted and reserves the right to seek recovery of its SERP expense in a future proceeding.

RMA 11 decreases rate base by $463,000 and increases operating income by $532,000 (PEPCO (D)-1, page 14 of 46).

Q30. Please describe RMA 12 with respect to executive incentive plan expense.

A30. In Order No. 18846, in approving Pepco's adjusted test year expenses for the Annual Incentive Plan (AIP) and for the Executive Incentive Compensation Plan (EICP) in Formal Case No. 1139, the Commission found that:

> [R]atepayers benefit to a sufficient degree from the customer-oriented metrics applicable to the award of compensation from the AIP and the EICP programs. Consequently, we find that these two programs, as presented in this proceeding, are consistent with the standards we have established for cost recovery for incentive compensation in that they are not dependent on achieving corporate financial goals, they are consistent with comparable companies, and they provide benefit to the ratepayers.[16]

Consistent with Order No. 18846, RMA 12 removes the financial portion of

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[15] Formal Case No. 1139, Order No. 18846 at ¶77.
[16] *Id.* at ¶235.

executive incentive plan expense from the cost of service, so that only the portion of executive incentive plan expense associated with customer-related goals remains.[17]

RMA 12 decreases rate base by $359,000 and increases operating income by $2,081,000 (PEPCO (D)-1, page 15 of 46).

Q31. Did Pepco remove costs associated with non-customer-related goals for any other incentive plan?

A31. Yes. RMA 12 also removes costs associated with Long-Term Incentive Plan (LTIP) expense not tied to customer-related goals. The customer-related goals (to which the portion of LTIP that remains in cost of service are tied) include, but are not limited to, customer satisfaction, reliability performance, and call center satisfaction. As such, the portion of LTIP expense remaining in cost of service is directly tied to metrics that incentivize the Company to provide reliable electric service to the satisfaction of its customers. Therefore, Pepco's inclusion of this portion of LTIP in cost of service is consistent with the Commission's decision in Formal Case No. 1139, in which the Commission indicated: "The standard we have set for a utility to receive cost recovery for LTIP in rates requires Pepco establish a persuasive nexus between its use of LTIP and tangible benefits to ratepayers."[18]

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[17] The Chief Executive Officer is the only employee of PHI whose AIP target payout is determined, at least partially, by financial goals.

[18] Formal Case No. 1139, Order No. 18846 at ¶243.

Q32. Please describe RMA 13, with respect to deferred compensation adjustments.

A32. RMA 13 reflects exclusion of test year adjustments to deferred compensation balances, consistent with Commission precedent, most recently in Formal Case No. 1139.[19]

RMA 13 increases operating income by $32,000 (PEPCO (D)-1, page 16 of 46).

Q33. Please describe RMA 14 with respect to three-year-average regulatory expenses.

A33. RMA 14 adjusts operating expenses to reflect a three-year-average amount of regulatory expense, consistent with Commission precedent,[20] including most recently Formal Case No. 1139.[21]

RMA 14 decreases operating income by $449,000 (PEPCO (D)-1, page 17 of 46).

Q34. Please describe RMA 15, related to three-year-average storm restoration expense.

A34. RMA 15 normalizes O&M expense associated with storm restoration efforts to their three-year average level to include a normal level of expense in adjusted cost of service, consistent with the treatment approved in Formal Case No. 1053[22] and subsequent cases, including Formal Case No. 1139.[23]

RMA 15 decreases operating income by $642,000 (PEPCO (D)-1, page 18 of 46).

Q35. Please describe RMA 16, relating to employee club costs.

A35. RMA 16 removes from the cost of service certain employee benefit costs associated with employee club activities, as the Commission directed in Order No. 15710 in Formal

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[19] *Id*. at ¶171.
[20] Formal Case No. 905, Order No. 9868, pg. 69, "we accept OPC's three-year averaging approach as reasonable and reflective of litigation and regulatory expenses for this proceeding."
[21] Formal Case No. 1139, Order No. 18846 at ¶171.
[22] Formal Case No. 1053, Order No. 14712 at ¶¶195, 199.
[23] Formal Case No. 1139, Order No. 18846 at ¶171.

Case No. 1076.[24] The Commission approved a similar uncontested adjustment in Formal Case No. 1139.[25]

RMA 16 increases operating income by $31,000 (PEPCO (D)-1, page 19 of 46).

Q36. Please describe RMA 17 with respect to costs associated with industry memberships and contributions.

A36. RMA 17 removes from test year operating expense the costs associated with industry memberships and contributions. The Commission approved a similar uncontested adjustment in Formal Case No. 1139.[26]

RMA 17 increases operating income by $270,000 (PEPCO (D)-1, page 20 of 46).

Q37. Has the Company removed institutional and promotional advertising expenses from the test year (RMA 18)?

A37. Yes. RMA 18 removes from the test year the expenses associated with institutional and promotional advertising, consistent with Commission precedent. Any advertising expenditures remaining in the test year are associated with advertising that is educational in nature and, therefore, are properly included in the cost of service. The Commission approved a similar uncontested adjustment in the Company's most recent fully litigated rate case, Formal Case No. 1139.[27]

RMA 18 increases operating income by $102,000 (PEPCO (D)-1, page 21 of 46).

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[24] Formal Case No. 1076, Order No. 15710 at ¶168.
[25] Formal Case No. 1139, Order No. 18846 at ¶171.
[26] *Id.*
[27] *Id.*

Q38. Please discuss RMA 19 with respect to the reflection of the increase in DC Water rates?

A38. RMA 19 adjusts the cost of service to annualize the increase in DC Water rates charged to the Company that became effective on October 1, 2018 along with the known and certain increase that will become effective on October 1, 2019. A similar adjustment was approved as an uncontested adjustment in Formal Case Nos. 1087, 1103, and 1139 (Order Nos. 16930, 17424, and 18846, respectively).

RMA 19 decreases operating income by $36,000 (PEPCO (D)-1, page 22 of 46).

Q39. What was the Commission ruling in Formal Case Nos. 1150 and 1151 related to the Benning Road environmental efforts?

A39. In Formal Case Nos. 1150 and 1151 as part of the non-unanimous full settlement agreement and stipulation the Commission approved Pepco's request to establish a regulatory asset to recover $3.3 million of previously incurred costs to conduct a remedial investigation (RI) at the Benning Road facility.[28] Since then, the Company has begun to recover the $3.3 million over a 10-year amortization period. The Commission noted in its decision that the $3.3 million recovery only pertained to the Remedial Investigation costs that have already been incurred as a result of the Benning Consent Decree with the District of Columbia Department of Energy and Environment. [29]

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[28] Formal Case Nos. 1150 and 1151, Order No. 19433 at ¶12.
[29] Formal Case Nos. 1150 and 1151, Order No. 19433 at ¶14.

Q40. Please discuss RMA 20a and 20b, which propose to address the Benning Road facility environmental remediation efforts.

A40. RMA 20a adjusts the cost of service to reflect actual costs incurred from January 1, 2018 through March 31, 2019 associated with the RI/FS[30] as well as the costs of removing the cooling tower basins at the Benning Road facility. RMA 20b proposes to adjust costs of service to reflect forecast spend to complete the RI/FS and treatability study. All of these accords were required by the Consent Decree with District of Columbia Department of Energy & Environment.[31]

In summary, through RMA 20a and RMA 20b, the Company is requesting the approval of the following (see Table 3):

Table 3

RMA #	Name	Period Covered	Pepco DC Distribution Amount (In Millions)
RMA20a	Costs of removal of the cooling tower (CT) basins	From January 1, 2011 to March 31, 2019	$1.98
	Actual Dollars Spent for RI/FS	From January 1, 2018 through March 31, 2019	$0.90
RMA20b	Future Costs for RI/FS	From April 1, 2019 through December 2020	$0.48

RMA 20a increases rate base by $1,985,000 and decreases operating income by $209,000 (PEPCO (D)-1, page 23 of 46). RMA 20b increases rate base by $334,000 and decreases operating income by $35,000 (PEPCO (D)-1, page 24 of 46).

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[30] The cost for this RMA will be updated throughout the proceeding to include actual costs incurred.
[31] *Id*.

Q41. Were the costs of removal of the cooling tower (CT) basins and actual remediation costs incurred from January 1, 2011 through December 31, 2017 in connection with the Benning Road facility previously addressed before this Commission?

A41. Yes. The costs of removing the cooling tower basins at the Benning Road facility represented actual costs incurred and were presented in Formal Case No. 1150 as part of the RI/FS. These remediation costs were not included in the $3.3 million regulatory asset authorized by the Commission in Formal Case Nos. 1150 and 1151. As the settlement approved by the Commission explained:

> This recovery related only to the RI costs that have already been incurred as a result of the Benning consent decree with the Benning Consent Decree with District of Columbia Department of Energy & Environment. …In addition, Pepco will track in a separate regulatory asset the actual remediation costs incurred.[32]

The Company has complied with the Commission directive to separately track actual remediation costs incurred. Through RMA 20a, the Company is requesting recovery of these costs allocated to Pepco DC distribution in the amount of $1.98 million for the removal of the cooling towers concrete basins and contaminated soil at the site of the cooling towers at the Benning Road facility. For further discussion of the nature of these costs, please see the Direct Testimony of Company Witness Sanford.

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[32] Non-Unanimous Full Settlement Agreement and Stipulation at ¶14(d). *See also* Formal Case Nos. 1150 and 1151, Order No. 19433 at ¶49(s).

Q42. Has the Commission previously addressed the issue of utility recovery of environmental remediation costs?

A42. Yes. The Commission's precedent regarding recovery of environmental remediation costs relates to the Washington Gas Light Company's (WGL) East Station, redeveloped as Maritime Plaza. The Commission's determination as to the treatment of East Station was developed through a series of orders issued over a span of 14 years.[33] In Formal Case No. 922, the Commission first examined the recovery of environmental assessment and remediation costs for WGL's East Station property, the site of a former manufactured gas plant that had ceased operations several decades earlier.

Q43. Please provide more information regarding the facts of Formal Case No. 922.

A43. At issue in Formal Case No. 922 was the recovery of the District of Columbia's jurisdictional portion of costs that WGL had already incurred to conduct an environmental investigation of the East Station property.[34] WGL argued that there were compelling reasons for customers to pay for the remediation costs of the site, including direct and indirect benefits from remediation of the East Station facility, significant revenues from the sale or lease of the remediated facility, and increased tax revenues associated with the remediated facility.[35]

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[33] Formal Case Nos. 922, 934, and 989.

[34] *In the Matter of the Application of Washington Gas Light Company District of Columbia Division For Authority to Increase Existing Rates and Charges for Gas Service*, Formal Case No. 922, Order No. 10307 at pp. 114-115 (October 8, 1993). The investigation, which included soil and ground water sampling and testing, showed that coal tar was present in the soil at the site.

[35] *Id*. at p. 114.

Q44. Did the Commission agree with WGL that there were compelling reasons for customers to pay for the remediation?

A44. Yes. The Commission in Order No. 10307 agreed, finding that there were many reasons justifying the adoption of a sound cost recovery scheme for the recovery of necessary and prudent environmental remediation costs.[36] The Commission noted that there were clearly advantages to District of Columbia customers from the environmental remediation of WGL's East Station property, such as a cleaner river and the removal of potentially harmful compounds from the soil and water near the site.[37] In addition, the Commission accepted WGL's view that the sale or lease of the property may generate significant revenues, and the reuse of the property after remediation could increase tax revenues to the District of Columbia.[38]

After recognizing that "it is important to encourage effective remediation efforts,"[39] the Commission held that it would:

> ...allow the recovery of environmental assessment and remediation costs when: (1) the costs are necessary; (2) the costs are prudently incurred; (3) the Commission has the opportunity to review the Company's actions during a general rate case; and (4) District of Columbia ratepayers have an opportunity to share in monetary benefits which may accrue from an environmental cleanup that enhances the value of the property.[40]

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[36] *Id*. at p. 118.
[37] *Id*. at p. 119.
[38] *Id*.
[39] *In the Matter of the Application of Washington Gas Light Company District of Columbia Division for Authority to Increase Existing Rates and Charges for Gas Service*, Formal Case No. 922, Order No. 10307 at p.119 (October 8, 1993).
[40] *Id*. The Commission also held that "[i]n deferring these costs between rate cases, the Commission also reserves the option to consider whether it may be appropriate, under certain circumstances, to require shareholders to participate in the cost of cleanup. We are of the view that this cost recovery scheme will encourage prompt and effective environmental remediation while protecting ratepayers from inappropriate costs." *Id*.

Similar to the activities at issue here, in Order No. 10307, the Commission noted that "these costs are the result of gas service which was rendered to ratepayers in the normal course of business and should therefore be recoverable from ratepayers as incurred."[41]

Q45. Is the Company's proposed recovery of related costs in this case consistent with the Commission decision in Formal Case No. 922?

A45. Yes. The criteria above describe a four-part test that can be used in the instant proceeding. When the four-part test is applied to the costs related to the RI/FS and cooling tower basins removal for which Pepco seeks recovery in this case, it is evident that the costs are appropriate for recovery in this case.

Q46. Were the Benning Road facility remediation costs necessary?

A46. Yes. Remediation of the Benning Road facility is mandated by governmental environmental authorities and is necessary to help protect the public from health hazards.

Q47. Were the Benning Road facility remediation costs prudently incurred?

A47. The actual expenses sought for recovery by Pepco in this proceeding are related directly to remediation efforts required by a government agency and are, therefore, prudently incurred costs, as described by Company Witness Sanford in her Direct Testimony. Moreover, as Company Witness Sanford explains, the Benning Road facility remediation costs incurred were not the result of violations of environmental requirements or of negligence on the part of Pepco. Rather, the contamination resulted from activities that were otherwise in compliance with applicable environmental requirements and could not have been reasonably expected to necessitate remediation of the Benning Road facility.

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[41] *Id*.

Moreover, Company Witness Sanford testified that the Company did not engage in any unnecessary delays upon learning of the contamination at the Benning Road facility. Rather, the Company was diligent in studying the conditions at the site and developed an appropriate solution to the problem.

Q48. Will the Commission have the opportunity to review the Company's actions during a traditional base rate case?

A48. Yes, during this proceeding, the Commission, as well as all parties in the proceeding, will have ample opportunity to review the Company's related actions.

Q49. Will District of Columbia customers benefit from the Benning Road facility environmental remediation activities and costs?

A49. Yes. By conducting the RI/FS and future remediation work, Pepco ensures the continued safe operation of its Benning Road facility, including its service center, and allows Pepco customers to continue to accrue the benefits of the facility into the future. Moreover, as with the Benning Road facility here, in Formal Case No. 922, the Commission recognized that one of the benefits District customers received from the environmental remediation under consideration in that proceeding was "a cleaner river and the removal of potentially harmful compounds from soils and water underlying the site."[42] In allowing cost recovery there, the Commission emphasized that "it is important to encourage environmental remediation efforts."[43]

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[42] Formal Case No. 922, Order No. 10307 at 119 (October 3, 1993).
[43] *Id*.

Additionally, Pepco customers will have an opportunity to share in those benefits which may accrue from an environmental cleanup that enhances the value of the property. Also, consistent with the Commission directive in Order No. 19433, the Company is seeking insurance recovery related to the Benning Road facility environmental remediation, but the timing and amount of any future insurance recoveries are unknown at this time. Any potential future insurance proceeds will be tracked and used to offset expenses incurred.

Q50. Has Pepco complied with Commission directive in Formal Case Nos. 1150 and 1151 to file bi-annual reports detailing its efforts to recover insurance proceeds that would offset the amounts recovered through the RI costs recovered?

A50. Yes. The Company filed its first bi-annual report with the Commission in Formal Case No. 1150 on December 27, 2018. The Company will file another report by July of this year.

Q51. Pertaining to RMA 20a, what costs has the Company incurred since Formal Case Nos. 1150 and 1151?

A51. From January 1, 2018 to March 31, 2019, Pepco has incurred approximately $1.56 million in costs related to the RI/FS. The primary drivers of these cost are the execution of the RI study. The portion of these costs allocated to Pepco DC distribution is approximately $0.9 million. Through RMA 20a, the Company is requesting regulatory asset approval for the recovery of costs that have already been incurred [44] as a result of the Benning Consent Decree with the District of Columbia Department of Energy and

[44] The cost for this RMA will be updated throughout the proceeding to include actual costs incurred.

Environment (DOEE). For further discussion of the nature of these costs, please see the Direct Testimony of Company Witness Sanford.

Q52. How is the Company proposing to address future costs related to the environmental costs at the Benning Road facility?

A52. The environmental liability for future anticipated costs at the Benning Road facility is approximately $17.79 million. Given that remediation activities are anticipated to span multiple years, the Company is proposing RMA 20b to include forecasted spending related to the RI/FS for the period of April 1, 2019 through December 31, 2020 in its rate base through a regulatory asset, with a ten-year amortization period. The portion of these costs allocated to Pepco DC distribution is approximately $485,000.

Q53. Is Pepco proposing that its District of Columbia customers pay for 100% of the environmental remediation costs at the Benning Road facility?

A53. No. The Company is proposing to allocate these costs between its District of Columbia and Maryland jurisdictions based on a two-factor allocation, with equal weighting given to the factors. The first factor is based on the allocation of distribution plant at the Benning Road facility. The second factor is based on the allocation of Benning Road facility distribution labor operation and maintenance expense.

Q54. What are your conclusions regarding the appropriate ratemaking treatment for the Benning Road facility environmental remediation costs?

A54. Costs to remediate the Benning Road facility should be borne by District of Columbia customers (as well as Maryland customers) because they both benefited and continue to benefit from the services rendered by the operations at the site. The appropriate

amortization period of the actual costs to remediate the Benning Road facility is ten years, and the amortization should be included in the revenue requirement of this proceeding.

Q55. Has Pepco incurred costs for any other environmental initiative in the District of Columbia jurisdiction?

A55. Yes. In her Direct Testimony, Company Witness Sanford describes Pepco's efforts in the Anacostia River Sediment Project (ARSP). This project is a joint effort by the District of Columbia (acting through DOEE) and the National Park Service to assess environmental conditions within the lower Anacostia River and select and implement cleanup actions as deemed necessary.

Q56. Please outline costs for which recovery is sought in this case, if any

A56. Pepco accrued a $3 million liability in December 2017 and this amount was not included in rates. Pepco is requesting to defer costs associated with ARSP that are going against the $3 million liability in a regulatory asset with the opportunity to seek recovery in a future rate case.[45]

Q57. Do you anticipate incurring additional costs in the future in connection with the ARSP?

A57. Yes. While these additional costs are difficult to quantify given the current state of the assessment, they are expected to be material. The Company will provide updates in regard to the estimated costs as they become available.

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[45] Company Witness Sanford discusses incurred costs related to the ARSP that are not impacting the $3 million liability. Pepco tracks and records these costs as O&M as these are considered routine environmental costs.

Q58. Please describe RMA 21 with respect to interest expense on customer deposits and credit facility quarterly maintenance fees.

A58. In accordance with Commission precedent, RMA 21 increases O&M expense to reflect the interest expense related to the average level of customer deposits at the 2019 rate of 2.64%.[46] In Order No. 7453 in Formal Case No. 748, the Commission determined that customer deposits constitute a customer-supplied source of capital which should be deducted from rate base. The Commission also found it appropriate to adjust operating expense to reflect the interest paid on such deposits. This adjustment also includes the quarterly maintenance fees associated with the Company's credit facility, consistent with the approach previously approved by the Commission, most recently in Formal Case No. 1139.[47]

RMA 21 decreases operating income by $331,000 (PEPCO (D)-1, page 25 of 46).

Q59. Please describe RMA 22 with respect to software amortization.

A59. RMA 22 adjusts amortization expense and rate base for the impacts of known and certain changes to Pepco software amortization in the rate-effective period, consistent with Commission precedent, including most recently Formal Case No. 1139.[48]

RMA 22 decreases rate base by $1,076,000 and decreases operating income by $1,511,000 (PEPCO (D)-1, page 26 of 46).

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[46] Formal Case No. 712, Order No. 19771 (December 13, 2018).
[47] Formal Case No. 1139, Order No. 18846 at ¶171.
[48] *Id.*

Q60. Please describe RMA 23 with respect to executive perquisites.

A60. Consistent with the Commission's decision in Formal Case No. 1139,[49] RMA 23 reflects the removal of executive perquisite expense from cost of service.

RMA 23 increases operating income by $20,000 (PEPCO (D)-1, page 27 of 46).

Q61. Please describe RMA 24 with respect to the annualization of approved depreciation rates.

A61. Per the settlement agreement in Formal Case Nos. 1150 and 1151, the Commission adopted new depreciation rates as outlined in page 25 of the joint settlement agreement in Formal Case No. 1150. Because the adoption of the depreciation rates occurred part way through the test period on August 13, 2018, the Company seeks to annualize depreciation expense according to the new depreciation schedule.

RMA 24 increases rate base by $26,000 and increases operating income by $52,000 (PEPCO (D)-1, page 28 of 46).

Q62. Please describe RMA 25 reflecting the January 1, 2018 change in the DC income tax rate to 8.25%.

A62. Per the settlement agreement in Formal Case Nos. 1150 and 1151, Pepco agreed to flow-back the benefit of excess District of Columbia income taxes over a period of three years. The excess deferred DC income taxes are the result of the District's decrease in its corporate income tax rate from 9.0% to 8.25% for years prior to 2015 and with an effective date of January 1, 2018. Because the amortization of the excess income taxes began part

[49] Formal Case No. 1139, Order No. 18846 at ¶171.

way through the test year on August 13, 2018, this RMA seeks to reflect a full year of amortization.

RMA 25 increases operating income by $357,000 (PEPCO (D)-1, page 29 of 46).

Q63. Please describe RMA 26 with respect to annualization of federal excess deferred income tax (EDIT) liability amortization.

A63. RMA 26 annualizes the amortization associated with the EDIT liability as a result of the Tax Cuts and Jobs Act of 2017 (TCJA).

In Formal Case Nos. 1150 and 1151[50] the Commission determined that the amortization periods are as follows: protected property[51] related plant EDIT by the use of the Average Rate Assumption Method (ARAM); non-protected property[52] related plant EDIT by the use of a 10-year amortization period; and non-protected non-property[53] related plant EDIT by the use of a five-year amortization period.[54] Prior to August 13, 2018, the Pepco DC EDIT liability was amortized on Pepco's books based on Pepco's proposed amortization periods,[55] as opposed to the Commission authorized periods. As such, the first month and 13 days of the test period in the instant proceeding do not reflect the

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[50] Formal Case Nos. 1150 and 1151, Order No. 19433 at ¶6.

[51] *Protected Property*: These EDIT balances include items protected by the normalization provisions, such as depreciation. Protected EDIT can be returned to customers; however, they cannot be returned more rapidly than over the Average Rate Assumption Method (ARAM), which represents the average remaining book lives of the related assets and changes each year.

[52] *Non-Protected Property:* These EDIT balances include items such as repair allowance. These balances are not protected by the normalization provisions of the TCJA.

[53] *Non-Protected Non-Property:* These EDIT balances include but are not limited to labor-related items, such as pension, as well as regulatory assets. These balances are not protected by the normalization provisions of the TCJA.

[54] Formal Case Nos. 1150 and 1151, Order No. 19433 at ¶6.

[55] Property-related: ARAM, which represents the average remaining book lives of the related assets and changes each year. Non-Property-Related: 10-year amortization period.

Commission's approved amortization periods for non-protected EDIT. This RMA annualizes the impact of the Commission's authorized EDIT liability amortization periods.

RMA 26 increases rate base by $2,123,000 and increases operating income by $2,123,000 (PEPCO (D)-1, page 30 of 46).

Q64. Please describe RMA 27 with respect to TCJA revenue debit.

A64. During the period of January 1, 2018 through August 13, 2018, Pepco recorded a regulatory liability associated with the TCJA benefits to customers that had not yet been reflected in customer rates. To establish this regulatory liability, Pepco debited, and thus reduced, its distribution revenue and credited a regulatory liability. Ultimately, these "pre-rate change" TCJA benefits were refunded to customers through a one-time $24.163 million payment. RMA 27 adds back the test period amount of these non-recurring debits to Pepco's revenue such that the test period will reflect an appropriate level of on-going distribution revenues.

In total, RMA 27 increases operating income by $3,666,000 (PEPCO (D)-1, page 31 of 46).

Q65. Please describe RMA 28 with respect to Frederick Douglass Memorial Bridge project costs.

A65. As part of the South Capitol Street Corridor Project, the District Department of Transportation (DDOT) is replacing the current Frederick Douglass Memorial Bridge. As discussed by Company Witness Clark, Pepco's involvement in the Bridge project consists of the construction of two eight-way subtransmission duct banks and cables through the newly replaced bridge. The project's work will be completed based on agreed-upon Memorandum of Understanding (MOA) between Pepco and DDOT that was finalized and

signed on November 26, 2017. Phase: 1 of the project is "Engineering and Bridge Enhancement." During Phase I, Pepco made a $3.4 million payment to DDOT[56] on February 19, 2019, to reinforce the new bridge and enable it to support the duct bank and cable prior to Phase II "Civil Construction," which is set to begin in October of 2019. Phase III of the project is "Electrical and cable pulling" and is scheduled for October 2021. Currently, the cost incurred for this project is placed in CWIP.

Through this RMA the Company is requesting regulatory asset approval for the recovery of costs that have already been incurred as a result of the $3.4 million payment to DDOT. This regulatory asset has been allocated to the District of Columbia based on the Average and Excess Non-coincident Peak Demand (AED-NCP)[57] with a proposed amortization period of 36.23 years (based on 2.76% composite depreciation rate per Formal Case No. 1150).

RMA 28 increases rate base by $1,005,000 and decreases operating income by $29,000 (PEPCO (D)-1, page 32 of 46).

Q66. Please describe RMA 29 amortization of PHISCO deficient deferred income tax.

A66. As a result of TCJA, PHISCO re-measured its ADIT balance based on the change in the federal income tax rate from 35% to 21%, similar to Pepco in Formal Case Nos. 1150 and 1151. PHISCO costs are allocated to the PHI utilities pursuant to the Cost Allocation Manual, and, as such, these deficient deferred income tax balances related to these PHISCO costs were allocated to the utilities.

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[56] Based on the (Average and Excess – NCP) the allocated portion to DC is $1.42 million.

[57] The Frederick Douglass Memorial Bridge project is considered subtransmission as Pepco will run two eight-way sutransmission duct banks and cables through the newly replaced bridge.

As can be seen on PEPCO (D)-1, page 33, these PHISCO excess deferred tax balances are made up of the property-related excess deferred tax liability and the non-property-related excess deferred tax asset. The property-related excess deferred tax liability is generated primarily by the underlying tax depreciation (accelerated) versus book depreciation (straight-line) timing differences on PHISCO property. The non-property-related excess deferred tax asset is generated primarily by payroll-related timing differences, where Pepco has deducted accrued expense on its books and, for tax purposes, it must deduct the cash payment.

This RMA represents the amortization of PHISCO's recoverable deficient deferred tax asset balances allocated to Pepco. Consistent with the amortization periods agreed to in Formal Case Nos. 1150 and 1151,[58] Pepco proposes to amortize the property-related excess deferred income tax liability over 10 years and the non-property-related excess deferred income tax asset over a five-year period.

RMA 29 increases rate base by $1,039,000 and decreases operating income by $616,0000 (PEPCO (D)-1, page 33 of 46).

Q67. Please describe RMA 30 with respect to reflection of Control Center capital lease expiration.

A67. Pepco's Control Center is located in Bethesda, Maryland and it serves both District of Columbia and Maryland customers. The Control Center's 25-year capital lease expires in November of 2019. When the lease expires the underlying property will transfer to Pepco for a nominal value of $1. The lease expense for the Control Center is approximately

[58] Formal Case Nos. 1150 and 1151, Order No. 19433 at ¶6.

$3.8 million allocated to District of Columbia distribution. Because the capital lease is set to expire prior to the expected rate-effective period in this proceeding the Company is proposing, through this RMA, to remove the amortization expense for this facility.

RMA 30 increases operating income by $2,804,000 (PEPCO (D)-1, page 34 of 46).

Q68. Please describe RMA 31 with respect to reflection of Additional Subtraction Modification.

A68. RMA 31 proposes to provide customers with the state income tax benefit attributable to the recognition of an incremental increase to the Maryland "Statutory Subtraction" Modification. This $27.6 million tax benefit will be monetized by Pepco in the future. That notwithstanding, Pepco is proposing to begin giving this tax benefit to customers over the average remaining book lives of District of Columbia assets, starting as of the rate-effective date of this proceeding.

Q69. Please provide the background and definition of the Maryland "Statutory Subtraction" Modification.

A69. Prior to January 1, 2000, Maryland public utilities were subject to the Public Service Company Franchise Tax (Franchise Tax) and generally were not subject to the Maryland Corporation Income Tax (Income Tax). Beginning January 1, 2000, in conjunction with deregulation of the utility industry, Maryland public utilities were no longer subject to the Franchise Tax and became only subject to the corporate Income Tax regime.[59]

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[59] Maryland House Bill 366, Chapter 6 of the Laws of Maryland of 1999.

The change in taxing mechanism resulted in public utilities effectively forgoing the benefit of tax depreciation recognized prior to January 1, 2000. As an accommodation, for assets that were owned by a public utility on January 1, 2000 ("pre-2000 assets"), Maryland tax law provides for a deduction (the "Statutory Subtraction" modification)[60] from taxable income equal to the excess of net "book" value over net tax value as of January 1, 2000 for assets owned by public utilities (please see Table 4, specifically the column labeled "Statutory Subtraction Modification"). This deduction is "triggered" when the asset is sold, retired, or otherwise disposed.

Q70. How does the Additional Subtraction Modification approved in Maryland pertain to the District of Columbia?

A70. For corporations like Pepco with taxable income in multiple jurisdictions, their total taxable income is apportioned to each taxing jurisdiction using an apportionment formula, and then the appropriate jurisdictional income tax rate is applied to the apportioned income. This means that the starting point for Maryland income taxes is Pepco's total taxable income, including both its District of Columbia and Maryland revenues net of expenses. As such, the Additional Subtraction Modification described in this section is based on Pepco's total depreciation expense. This means that both Maryland and District of Columbia customers have funded the amounts for which Pepco will now be able to take additional tax deductions in Maryland. Thus, it is appropriate for a portion of this tax benefit to be allocated to District of Columbia customers.

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[60] Md. Code Ann., Tax-Gen. § 10-309.

Q71. What led to this incremental increase to the Maryland Statutory Subtraction Modification (i.e., the "Additional Subtraction") for Pepco?

A71. Pepco proposed an alternative methodology for calculating the Statutory Subtraction Modification that results in an additional deduction for tax purposes.

Q72. What is the alternative methodology that Pepco proposed?

A72. The alternative methodology for determining the Statutory Subtraction Modification is calculated by using the "book" costs[61] (rather than net "book" value)[62] over the net tax value[63] as of January 1, 2000 (please refer to Table 4, specifically the column labeled "Alternative Methodology") resulting in an Additional Subtraction Modification equal to the pre-2000 accumulated "book" depreciation (please refer to Table 4, specifically the column labeled "Additional Subtraction Modification"). The alternative methodology effectively permits Pepco to deduct all the foregone pre-2000 tax depreciation rather than just a portion.

Q73. Please provide an example of how the Additional Subtraction Modification is calculated.

A73. See Table 4: Maryland Additional Subtraction Modification Illustrative Example.

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[61] "Book" cost is the gross plant in service amount. (See Table 4)
[62] Net "Book" value is the gross plant less accumulated book depreciation. (See Table 4)
[63] Net "Tax" Value is the gross plant less the accumulated "Tax" depreciation. (See Table 4)

Table 4

Illustrative Example				
January 1, 2000 Public Utility Property		**Statutory Subtraction Modification**	**Alternative Methodology**	**Additional Subtraction Modification**
Book Cost		$ 100	$ 100	$ -
Accumulated Book Depreciation		(25)	-	25
Net, Book Value	A	75	100	25
Tax Cost		100	100	-
Accumulated Tax Depreciation		(45)	(45)	-
Net, Tax Value	B	55	55	-
Gross Subraction Modification	C = A - B	**20**	**45**	**25**
Marginal Tax Rate		8.25%	8.25%	8.25%
Tax Benefit / (Expense)		**$ 2**	**$ 4**	**$ 2**

As noted above, the statutory subtraction modification is equal to the excess of net "book" value over net tax value as of January 1, 2000 for assets owned by public utilities. The alternative methodology is equal to "book" cost over net tax value as of January 1, 2000, and thus the Additional Subtraction Modification is equal to the accumulated book depreciation as of January 1, 2000.

Q74. Why did Pepco propose this alternative methodology for calculating the Statutory Subtraction modification?

A74. Pepco pursued the position under the premise that the legislative intent of the statute was to permit the full deduction of pre-2000 tax depreciation and was further supported by analogous favorable federal tax case law.

Q75. Why is Pepco entitled to this Additional Subtraction now?

A75. There previously was no basis in tax law supporting the alternative methodology; therefore, there was insufficient legal authority to recognize the additional subtraction modification. Exelon Corporation, the parent company for Pepco, requested a declaratory

ruling from the Office of Maryland Comptroller seeking explicit approval for the use of the alternative methodology and by extension the additional subtraction modification.

In the fourth quarter of 2018, Exelon received a favorable declaratory ruling from the Office of the Maryland Comptroller approving the alternative methodology for calculating the statutory subtraction modification. The receipt of the favorable declaratory ruling permits Pepco to record the Additional Subtraction Modification for financial accounting purposes. Accordingly, Pepco recorded an income tax benefit of approximately $27.6 million related to District of Columbia distribution, for the Additional Subtraction Modification in December 2018.

Q76. When will the Company receive the cash tax benefit related to the Additional Subtraction Modification?

A76. As noted above, Pepco recorded an income tax benefit related to the Additional Subtraction Modification; however, the majority of that income tax benefit does not result in the immediate reduction in cash taxes. This outcome arises as the deduction is only "triggered" when the underlying assets are sold, retired, or otherwise disposed of and can only be monetized to the extent Pepco recognizes taxable income. As a result, for Pepco, the income tax benefit is reported as a deferred tax asset that will be monetized in the future.

Q77. Why does the Additional Subtraction Modification result in a deferred tax asset?

A77. As previously discussed, a deferred tax asset represents a future tax benefit that arises when a company realizes a cash tax benefit after it recognizes the expense for financial accounting purposes. In this instance, Pepco has already recognized the depreciation expense prior to January 1, 2000 on its books for financial accounting purposes but will later recognize the incremental cash tax benefit when it is able to deduct

this depreciation for tax purposes in the form of the Additional Subtraction Modification on its District of Columbia income tax return.

Q78. Will District of Columbia customers benefit from the recognition of the Additional Subtraction Modification?

A78. Yes. Even though Pepco has not received the cash tax benefit for the majority of this deduction, through this RMA, Pepco proposes beginning to provide customers with the income tax benefit immediately. To that end, Pepco is seeking to create a regulatory liability to offset the deferred tax asset balance that was recorded in the fourth quarter of 2018. Customers will receive the benefit of the Additional Subtraction Modification through the amortization of the regulatory liability. Pepco also proposes to include the deferred tax asset and related regulatory liability offset in rate base.

Q79. How does Pepco recommend these benefits be returned to customers?

A79. Pepco proposes to amortize this regulatory liability in a manner that is the most consistent with the time that it will take for this cash tax benefit to materialize. For this reason, the Company proposes to credit customers over the average remaining book lives of District of Columbia assets, approximately 36.42 years based on the most recent depreciation study approved by the Commission.

RMA 31 increases operating income by $598,000 (PEPCO (D)-1, page 35 of 46).

Q80. Please describe RMA 32 with respect to the merger commitment to adjust EBSC depreciation billed to Pepco.

A80. This adjustment relates to Pepco Merger Commitment 39, which states that "For depreciable assets that EBSC acquires for Pepco, the depreciation expense charged to Pepco by EBSC shall reflect the same depreciable lives and methods required by the

Commission for similar assets acquired directly by Pepco. In no event shall depreciable lives on plant acquired for Pepco by EBSC be shorter than those approved by the Commission for similar property acquired directly by Pepco."[64] Pepco has adjusted the depreciation expense charged to it from EBSC to align with the depreciable lives authorized by the Commission for similar assets in Formal Case No. 1150. This adjustment restates the 6+6 test period ending June 2019 amount of EBSC depreciation expense to recognize Pepco's approved depreciation rates for similar assets. This adjustment results in a $326,000 increase to test period operating income (PEPCO (D)-1, page 36 of 46).

Q81. Please describe RMA 33 with respect to expected rate case costs in the instant proceeding.

A81. RMA 33 adjusts the cost of service to defer and amortize incremental costs associated with this proceeding over a three-year amortization period, consistent with Commission precedent, including most recently in the fully litigated Formal Case No. 1139.[65]

RMA 33 increases rate base by $2,255,000 and decreases operating income by $229,000 (PEPCO (D)-1, page 37 of 46).

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[64] Formal Case No. 1119, Order No. 18148 ("Merger Order"), Attachment B (the "Merger Commitments") at ¶39. The Commission subsequently issued Order No. 18160 correcting certain errors in the Merger Order and the Merger Commitments. References herein to the Merger Order and the Merger Commitments are to Order No. 18148 and Attachment B to Order No. 18148, respectively, as corrected by Order No. 18160.

[65] *Id.*

Q82. How is the Company proposing to return the excess rate case costs associated in Formal Case Nos. 1150 and 1151 to customers?

A82. The Company is proposing to offset the costs incurred in the current proceeding by the amount by which the estimated rate case costs for Formal Case Nos. 1150 and 1151 exceeded actual costs incurred. In Formal Case Nos. 1150 and 1151, the Company estimated that rate case expenses would be $1.67 million. The Company incurred $1.96 million of rate case costs and recently received refunds from Staff and the Office of People's Counsel (OPC) in the amount of $1.02 million for this proceeding. To refund this amount to customers, Pepco created a regulatory liability in the amount of $723,212, as seen in Table 5.

Table 5: Refund from Case No. 1150

a	*Estimated Rate case Expense Case No. 1150 (RMA 17)*	*1,671,810*
b	Actual Cost Incurred Case No. 1150	1,968,598
c	Refund OPC & Staff	(1,020,000)
d	**Total Cost**	948,598
	Total Amount to refund. Difference (a-d):	723,212

The Company proposed to utilize the $723,212 excess costs from Formal Case Nos. 1150 and 1151 to offset the incremental costs incurred in this instant proceeding.

Q83. Has the Company included a ratemaking adjustment to reflect the costs to achieve (CTA) regulatory asset (RMA 34)?

A83. Yes. In Order No. 18846 in Formal Case No. 1139, the Commission found it appropriate "for Pepco to establish a regulatory asset to track and account for CTA merger-

related costs that can be reviewed in Pepco's next rate case."[66] Further, the Commission permitted Pepco to "record actual verifiable costs in the CTA regulatory asset."[67] Subsequently, in Formal Case Nos. 1150 and 1151, the settling parties agreed to the following:

> The parties agree to allow Pepco to defer the cumulative Costs to Achieve in a regulatory asset to allow more time for the Company to provide evidence of the merger synergy savings. The Company may seek recovery of these costs in its next rate case.[68]

RMA 34 adjusts rate base to reflect the CTA regulatory asset (and its impact on ADIT) and adjusts amortization expense to reflect the amortization of the CTA regulatory asset balance as of June 2018 over a five-year amortization period in accordance with the Commission's decision in Formal Case No. 1119.[69] RMA 34 also adjusts O&M expense to remove the CTA O&M expense from the test period, including the July 2017 O&M reduction resulting from the credit entry to establish the regulatory asset.

Q84. Is RMA 34 consistent with the Commission's directive in Merger Commitment 27 in Formal Case No. 1119?

A84. Yes. RMA 34 is consistent with the Commission's directive in Merger Commitment 27 in Formal Case No. 1119 which, in addition to requiring a five-year amortization period for the CTA regulatory asset, provided "Pepco shall not recover CTA in a Pepco rate case in an amount greater than the synergy savings that Pepco demonstrates

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66 Formal Case No. 1139, Order No. 18846 at ¶363.
67 *Id*.
68 Formal Case No. 1150 and 1151, Order No. 19433 at ¶12.
69 Merger Commitment 27.

for the applicable test year."[70] RMA 34 includes a $9.5 million CTA regulatory asset, which will be amortized over five years in the amount of $1.9 million per year. The Company's realized synergy savings in the test year are $11 million, as shown on PEPCO (D)-8. The demonstrated synergy savings in the traditional test period outweigh the CTA regulatory asset amortization in RMA 24.

As a result of the achieved synergies, customer rates will be approximately $9 million lower due to the merger than they otherwise would have been, as achieved synergies outweigh the annualized CTA by that amount. PEPCO (D)-8 provides a quantification of these test period synergies (labor versus non-labor, PHI versus EBSC), amortization expense related to CTA per RMA 34 and net synergies in the amount of $9.1 million.

RMA 34 increases rate base by $6,171,000 and decreases operating income by $1,371,000 (PEPCO (D)-1, page 38 of 46).

Q85. Please describe RMA 35 with respect to the reflection of five-year historical average inflation on non-labor O&M expense.

A85. RMA 35 adjusts test period non-labor O&M expense for the impacts of price inflation, based on the five-year average national Gross Domestic Product Price Index (GDPPI) for the years 2014-2018. As described by Company Witness Wolverton, the GDPPI index is a reliable, accurate and easy to obtain index and was selected for this RMA since it:

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[70] The Merger Commitments regarding CTA and other issues germane to this proceeding are discussed further below under "Merger Commitments."

- Measures the changes in price of consumer goods and services, investment goods, government services, imports and exports;
- Is measured by U. S. Commerce Department,
- Is readily available and calculated on a timely basis every quarter.

RMA 35 decreases operating income by $1,035,000 (PEPCO (D)-1, page 39 of 46).

Q86. Why is the Company proposing this adjustment?

A86. According to the Bureau of Labor Statistics (BLS), "Inflation can be defined as the overall general upward price movement of goods and services in an economy."[71] In a period of rising prices (which has generally been the case over the period 2000-2018), the use of an historical test year for setting customer rates will not be sufficient to cover the actual costs incurred during the rate-effective period. This inflation creates a mismatch between rates and costs in the rate-effective period, and, as noted in Company Witness McGowan's Direct Testimony, Pepco has a history of under earning its authorized return on equity. For this reason, Pepco is proposing an adjustment to address inflation of non-labor O&M expenses to partly address this mismatch between rates and costs in the rate effective period.

Q87. Please describe RMA 36 with respect to inclusion of Cost to Optimize (CTO) regulatory asset.

A87. CTO represent up-front costs incurred to achieve future savings through EBSC's Transformation Initiative. The EBSC Transformation Initiative is a process whereby

[71] https://www.bls.gov/bls/inflation.htm

EBSC has identified O&M savings in 2021 and beyond. These savings are expected to be achieved through a focus on improving efficiencies, eliminating redundancies, and leveraging innovation and technologies. In order to achieve these cost savings, EBSC has and will incur certain costs, referred to as CTO.

Pepco is proposing to remove the CTO from its traditional test period compliance filing O&M expense and defer it to a regulatory asset to be amortized over a five-year period, to better match the recovery of CTO with the projected savings.

RMA 36 increases rate base by $809,000 and increases operating income by $719,000 (PEPCO (D)-1, page 40 of 46).

Q88. Please describe RMA 37, which reflects adjustments to the Company's cash working capital (CWC) requirement.

A88. RMA 37 reflects adjustments to the Company's CWC allowance to reflect the use of fully adjusted cost-of-service amounts. In the calculation of the CWC allowance, RMA 37 utilizes the lead-lag days as presented in PEPCO (D)-7, which contains the 2017 Lead-Lag Study.

RMA 37 decreases rate base by $62,000 (PEPCO (D)-1, page 41 of 46).

Q89. Please describe RMA 38 with respect to interest synchronization.

A89. Consistent with Commission precedent, including Formal Case No. 1139,[72] RMA 38 adjusts District of Columbia and federal income tax expense to reflect the impact on

[72] Formal Case No. 1139, Order No. 18846 at ¶57.

synchronized income taxes of the ratemaking adjustments to rate base and their impact on interest expense.[73]

RMA 38 increases operating income by $1,563,000 (PEPCO (D)-1, page 44 of 46).

V. JURISDICTIONAL COST OF SERVICE STUDY

Q90. Please summarize the Company's jurisdictional cost of service study (JCOS).

A90. The JCOS presented at PEPCO (D)-3 assigns and allocates each element of Pepco's unadjusted test period rate base, revenues, and expenses to the Company's District of Columbia jurisdiction. Costs assigned and allocated to customers outside of the District are in the "Other" jurisdiction, as shown in PEPCO (D)-3. The jurisdictional allocations and assignments presented in the JCOS are consistent with those presented in Formal Case No. 1139, in which the Commission found Pepco's jurisdictional cost of service study to be reasonable.[74] The allocations in the Company's JCOS are driven primarily by direct jurisdictional assignments and allocations of plant, depreciation expense, and O&M expenses.

Q91. Please discuss the allocation methods for distribution EPIS in the JCOS.

A91. Pepco's EPIS is maintained in the Company's asset accounting system within FERC Uniform System of Accounts.

The majority of the Company's distribution facilities are primary- and secondary-voltage systems. These facilities include distribution substations, overhead and

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[73] The impact on taxes of the effect of interest synchronization related to unadjusted rate base (as presented at page 1 of PEPCO (D)-1) is reflected in the unadjusted column of PEPCO (D)-1, page 1, lines 20 and 21, and the calculation is shown at PEPCO (D)-1, page 45 of 46.

[74] Formal Case No. 1139, Order No. 18846 at ¶399.

underground lines, and line transformers, all of which serve customers in a local area and are, therefore, directly assigned to the appropriate jurisdiction.

A lesser portion of the Company's EPIS assets are subtransmission facilities, which serve customers in each jurisdiction throughout Pepco's service territory. These facilities have been allocated between the Company's jurisdictions based on the Average and Excess Non-coincident Peak Demand (AED-NCP) method, consistent with Commission precedent, including most recently Formal Case No. 1139.[75]

The Company has also maintained its method of allocating distribution-general and intangible plant to jurisdiction based on the subtransmission and distribution plant less AFUDC ratios, which was most recently accepted by the Commission in its approval of the jurisdictional cost of service study in Formal Case No. 1139.[76]

Q92. How is distribution depreciation expense assigned to jurisdiction?

A92. Distribution and general depreciation expense are assigned to the appropriate jurisdiction based on Company's plant-related records.

Q93. Please explain the methods used to allocate O&M expense to jurisdiction.

A93. Distribution O&M expenses are assigned to the District of Columbia and Other jurisdictions based on the 2018 detailed analyses of O&M FERC accounts (Accounts 583, 584, 593, and 594) or allocated using relevant plant ratios. Incremental storm and tree trimming costs have been separately identified and are assigned to jurisdiction based upon Company records.

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[75] *Id.*
[76] *Id.*

Customer accounts and sales expense (FERC Accounts 901 through 913) are assigned to customer classes based on the results of the Company's detailed analysis of the same accounts and then allocated to jurisdictions based on the number of customers in the test period.

The majority of administrative and general (A&G) expenses are allocated based on the O&M expense less A&G, storm, and tree trimming allocator, which is developed based on total distribution O&M less A&G and incremental storm and tree trimming costs. Account 924, property insurance, is allocated on the Subtransmission and Distribution Plant ratio (STDPLT) and Account 928, regulatory expenses, is directly assigned to jurisdictions.

All of these allocation methods have previously been approved by the Commission and were used in the jurisdictional cost-of-service study the Commission approved in Formal Case No. 1139.

VI. MULTIYEAR RATE PLAN (MRP) AND THE TRADITIONAL TEST PERIOD COMPLIANCE FILING SUPPORT

A. Capital Structure

Q94. What overall rate of return is Pepco requesting?

A94. As shown in PEPCO (D)-5, the Company is requesting an overall rate of return of 7.81% on its distribution rate base in the District of Columbia.

Q95. On what capital structure is the overall rate of return based?

A95. The overall rate of return is the weighted average, based on the Company's actual December 2018 capital structure ratios of 50.46% common equity and 49.54% long-term debt, its embedded long-term debt cost of 5.27% (see PEPCO (D)-5) and its return on

common equity of 10.30%, as recommended by Company Witness Hevert. This capital structure is being used in both the traditional test period compliance filing revenue requirement presented in my Direct Testimony as well as the MRP revenue requirement presented in Company Witness Wolverton's Direct Testimony.

Q96. Is this capital structure consistent with the Company's goals and objectives regarding capital structure?

A96. Yes, this capital structure is consistent with the Company's goals and objectives to maintain the Company's credit ratings and a target equity ratio of at least 50%.

Q97. Why are credit ratings significant to Pepco?

A97. As discussed in the Direct Testimony of Company Witness Hevert, credit ratings are significant because they indicate the assessment of Pepco's ability to meet its obligations to its long-term debt holders. The higher the credit rating, the greater the perceived likelihood that debt investors will receive their expected interest and principal payments and thus, all things equal, the investors will require a lower interest rate.

Q98. Are there other reasons this capital structure is appropriate for use in this proceeding?

A98. Yes. As indicated in the Direct Testimony of Company Witness Hevert, the Company's recommended capital structure is reasonable, although on the low end, given a mean common equity ratio of 53.28% and a range of equity ratios of 46.01% to 64.78% for the 24 companies in Company Witness Hevert's proxy group for the purpose of determining the cost of equity for this proceeding.[77]

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[77] PEPCO (G)-6.

Q99. How does Pepco fund its capital expenditures while maintaining its capital structure as noted above?

A99. Pepco uses three major sources to fund these requirements: internally generated cash flows, externally raised funds, and equity contributions from PHI. Pepco's internally generated cash flows are not sufficient to fund its significant capital spending program. Therefore, the Company must raise funds from the capital markets and receive equity contributions from its parent.

Pepco finances its long-term rate base with long-term debt and equity, which is reflected in its capital structure for ratemaking purposes. The Company uses short-term debt to fund changes in working capital and temporarily fund its construction requirements. Once the amount of short-term debt increases to a level sufficient to issuing permanent financing, the short-term debt is retired and replaced with long-term securities. This method is a cost-effective means of financing the Company's construction plan as opposed to only issuing long-term securities and holding large amounts of cash. Moreover, customers receive the benefit of the currently lower short-term debt costs in the form of lower Allowance for Funds Used During Construction (AFUDC) costs. These capitalized financing costs for rate base assets are lower than they otherwise would be by the inclusion of short-term debt in the AFUDC rate. Also, temporarily financing the construction plan with short-term debt allows the Company continually to assess market conditions and issue long-term debt under favorable terms and conditions at the time. Accordingly, Pepco's ratemaking cost of capital reflects the Company's permanent sources of funding, such as long-term debt and equity.

Q100. Has the Company included short-term debt in its capital structure?

A100. No. The Company has excluded short-term debt from its capital structure, as the Commission has approved in Pepco's last four fully litigated base rate cases with Formal Case No. 1139 being the most recent one. The Company believes that long-term debt and equity fund long-term assets and, therefore, has only included long-term financings in its capital structure.

Q101. Is this capital structure consistent with the Commission's decision in Formal Case No. 1139?

A101. Yes. In Order No. 18846, the Commission found that it was "satisfied that Pepco is using short-term debt as a temporary funding source for the Company's construction and reliability requirements, which is then permanently financed with long-term debt and common equity."[78] The Commission also stated that it was "persuaded by Pepco's argument that customers are receiving the benefits of the lower costs of short-term debt because it is used as the first source of funding in computing AFUDC on construction projects, and as a result, short-term debt is reflected in the AFUDC portion of rate base. We also note that since short-term debt is capitalized in AFUDC, to include it in the capital structure would overstate the impact of interest on the debt."[79]

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[78] Formal Case No. 1139, Order No. 18846 at ¶258.
[79] *Id.* at ¶261.

Q102. Please summarize the relationship between the short-term debt balance and the CWIP balance.

A102. Short-term debt is used to temporarily finance construction costs (*i.e.*, CWIP) until the projects are completed and transferred to EPIS. The amount of any outstanding short-term debt was more than offset by the balance of capital expenditures in CWIP on any given month. Once a project is completed and placed in service, it is moved into EPIS where the balances at that time are funded with long-term debt and equity.

Q103. Do customers benefit from short-term interest rates?

A103. Yes. Short-term debt is reflected in the AFUDC rate and accrual. The AFUDC accrual, which reflects the carrying cost to finance projects while under construction, is lower than the Company's authorized rate of return. Since the AFUDC rate incorporates the short-term debt rate, assets transferred from CWIP to EPIS have a lower cost basis. Due to the fact that short-term debt serves as a primary source of CWIP funding, the AFUDC rate properly incorporates the short-term debt rate, which reduces the total cost of EPIS and, therefore, lowers customer rates.

Q104. Has the Company provided documentation regarding the calculation of the District of Columbia recordation fees for all debt issuances since the last filed base rate case per the Commission's directive in Formal Case No. 1103, Order No. 17424 at Paragraph 381?

A104. Yes. As shown in PEPCO (D)-6, the Company has provided the calculation of the District of Columbia recordation fees for the December 2018 long-term debt issuance.[80]

B. Cash Working Capital/Lead-Lag Study

Q105. What is cash working capital?

A105. Cash working capital represents the funds Pepco must have available to pay operating expenses in advance of the collection of bills from customers. Since the actual working capital on Pepco's balance sheet fluctuates greatly, a lead/lag study method is used for calculating this component of rate base.

Q106. Please discuss the reasons for the inclusion of cash working capital in rate base.

A106. As noted by the Commission in Order No. 10646 in Formal Case No. 939,

> PEPCO maintains a cash working capital allowance for the capital required by the Company to carry out its daily utility operations. This capital is advanced by PEPCO's investors to fund day-to-day operations prior to the receipt of revenues from customers. Inasmuch as these funds are provided by the Company's investors, this capital has been traditionally recognized as a component of PEPCO's rate base.[81]

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[80] Pepco priced and recorded the June issuance at the same time as the December issuance, so there were no separate fees associated with the December issuance.

[81] Formal Case No. 939, Order No. 10646 at p.61 (citations omitted).

Q107. What is a lead-lag study?

A107. The primary purpose of a lead-lag study is to accurately establish the amount of investors' funds used in sustaining utility operations from the time expenditures are made in providing services to the time revenues are received as reimbursement for these services. The lead-lag study requires comprehensive analysis of the test year transactions to determine the "net lag days" for: (1) the time lag between services rendered and the receipt of revenues for such services; and (2) the time lag between the recording of labor materials and other costs and the payment of such costs.

Q108. Please describe the Company's lead-lag study, including the period of time for which the lead-lag study applies.

A108. The Company conducted a new lead-lag study for this proceeding, which is included as PEPCO (D)-7. All revenue and disbursement transactions used in preparing the study were from 2017 data. The lead-lag study uses the same methodology as the study that the Commission approved in Formal Case No. 1139 as reasonable.[82]

Q109. Have you prepared an exhibit showing the derivation of the unadjusted cash working capital allowance the Company is recommending in this case?

A109. Yes. PEPCO (D)-1, page 43 of 46, presents the computation of the cash working capital allowance reflected in unadjusted rate base. As shown at PEPCO (D)-1, page 43 of 46, the revenue and expense lag factors from the new lead-lag study were applied to the test year operating results to derive the cash working capital allowance the Company is recommending in this proceeding. This lead-lag study is being used in both the traditional

[82] Formal Case No. 1139, Order No. 18846 at ¶42.

test period compliance filing revenue requirement presented in my Direct Testimony, as well as the MRP revenue requirement presented in Company Witness Wolverton's Direct Testimony.

VII. MERGER COMMITMENTS AND OTHER DIRECTIVES

Q110. Please describe the Company's merger commitment with regard to CTA and synergy savings.

A110. In the Merger Order, the Commission directed Pepco to "track and account for Merger-related savings, and the cost to achieve those savings, in each of its base rate cases filed within in a three-year period following Merger close [and to] flow all synergy savings allocable to the District to customers through the normal ratemaking process."[83] Additionally, the Commission stated:

> Pepco will amortize the costs to achieve synergy savings ("CTA") over a five-year period of time commencing with the effective date of the first Pepco base rate case filed after Merger close. To the extent CTA are incurred after the first rate case, such CTA will be amortized over a five-year period commencing with the effective date of the first rate case after such costs are incurred. Pepco shall not recover CTA in a Pepco rate case in an amount greater than the synergy savings that Pepco demonstrates for the applicable test year.[84]

As discussed above, RMA 34 is consistent with this directive, as the CTA regulatory asset reflects a five-year amortization period.

In regard to the CTA amount requested in this proceeding compared to the synergy savings for the test year in this proceeding, there are more than $9.1 million of net synergies reflected into the adjusted cost of service in this proceeding. In other words, customer rates

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[83] Merger Commitment 26.
[84] Merger Commitment 27.

are $9.1 million lower than they otherwise would be as a result of the merger synergy benefits, net of the related CTA amortization expense.

Q111. Has the Commission made any other directives with regard to CTA and synergy savings?

A111. Yes. As previously discussed in RMA 34 the Company proposes to adjust rate base to reflect the CTA regulatory asset (and its impact on ADIT) and adjusts amortization expense to reflect the amortization of the CTA regulatory asset balance as of June 2018.

Q112. How are merger CTAs tracked by the Company?

A112. CTAs consist of expenses incurred to affect the merger and include costs associated with analyzing, designing and implementing the integration of Exelon and PHI. Pepco, PHISCO, EBSC, and other PHI companies have incurred CTAs.

All CTAs are appropriately tracked using specific cost centers rather than standard cost centers or work orders. EBSC and PHISCO CTAs are allocated to the utilities under the approved ratio for each service area. Costs charged to the CTA cost centers are subject to the existing controls that Exelon and PHI have over the approval of services to be performed and approval of payment for those services.

CTAs included in the calculation of the Pepco DC CTA regulatory asset are system-related integration activities, employee severance and relocation, and full-time integration office staff. These costs are considered to be incurred as costs to achieve merger synergies. Employee time and expenses spent working on integration activities as part of normal work activities are not included in the calculation of deferred CTA. The pool of costs considered to be CTA-related that were recorded by Pepco were then analyzed and an allocation for DC Distribution was calculated based on standard regulatory allocation factors to

determine the amount to be deferred each month in a regulatory asset.

Q113. How are merger synergy savings tracked by the Company?

A113. On a monthly basis, forecasted and achieved savings initiatives results are documented in a centralized tracking tool. A merger integration team made up of subject matter experts then validates implementation results to ensure accuracy and sustainability of savings. To monitor progress, on a monthly basis, executive leaders are briefed on the status of implementation schedules and savings results. PEPCO (D)-8 provides detail demonstrating the actual-to-date realized merger synergy savings by initiative.

Q114. Please describe Merger Commitment 39.

A114. Merger Commitment 39 states, "For depreciable assets that EBSC acquires for use by Pepco, the depreciation expense charged to Pepco by EBSC shall reflect the same depreciable lives and methods required by the Commission for similar assets acquired directly by Pepco."[85]

Q115. Has the Company addressed Merger Commitment 39?

A115. Yes, please see RMA 32.

Q116. Please describe Merger Commitment 40.

A116. Merger Commitment 40 states, "For assets that EBSC acquires for use by Pepco, the rate of return shall be based on Pepco's authorized rate of return, unless EBSC is able to finance the asset at a lower cost than Pepco."

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[85] Formal Case No. 1119, Order No. 18160 at ¶39.

Q117. How has the Company addressed Merger Commitment 40?

A117. For, "depreciable assets that EBSC acquires for use by Pepco, the rate of return shall be based on Pepco's authorized rate of return" would be recorded on Pepco's books and would therefore be financed through Pepco's cost of capital. As such, no adjustment to the test period cost of service is necessary to comply with Merger Commitment 40.

Q118. In terms of other directives, does the test year cost of service include any legal expenses associated with settled discrimination cases?

A118. No. Consistent with Commission precedent and as last approved in Formal Case No. 1139, the test year cost of service contains no legal expenses associated with settled discrimination cases.

Q119. What is the purpose of PEPCO (D)-9?

A119. Commission Rule 200.3(h) requires a rate change application to include the most recent historic balance sheet available as of the date of the filing. A balance sheet as of December 31, 2018 has been provided at PEPCO (D)-9. Note that the amounts presented reflect Pepco's total system results, as a Pepco distribution-only balance sheet is not available.

Q120. What is the purpose of PEPCO (D)-10?

A120. PEPCO (D)-10 sets forth the Company's regulatory expense related to matters before the Commission for the 12 months ended June 30, 2019. The exhibit shows amounts expended by the Company arising from assessments by the Commission and the Office of the People's Counsel. This exhibit also provides similar expenses for the three years prior to the test year, as required by Order No. 7135 in Formal Case No. 715.

Q121. Have you attached additional exhibits to your Direct Testimony?

A121. Yes, my Direct Testimony includes one additional exhibit. Commission Rule 200.5 (d) requires that an analysis of changes in jurisdictional rate base, jurisdictional expenses, and jurisdictional operating income between the historical test year and the proposed test year be provided when a utility submits forecasted data as part of its proposed test year data. PEPCO (D)-4 provides such an analysis.

Q122. Does this conclude your Direct Testimony?

A122. Yes, it does.

J.C. Ziminsky
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (D) – 1

Potomac Electric Power Company

District of Columbia
Ratemaking Results - Distribution Only
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.		Average Unadjusted (1)	Ratemaking Adjustments (2)	D.C. Adjusted (3)	Revenue to Achieve 10.3% Return on Equity (4)	Adjusted to Reflect 10.3% Return on Equity (5)
	Rate Base					
1	Electric Plant in Service	$ 3,762,607	$ 200,262	$ 3,962,869		$ 3,962,869
2	Accumulated Depreciation	(1,168,178)	7,347	(1,160,831)		(1,160,831)
3	Accumulated Amortization	(12,498)	(1,076)	(13,574)		(13,574)
4	Materials and Supplies	38,541	-	38,541		38,541
5	Cash Working Capital	9,631	(62)	9,569		9,569
6	Accumulated Deferred Income Taxes	(800,844)	1,434	(799,410)		(799,410)
7	Prepaid Pension/OPEB Liab. (net of tax)	72,903	(3,880)	69,023		69,023
8	Customer Deposits	(8,771)	-	(8,771)		(8,771)
9	Pepco Portion of Servco Assets	28,017	-	28,017		28,017
10	Regulatory Assets	44,475	13,547	58,022		58,022
11	Unamortized Credit Facility Costs	364	-	364		364
12	Total Rate Base	$ 1,966,247	$ 217,573	$ 2,183,820		$ 2,183,820
	Operating Revenues					
13	Sale of Electricity	$ 528,438	$ 38	$ 528,476		
14	Other Revenues	6,789	-	6,789		
15	Operating Revenues	$ 535,227	$ 38	$ 535,265	$ 88,632	$ 623,897
	Operating Expenses					
16	Operation and Maintenance	$ 174,773	$ (2,140)	$ 172,633		$ 172,633
17	Depreciation	103,711	5,423	109,134		109,134
18	Amortization	11,919	6,658	18,577		18,577
19	Other Taxes	145,550	236	145,786		145,786
20	D.C. Income Tax	(4,500)	(2,516)	(7,016)	$ 7,312	296
21	Federal Income Tax	(5,232)	(4,931)	(10,163)	17,077	6,914
22	Total Operating Expenses	$ 426,221	$ 2,729	$ 428,951	$ 24,389	$ 453,340
23	Operating Income	$ 109,006	$ (2,691)	$ 106,314	$ 64,243	$ 170,557
24	**D.C. Jurisdictional Return on Rate Base**	**5.54%**		**4.87%**		**7.81%**
	Less Weighted Cost of:					
	Long Term Debt	2.61%		2.61%		2.61%
	Preferred Stock	0.00%		0.00%		0.00%
	Net amount available for common equity	2.93%		2.26%		5.20%
	Common Equity ratio	50.46%		50.46%		50.46%
	D.C. Jurisdictional Return on Equity	**5.81%**		**4.48%**		**10.30%**

Potomac Electric Power Company

District of Columbia Ratemaking Adjustments -- Distribution Only
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

RMA No.	Ratemaking Adjustments	Rate Base (1)	Revenue (2)	Operation & Maintenance (3)	Depreciation (4)	Amortization (5)	Other Taxes (6)	DCIT (7)	FIT (8)	Operating Income (9)
1	Annualization of Test Year Reliability Closings				1,111			(92)	(214)	(805)
	Electric Plant in Service	40,255								
	Accumulated Depreciation	3,332								
	Accumulated Deferred Income Taxes	(156)								
2	Inclusion of Post Test Year Reliability Plant - Closings thru December 31, 2019				2,869			(237)	(553)	(2,079)
	Electric Plant in Service	103,961								
	Accumulated Depreciation	1,160								
	Accumulated Deferred Income Taxes	(325)								
3	Inclusion of Post Test Year Reliability Plant - Closings thru June 30, 2020				1,585			(131)	(305)	(1,149)
	Electric Plant in Service	57,441								
	Accumulated Depreciation	2,444								
	Accumulated Deferred Income Taxes	(198)								
4	Removal of DC Power Line Undergrounding (DC PLUG) Initiative Costs			-	(6)			-	1	5
	Electric Plant in Service	(203)								
	Accumulated Depreciation	6								
	Accumulated Deferred Income Taxes	-								
5	Annualization of Regulatory Assets			552		(57)		(41)	(95)	(360)
	Regulatory Assets	(51)								
6	Annualization of Formal Case No. 1150 Base Revenues		$ (5,020)					(414)	(967)	(3,639)
7	Reflection of Three-Year Average Overtime Level			$ 1,169			$ 80	$ (103)	$ (241)	(905)
8	Annualization of Wage Increases			2,285			156	(201)	(470)	(1,770)
9	Annualization of Employee Health and Welfare Costs			(93)				8	18	67
10	Reflection of 2019 Pension and Other Post-Employment Benefits (OPEB) Expense			1,160				(96)	(223)	(841)
	Prepaid Pension/OPEB Liab. (net of tax)	(3,880)								
11	Removal of Supplemental Executive Retirement Plan (SERP) Costs			(692)	(41)			60	141	532
	Electric Plant in Service	(754)								
	Accumulated Depreciation	291								
12	Adjustment for Executive Incentive Plan Costs			(2,848)	(23)			237	553	2,081
	Electric Plant in Service	(437)								
	Accumulated Depreciation	78								
13	Removal of Adjustments To Deferred Compensation Balances			(44)				4	8	32
14	Reflection of Three-Year Average Regulatory Expense			619				(51)	(119)	(449)
15	Reflection of Three-Year Average Storm Costs			886				(73)	(171)	(642)
16	Removal of Employee Club Costs			(42)				3	8	31
17	Removal of Industry Contributions and Membership Fees			(373)				31	72	270
18	Removal of Institutional Advertising/Selling Expenses			(141)				12	27	102
19	Reflection of Increase in DC Water And Sewer (WASA) Rates			50				(4)	(10)	(36)
20a	Reflection of Benning Road Facility Environmental Remediation Efforts Costs					288		(24)	(55)	(209)
	Regulatory Assets	1,985								
20b	Inclusion of Benning Road Facility Future Costs to Complete the RI/FS					48		(4)	(9)	(35)
	Regulatory Assets	334								
21	Inclusion of Customer Deposit Interest Expense and Credit Facility Expense and Maintenance Costs			457				(38)	(88)	(331)
22	Annualization of Software Amortization					$ 2,085		(172)	(402)	(1,511)
	Accumulated Amortization	(1,076)								
23	Removal of Executive Perquisite Expenses			(27)				2	5	20
24	Annualization of Formal Case No. 1150 Depreciation Rates				(72)			6	14	52
	Accumulated Depreciation	36								
	Accumulated Deferred Income Taxes	(10)								
25	Reflection of 8.25% D.C. Income Tax Rate Change							(452)	95	357
26	Annualization of Federal Excess Deferred Income Tax Liability Amortization								(2,123)	2,123
	Accumulated Deferred Income Taxes	2,123								
27	Removal of Tax Cuts and Jobs Act of 2017 (TCJA) Revenue Debit		$ 5,058					417	975	3,666
28	Inclusion of the Frederick Douglass Memorial Bridge Project Costs					39		(3)	(8)	(29)
	Regulatory Assets	1,005								
29	Amortization of Pepco Holdings Inc. Service Company (PHISCO) Deficient Deferred Income Tax					870		(72)	(183)	(616)
	Regulatory Assets	1,039								
30	Reflection of Control Center Capital Lease Expiration			(3,868)				$ 319	$ 745	2,804
31	Reflection of Maryland Additional Subtraction Modification							-757	159	598
32	Inclusion of Exelon Merger Commitment Adjustment related to EBSC Depreciation Billed to Pepco			$ (450)				$ 37	$ 87	326
33	Reflection of Current Rate Case Costs			(929)		1,244		(26)	(61)	(229)
	Regulatory Assets	2,255								
34	Inclusion of Cost to Achieve (CTA) Regulatory Asset					1,892		(156)	(365)	(1,371)
	Regulatory Assets	6,171								
35	Inclusion of Non-Labor Operation & Maintenance (O&M) Inflation Adjustment			$ 1,428				$ (118)	$ (275)	(1,035)
36	Reflection of Cost to Optimize Regulatory Asset			$ (1,240)		248		82	191	719
	Regulatory Assets	809								
37	Reflection of Cash Working Capital Impact of Ratemaking Adjustments									
	Cash Working Capital	(62)								
38	Reflection of Interest Synchronization							(469)	(1,094)	1,563
	Total Ratemaking Adjustments	$ 217,573	$ 38	$ (2,140)	$ 5,423	$ 6,658	$ 236	$ (2,516)	$ (4,931)	(2,691)

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Analysis of Revenue Requirement -- Distribution Only
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

		Rate Base	Operating Income	Revenue Requirement
	Unadjusted amounts based on 10.10% return on equity	$ 1,966,247	109,006	$ 61,474
	Adjustments			
1	Annualization of Test Year Reliability Closings	43,431	(805)	5,790
2	Inclusion of Post Test Year Reliability Plant - Closings thru December 31, 2019	104,796	(2,079)	14,160
3	Inclusion of Post Test Year Reliability Plant - Closings thru June 30, 2020	59,687	(1,149)	8,016
4	Removal of DC Power Line Undergrounding (DC PLUG) Initiative Costs	(197)	5	(28)
5	Annualization of Regulatory Assets	(51)	(360)	491
6	Annualization of Formal Case No. 1150 Base Revenues		(3,639)	5,021
7	Reflection of Three-Year Average Overtime Level		(905)	1,249
8	Annualization of Wage Increases		(1,770)	2,442
9	Annualization of Employee Health and Welfare Costs		67	(92)
10	Reflection of 2019 Pension and Other Post-Employment Benefits (OPEB) Expense	(3,880)	(841)	742
11	Removal of Supplemental Executive Retirement Plan (SERP) Costs	(463)	532	(784)
12	Adjustment for Executive Incentive Plan Costs	(359)	2,081	(2,910)
13	Removal of Adjustments To Deferred Compensation Balances		32	(44)
14	Reflection of Three-Year Average Regulatory Expense		(449)	619
15	Reflection of Three-Year Average Storm Costs		(642)	886
16	Removal of Employee Club Costs		31	(43)
17	Removal of Industry Contributions and Membership Fees		270	(373)
18	Removal of Institutional Advertising/Selling Expenses		102	(141)
19	Reflection of Increase in DC Water And Sewer (WASA) Rates		(36)	50
20a	Reflection of Benning Road Facility Environmental Remediation Efforts Costs	1,985	(209)	502
20b	Inclusion of Benning Road Facility Future Costs to Complete the RI/FS	334	(35)	84
21	Inclusion of Customer Deposit Interest Expense and Credit Facility Expense and Maintenance Costs		(331)	457
22	Annualization of Software Amortization	(1,076)	(1,511)	1,969
23	Removal of Executive Perquisite Expenses		20	(28)
24	Annualization of Formal Case No. 1150 Depreciation Rates	26	52	(69)
25	Reflection of 8.25% D.C. Income Tax Rate Change		357	(492)
26	Annualization of Federal Excess Deferred Income Tax Liability Amortization	2,123	2,123	(2,701)
27	Removal of Tax Cuts and Jobs Act of 2017 (TCJA) Revenue Debit		3,666	(5,057)
28	Inclusion of the Frederick Douglass Memorial Bridge Project Costs	1,005	(29)	148
29	Amortization of Pepco Holdings Inc. Service Company (PHISCO) Deficient Deferred Income Tax	1,039	(616)	961
30	Reflection of Control Center Capital Lease Expiration		2,804	(3,869)
31	Reflection of Maryland Additional Subtraction Modification		598	(825)
32	Inclusion of Exelon Merger Commitment Adjustment related to EBSC Depreciation Billed to Pepco		326	(450)
33	Reflection of Current Rate Case Costs	2,255	(229)	558
34	Inclusion of Cost to Achieve (CTA) Regulatory Asset	6,171	(1,371)	2,557
35	Inclusion of Non-Labor Operation & Maintenance (O&M) Inflation Adjustment		(1,035)	1,428
36	Reflection of Cost to Optimize Regulatory Asset	809	719	(905)
37	Reflection of Cash Working Capital Impact of Ratemaking Adjustments	(62)		(7)
38	Reflection of Interest Synchronization		1,563	(2,156)
	Total adjustments	**217,573**	**(2,692)**	**25,681**
	Total revenue requirement at 7.74% rate of return based on adjusted results	**2,183,820**	**106,314**	**88,631**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	**Adjustment 1 - Annualization of Test Year Reliability Closings**		
	Rate Base		
	Electric Plant In Service		
1	Adjustment to EPIS to annualize actual test year Reliability closings	$	44,698
2	Adjustment to annualize test year reliability retirements		(4,443)
3	Total Adjustment to D.C. electric plant in service	$	40,255
	Accumulated Depreciation		
4	Reliability retirements during test year	$	4,443
5	Provision for Depreciation on annualized test year closings		(1,111)
6	Adjustment to D.C. accumulated depreciation	$	3,332
	Accumulated Deferred Taxes		
7	Adjustment to Deferred D.C. income taxes	$	(47)
8	Adjustment to Deferred D.C. income taxes - NOL offset		-
9	Adjustment to Deferred Federal income taxes		(109)
10	Adjustment to Deferred Federal income taxes - NOL offset		-
11	Adjustment to Deferred Income Taxes	$	(156)
	Total Rate Base	**$**	**43,431**
	Earnings		
12	Adjustment to D.C. depreciation expense	$	1,111
13	Adjustment to D.C. income tax expense	$	(92)
14	Adjustment to Federal income tax expense	$	(214)
	Total Earnings	**$**	**(805)**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	Adjustment 2 - Inclusion of Post Test Year Reliability Plant - Closings thru December 31, 2019		
	Rate Base		
	Electric Plant In Service		
1	Reliability closings to EPIS for - December 2019	$	107,990
2	Reliability retirements for December 2019		(4,029)
3	Total Adjustment to D.C. electric plant in service	$	103,961
	Accumulated Depreciation		
4	Reliability retirements for December 2019	$	4,029
5	Provision for Depreciation on annualized post test year closings		(2,869)
6	Adjustment to D.C. accumulated depreciation	$	1,160
	Accumulated Deferred Taxes (MACRS only)		
8	Adjustment to Deferred D.C. income taxes for accelerated depreciation	$	(97)
9	Adjustment to Deferred D.C. income taxes for NOL offset		-
10	Adjustment to Deferred Federal income taxes (D.C.) for accelerated depreciation		(228)
11	Adjustment to Deferred Federal income taxes (D.C.) NOL offset		-
12	Adjustment to D.C. Deferred Income Taxes	$	(325)
	Total Rate Base	**$**	**104,796**
	Earnings		
13	Adjustment to D.C. depreciation expense	$	2,869
14	Adjustment to D.C. income tax expense	$	(237)
15	Adjustment to Federal income tax expense	$	(553)
	Total Earnings	**$**	**(2,079)**

POTOMAC ELECTRIC POWER COMPANY

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(Thousands of Dollars)

Line No.	**Adjustment 3 - Inclusion of Post Test Year Reliability Plant - Closings thru June 30, 2020**		
	Rate Base		
	Electric Plant In Service		
1	Reliability closings to EPIS for - January - June 2020	$	61,470
2	Reliability retirements for January - June 2020		(4,029)
3	Total Adjustment to D.C. electric plant in service	$	57,441
	Accumulated Depreciation		
4	Reliability retirements for January - June 2020	$	4,029
5	Provision for Depreciation on annualized post test year closings		(1,585)
6	Adjustment to D.C. accumulated depreciation	$	2,444
	Accumulated Deferred Taxes (MACRS only)		
8	Adjustment to Deferred D.C. income taxes for accelerated depreciation	$	(59)
9	Adjustment to Deferred D.C. income taxes for NOL offset		-
10	Adjustment to Deferred Federal income taxes (D.C.) for accelerated depreciation		(139)
11	Adjustment to Deferred Federal income taxes (D.C.) NOL offset		-
12	Adjustment to D.C. Deferred Income Taxes	$	(198)
	Total Rate Base	**$**	**59,687**
	Earnings		
13	Adjustment to D.C. depreciation expense	$	1,585
14	Adjustment to D.C. income tax expense	$	(131)
15	Adjustment to Federal income tax expense	$	(305)
	Total Earnings	**$**	**(1,149)**

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Line No.	Adjustment 4 - Removal of DC Power Line Undergrounding (DC PLUG) Initiative Costs		
	Rate Base		
1	Adjustment to D.C. electric plant in service	$	(203)
2	Adjustment to D.C. accumulated depreciation	$	6
3	Adjustment to Deferred D.C. income taxes	$	-
4	Adjustment to Deferred D.C. income taxes - NOL offset		-
5	Adjustment to Deferred Federal income taxes		1
6	Adjustment to Deferred Federal income taxes - NOL offset		(1)
7	Adjustment to D.C. Deferred Income Taxes	$	-
	Total Rate Base	**$**	**(197)**
	Earnings		
8	Adjustment to D.C. O&M Expense		-
9	Adjustment to D.C. depreciation expense		(6)
10	Adjustment to D.C. income tax expense	$	-
11	Adjustment to Federal income tax expense	$	1
	Total Earnings	**$**	**5**

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Line No.	**Adjustment 5 - Annualization of Regulatory Assets**	Annualized	Test Period	
	Earnings			
1	Adjustment to Amortization Expense:			
2	DC Excess 1139	$ (290)	$ (256)	
3	DC Over-Collected Depr	(203)	(179)	
4	Total	(492)	(435)	(57)
5	Adjustment to O&M Expense:			
6	DC 1150 costs	557	493	
7	DC I-Street Lease Deferral	608	537	
8	DC Benning Remedial Study Costs	329	291	
9	Total	1,494	1,321	173
10	I Street lease expense run rate			
11	lease @ old rate in the TY		40	
12	lease @ new rate in the TY		2,941	
13	annualized rent expense @ new rate	3,361		
14	Adjustment to O&M expense to reflect new I Street lease ra	3,361	2,981	380
15	Total Adjustment to O&M expense			552
16	Adjustment to D.C. income tax			(41)
17	Adjustment to Federal income tax			(95)
18	**Total Expense**			360
	Total Earnings			**$ (360)**
19	**Rate Base**	Annualized	Test Period	
20	DC Excess 1139	(423)	(450)	
21	DC Over-Collected Depr	(296)	(315)	
22	DC 1150 costs	848	902	
23	DC I-Street Lease Deferral	1,641	1,668	
24	DC Benning Remedial Study Costs	1,871	1,886	
25	Total	$ 3,642	$ 3,692	$ (51)
	Total Rate Base			**$ (51)**

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Line No.	Adjustment 6 - Annualization of Formal Case No. 1150 Base Revenues		
1	Adjustment to annualize billed distribution revenues to levels set in Case No. 1150		$ (5,020)
2	Adjustment to D.C. income tax expense	(414)	
3	Adjustment to Federal Income Tax expense	(967)	1,381
	Total Earnings		**$ (3,639)**

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Line No.	**Adjustment 7 - Reflection of Three-Year Average Overtime Level**	Total	Incremental Major Storm Cost	Overtime Excl. Storm Costs
	Earnings			
1	12 mos. ended June 2017 overtime, net of storm costs	$ 16,480	$ (157)	$ 16,323
2	12 mos. ended June 2018 overtime, net of storm costs	14,001	(198)	13,803
3	12 mos. ended June 2019 overtime, net of storm costs	11,152	(116)	11,036
4	3-year total overtime, net of storm costs	$ 41,633	$ (471)	$ 41,162
5	3-year average overtime, net of storm costs			$ 13,721
6	Overtime included in test year			11,036
7	Net adjustment to overtime			$ 2,685
8	Allocation to D.C. (O&M less A&G ratio)			0.4353
9	Adjustment to D.C. operations and maintenance expense			$ 1,169
10	Adjustment to D.C. payroll taxes			$ 80
11	Adjustment to D.C. income tax expense			$ (103)
12	Adjustment to Federal income tax expense			$ (241)
	Total Earnings			**$ (905)**

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Line No.	Adjustment 8 - Annualization of Wage Increases	Mgmt	Union	Total
	Earnings			
	ANNUALIZATION OF TEST YEAR INCREASES (3/1/19 MGMT, 6/1/19 UNION)			
	Distr-related O&M wages/overtime, excl one-time payments, before increases			
	Pepco			
1	Pepco base distribution wages before increase	$ 12,221	$ 34,959	
2	Pepco overtime wages before increase, net of major storms	519	8,766	
3	Net amount	12,739	43,725	$ 56,465
	Charged to Pepco from Service Company			
4	Servco base distribution wages charged to Pepco before increase	15,784	4,027	
5	Servco overtime wages charged to Pepco before increase, net of major storms	49	167	
6	Net amount	15,833	4,195	20,028
	Charged to Pepco from EBSC			
7	EBSC base distribution wages charged to Pepco before increase	11,686	-	
8	EBSC overtime wages charged to Pepco before increase, net of major storms	95	-	
9	Net amount	11,781	-	11,781
10	Test year percentage wage increase	2.33%	2.50%	
	Adjustment to annualize wage increases occurring in test year:			
11	Pepco (line 3 * line 10)	297	1,093	
12	Charged to Pepco from Servco (line 6 * line 10)	369	105	
13	Charged to Pepco from EBSC (line 9 * line 10)	274	-	
14	**Total adjustment to annualize wage increases in test year**	**940**	**1,198**	2,138
	ADJUSTMENT TO REFLECT INCREASES WITHIN 12 MOS. OF TEST YEAR			
15	Actual test year base wages (distribution-related O&M) - Pepco	18,883	38,078	
16	Pepco overtime wages, net of major storms	875	9,755	
17	Plus annualization (line 11)	297	1,093	
18	Net amount	20,055	48,926	68,981
19	Actual test year base wages (distr-related O&M) charged to Pepco from Servco	24,599	4,396	
20	Servco overtime wages charged to Pepco before increase, net of major storms	118	190	
21	Plus annualization of test year increase (line 12)	369	105	
22	Total	25,086	4,691	29,777
23	Actual test year base wages (distr-related O&M) charged to Pepco from EBSC	18,205	-	
24	EBSC overtime wages charged to Pepco before increase, net of major storms	97	-	
25	Plus annualization of test year increase (line 13)	274	-	
26	Total	18,576	-	18,576
27	Pre-Rate Eff. Period % wage increase (3/1/20 Mgmt; 6/1/20 Union)	2.50%	2.50%	
	Adjustment to annualize known increases in rate effective period:			
28	Pepco (line 18 * line 27)	501	1,223	
29	Charged to Pepco from Servco (line 22 * line 27)	627	117	
30	Charged to Pepco from EBSC (line 26 * line 27)	464	-	
31	**Total adjustment**	**1,592**	**1,340**	2,932
	ADJUSTMENT TO REFLECT END OF PERIOD HEADCOUNT			
32	Wage annualization adjustments - Pepco (line 11 + line 28)	798	2,316	
	Full Time Employee Count-Pepco			
33	Average number of Pepco employees during test year	409	1,070	
34	Number of Pepco employees as of end of test year	429	1,096	
35	% end-of-period to average workforce level	104.82%	102.45%	
36	**Pepco Headcount Adjustment ((line 32 * line 35) - line 32)**	**38**	**57**	
37	Wage annualization adjustments - Servco to Pepco (line 12 + line 29)	996	222	
	Full Time Employee Count-Servco			
38	Average number of Servco employees during test year	996	296	
39	Number of Servco employees as of end of test year	1,029	310	
40	% end-of-period to average workforce level	103.33%	104.81%	
41	**Servco Headcount Adjustment ((line 37 * line 40) - line 37)**	**33**	**11**	
42	Wage annualization adjustments - EBSC to Pepco (line 13 + line 30)	738	-	
	Employee Count-EBSC			
43	Average number of EBSC employees during test year	3,353	-	
44	Number of EBSC employees as of end of test year	3,541	-	
45	% end-of-period to average workforce level	105.62%	-	
46	**EBSC Headcount Adjustment ((line 42 * line 45) - line 42)**	**41**	**-**	
	Total adjustment to wages:			
47	Pepco (line 11 + line 28 + line 36)	836	2,373	
48	Charged to Pepco from Servco (line 12 + line 29 + line 41)	1,029	233	
49	Charged to Pepco from EBSC (line 13 + line 30 + line 46)	779	-	
50	**Total adjustment**	**2,644**	**2,606**	**$ 5,250**
51	Allocation factor - DC (O&M less A&G)	0.4353	0.4353	0.4353
52	Adjustment to operations & maintenance for wage increases	$ 1,151	$ 1,134	$ 2,285
53	Adjustment to D.C. payroll tax expense	79	77	156
54	Adjustment to DC income tax expense			$ (201)
55	Adjustment to federal income tax expense			$ (470)
	Total Earnings			**$ (1,770)**

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Line No.	**Adjustment 9 - Annualization of Employee Health and Welfare Costs**				
	Earnings				
	Plan	Test Period Amount	Rate Effective Period Amount	Projected Change	
1	**Shared Benefits costs in O&M Expense**				
2	Medical	$ 12,978	$ 12,822	$ (156)	
3	Dental	862	825	(37)	
4	Vision	339	313	(26)	
5	Change in employee health & welfare costs	14,178	13,960	(218)	
6	Allocation to distribution (labor ratio)			0.8755	
7	Adjustment to distribution-related O&M expense			(191)	
8	**Direct Distribution shared benefits charged to O&M**				
9	Medical	$ 1,302	$ 1,286	$ (16)	
10	Dental	89	86	(3)	
11	Vision	38	36	(2)	
12	Change in employee health & welfare costs direct dist.	1,430	1,408	(22)	
13	Total adjustment to distribution			(213)	
14	Allocation to DC (O&M less A&G ratio)			0.4353	
15	Adjustment to DC O&M expense				(93)
16	Adjustment to DC income tax expense				8
17	Adjustment to federal income tax expense				18
	Total Earnings				$ 67

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Line No.	Adjustment 10 - Reflection of 2019 Pension and Other Post-Employment Benefits (OPEB) Expense	Pension	OPEB	Total
	Rate Base			
	RATE BASE ADJUSTMENT FOR AVG, NET OF TAX, DISTRIBUTION-RELATED BALANCES:			
1	Average net-of-tax prepaid pension and OPEB balance - Pepco - at 12/31/2019	$ 194,530	$ (16,109)	$ 178,421
2	Average net-of-tax prepaid pension and OPEB balance - Pepco - at 6/30/2019	201,990	(17,776)	184,214
3	Adjustment to reflect change in average Pepco balance	$ (7,460)	$ 1,667	(5,793)
4	Average net-of-tax prepaid pension and OPEB balance - Service Co - at 12/31/2019	$ (11,935)	$ (7,915)	$ (19,850)
5	Average net-of-tax prepaid pension and OPEB balance - Service Co - at 6/30/19	(8,746)	(7,983)	(16,730)
6	Adjustment to reflect change in Pepco portion of Service Company average balance	$ (3,189)	$ 68	$ (3,121)
7	Total adjustment to average rate base			$ (8,914)
8	Allocation to D.C. (O&M less A&G ratio)			0.4353
9	Adjustment to D.C. net-of-tax prepaid pension and OPEB (line 7* {line 3 + line 6})			$ (3,880)
	Total Rate Base			**$ (3,880)**
	Earnings			
	DISTRIBUTION-RELATED OPERATIONS & MAINTENANCE EXPENSE ADJUSTMENT:			
10	2019 Annualized Pepco pension and OPEB expense	$ 9,757	$ 1,414	$ 11,170
11	Pepco pension and OPEB expense for the 12 months ended 06/30/19	7,345	1,179	8,525
12	Adjustment for change in Pepco pension and OPEB expense	$ 2,411	$ 234	$ 2,646
13	Pepco portion of 2019 Annualized Service Company pension and OPEB expense	$ 6,316	$ 328	$ 6,645
14	Pepco portion of Servco pension and OPEB expense for the 12 months 06/30/2019	5,971	283	6,254
15	Adjustment for change in Pepco portion of Servco pension and OPEB expense	$ 346	$ 45	$ 391
16	Pepco portion of 2019 Annualized Exelon Business Servco pension and OPEB expense	$ 1,601	$ (121)	$ 1,480
17	Pepco portion of Exelon Business Servco pension and OPEB expense for the 12 months 06/30/2019	1,930	(77)	1,852
18	Adjustment for change in Pepco portion of Exelon Business Servco pension and OPEB expense	$ (328)	$ (44)	$ (372)
19	Adjustment to Pepco distribution-related O&M pension and OPEB expense			$ 2,664
20	Allocation to D.C. (O&M less A&G ratio)			0.4353
21	Adjustment to D.C. operations and maintenance expense			$ 1,160
22	Adjustment to D.C. income tax expense			$ (96)
23	Adjustment to Federal income tax expense			$ (223)
	Total Earnings			**$ (841)**

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Line No.	Adjustment 11 - Removal of Supplemental Executive Retirement Plan (SERP) Costs		
	Rate Base		
1	13 month average capitalized Pepco utility SERP expense	$	1,030
2	13 month average capitalized Service Company SERP expense charged to Pepco		785
3	Total 13 month average capitalized SERP expense	$	1,815
4	Allocation to Distribution (Plant less AFUDC ratio)		0.8175
5	Distribution-related capitalized SERP expense		1,484
6	Allocation to D.C. (Plant less AFUDC ratio)		0.5079
7	Adjustment to D.C. electric plant in service	$	(754)
8	13 month average accumulated depreciation on capitalized SERP	$	(768)
9	Allocation to Distribution (Depreciation less AFUDC ratio)		0.8334
10	Distribution-related portion of 13 month average SERP accumulated depreciation		(640)
11	Allocation to D.C. (Accumulated Depreciation less AFUDC ratio)		0.4546
12	Adjustment to D.C. accumulated depreciation	$	291
	Total Rate Base	**$**	**(463)**
	Earnings		
13	Depreciation expense on capitalized SERP costs	$	90
14	Allocation to Distribution (Depreciation less AFUDC ratio)		0.8334
15	Distribution-related portion of SERP depreciation expense		75
16	Allocation to D.C. (Depreciation less AFUDC ratio)		0.5455
17	Adjustment to D.C. depreciation expense	$	(41)
18	Total distribution SERP expense attributable to Bonus / Other Non-Qualified Benefits		1,361
19	Allocation to Distribution (Labor ratio)		0.8755
20	Distribution-related operation & maintenance expense		1,192
21	Direct Distribution-related operation & maintenance expense		398
22	Allocation to D.C. (O&M less A&G ratio)		0.4353
23	Adjustment to D.C. operations & maintenance expense	$	(692)
24	Adjustment to D.C. income tax expense	$	60
25	Adjustment to Federal income tax expense	$	141
	Total Earnings	**$**	**532**

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Line No.	Adjustment 12 - Adjustment for Executive Incentive Plan Costs	AIP/Exec.total
	Rate Base	
1	Average capitalized Exec incentive costs in electric plant in service (EPIS)	$ 1,052
2	Allocation to Distribution (Plant less AFUDC ratio)	0.8175
3	Average distribution related capitalized Exec incentive costs in EPIS	860
4	Allocation to D.C. (Plant less AFUDC ratio)	0.5079
5	Adjustment to remove average capitalized Exec incentive costs from D.C. EPIS	$ (437)
6	Average capitalized incentive costs in accumulated depreciation	$ (206)
7	Allocation to Distribution (Depreciation less AFUDC ratio)	0.8334
8	Average distribution related capitalized incentive costs in accumulated depreciation	(172)
9	Allocation to D.C. (Accumulated depreciation less AFUDC ratio)	0.4546
10	Adjustment to remove average capitalized incentive costs from D.C. accum. depreciation	$ 78
	Total Rate Base	**$ (359)**
	Earnings	
11	Average capitalized exec incentive costs included in depreciation expense	$ 52
12	Allocation to Distribution (Depreciation less AFUDC ratio)	0.8334
13	Average distribution related capitalized incentive costs in depreciation expense	43
14	Allocation to D.C. (Depreciation less AFUDC ratio)	0.5455
15	Adjustment to remove average capitalized incentive costs from D.C. depreciation	$ (23)
16	Adjustment to remove Earnings-Related CEO EIP Expense	$ 56
17	Adjustment to remove Non Customer-Related LTIP Expense	6,486
18	Distribution-related incentive costs in Pepco O&M expense	6,542
19	Allocation to D.C. (O&M less A&G ratio)	0.4353
20	Adjustment to D.C. operations and maintenance expense to remove incentive costs	$ (2,848)
21	Adjustment to D.C. income tax expense	$ 237
22	Adjustment to Federal income tax expense	$ 553
	Total Earnings	**$ 2,081**

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Line No.	**Adjustment 13 - Removal of Adjustments to Deferred Compensation Balances**	
	Earnings	
1	Impact of adjustments to deferred compensation liability on O&M expense	$ 77
2	Allocation to Distribution (Labor ratio)	0.8755
3	expense	67
4	Direct Distribution Deferred Compensation charged to O&M	35
5	Total adjustment to distribution	102
6	Allocation to D.C. (O&M less A&G ratio)	0.4353
7	Adjustment to D.C. operations and maintenance expense	$ (44)
8	Adjustment to D.C. income tax expense	$ 4
9	Adjustment to Federal income tax expense	$ 8
	Total Earnings	**$ 32**

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Line No.	**Adjustment 14 - Reflection of Three-Year Average Regulatory Expense**		
	Earnings		
			D.C. Direct
1	12 mos. ending 06/30/2017 non-deferred regulatory expense	$	1,080
2	12 mos. ending 06/30/2018 non-deferred regulatory expense	$	1,875
3	12 mos. ending 06/30/2019 non-deferred regulatory expense	$	549
4	D.C. 3-year total (excludes deferred and amortized costs)	$	3,505
5	Three-year average D.C. regulatory expense (line 4 ÷ 3 years)	$	1,168
6	D.C. non-deferred regulatory expense for the twelve months ended December 31, 2017		549
7	Adjustment to D.C. operations & maintenance expense	$	619
8	Adjustment to D.C. income tax expense	$	(51)
9	Adjustment to Federal income tax expense	$	(119)
	Total Earnings	**$**	**(449)**

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Line No.	**Adjustment 15 - Reflection of Three-Year Average Storm Costs**				
	Earnings	System	Allocator	D.C.	
	Twelve months ended June 30, 2017				
1	Directly assigned based on restorations:				
2	Snow Storm Stella March 13, 2017	$ 1,207	-	$	-
3	MD Storm Costs	$ 2,688	-	$	-
4	Allocable	3,070	0.3788		1,163
5	Total for twelve months ended June 30, 2017	$ 6,965		$	1,163
	Twelve months ended June 30, 2018				
6	Directly assigned based on restorations:				
7	Snow Storm Stella March 13, 2017	$ (107)	-	$	-
8	Winter Wind Storm Riley 2018	6,555	0.2346		1,538
9	Winter Storm Toby 2018	968	0.0139		13
10	Allocable	4,597	0.3788		1,741
	Total for twelve months ended June 30, 2018	$ 12,014		$	3,292
	Twelve months ended June 30, 2019				
11	Directly assigned based on restorations:				
12	Winter Wind Storm Riley 2018	(727)	0.2346		(171)
13	Winter Storm Toby 2018	(217)	0.0139		(3)
	DC Major Storm Fund (Budget)	894	1.0000		894
14	Allocable	467	0.3788		177
15	Total for twelve months ended June 30, 2019	$ 417		$	898
16	Three-year average storm costs - DC			$	1,784
17	Adjustment to D.C. O&M expense to reflect 3-year average storm damage costs (Line 12 - Line 11)			$	886
18	Adjustment to D.C. income tax expense			$	(73)
19	Adjustment to Federal income tax expense			$	(171)
	Total Earnings			**$**	**(642)**

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Line No.	**Adjustment 16 - Removal of Employee Club Costs**		
	Earnings		
1	Total employee association costs to be excluded per Formal Case 1103	$	111
2	Allocation to Distribution (Labor Ratio)		0.8755
3	Excludable employee association costs included in distribution O&M	$	97
4	Allocation to D.C. (O&M less A&G ratio)		0.4353
5	Adjustment to D.C. operations and maintenance expense	$	(42)
6	Adjustment to D.C. income tax expense	$	3
7	Adjustment to Federal income tax expense	$	8
	Total Earnings	**$**	**31**

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Line No.	Adjustment 17 - Removal of Industry Contributions and Membership Fees		
	Earnings		
1	Industry contributions and membership fees - A&G	$	812
2	Allocation to Distribution (Labor Ratio)		0.8755
3	Excludable industry contributions & membership fees included in distribution O&M		711
4	Industry contributions and membership fees - Distribution	$	45
5	Industry contributions and membership fees - Total	$	856
6	Allocation to D.C. (O&M less A&G ratio)		0.4353
7	Adjustment to D.C. operations and maintenance expense	$	(373)
8	Adjustment to D.C. income tax expense	$	31
9	Adjustment to Federal income tax expense	$	72
	Total Earnings	**$**	**270**

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Line No.	**Adjustment 18 - Removal of Institutional Advertising and Selling Expenses**	
	Earnings	
1	Institutional/promotional advertising, selling expenses excludable from cost of service	$ 324
2	Allocation to D.C. (O&M less A&G ratio)	0.4353
3	Adjustment to D.C. operations and maintenance expense	$ (141)
4	Adjustment to D.C. income tax expense	$ 12
5	Adjustment to Federal income tax expense	$ 27
	Total Earnings	**$ 102**

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(Thousands of Dollars)

Line No. **Adjustment 19 - Reflection of Increase in D.C. Water and Sewer Authority (WASA) Rates**

Earnings

Line No.		Rate Effective 10/1/2017	Rate Effective 10/1/2018	Rate Effective 10/1/2019	Total Increase
	Volumetric Rates				
1	Water Service	$ 4.40	$ 4.05	$ 4.25	
2	Sewer Service	6.00	7.75	8.14	
3	Right of Way Fee	0.18	0.18	0.19	
4	Payment in Lieu of Taxes (PILOT)	0.49	0.50	0.51	
5	Total cost per one hundred cubic feet (Ccf)	$ 11.07	$ 12.48	$ 13.09	
6	Pepco Annual Ccf usage (hundred cubic feet)	4,755	4,755		
7	Factor for months in effect - 12 mos ended June 30, 2019	25%	75%		
8	Test year D.C. operations and maintenance expense	13.16	44.51	-	$ 58
9	Pepco Annual Ccf usage (hundred cubic feet)		4,755	4,755	
10	Factor for months in effect - 12 mos ended June 30, 2020		25%	75%	
11	Rate Effective Period D.C. operations and maintenance expense	-	14.84	46.68	62
12	Net increase in D.C. operations and maintenance expense				$ 4
	Fixed Rates				
13	Impervious Area Charge (IAC)	$ 25.18	$ 23.00	25.58	
14	Storm Water Fee	2.67	2.67	2.67	
15	Total cost per equivalent residential unit (ERU)	$ 27.85	$ 25.67	$ 28.25	
16	Pepco monthly equivalent residential units (1000 ERU's)	2,709	2,709	2,709	
17	Months in effect - 12 mos ended June 30, 2018	3	9		
18	Test year D.C. operations and maintenance expense	226	626	-	$ 852
19	Pepco monthly equivalent residential units (1000 ERU's)		2,709	2,709	
20	Months in effect - 12 mos ended June 30, 2019		3	9	
21	Rate Effective Period D.C. operations and maintenance expense		209	689	898
22	Net increase in D.C. operations and maintenance expense				$ 46
23	Total adjustment to D.C. distribution-related O&M expense				$ 50
24	Adjustment to D.C. income tax				$ (4)
25	Adjustment to Federal income tax				$ (10)
	Total Earnings				**$ (36)**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	**Adjustment 20a - Reflection of Benning Road Facility Environmental Remediation Efforts Costs**		
	Earnings		
1	Dollars Spent for the RI/FS from 1/1/2018 to Date - Pepco	$ 1,560	
2	CT Basins Removal Pepco	3,434	
3	Allocation to DC	57.7%	
4	Dollars Spent for the RI/FS from 1/1/2018 to Date - Pepco DC	900	
5	CT Basing Removal Pepco DC	1,981	
6	Total Benning	2,882	
7	Adjustment to Amortization Expense (10 year amortization period)		288
8	Adjustment to DC income tax expense		(24)
9	Adjustment to federal income tax expense		(55)
	Total Earnings		**$ (209)**
	Rate Base		
11	Test year average unamortized rate base, net of accumulated deferred taxes:		
12	Average DC regulatory asset balance	$ 2,882	
13	Decline in balance After Year 1	(144)	
14	Total average unamortized rate base balances		2,738
15	Adjustment to accumulated deferred income taxes		(753)
16	Adjustment to rate base, net of accumulated deferred taxes		1,985
	Total Rate Base		**$ 1,985**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	**Adjustment 20b - Inclusion of Benning Road Facility Future Costs to Complete the RI/FS**			
	Earnings			
1	Future Costs for RI/FS - Pepco (April 2019 - December 2020)	$ 840		
2	Allocation to DC	57.7%		
3	Future Costs for RI/FS - Pepco (April 2019 - December 2020) - Pepco DC	485		
4	Adjustment to Amortization Expense (10 year amortization period)			48
5	Adjustment to DC income tax expense			(4)
6	Adjustment to federal income tax expense			(9)
	Total Earnings		**$**	**(35)**
	Rate Base			
8	Test year average unamortized rate base, net of accumulated deferred taxes:			
9	Average DC regulatory asset balance	$ 485		
10	Decline in balance After Year 1	(24)		
11	Total average unamortized rate base balances			461
12	Adjustment to accumulated deferred income taxes			(127)
13	Adjustment to rate base, net of accumulated deferred taxes			334
	Total Rate Base		**$**	**334**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	**Adjustment 21 - Inclusion of Customer Deposit Interest Expense and Credit Facility Expense and Maintenance Costs**		
	Earnings		
1	Interest on customer deposits at 2019 rate of 2.64%	$	232
2	Credit facility costs (quarterly maintenance fee)	$	591
3	Allocation to Distribution (Labor ratio)		0.8755
4	Distribution-related credit facility costs	$	517
5	Allocation factor - District of Columbia (O&M less A&G ratio)		0.4353
6	District of Columbia allocated credit facility costs	$	225
7	Adjustment to include Commission-allowed interest charges in distribution O&M expense	$	457
8	Adjustment to D.C. income tax expense	$	(38)
9	Adjustment to Federal income tax expense	$	(88)
	Total Earnings	**$**	**(331)**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	**Adjustment 22 - Annualization of Software Amortization**	Non-AFUDC	DC AFUDC	Total
	Rate Base			
1	Annualization of accumulated amortization expense on new software assets added during the test year	$ (2,373)	$ (24)	$ (2,396)
2	Allocation to Distribution (Labor ratio)	0.8755	0.8755	
3	Distribution-related adjustment to accumulated amortization	(2,077)	(21)	(2,098)
4	Allocation to DC (Plant less AFUDC ratio)	0.5079	1.0000	
5	Adjustment to D.C. accumulated amortization	$ (1,055)	$ (21)	$ (1,076)
	Total Rate Base			**$ (1,076)**
	Earnings			
6	Annualization of amortization expense for new software assets added in test year	$ 4,745	$ 47	$ 4,792
7	Removal of D.C. amortization expense included in test year for software assets ending by June 30, 2019	(44)	-	(44)
8	Removal of D.C. amortization expense included in test year for software assets ending by June 30, 2020	(99)	(2)	(101)
9	Adjustment to amortization expense	4,602	45	4,647
10	Allocation to Distribution (Labor ratio)	0.8755	0.8755	
11	Distribution-related adjustment to amortization expense	4,029	39	4,068
12	Allocation to DC (Plant less AFUDC ratio)	0.5079	1.0000	
13	Adjustment to D.C. amortization expense	$ 2,046	$ 39	$ 2,085
14	Adjustment to D.C. income tax expense			$ (172)
15	Adjustment to Federal income tax expense			$ (402)
	Total Earnings			**$ (1,511)**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	**Adjustment 23 - Removal of Executive Perquisite Expenses**	
	Earnings	
1	Executive Perquisite Expenses Charged to Pepco	$ 72
2	Allocation to Distribution (Labor ratio)	0.8755
3	Allocation factor - District of Columbia (O&M less A&G ratio)	0.4353
4	Executive Perquisite Expenses Charged to Pepco - DC Distribution	$ (27)
5	Adjustment to D.C. income tax expense	$ 2
6	Adjustment to Federal income tax expense	$ 5
	Total Earnings	**$ 20**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	**Adjustment 24 - Annualization of Formal Case No. 1150 Depreciation Rates**		
	Earnings		
	FC 1150 Depreciation Rates		
1	Adjustment to D.C. depreciation expense for Approved Depreciation Rates		31
	Amortization of Unrecovered Reserve		
2	Approved Amortization of Unrecovered Reserve	(1,205)	
3	Test Period Amortization of Unrecovered Reserve	(1,102)	(103)
4	Total Taxable Income		(72)
5	Adjustment to D.C. income tax expense		6
6	Adjustment to Federal income tax expense		14
	Total Earnings		**52**
	Rate Base		
7	Adjustment to D.C. Average accumulated depreciation for New Depreciation Rates	36	
8	Adjustment to accumulated deferred income taxes		(10)
	Total Rate Base		**$ 26**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	**Adjustment 25 - Reflection of 8.25% D.C. Income Tax Rate Change**				
	Earnings				
1	Flow Back Excess Deferred Taxes to Customers over 3 Years:		Years		
	Total Liability				
2	DC Income Tax - Distribution Portion	$ (5,704)	3	$	(1,901)
3	Test Period Amortization				(1,449)
4	Adjustment to DC income tax expense			$	(452)
5	Adjustment to Federal income tax expense			$	95
	Total Earnings			**$**	**357**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	**Adjustment 26 - Annualization of Federal Excess Deferred Income Tax Liability Amortization**				
	Earnings	Amount	Flow Back Period		Amortization
1	Excess Deferred Tax Liability - Prot Property	(141,259)	ARAM	1/	(1,790)
2	Excess Deferred Tax Liability - Non Prot Property	(128,080)	10 Yrs		(12,808)
3	Excess Deferred Tax Liability - Non-Property	(21,329)	5 Years		(4,266)
4	Total Amortization - Annualized				(18,864)
5	Excess Deferred Tax Liability - Test Period Amortization				(16,741)
6	Difference: Total Impact to Federal Income Taxes				(2,123)
	Total Earnings				**2,123**
	Rate Base				
7	Reduction in Excess Tax Liability				2,123
	Total Rate Base				**2,123**

1/ Average Rate Assumption Method (ARAM) is a prescribed methodology for calculating the reversal of protected property related excess deferred taxes that roughly equates to the remaining useful book life of the asset to which it relates.
Non-protected property is amortized over remaining book life.

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	Adjustment 27 - Removal of Tax Cuts and Jobs Act of 2017 (TCJA) Revenue Debit		
1	Revenue Adjustment		$ 5,058
2	Adjustment to D.C. income tax expense	417	
3	Adjustment to Federal Income Tax expense	975	(1,392)
	Total Earnings		$ 3,666

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	**Adjustment 28 - Inclusion of the Frederick Douglass Memorial Bridge Project Costs**		
	Earnings	D.C. Direct	
1	Engineering and Bridge Enhancement payment	$ 3,394	
2	Allocation to DC (Average & Excess - NCP)	42.03%	
3	Regulatory Asset	$ 1,426	
4	Proposed Amortization Period (based on 2.76% composite depreciation rate per FC 1150)	36.23	
5	Adjustment to Amortization Expense		39
6	Adjustment to D.C. income tax expense		$ (3)
7	Adjustment to Federal income tax expense		$ (8)
	Total Earnings		**$ (29)**
	Rate Base		
8	Test year average unamortized rate base, net of accumulated deferred taxes:		
9	Average DC regulatory asset balance	$ 1,426	
10	Decline in balance After Year 1	(39)	
11	Total average unamortized rate base balances		1,387
12	Adjustment to accumulated deferred income taxes		(382)
13	Adjustment to rate base, net of accumulated deferred taxes		1,005
	Total Rate Base		**$ 1,005**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	**Adjustment 29 - Amortization of Pepco Holdings Inc. Service Company (PHISCO) Deficient Deferred Income Tax**		
	Earnings		
1	PHISCO Deficient Deferred Income Tax Balances	DC Amount	Amortization Expense
2	Property-Related (10 year amortization)	$ (4,965)	$ (497)
3	Non-Property Related (5 year amortization)	6,834	1,367
4	Total	1,868	870
5	Adjustment to Amortization expense		870
6	Adjustment to DC Income Tax expense		(72)
7	Adjustment to Federal Income Tax expense		(183)
	Total Earnings		**$ (616)**
	Rate Base		
8	Average DC Regulatory Asset Balance	$ 1,868	
9	Decline in Balance After Year 1	(435)	
10	Adjustment to DC regulatory assets		1,433
11	Adjustment to accumulated deferred income taxes		(394)
	Total Rate Base		**$ 1,039**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	**Adjustment 30 - Reflection of Control Center Capital Lease Expiration**		
	Earnings		
1	Removal of Control Center Lease Payment	$	7,617
2	Allocation to D.C. (Plant less AFUDC ratio)		0.5079
3	Adjustment to distribution-related O&M expense		(3,868)
4	Adjustment to D.C. income tax expense	$	319
5	Adjustment to Federal income tax expense	$	745
	Total Earnings	**$**	**2,804**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	**Adjustment 31 - Reflection of Maryland Additional Subtraction Modification**			
	Earnings	Amount	Flow Back Period	Amortization
1	Regulatory Liability	(27,560)	36.42 Years	(757)
2	Change in DC Income Tax Expense			(757)
3	Change in Federal Income Tax Expense			159
	Total Earnings			**$ 598**
	Rate Base			
4	Adjustment to ADIT to reflect Deferred Tax Asset	27,560		
5	Adjustment to Regulatory Liability	(27,560)		
	Total Rate Base			$ -

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	Adjustment 32 - Inclusion of Exelon Merger Commitment Adjustment related to EBSC Depreciation Billed to Pepco		
	Earnings		
1	BSC Depreciation Expense Billed to Pepco Adjustment	$	1,186
2	Allocation to Distribution (Labor Ratio)		0.8755
3	BSC Depreciation Expense included in distribution O&M	$	1,038
4	Allocation to D.C. (O&M less A&G ratio)		0.4340
5	Adjustment to D.C. operations and maintenance expense	$	(450)
6	Adjustment to D.C. income tax expense	$	37
7	Adjustment to Federal income tax expense	$	87
	Total Earnings	**$**	**326**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	Adjustment 33 - Reflection of Current Rate Case Costs		
	Earnings		
1	Current Rate Case Costs Estimate	$ 4,456	
2	Less: Refund of 1150 Rate Case Costs	(723)	
3	Subtotal Rate Case Costs Estimate	3,733	
4	Less: Included in the O&M Expenses		(929)
5	Adjustment to Amortization Expense (3 Year Amortization Period)		1,244
6	Adjustment to DC Income Tax expense		(26)
7	Adjustment to Federal Income Tax expense		(61)
	Total Earnings		**$ (229)**
	Rate Base		
8	Test year average unamortized rate base, net of accumulated deferred taxes:		
9	Average DC regulatory asset balance	$ 3,733	
10	Decline in balance After Year 1	(622)	
11	Total average unamortized rate base balances		3,111
12	Adjustment to accumulated deferred income taxes		(856)
13	Adjustment to rate base, net of accumulated deferred taxes		2,255
	Total Rate Base		**$ 2,255**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	Adjustment 34 - Inclusion of Cost to Achieve (CTA) Regulatory Asset		
	Earnings		
1	Actual CTA Costs	$ 9,460	
2	Adjustment to Amortization Expense (5 Year Amortization Period)		$ 1,892
3	Adjustment to DC Income Tax expense		(156)
4	Adjustment to Federal Income Tax expense		(365)
	Total Earnings		**$ (1,371)**
	Rate Base		
5	Test year average unamortized rate base, net of accumulated deferred taxes:		
6	Average DC regulatory asset balance	$ 9,460	
7	Decline in balance After Year 1	(946)	
8	Total average unamortized rate base balances		$ 8,514
9	Adjustment to accumulated deferred income taxes		(2,343)
10	Adjustment to rate base, net of accumulated deferred taxes		6,171
	Total Rate Base		**$ 6,171**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	Adjustment 35 - Inclusion of Non-Labor Operation & Maintenance (O&M) Inflation Adjustment	
	Earnings	
1	Non-Labor OM Expense	$ 88,170
2	Inflation Factor	0.0162
3	Inflation Adjustment	$ 1,428
4	Adjustment to D.C. income tax expense	$ (118)
5	Adjustment to Federal income tax expense	$ (275)
	Total Earnings	**$ (1,035)**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	**Adjustment 36 - Reflection of Cost to Optimize Regulatory Asset**		
	Earnings		
1	Test Period CTO Expense	$ 2,849	
2	Allocation to D.C. (O&M less A&G ratio)	43.53%	
3	Adjustment to O&M Expense		$ (1,240)
4	Adjustment to Amortization Expense (5 Year Amortization Period)		$ 248
5	Adjustment to DC Income Tax expense		82
6	Adjustment to Federal Income Tax expense		191
	Total Earnings		**$ 719**
	Rate Base		
	Test year average unamortized rate base, net of accumulated deferred taxes:		
7	Average DC regulatory asset balance	$ 1,240	
8	Decline in balance After Year 1	(124)	
9	Total average unamortized rate base balances		$ 1,116
10	Adjustment to accumulated deferred income taxes		(307)
11	Adjustment to rate base, net of accumulated deferred taxes		809
	Total Rate Base		**$ 809**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	Adjustment 37 - Reflection of Cash Working Capital Impact of Ratemaking Adjustments		
	Rate Base		
1	D.C. unadjusted Cash Working Capital allowance for test year	$	9,631
2	Impact of Ratemaking Adjustments on Cash Working Capital Allowance		(62)
3	D.C. Cash Working Capital allowance adjusted for Ratemaking Adjustments	$	9,569

Potomac Electric Power Company

District of Columbia - Impact of Ratemaking Adjustments on Cash Working Capital
Twelve Months Ended June 30, 2019

Line No.	Adjustment 37 - Reflection of Cash Working Capital Impact of Ratemaking Adjustments	(1) D.C. Distribution Amount	(2) 2015 Study Expense Lag	(3) Test Year Lag Dollars (column 1 x column 2)
1	Pepco Labor	$ 3,454	8.70	$ 30,050
2	Pepco AIP		241.00	
3	Incremental Storm Expense	-	137.47	-
4	Control Center Lease	-	88.25	-
5	Other O&M Expense	(5,767)	35.79	(206,378)
6	Other Taxes:			
7	Property Tax - D.C.	-	97.21	-
8	Property Tax - Montgomery County	-	(4.10)	-
9	Property Tax - PG County	-	(59.76)	-
10	Property Tax - Charles County	-	(59.60)	-
11	Property Tax - Other Maryland	-	(76.77)	-
12	Property Tax - Alexandria	-	151.09	-
13	Property Tax - Arlington	-	234.50	-
14	Property Tax - Fairfax	-	0.00	-
15	Property Tax - Pr William	-	153.68	-
16	D.C. Delivery Tax	-	35.41	-
17	D.C. Public Space Occupancy Fee	-	(49.13)	-
18	D.C. RETF,SETF, EATF	-	36.27	-
19	D.C. PSC Reimbursement	-	172.50	-
20	D.C. Business Improvement Tax	-	(99.94)	-
21	D.C. Ballpark Fee	-	197.50	-
22	D.C. Sales & Use Tax	-	35.69	-
23	Montgomery County Fuel & Energy	-	45.67	-
24	Maryland Delivery Tax	-	39.26	-
25	Maryland Gross Receipts	-	44.86	-
26	Maryland Universal Surcharge	-	30.25	-
27	Maryland Environmental Surcharge	-	40.25	-
28	Maryland Sales, Use & Diesel Tax	-	35.24	-
29	Maryland PSC Reimbursement	-	(26.00)	-
30	Federal Heavy Vehicle Highway Use Tax	-	(138.50)	-
31	Payroll Tax-FICA	236	9.15	2,159
32	Payroll Tax-FUTA/SUTA	-	9.03	-
33	D.C. Income Tax (Current Portion)	-	59.05	-
34	Federal Income Tax (Current Portion)	-	59.05	-
35	Subtotal	$ (2,077)		$ (176,328)
36				
37	D.C. Composite Expense Lag		33.47	
38	D.C. Revenue Lag		44.34	
39	D.C. Net Lag		10.87	
40	D.C. Average Daily Expense			$ (6)
41				
42	D.C. Impact of Ratemaking Adjustments on CWC			$ (62)

Adjustments Impacting Cash Working Capital			
	Pepco Labor		
	Annualization of wage increases	2,285	
	Reflect 3 year average overtime in test year	1,169	3,454
	Other O&M		
4	DCPLUG	-	
5	Annualization of Reg Assets (Adj to OM Expense)	380	
9	Annualization of employee health and welfare costs	(93)	
10	Reflection of 2019 pension and OPEB expense	1,160	
11	Supplemental executive retirement plans (SERP)	(692)	
12	Pepco Incentive Payments	(2,848)	
13	Removal of Adjustments To Deferred Compensation Balances	(44)	
14	Reflection of 3-year average regulatory expense	619	
15	Reflection of 3-year average incr storm costs excl labor	886	
16	Removal of Employee Club Costs	(42)	
17	Removal of Industry Contributions and Membership Fees	(373)	
18	Removal of Institutional Advertising/Selling Expenses	(141)	
19	Reflection of Increase in DC Water And Sewer (WASA) Rates	50	
21	Inclusion of Customer Deposit and Credit Facility	457	
23	Removal of executive prerequisite expenses	(27)	
30	Removal of Control Center Lease Payment	(3,868)	
32	Adjust BSC Depreciation Expense per Merger Commitment	(450)	
33	Current rate costs	(929)	
35	Non Labor Inflation Adjustment	1,428	
36	Reflection of Cost to Optimize Regulatory Asset	(1,240)	
			(5,767)
	Other Taxes		
	Payroll Tax		
	Annualization of wage increases	156	
	Reflect 3 year average overtime in test year	80	236
	D.C. Income Tax		
	Federal Tax		

Potomac Electric Power Company
Distribution Cash Working Capital
Twelve Months Ended June 30, 2019

LINE NO.	ITEM	(1) Test Year D.C. Distribution Amount	(2) 2017 Study (Lead)/Lag Days	(3) Test Year D.C. Distribution Lag Dollars
	D.C. Operating Revenues			
1	Billed Sale of Electric	$ 528,437,658	44.24	$ 23,378,082,010
2	Late Payment Penalty	1,367,791	44.24	60,511,076
3	Reconnect/Return Check	329,798	44.24	14,590,252
4	CEO Online	-	44.24	-
5	Rent from Electric Property	1,574,845	(46.28)	(72,877,104)
6	Miscellaneous Services	(673)	21.52	(14,495)
7	Other	3,517,005	99.52	350,028,950
8	**Composite Revenue Lag - D.C.**	**$ 535,226,424**	**44.34**	**$ 23,730,320,689**
	D.C. Operating Expenses			
9	Pepco Gross Wages	$ 29,144,689	8.70	$ 253,558,795
10	Pepco AIP	1,561,378	241.00	376,292,116
11	Pepco D.C. - Major Storm Expense	921,854	137.47	126,727,298
12	Control Center Lease	3,868,105	88.25	341,360,298
13	Other O&M Expense	129,183,773	35.79	4,622,970,601
14	Property tax - District of Columbia	5,018,184	97.21	487,817,681
15	Property tax - Montgomery County	928,357	(4.10)	(3,806,265)
16	Property tax - PG County	837,823	(59.76)	(50,068,312)
17	Property tax - Charles County	29,967	(59.60)	(1,786,017)
18	Property tax - Other MD Counties	98,701	(76.77)	(7,577,276)
19	Property tax - Alexandria	149,985	151.09	22,661,181
20	Property tax - Arlington	18,435	234.50	4,323,097
21	Property tax - Fairfax	-	-	-
22	Property tax - Pr William	3,124	153.68	480,151
23	D.C. Delivery Tax	83,200,953	35.41	2,946,145,732
24	D.C. Public Space Occupancy Fee	22,836,435	(49.13)	(1,121,954,047)
25	D.C. RETF, SETF, EATF	20,011,407	36.27	725,813,748
26	D.C. PSC Reimbursement	9,549,070	172.50	1,647,214,575
27	D.C. Business Improvement District Tax	175,011	(99.94)	(17,490,587)
28	D.C. Ball Park Fee	-	197.50	-
29	D.C. Sales & Use Tax	282,238	35.69	10,073,074
30	Federal Heavy Highway Vehicle Use Tax (FHUT)	15,676	(138.50)	(2,171,100)
31	FICA	2,377,268	9.15	21,752,004
32	FUTA/SUTA	27,834	9.03	251,343
33	DCIT currently payable	-	59.05	-
34	FIT currently payable	-	59.05	-
35	**Total D.C. Distribution Expenses**	**$ 310,240,269**		**$ 10,382,588,090**
36	**Composite Expense Lag**		**33.47**	
37	**Net Lag**		**10.87**	
38	D.C Average Daily Expenses (ln 35, col 1 ÷ 365 days)			$ 849,973.34
39	Cash Working Capital allowance before Imprest Funds			9,239,800
40	D.C. Imprest Funds			390,785
41	D.C. CWC			$ 9,630,585
				$ 9,631

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Ratemaking Adjustment Calculation
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.	**Adjustment 38 - Reflection of Interest Synchronization**	
	Earnings	
1	Ratemaking Adjustments to Average D.C. Rate Base	$ 217,573
2	Weighted cost of long term debt	2.61%
3	Pro-forma interest on Ratemaking Adjustments to D.C. Rate Base	5,679
4	Adjustment to D.C. income tax expense to reflect interest synchronization per Commission Order No. 9216	$ (469)
5	Adjustment to Federal income tax expense to reflect interest synchronization per Commission Order No. 9216	$ (1,094)
	Total Earnings	**$ 1,563**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Interest Synchronization of Unadjusted Cost of Service
Twelve Months Ended June 30, 2019

(Thousands of Dollars)

Line No.		
1	Unadjusted D.C. income tax expense for the twelve months ended June 30, 2019	$ (4,812)
2	Unadjusted D.C. portion of Federal income tax expense for the twelve months ended June 30, 2019	$ (5,959)
3	Unadjusted Average D.C. Rate Base	$ 1,966,247
4	Weighted Cost of Debt @ June 30, 2019	2.61%
5	Pro-forma interest on Average D.C. Rate Base	51,319
6	less: Per Book D.C. Interest Expense	$ 55,095
7	Adjustment to D.C. Interest Expense for Interest Synchronization	$ (3,776)
8	Adjustment to Unadjusted D.C. Income Tax Expense for pro-forma interest expense	$ 312
9	Adjustment to Unadjusted D.C. Federal Income Tax Expense for pro-forma interest expense	$ 727
10	Unadjusted D.C. income tax reflecting synchronization of interest with unadjusted rate base (line 1 + line 8)	$ (4,500)
11	Unadjusted D.C. portion of federal income tax reflecting synchronization of interest with unadjusted rate base (line 2 + line 9)	$ (5,232)

POTOMAC ELECTRIC POWER COMPANY

Computation of District of Columbia Tax Factors
Twelve Months Ended June 30, 2019

Line No.	Description	Statutory Tax Rate
1	D.C. Franchise Tax Rate	8.250%
2	Federal Income Tax Rate	21.00%

Line No.	Description	Computation	Tax Factor
3	D.C. Franchise Tax Factor	line 1	8.25000%
4	Federal Income Tax Factor	(100% - (line 3)) x line 2	19.26750%
5	Complement of Composite Tax Factor	100% - (line 3 + line 4)	72.48250%

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POTOMAC ELECTRIC POWER COMPANY

Functionalized Cost of Service Elements

Line No.	Item	June 2019 (6+6) Total System	June 2019 (6+6) Distribution Amount
	Rate Base		
1	Electric Plant in Service	$ 9,052,910,845	$ 7,404,416,083
2	Accumulated Depreciation	(3,070,935,747)	(2,558,452,667)
3	Accumulated Amortization	(26,215,476)	(22,951,649)
4	Materials & Supplies	84,864,562	75,501,755
5	Cash Working Capital	21,948,276	21,948,276
6	Accumulated Deferred Income Taxes	(1,800,065,230)	(1,483,692,081)
7	Net Prepaid Pension/OPEB Liability	191,301,306	167,484,293
8	Customer Deposits	(53,983,992)	(53,983,992)
9	Net Service Company Assets	62,939,002	55,474,581
10	Regulatory Assets	89,148,904	89,148,904
11	Credit Facility Costs	819,759	717,699
12	Total rate Base	$ 4,552,732,210	$ 3,695,611,202
13			
14			
15	Operating Income		
16	Sale of Electricity[1]	$ 1,570,545,352	$ 1,231,501,868
17	Other Revenues	24,428,765	17,901,758
18	Total Revenues	$ 1,594,974,117	$ 1,249,403,626
19			
20	O & M Expense[1]	$ 482,943,388	$ 412,127,183
21	Depreciation Expense	228,842,824	190,717,472
22	Amortization Expense	33,529,622	32,662,907
23	Taxes Other than Income Taxes	386,562,222	368,789,564
24	D.C. Income Tax	1,475,537	6,881,938
25	Maryland Income Tax	16,902,427	(4,811,833)
26	Federal Income Tax	27,554,168	(501,758)
27	Total Operating Expenses	$ 1,177,810,189	$ 1,005,865,472
28			
29	Operating Income Before AFUDC	$ 417,163,928	$ 243,538,154

[1]Excluding SOS/Purchased Power

Potomac Electric Power Company
Development of Distribution Cost of Service

Rate Base

1. **Electric Plant in Service**
   The thirteen-month average balance for distribution Electric Plant in Service is based on historical data as recorded in the financial records of the Company. Included are all balances reflected in distribution accounts, plus general and intangible plant account balances allocated to distribution based on the Distribution Labor ratio.

2. **Accumulated Depreciation**
   The thirteen-month average distribution balance for Accumulated Depreciation is based on historical data as recorded in the financial records of the Company. Included are all balances reflected in distribution accounts, plus general accumulated depreciation balances allocated to distribution based on the Distribution Labor ratio.

3. **Accumulated Amortization**
   The thirteen-month average distribution balance for Accumulated Amortization is based on historical data as recorded in the financial records of the Company. The balances are allocated to distribution based on the Distribution Labor ratio.

4. **Materials & Supplies**
   The thirteen-month average balance for Materials & Supplies is based on historical data, less amounts estimated to be related to transmission based on FERC Form 1 data.

5. **Accumulated Deferred Income Taxes**
   The thirteen-month average distribution balance for Accumulated Deferred Income Taxes is based on historical data as recorded in the financial records of the Company. Rate base deferred taxes are allocated to distribution based on Plant ratios.

6. **Net Prepaid Pension/OPEB Liability**
   The average prepaid pension asset/OPEB liability, net of associated deferred taxes, is based on historical data as recorded in the financial records of the Company. The balance is allocated to distribution based on the Distribution Labor ratio.

7. **Customer Deposits**
   Thirteen-month average Customer Deposits is based on historical data as recorded in the financial records of the Company. The balance is derived from a detailed analysis of accounting records.

8. **Pepco Portion of Service Company Assets**
   The thirteen-month average Pepco Portion of Service Company Assets is based on historical data as recorded in the financial records of the Company. The net service company assets are allocated to distribution based on the Distribution Labor ratio.

9. **Regulatory Assets**
   The thirteen-month average distribution related Regulatory Assets, net of accumulated deferred taxes, is based on historical data as recorded in the financial records of the Company.

10. **Credit Facility**
    The thirteen-month average unamortized balance of credit facility start-up costs is allocated to distribution based on the Distribution Labor ratio.

Potomac Electric Power Company
Development of Distribution Cost of Service

Operating Income

11. Sale of Electricity

Revenue is comprised of billed jurisdictional distribution revenue, based on unbundled jurisdictional distribution rates.

12. Other Revenues

Other revenues are assigned to distribution based on detailed analysis.

13. Operation & Maintenance Expense

Operation & Maintenance expense for the distribution business is based on historical data as recorded in the financial records of the Company. It reflects all distribution and customer accounts, plus a portion of the A&G accounts determined as follows: after elimination of costs in A&G accounts specifically identifiable as pertaining to the Company's Standard Offer Service business, the remaining costs are allocated to distribution based on the Distribution Labor ratio, with the exception of account 924 (property insurance), which is allocated based on plant less AFUDC, and accounts 928 (regulatory expense) and 904 (uncollectible expense), which are directly assigned based on detailed analysis.

14. Depreciation and Amortization Expense

Depreciation and amortization expense is based on historical data as recorded in the financial records of the Company. The amounts include all expenses reflected in distribution accounts, plus an allocation of expenses in general and intangible functional accounts based on the Distribution Labor ratio.

15. Other Taxes

Taxes other than income taxes is based on historical data as recorded in the financial records of the Company. Other taxes not directly assignable to distribution are allocated as follows: property taxes are allocated to distribution based on assessable plant; payroll taxes are allocated based on the Distribution Labor ratio.

16. Maryland State Income Tax

Maryland state income tax is determined by applying a Maryland apportioned income tax rate of 5.10% (based on the latest available tax return) to distribution-related system taxable income.

17. District of Columbia Income Tax

District of Columbia income tax is determined by applying a District of Columbia apportioned income tax rate 3.20% (based on the latest available tax return) to distribution-related system taxable income.

18. Federal Income Tax

Federal income tax is determined by applying the statutory rate of 21% to distribution-related system taxable income.

J.C. Ziminsky
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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

SUMMARY OF RESULTS-1

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	RATE BASE				
1	Total System Electric Distribution		7,404,416,083	3,762,607,473	3,641,808,610
2	Less: Depreciation Reserve		2,558,452,667	1,168,177,845	1,390,274,822
3	Total Net Plant		4,845,963,415	2,594,429,628	2,251,533,788
	ADD:				
4	Construction Work in Progress		0	0	0
5	Working Capital		21,948,276	9,630,585	12,317,691
6	Plant Held for Future Use		0	0	0
7	Materials & Supplies		75,501,755	38,541,419	36,960,336
8	Regulatory Assets		89,148,904	44,475,159	44,673,745
9	Net Service Company Assets - Plant Related		55,474,581	28,016,556	27,458,025
10	Net Service Company Assets - CWIP Related		0	0	0
11	Net of Tax Prepaid Pension/OPEB		167,484,293	72,902,907	94,581,386
12	Credit Facility Costs		717,699	364,485	353,214
	DEDUCT:				
13	Accumulated Amortization		(22,951,649)	(12,498,326)	(10,453,323)
14	Customer Deposits		(53,983,992)	(8,770,607)	(45,213,385)
15	Deferred FIT		(1,277,255,133)	(688,744,121)	(588,511,012)
16	Deferred SIT		(206,436,948)	(112,099,907)	(94,337,040)
17	TOTAL ADIT		(1,483,692,081)	(800,844,028)	(682,848,053)
18	**TOTAL RATE BASE**		3,695,611,202	1,966,247,778	1,729,363,424
	DEVELOPMENT OF RETURN				
19	Revenue - Retail Sales		1,231,501,868	528,437,658	703,064,210
20	Other Operating Revenue		17,901,758	6,788,765	11,112,993
21	Total Electric Operating Revenue		1,249,403,626	535,226,424	714,177,203
	LESS:				
22	Operating & Maintenance Expense		412,127,183	174,772,573	237,354,610
23	Depreciation Expense		190,717,472	103,710,809	87,006,663
24	Amortization Expense		32,662,907	11,919,012	20,743,894
25	Other Taxes		368,789,564	145,550,223	223,239,341
26	State Income Taxes		2,382,105	(4,499,833)	6,881,938
27	Federal Income Taxes		28,649,003	11,579,733	17,069,270
28	Net ITC Adjustment & Excess Deferred Amortization		(28,404,421)	(16,810,897)	(11,593,524)
29	Total Federal Income Taxes		244,582	(5,231,164)	5,475,746
30	Total Operating Expenses		1,006,923,812	426,221,620	580,702,192
31	**OPERATING INCOME**		242,479,814	109,004,804	133,475,010
32	AFUDC		0	0	0
33	**OPERATING INCOME FOR ROR CALCULATION**		242,479,814	109,004,804	133,475,010
34	**RATE OF RETURN**		6.56%	5.54%	7.72%
35	**RELATIVE RATE OF RETURN**		0.94	0.80	1.11

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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

DEVELOPMENT OF RATE BASE-2

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	ELECTRIC PLANT IN SERVICE				
	SUBTRANSMISSION - CLASS				
1	3600 Land and Land Rights - Subs	STAED	2,404,237	1,010,501	1,393,736
2	3600 Land and Land Rights - OH Lines	STAED	0	0	0
3	3600 Land and Land Rights - UG Lines	STAED	0	0	0
4	3610 Structures and Improvements	STAED	5,817,048	2,444,905	3,372,143
5	3620 Station Equipment	STAED	261,491,126	109,904,720	151,586,406
6	3627 Station Equipment	STAED	5	2	3
7	3640 Poles, Towers and Fixtures	STAED	43,810,154	18,413,408	25,396,746
8	3650 Overhead Conductors and Devices	STAED	42,098,395	17,693,956	24,404,440
9	3660 Underground Conduit	STAED	136,831,997	57,510,488	79,321,508
10	3670 Underground Conductors and Devices	STAED	150,055,578	63,068,360	86,987,219
11	3680 Line Transformers	STAED	0	0	0
12	TOTAL SUBTRANSMISSION		642,508,540	270,046,339	372,462,200
	SUBTRANSMISSION - SMECO				
13	3600 Land and Land Rights - Subs	DISTROTH	45,821	0	45,821
14	3600 Land and Land Rights - OH Lines	DISTROTH	0	0	0
15	3600 Land and Land Rights - UG Lines	DISTROTH	0	0	0
16	3610 Structures and Improvements	DISTROTH	68,944	0	68,944
17	3620 Station Equipment	DISTROTH	2,606,541	0	2,606,541
18	3627 Station Equipment	DISTROTH	0	0	0
19	3640 Poles, Towers and Fixtures	DISTROTH	565,723	0	565,723
20	3650 Overhead Conductors and Devices	DISTROTH	228,730	0	228,730
21	3660 Underground Conduit	DISTROTH	484,565	0	484,565
22	3670 Underground Conductors and Devices	DISTROTH	0	0	0
23	3680 Line Transformers	DISTROTH	0	0	0
24	TOTAL SUBTRANSMISSION - SMECO		4,000,324	0	4,000,324

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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	DEVELOP OF RATE BASE CON'T-3				
	DISTRIBUTION PLANT				
	DISTRIBUTION - DC				
1	3600 Land and Land Rights - Subs	DISTRDC	44,194,009	44,194,009	0
2	3600 Land and Land Rights - OH Lines	DISTRDC	243,306	243,306	0
3	3600 Land and Land Rights - UG Lines	DISTRDC	25,250	25,250	0
4	3610 Structures and Improvements	DISTRDC	65,102,119	65,102,119	0
5	3620 Station Equipment	DISTRDC	410,193,160	410,193,160	0
6	3627 Capitalize Control Ctr	DISTRDC	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRDC	120,226,926	120,226,926	0
8	3650 Overhead Conductors and Devices	DISTRDC	132,727,385	132,727,385	0
9	3660 Underground Conduit	DISTRDC	803,013,957	803,013,957	0
10	3670 Underground Conductors and Devices	DISTRDC	781,020,464	781,020,464	0
11	3680 Line Transformers	DISTRDC	540,388,296	540,388,296	0
12	3691 Services	DISTRDC	18,123,096	18,123,096	0
13	3692 Services	DISTRDC	117,410,790	117,410,790	0
14	3693 Services	DISTRDC	166,996,697	166,996,697	0
15	3700 Meters	DISTRDC	7,001,304	7,001,304	0
16	3701 AMI Meters	DISTRDC	59,032,405	59,032,405	0
17	3711 Installations on Customer Premises	DISTRDC	1,367,203	1,367,203	0
18	3731 Street Lighting and Signal Systems	DISTRDC	57,256	57,256	0
19	3732 Street Lighting and Signal Systems	DISTRDC	9,999,466	9,999,466	0
20	3734 Street Lighting and Signal Systems	DISTRDC	49,789	49,789	0
21	TOTAL DISTRIBUTION - DC		3,277,172,881	3,277,172,881	0
	DEVELOP OF RATE BASE CON'T-4				
	DISTRIBUTION - MARYLAND				
1	3600 Land and Land Rights - Subs	DISTRMD	11,558,469	0	11,558,469
2	3600 Land and Land Rights - OH Lines	DISTRMD	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRMD	0	0	0
4	3610 Structures and Improvements	DISTRMD	60,667,428	0	60,667,428
5	3620 Station Equipment	DISTRMD	370,535,689	0	370,535,689
6	3627 Capitalize Control Ctr	DISTRMD	(5)	0	(5)
7	3640 Poles, Towers and Fixtures	DISTRMD	295,019,687	0	295,019,687
8	3650 Overhead Conductors and Devices	DISTRMD	505,427,502	0	505,427,502
9	3660 Underground Conduit	DISTRMD	285,510,576	0	285,510,576
10	3670 Underground Conductors and Devices	DISTRMD	643,926,327	0	643,926,327
11	3680 Line Transformers	DISTRMD	518,497,153	0	518,497,153
12	3691 OH Services	DISTRMD	48,323,572	0	48,323,572
13	3692 UG Services	DISTRMD	23,745,848	0	23,745,848
14	3693 UG Services	DISTRMD	157,125,919	0	157,125,919
15	3700 Meters	DISTRMD	15,577,143	0	15,577,143
16	3701 AMI Meters	DISTRMD	72,816,125	0	72,816,125
17	3711 Installations on Customer Premises	DISTRMD	1,278,829	0	1,278,829
18	3731 Street Lighting and Signal Systems	DISTRMD	27,944,182	0	27,944,182
19	3732 Street Lighting and Signal Systems	DISTRMD	20,587,024	0	20,587,024
20	3734 Street Lighting and Signal Systems	DISTRMD	2,003,566	0	2,003,566
21	TOTAL DISTRIBUTION -MARYLAND		3,060,545,034	0	3,060,545,034

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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	DEVELOP OF RATE BASE CON'T-5				
	ELECTRIC PLANT IN SERVICE				
	DISTRIBUTION PLANT CON'T				
	DISTRIBUTION - VIRGINIA & SMECO				
1	3600 Land and Land Rights - Subs	DISTROTH	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTROTH	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTROTH	0	0	0
4	3610 Structures and Improvements	DISTROTH	0	0	0
5	3620 Station Equipment	DISTROTH	0	0	0
6	3627 Station Equipment	DISTROTH	0	0	0
7	3640 Poles, Towers and Fixtures	DISTROTH	0	0	0
8	3650 Overhead Conductors and Devices	DISTROTH	0	0	0
9	3660 Underground Conduit	DISTROTH	0	0	0
10	3670 Underground Conductors and Devices	DISTROTH	0	0	0
11	3680 Line Transformers	DISTROTH	0	0	0
12	3691 OH Services	DISTROTH	0	0	0
13	3692 UG Services	DISTROTH	0	0	0
14	3693 UG Services	DISTROTH	99,160	0	99,160
15	3700 Meters	DISTROTH	418,911	0	418,911
16	3701 AMI Meters	DISTROTH	0	0	0
17	3711 Installations on Customer Premises	DISTROTH	0	0	0
18	3731 Street Lighting and Signal Systems	DISTROTH	0	0	0
19	3732 Street Lighting and Signal Systems	DISTROTH	0	0	0
20	3734 Street Lighting and Signal Systems	DISTROTH	0	0	0
21	TOTAL DISTRIBUTION - VIRGINIA & SMECO		518,071	0	518,071
	DEVELOP OF RATE BASE CON'T-6				
	DISTRIBUTION - SYSTEM TOTAL				
1	3600 Land and Land Rights - Subs		55,752,478	44,194,009	11,558,469
2	3600 Land and Land Rights - OH Lines		243,306	243,306	0
3	3600 Land and Land Rights - UG Lines		25,250	25,250	0
4	3610 Structures and Improvements		125,769,546	65,102,119	60,667,428
5	3620 Station Equipment		780,728,849	410,193,160	370,535,689
6	3627 Station Equipment		(5)	0	(5)
7	3640 Poles, Towers and Fixtures		415,246,613	120,226,926	295,019,687
8	3650 Overhead Conductors and Devices		638,154,888	132,727,385	505,427,502
9	3660 Underground Conduit		1,088,524,533	803,013,957	285,510,576
10	3670 Underground Conductors and Devices		1,424,946,791	781,020,464	643,926,327
11	3680 Line Transformers		1,058,885,449	540,388,296	518,497,153
12	3691 OH Services		66,446,668	18,123,096	48,323,572
13	3692 UG Services		141,156,638	117,410,790	23,745,848
14	3693 UG Services		324,221,777	166,996,697	157,225,079
15	3700 Meters		22,997,359	7,001,304	15,996,055
16	3701 AMI Meters		131,848,530	59,032,405	72,816,125
17	3711 Installations on Customer Premises		2,646,032	1,367,203	1,278,829
18	3731 Street Lighting and Signal Systems		28,001,439	57,256	27,944,182
19	3732 Street Lighting and Signal Systems		30,586,490	9,999,466	20,587,024
20	3734 Street Lighting and Signal Systems		2,053,355	49,789	2,003,566
21	TOTAL DISTRIBUTION - SYSTEM		6,338,235,986	3,277,172,881	3,061,063,105

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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-7

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	SUBTRANSMISSION & DISTRIBUTION - TOTAL				
1	3600 Land and Land Rights - Subs		58,202,536	45,204,510	12,998,026
2	3600 Land and Land Rights - OH Lines		243,306	243,306	0
3	3600 Land and Land Rights - UG Lines		25,250	25,250	0
4	3610 Structures and Improvements		131,655,538	67,547,024	64,108,514
5	3620 Station Equipment		1,044,826,516	520,097,881	524,728,635
6	3627 Station Equipment		0	2	(2)
7	3640 Poles, Towers and Fixtures		459,622,490	138,640,334	320,982,156
8	3650 Overhead Conductors and Devices		680,482,013	150,421,341	530,060,672
9	3660 Underground Conduit		1,225,841,094	860,524,445	365,316,650
10	3670 Underground Conductors and Devices		1,575,002,370	844,088,824	730,913,546
11	3680 Line Transformers		1,058,885,449	540,388,296	518,497,153
12	3691 OH Services		66,446,668	18,123,096	48,323,572
13	3692 UG Services		141,156,638	117,410,790	23,745,848
14	3693 UG Services		324,221,777	166,996,697	157,225,079
15	3700 Meters		22,997,359	7,001,304	15,996,055
16	3701 AMI Meters		131,848,530	59,032,405	72,816,125
17	3711 Installations on Customer Premises		2,646,032	1,367,203	1,278,829
18	3731 Street Lighting and Signal Systems		28,001,439	57,256	27,944,182
19	3732 Street Lighting and Signal Systems		30,586,490	9,999,466	20,587,024
20	3734 Street Lighting and Signal Systems		2,053,355	49,789	2,003,566
21	TOTAL SUBTRANSMISSION & DISTRIBUTION - SYSTEM		6,984,744,849	3,547,219,220	3,437,525,629

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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-8

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	ELECTRIC PLANT IN SERVICE				
	GENERAL PLANT				
1	3890 Land and Land Rights	STDPLT	6,118,368	3,107,228	3,011,141
2	3900 Structures and Improvements	STDPLT	101,445,783	51,519,481	49,926,302
3	3903 Structures and Improvements	STDPLT	9,863,480	5,009,192	4,854,288
4	3911 Office Furniture and Equipment	STDPLT	7,013,051	3,561,594	3,451,456
5	3913 Office Furniture and Equipment	STDPLT	17,516,557	8,895,825	8,620,732
6	3915 Office Furniture and Equipment	STDPLT	0	0	0
7	3920 Transportation Equipment	STDPLT	0	0	0
8	3930 Stores Equipment	STDPLT	165,184	83,889	81,295
9	3940 Tools, Shop and Garage Equipment	STDPLT	8,999,879	4,570,610	4,429,269
10	3950 Laboratory Equipment	STDPLT	995,100	505,364	489,736
11	3960 Power Operated Equipment	STDPLT	1,885,391	957,501	927,891
12	3970 Communication Equipment	STDPLT	148,904,252	75,621,377	73,282,875
13	3980 Miscellaneous Equipment	STDPLT	8,788,291	4,463,154	4,325,137
14	3990 Other Tangible Property	STDPLT	0	0	0
15	TOTAL GENERAL PLANT		311,695,336	158,295,215	153,400,121
	INTANGIBLE PLANT				
16	3020 Franchises and Consents	DISTRMD	219	0	219
17	3030 Miscellaneous Intangible Plant	STDPLT	45,006,449	22,856,632	22,149,817
18	3030 Miscellaneous Intangible Plant Direct DC	DISTRDC	(1,880,244)	(1,880,244)	0
19	3030 Miscellaneous Intangible Plant Direct MD	DISTRMD	(3,959,024)	0	(3,959,024)
20	TOTAL INTANGIBLE PLANT		39,167,399	20,976,387	18,191,012

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JURISDICTIONAL COST OF SERVICE STUDY
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ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-9

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	AFUDC				
	SUBTRANSMISSION AFUDC - DC				
1	3600 Land and Land Rights - Subs	DISTRDC	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTRDC	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRDC	0	0	0
4	3610 Structures and Improvements	DISTRDC	0	0	0
5	3620 Station Equipment	DISTRDC	0	0	0
6	3627 Station Equipment	DISTRDC	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRDC	0	0	0
8	3650 Overhead Conductors and Devices	DISTRDC	0	0	0
9	3660 Underground Conduit	DISTRDC	0	0	0
10	3670 Underground Conductors and Devices	DISTRDC	0	0	0
11	TOTAL SUBTRANSMISSION AFUDC - DC		0	0	0
	SUBTRANSMISSION AFUDC - MD				
12	3600 Land and Land Rights - Subs	DISTRMD	0	0	0
13	3600 Land and Land Rights - OH Lines	DISTRMD	0	0	0
14	3600 Land and Land Rights - UG Lines	DISTRMD	0	0	0
15	3610 Structures and Improvements	DISTRMD	0	0	0
16	3620 Station Equipment	DISTRMD	0	0	0
17	3627 Station Equipment	DISTRMD	0	0	0
18	3640 Poles, Towers and Fixtures	DISTRMD	0	0	0
19	3650 Overhead Conductors and Devices	DISTRMD	0	0	0
20	3660 Underground Conduit	DISTRMD	0	0	0
21	3670 Underground Conductors and Devices	DISTRMD	0	0	0
22	TOTAL SUBTRANSMISSION AFUDC - MD		0	0	0

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ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-10

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	DISTRIBUTION AFUDC - DC				
1	3600 Land and Land Rights - Subs	DISTRDC	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTRDC	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRDC	0	0	0
4	3610 Structures and Improvements	DISTRDC	3,392,880	3,392,880	0
5	3620 Station Equipment	DISTRDC	10,078,361	10,078,361	0
6	3627 Station Equipment	DISTRDC	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRDC	418,845	418,845	0
8	3650 Overhead Conductors and Devices	DISTRDC	584,947	584,947	0
9	3660 Underground Conduit	DISTRDC	9,477,823	9,477,823	0
10	3670 Underground Conductors and Devices	DISTRDC	4,250,651	4,250,651	0
11	3680 Line Transformers	DISTRDC	109,757	109,757	0
12	3691 OH Services	DISTRDC	4,426	4,426	0
13	3692 UG Services	DISTRDC	133	133	0
14	3693 UG Services	DISTRDC	13,871	13,871	0
15	3700 Meters	DISTRDC	0	0	0
16	3701 AMI Meters	DISTRDC	0	0	0
17	3711 Installations on Customer Premises	DISTRDC	0	0	0
18	3731 Street Lighting and Signal Systems	DISTRDC	111	111	0
19	3732 Street Lighting and Signal Systems	DISTRDC	22,242	22,242	0
20	3734 Street Lighting and Signal Systems	DISTRDC	526	526	0
21	TOTAL DISTRIBUTION AFUDC - DC		28,354,573	28,354,573	0

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ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-11

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	DISTRIBUTION AFUDC - MD				
1	3600 Land and Land Rights - Subs	DISTRMD	0	0	0
2	3600 Land and Land Rights - OH Lines	DISTRMD	0	0	0
3	3600 Land and Land Rights - UG Lines	DISTRMD	0	0	0
4	3610 Structures and Improvements	DISTRMD	1,873,383	0	1,873,383
5	3620 Station Equipment	DISTRMD	11,858,545	0	11,858,545
6	3627 Station Equipment	DISTRMD	0	0	0
7	3640 Poles, Towers and Fixtures	DISTRMD	1,051,208	0	1,051,208
8	3650 Overhead Conductors and Devices	DISTRMD	1,654,500	0	1,654,500
9	3660 Underground Conduit	DISTRMD	1,953,224	0	1,953,224
10	3670 Underground Conductors and Devices	DISTRMD	2,217,411	0	2,217,411
11	3680 Line Transformers	DISTRMD	136,184	0	136,184
12	3691 OH Services	DISTRMD	8,462	0	8,462
13	3692 UG Services	DISTRMD	205	0	205
14	3693 UG Services	DISTRMD	24,077	0	24,077
15	3700 Meters	DISTRMD	0	0	0
16	3701 AMI Meters	DISTRMD	0	0	0
17	3711 Installations on Customer Premises	DISTRMD	0	0	0
18	3731 Street Lighting and Signal Systems	DISTRMD	165	0	165
19	3732 Street Lighting and Signal Systems	DISTRMD	38,745	0	38,745
20	3734 Street Lighting and Signal Systems	DISTRMD	1,057	0	1,057
21	TOTAL DISTRIBUTION AFUDC - MD		20,817,165	0	20,817,165

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JURISDICTIONAL COST OF SERVICE STUDY
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ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-12

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	SUBTRANSMISSION AND DISTRIBUTION AFUDC - SYSTEM				
1	3600 Land and Land Rights - Subs		0	0	0
2	3600 Land and Land Rights - OH Lines		0	0	0
3	3600 Land and Land Rights - UG Lines		0	0	0
4	3610 Structures and Improvements		5,266,263	3,392,880	1,873,383
5	3620 Station Equipment		21,936,906	10,078,361	11,858,545
6	3627 Station Equipment		0	0	0
7	3640 Poles, Towers and Fixtures		1,470,053	418,845	1,051,208
8	3650 Overhead Conductors and Devices		2,239,447	584,947	1,654,500
9	3660 Underground Conduit		11,431,046	9,477,823	1,953,224
10	3670 Underground Conductors and Devices		6,468,062	4,250,651	2,217,411
11	3680 Line Transformers		245,941	109,757	136,184
12	3691 OH Services		12,888	4,426	8,462
13	3692 UG Services		338	133	205
14	3693 UG Services		37,948	13,871	24,077
15	3700 Meters		0	0	0
16	3701 AMI Meters		0	0	0
17	3711 Installations on Customer Premises		0	0	0
18	3731 Street Lighting and Signal Systems		277	111	165
19	3732 Street Lighting and Signal Systems		60,987	22,242	38,745
20	3734 Street Lighting and Signal Systems		1,583	526	1,057
21	TOTAL SUBTR. AND DISTR. AFUDC - SYSTEM		49,171,738	28,354,573	20,817,165
			7,033,916,587		

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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-13

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	GENERAL PLANT AFUDC - DC				
1	3890 Land and Land Rights	DISTRDC	0	0	0
2	3900 Structures and Improvements	DISTRDC	3,379,283	3,379,283	0
3	3903 Structures and Improvements	DISTRDC	298,672	298,672	0
4	3911 Office Furniture and Equipment	DISTRDC	14,515	14,515	0
5	3913 Office Furniture and Equipment	DISTRDC	112,537	112,537	0
6	3915 Office Furniture and Equipment	DISTRDC	4	4	0
7	3920 Transportation Equipment	DISTRDC	0	0	0
8	3930 Stores Equipment	DISTRDC	0	0	0
9	3940 Tools, Shop and Garage Equipment	DISTRDC	70,787	70,787	0
10	3950 Laboratory Equipment	DISTRDC	0	0	0
11	3960 Power Operated Equipment	DISTRDC	0	0	0
12	3970 Communication Equipment	DISTRDC	3,168,764	3,168,764	0
13	3980 Miscellaneous Equipment	DISTRDC	63,353	63,353	0
14	3990 Other Tangible Property	DISTRDC	0	0	0
15	TOTAL GENERAL PLANT AFUDC - DC		7,107,916	7,107,916	**0**
	GENERAL PLANT AFUDC - MD				
16	3890 Land and Land Rights	DISTRMD	0	0	0
17	3900 Structures and Improvements	DISTRMD	0	0	4,221,095
18	3903 Structures and Improvements	DISTRMD	677,053	0	677,053
19	3911 Office Furniture and Equipment	DISTRMD	15,091	0	15,091
20	3913 Office Furniture and Equipment	DISTRMD	286,025	0	286,025
21	3915 Office Furniture and Equipment	DISTRMD	0	0	0
22	3920 Transportation Equipment	DISTRMD	0	0	0
23	3930 Stores Equipment	DISTRMD	0	0	0
24	3940 Tools, Shop and Garage Equipment	DISTRMD	1,806	0	1,806
25	3950 Laboratory Equipment	DISTRMD	0	0	0
26	3960 Power Operated Equipment	DISTRMD	0	0	0
27	3970 Communication Equipment	DISTRMD	5,292,146	0	5,292,146
28	3980 Miscellaneous Equipment	DISTRMD	90,885	0	90,885
29	3990 Other Tangible Property	DISTRMD	0	0	0
30	TOTAL GENERAL PLANT AFUDC - MD		10,584,100	**0**	10,584,100

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ELECTRIC DISTRIBUTION

	DEVELOP OF RATE BASE CON'T-14	ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	GENERAL PLANT AFUDC - SMECO				
1	3890 Land and Land Rights	DISTROTH	0	0	0
2	3900 Structures and Improvements	DISTROTH	248,384	0	248,384
3	3903 Structures and Improvements	DISTROTH	35,301	0	35,301
4	3911 Office Furniture and Equipment	DISTROTH	0	0	0
5	3913 Office Furniture and Equipment	DISTROTH	3,807	0	3,807
6	3915 Office Furniture and Equipment	DISTROTH	0	0	0
7	3920 Transportation Equipment	DISTROTH	0	0	0
8	3930 Stores Equipment	DISTROTH	0	0	0
9	3940 Tools, Shop and Garage Equipment	DISTROTH	0	0	0
10	3950 Laboratory Equipment	DISTROTH	0	0	0
11	3960 Power Operated Equipment	DISTROTH	0	0	0
12	3970 Communication Equipment	DISTROTH	165,114	0	165,114
13	3980 Miscellaneous Equipment	DISTROTH	100	0	100
14	3990 Other Tangible Property	DISTROTH	0	0	0
15	TOTAL GENERAL PLANT AFUDC - SMECO		452,705	0	452,705
	INTANGIBLE PLANT AFUDC				
16	3030 Miscellaneous Intangible Plant DC	DISTRDC	654,162	654,162	0
17	3030 Miscellaneous Intangible Plant MD	DISTRMD	821,089	0	821,089
18	3030 Miscellaneous Intangible Plant SM	DISTROTH	16,789	0	16,789
19	TOTAL INTANGIBLE PLANT AFUDC		1,492,040	654,162	837,878
20	TOTAL AFUDC		68,808,499	36,116,651	32,691,848
21	Total Electric Plant In Service		7,404,416,083	3,762,607,473	3,641,808,610

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ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-15

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	DEPRECIATION RESERVE				
1	Subtransmission - DC	DISTRDC	98,120,863	98,120,863	0
2	Subtransmission - MD	DISTRMD	156,464,881	0	156,464,881
3	Subtransmission - SM	DISTROTH	2,133,360	0	2,133,360
4	Distribution - DC	DISTRDC	965,200,914	965,200,914	0
5	Distribution - DC - Meters	DISTRDC	23,686,866	23,686,866	0
6	Distribution - MD	DISTRMD	1,136,432,711	0	1,136,432,711
7	Distribution - MD - Meters	DISTRMD	25,432,211	0	25,432,211
8	Distribution - VA	DISTROTH	10,355	0	10,355
9	Distribution - SMECO	DISTROTH	202,874	0	202,874
10	General - DC	DISTRDC	64,269,812	64,269,812	0
11	General - MD	DISTRMD	60,725,937	0	60,725,937
13	TOTAL DEPRECIATION RESERVE (LESS AFUDC)		2,532,680,784	1,151,278,455	1,381,402,329
14	DEPRECIATION RESERVE - AFUDC				
15	Distribution - DC	DISTRDC	13,070,737	13,070,737	0
16	Distribution - MD	DISTRMD	10,995,983	0	10,995,983
18	General - DC	DISTRDC	3,828,653	3,828,653	0
19	General - MD	DISTRMD	(2,352,972)	0	(2,352,972)
20	General - SM	DISTROTH	229,482	0	229,482
21	TOTAL AFUDC		25,771,883	16,899,390	8,872,493
22	TOTAL DEPRECIATION RESERVE		2,558,452,667	1,168,177,845	1,390,274,822
	TOTAL NET PLANT		4,845,963,415	2,594,429,628	2,251,533,788
23	**AMORTIZATION RESERVE**				
24	General	STDPLT	(6,453,164)	(3,277,255)	(3,175,909)
25	Software	STDPLT	(20,630,337)	(10,477,166)	(10,153,172)
26	AMI Software - DC	DISTRDC	1,880,244	1,880,244	0
27	AMI Software - MD	DISTRMD	3,959,024	0	3,959,024
28	AMORTIZATION RESERVE - AFUDC				
29	AFUDC DC	DISTRDC	(624,150)	(624,150)	0
30	AFUDC MD	DISTRMD	(1,043,444)	0	(1,043,444)
31	AFUDC SM	DISTROTH	(39,822)	0	(39,822)
32	TOTAL AMORTIZATION RESERVE		(22,951,649)	(12,498,326)	(10,453,323)

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ELECTRIC DISTRIBUTION

	DEVELOP OF RATE BASE CON'T-16	ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
1	**CWIP**				
2	Distribution - DC	ZERO	0	0	0
3	Distribution - Maryland	ZERO	0	0	0
4	Sub-transmission	ZERO	0	0	0
5	General & Intangible	ZERO	0	0	0
7	CWIP - AFUDC				
8	CWIP AFUDC - DC Subtransmission	ZERO	0	0	0
9	CWIP AFUDC - DC Distribution	ZERO	0	0	0
10	CWIP AFUDC - MD Subtransmission	ZERO	0	0	0
11	CWIP AFUDC - MD Distribution	ZERO	0	0	0
12	CWIP AFUDC - SM General	ZERO	0	0	0
13	CWIP AFUDC - DC General & Intangible	ZERO	0	0	0
14	CWIP AFUDC - MD General & Intangible	ZERO	0	0	0
17	Other				
18	Total CWIP		0	0	0
	PLANT HELD FOR FUTURE USE				
19	Distribution - DC	ZERO	0	0	0
20	Distribution - Maryland	ZERO	0	0	0
21	PLANT HELD FOR FUTURE USE - AFUDC				
22	Distribution - DC	ZERO	0	0	0
23	Distribution - Maryland	ZERO	0	0	0
24	Total Plant Held for Future Use		0	0	0
25	**MATERIALS & SUPPLIES**				
26	Subtransmission	PLTSUBT	5,186,353	2,166,336	3,020,017
27	Distribution-Demand	PLTDEM	63,590,442	32,967,239	30,623,203
28	Distribution-Customer	PLTCUST	6,724,960	3,407,843	3,317,116
29	TOTAL MATERIALS & SUPPLIES		75,501,755	38,541,419	36,960,336

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ELECTRIC DISTRIBUTION

	DEVELOP OF RATE BASE CON'T-17	ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
1	**MISC RATE BASE ITEMS**				
2	Net Service Company Assets - CWIP	ZERO	0	0	0
3	Net Service Company Assets - Plant	STDPLT	54,633,369	27,745,686	26,887,683
4	Net Service Company Assets - Plant Direct MD	DISTRMD	570,342	0	570,342
5	Net Service Company Assets - Plant Direct DC	DISTRDC	270,870	270,870	0
6	Net Prepaid Pension/OPEB Asset	OMLESAGS	167,484,293	72,902,907	94,581,386
8	Credit Facility Costs	STDPLT	717,699	364,485	353,214

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ELECTRIC DISTRIBUTION

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
9	**REGULATORY ASSETS**				
10	DC				
11	DC FC 1150 Costs	DISTRDC	1,451,418	1,451,418	0
12	DC FC 1139 Excess Rate Case Costs	DISTRDC	(754,054)	(754,054)	0
13	DC I Street Substation Rent	DISTRDC	2,797,208	2,797,208	0
14	DC Benning RI Costs	DISTRDC	3,162,268	3,162,268	0
15	DC Over-Collected Depreciation Expense	DISTRDC	(527,379)	(527,379)	0
16	DC AMI (FC 1076)	DISTRDC	379,429	379,429	0
17	DC AMI Expense (FC 1087)	DISTRDC	29,013,672	29,013,672	0
18	DC AMI Return (FC 1087)	DISTRDC	(38,674)	(38,674)	0
19	DC Formal Case 1139 Costs	DISTRDC	2,384,417	2,384,417	0
20	DC DLC Program Costs	DISTRDC	10,325,450	10,325,450	0
21	DC Interval Billing Costs	DISTRDC	3,323,400	3,323,400	0
22	DC AMI True Up	DISTRDC	6,192,950	6,192,950	0
23	DC Third Party Audit Costs	DISTRDC	57,417	57,417	0
24	DC 1076 Management Audit Costs	DISTRDC	941,417	941,417	0
25	DC CRM&B Stabilization Expense	DISTRDC	1,770,450	1,770,450	0
26	DC Legacy Billing System Expense	DISTRDC	216,775	216,775	0
27	DC Tax Prep	DISTRDC	71,050	71,050	0
	ADIT on DC Regulatory Assets in Rate Base	DISTRDC	(16,292,053)	(16,292,053)	0
28	Total DC Regulatory Assets		44,475,159	44,475,159	0
29	MD				
30	MD February 2010 Storm Costs	DISTRMD	88,459	0	88,459
31	MD January 2011 Storm	DISTRMD	340,467	0	340,467
32	MD 2013 Storm (Nor'easter) Prep	DISTRMD	55,662	0	55,662
33	MD Hurricane Irene (August 2011)	DISTRMD	379,412	0	379,412
34	MD Derecho	DISTRMD	464,441	0	464,441
35	MD Hurricane Sandy	DISTRMD	99,443	0	99,443
36	MD Approved AMI Costs 2	DISTRMD	2,661,300	0	2,661,300
37	MD Winter Storm Stella	DISTRMD	748,227	0	748,227
38	MD Approved AMI Costs	DISTRMD	40,484,588	0	40,484,588
39	MD Billing System Transition	DISTRMD	4,184,275	0	4,184,275
40	MD Storm Jonas Costs	DISTRMD	989,174	0	989,174
41	MD Storm Pax Costs	DISTRMD	391,575	0	391,575
42	MD Pepco CTA Costs	DISTRMD	9,324,200	0	9,324,200
	ADIT on MD Regulatory Assets in Rate Base	DISTRMD	(15,537,477)	0	(15,537,477)
43	Total MD Regulatory Assets		44,673,745	0	44,673,745
44	TOTAL REGULATORY ASSETS		89,148,904	44,475,159	44,673,745

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ELECTRIC DISTRIBUTION

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
45	**CASH WORKING CAPITAL**				
46	Operating Expenses - Other	DISTRMD	11,938,990	0	11,938,990
47	Operating Expenses - DC	DISTRDC	9,239,800	9,239,800	0
48	Plant Portion - Imprest Funds	STDPLT	769,485	390,785	378,700
49	TOTAL CASH WORKING CAPITAL		21,948,276	9,630,585	12,317,691
50	**CUSTOMER DEPOSITS**				
51	DC	DISTRDC	(8,770,607)	(8,770,607)	0
52	Maryland	DISTRMD	(45,213,385)	0	(45,213,385)
53	TOTAL CUSTOMER DEPOSITS		(53,983,992)	(8,770,607)	(45,213,385)

DEVELOP OF RATE BASE CON'T-18

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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
1	**DEFERRED TAXES**				
2	**Plant Related**				
3	DCIT @ 21%	STDPLT	21,444,067	10,890,420	10,553,647
4	MDIT @ 21%	STDPLT	23,265,485	11,815,431	11,450,053
5	FIT	STDPLT	759,567,830	385,748,322	373,819,508
6	Adjusted FIT		804,277,381	408,454,174	395,823,208
7	LESS: DCIT @ 21%	DISTRDC	21,444,067	21,444,067	0
8	LESS: MDIT @ 21%	DISTRMD	23,265,485	0	23,265,485
9	FIT		759,567,830	387,010,106	372,557,723
10	NOVA FIT - Direct	DISTROTH	0	0	0
11	DCIT	DISTRDC	102,114,606	102,114,606	0
12	MDIT	DISTRMD	110,788,022	0	110,788,022
13	NOVA Related Deferred DCIT	DISTRDC	0	0	0
14	Total Depreciation Related		972,470,457	489,124,712	483,345,745
15	Total Plant Less CIAC		7,404,416,083	3,762,607,473	3,641,808,610
16	Total Depre Reserve		2,558,452,667	1,168,177,845	1,390,274,822
17	Average		0.345530645	0.310470293	0.381753950
18	Difference			(0.035060352)	0.036223305
19	Adjustment			(131,918,343)	131,918,343
20	Tax			27,702,852	(27,702,852)
21	Total Plant Related		972,470,457	516,827,564	455,642,893

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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

DEVELOP OF RATE BASE CON'T-19

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
1	**Loss on Debt Reacquisition**				
2	DCIT @ 21%	STDPLT	73,202	37,176	36,026
3	MDIT @ 21%	STDPLT	114,041	57,916	56,125
4	FIT	STDPLT	2,112,303	1,072,738	1,039,565
5	Adjusted FIT		2,299,546	1,167,830	1,131,716
6	LESS: DCIT @ 21%	DISTRDC	73,202	73,202	0
7	LESS: MDIT @ 21%	DISTRMD	114,041	0	114,041
8	FIT		2,112,303	1,094,628	1,017,676
9	DCIT	DISTRDC	348,583	348,583	0
10	MDIT	DISTRMD	543,050	0	543,050
11	Total Loss on Debt Reacquisition		3,003,936	1,443,210	1,560,726

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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

	DEVELOP OF RATE BASE CON'T-20	ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
1	**Def Inc. Tax Asset Federal NOL**				
2	DCIT @ 21%	STDPLT	0	0	0
3	MDIT @ 21%	STDPLT	0	0	0
4	FIT	STDPLT	(756,201)	(384,038)	(372,162)
5	Adjusted FIT		(756,201)	(384,038)	(372,162)
6	LESS: DCIT @ 21%	DISTRDC	0	0	0
7	LESS: MDIT @ 21%	DISTRMD	0	0	0
8	FIT		(756,201)	(384,038)	(372,162)
9	DCIT	DISTRDC	0	0	0
10	MDIT	DISTRMD	0	0	0
11	Total Def Inc. Tax Asset Federal NOL		(756,201)	(384,038)	(372,162)
12	**Def Inc. Tax Asset State NOL**				
13	DCIT @ 21%	STDPLT	0	0	0
14	MDIT @ 21%	STDPLT	0	0	0
15	FIT	STDPLT	0	0	0
16	Adjusted FIT		0	0	0
17	LESS: DCIT @ 21%	DISTRDC	0	0	0
18	LESS: MDIT @ 21%	DISTRMD	0	0	0
19	FIT		0	0	0
20	DCIT	DISTRDC	0	0	0
21	MDIT	DISTRMD	0	0	0
22	Total Def Inc. Tax Asset State NOL		0	0	0
24	**DIRECTS**				
25	Federal Excess DIT - DC Protected Property	DISTRDC	139,884,487	139,884,487	0
26	Federal Excess DIT - DC Non-Protected Property	DISTRDC	113,201,848	113,201,848	0
27	Federal Excess DIT - DC Non-Protected Non-Property	DISTRDC	19,180,538	19,180,538	0
28	Federal Excess DIT - MD Protected Property	DISTRMD	119,092,028	0	119,092,028
29	Federal Excess DIT - MD Non-Protected Property	DISTRMD	95,497,098	0	95,497,098
30	Federal Excess DIT - MD Non-Protected Non-Property	DISTRMD	26,935,247	0	26,935,247
31	DC Excess DIT - Order No. 188446	DISTRDC	9,736,463	9,736,463	0
32	DC Excess DIT - Order No. 19247	DISTRDC	4,917,876	4,917,876	0
33	MD Excess DIT	DISTRMD	(9,916,623)	0	(9,916,623)
34	MD NOL MDIT	DISTRMD	(7,077,408)	0	(7,077,408)
35	MD NOL FIT	DISTRMD	1,486,256	0	1,486,256
36	Benefit DC NOL DCIT	DISTRDC	(5,017,620)	(5,017,620)	0
37	Benefit DC NOL FIT	DISTRDC	1,053,700	1,053,700	0
38	ITC	ZERO	0	0	0
39	DEFERRED STATE TAXES		206,436,948	112,099,907	94,337,040
40	DEFERRED FEDERAL INCOME TAXES		1,277,255,133	688,744,121	588,511,012
41	TOTAL DEFERRED TAXES		1,483,692,081	800,844,028	682,848,053
42	**TOTAL RATE BASE**		3,695,611,202	1,966,247,778	1,729,363,424

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PEPCO - DC
JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

	OPERATING REVENUES-21	ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	ELECTRIC SALES REVENUES				
	Revenue - Retail Sales				
1	DC - Retail Sales	DISTRDC	528,437,658	528,437,658	0
2	MD - Retail Sales	DISTRMD	703,064,210	0	703,064,210
3	Retail Total		1,231,501,868	528,437,658	703,064,210
	REVENUE - OTHER				
4	Late Payment Revenue DC	DISTRDC	1,367,791	1,367,791	0
5	Late Payment Revenue MD	DISTRMD	2,875,444	0	2,875,444
6	Miscellaneous Service Revenue DC	DISTRDC	(673)	(673)	0
7	Miscellaneous Service Revenue MD	DISTRMD	(13,274)	0	(13,274)
8	MD Opt Out Fees	DISTRMD	269,650	0	269,650
9	Rent from Electric Property DC	DISTRDC	1,574,845	1,574,845	0
10	Rent from Electric Property MD	DISTRMD	2,988,320	0	2,988,320
11	Rents - Customer Related DC	DISTRDC	0	0	0
12	Rents - Customer Related MD	DISTRMD	0	0	0
13	Other DC	DISTRDC	3,846,803	3,846,803	0
14	Other MD	DISTRMD	4,992,853	0	4,992,853
15	TOTAL OTHER REVENUE		17,901,758	6,788,765	11,112,993
16	TOTAL REVENUE		**1,249,403,626**	**535,226,424**	**714,177,203**

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PEPCO - DC
JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

	OPERATION & MAINT EXP-22	ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	DISTRIBUTION EXPENSES				
	OPERATION				
1	958000 Operation Supervision & Engineering	OMEXP580	4,025,130	2,153,436	1,871,695
2	958100 Load dispatching	OMEXP581	6,528,531	3,314,545	3,213,986
3	958200 Station expenses	OMEXP582	1,702,597	962,789	739,808
4	958300 Overhead line expenses	OMEXP583	2,153,912	1,476,740	677,172
5	958400 Underground line expenses	OMEXP584	10,152,118	7,580,103	2,572,015
6	958500 Street lighting	OMEXP585	1,021,505	0	1,021,505
7	958600 Meter expenses	OMEXP586	7,263,815	3,439,815	3,823,999
8	958700 Customer installations expenses	OMEXP587	8,479,203	3,414,877	5,064,326
9	958800 Miscellaneous distribution expenses	OMEXP588	11,281,966	6,600,195	4,681,771
10	958900 Rents Control Center	OMEXP589	11,498,479	7,368,390	4,130,089
11	TOTAL OPERATION		64,107,256	36,310,890	27,796,366
	MAINTENANCE				
12	959000 Maintenance Supervision & Engineering	OMEXP590	673,121	281,685	391,436
13	959100 Maintenance Structures	OMEXP591	100,127	54,056	46,072
14	959200 Maintain equipment	OMEXP592	17,550,984	8,503,018	9,047,966
15	959300 Maintain overhead lines	OMEXP593	35,628,948	7,410,908	28,218,040
16	959400 Maintain underground line	OMEXP594	17,980,445	10,943,561	7,036,883
17	959500 Maintain line transformers	OMEXP595	3,740,228	1,809,123	1,931,105
18	959600 Maintain street lighting & signal sys	OMEXP596	5,539,280	(3,991)	5,543,271
19	959700 Maintain meters	OMEXP597	667,461	272,928	394,533
20	959800 Maintain distribution plant	OMEXP598	3,664,254	1,672,801	1,991,452
21	TOTAL MAINTENANCE		85,544,847	30,944,089	54,600,758
22	TOTAL DISTRIBUTION EXPENSES		149,652,103	67,254,979	82,397,125

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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

	OPERATION & MAINT EXP CON'T-23	ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	CUSTOMER ACCOUNTS EXPENSE				
1	990200 Meter reading expenses	OMEXP902	1,056,841	382,133	674,707
2	990300 Cust records and collection exp	OMEXP903	81,200,712	27,587,759	53,612,953
3	990500 Miscellaneous cust accounts exp	OMEXP905	0	0	0
4	990400 Uncollectible accounts	OMEXP904	6,021,503	2,516,865	3,504,637
5	TOTAL CUSTOMER ACCOUNTS EXPENSE		88,279,055	30,486,758	57,792,298
	CUSTOMER SERVICE EXPENSE				
6	990700 Supervision	OMEXP907	0	0	0
7	990800 Customer assistance expenses	OMEXP908	5,189,460	1,382,213	3,807,248
8	990900 Informational & instructional adv	OMEXP909	1,195,948	398,755	797,192
9	991000 Miscellaneous customer service & informational exp	OMEXP910	0	0	0
10	TOTAL CUSTOMER SERVICE EXPENSE		6,385,408	1,780,968	4,604,440
	SALES EXPENSE				
11	991200 Demonstrating & selling expenses	OMEXP912	0	0	0
12	991300 Advertising expense	OMEXP913	0	0	0
13	TOTAL SALES EXPENSE		0	0	0
14	**OPERATIONS & MAINTENANCE LESS A&G**		244,316,567	99,522,704	144,793,862

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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

	OPERATION & MAINT EXP CON'T-24	ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	ADMINISTRATIVE & GENERAL EXPENSE				
	OPERATION				
1	992000 Administrative & General salaries	OMLESAGS	3,464,797	1,508,164	1,956,633
2	992000 Administrative & General salaries Direct MD	DISTRMD	615,212	0	615,212
3	992000 Administrative & General salaries Direct DC	DISTRDC	650,606	650,606	0
4	992100 Office supplies & expenses	OMLESAGS	9,824,352	4,276,364	5,547,988
5	992100 Office supplies & expenses -DC	DISTRDC	287,668	287,668	0
6	992100 Office supplies & expenses -MD	DISTRMD	828,709	0	828,709
7	992300 Outside services employed	OMLESAGS	118,003,319	51,364,727	66,638,592
8	992300 Outside services employed - MD	DISTRMD	(443,688)	0	(443,688)
9	992300 Outside services employed - DC	DISTRDC	1,361,929	1,361,929	0
10	992400 Property insurance	STDPLT	1,085,372	551,209	534,163
11	992500 Injuries & damages	OMLESAGS	5,592,570	2,434,345	3,158,224
12	992600 Employee pensions & benefits	OMLESAGS	17,979,947	7,826,348	10,153,599
13	992600 Distr-direct empl pensions & benefits- DC	DISTRDC	0	0	0
14	992600 Distr-direct empl pensions & benefits- MD	DISTRMD	0	0	0
15	992800 Regulatory commission expenses	OMLESAGS	83,401	36,303	47,098
16	Regulatory commission exp - DC	DISTRDC	3,378,190	3,378,190	0
17	Regulatory commission exp - MD	DISTRMD	1,482,150	0	1,482,150
18	992900 Duplicate charges-Credit	OMLESAGS	14	6	8
19	993010 General ad expenses	OMLESAGS	229,122	99,733	129,389
20	993020 Miscellaneous general expenses	OMLESAGS	3,387,465	1,474,503	1,912,962
21	993100 Rents	OMLESAGS	0	0	0
22	TOTAL OPERATION		167,811,134	75,250,094	92,561,040
23	**MAINTENANCE**				
24	993500 Maintenance of general plant	OMLESAGS	(518)	(225)	(292)
25	TOTAL MAINTENANCE		(518)	(225)	(292)
26	TOTAL ADMINISTRATIVE & GENERAL EXPENSE		167,810,616	75,249,869	92,560,747
27	**TOTAL OPERATION & MAINTENANCE EXPENSE**		412,127,183	174,772,573	237,354,610

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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	DEPRECIATION & AMORT EXP-25				
	DEPRECIATION EXPENSE				
1	Distribution - DC	DISTRDC	85,163,378	85,163,378	0
2	Distribution - Maryland	DISTRMD	64,904,136	0	64,904,136
3	Distribution - VA	DISTROTH	2,763	0	2,763
4	Distribution - SM	DISTROTH	0	0	0
5	Meters DC	DISTRDC	4,384,208	4,384,208	0
6	Meters MD	DISTRMD	7,589,608	0	7,589,608
7	Meters SM	DISTROTH	10,449	0	10,449
8	Subtransmission - DC	DISTRDC	6,682,604	6,682,604	0
9	Subtransmission - MD	DISTRMD	6,849,813	0	6,849,813
10	Subtransmission - SM	DISTROTH	41,286	0	41,286
11	General DC	DISTRDC	6,529,102	6,529,102	0
12	General MD	DISTRMD	6,204,028	0	6,204,028
13	TOTAL DEPRECIATION EXPENSE (LESS AFUDC)		188,361,376	102,759,293	85,602,083
14	DEPRECIATION EXPENSE - AFUDC				
15	Distribution - DC	DISTRDC	654,037	654,037	0
16	Distribution - Maryland	DISTRMD	388,911	0	388,911
17	General MD	DISTRMD	1,007,012	0	1,007,012
18	General DC	DISTRDC	297,479	297,479	0
19	General SM	DISTROTH	8,657	0	8,657
20	TOTAL DEPRECIATION EXPENSE - AFUDC		2,356,096	951,516	1,404,580
21	TOTAL DEPRECIATION EXPENSE		190,717,472	103,710,809	87,006,663
	AMORTIZATION EXPENSE				
22	Software	STDPLT	5,452,247	2,768,936	2,683,310
23	AMI Software - DC	DISTRDC	0	0	0
24	AMI Software - MD	DISTRMD	0	0	0
25	General	STDPLT	341,031	173,194	167,838
26	Credit Facility	STDPLT	162,596	82,575	80,021
27	Regulatory Assets - DC				
28	DC AMI (2008)	DISTRDC	60,708	60,708	0
29	DC AMI Expense	DISTRDC	3,295,734	3,295,734	0
30	DC DLC Program Costs	DISTRDC	2,848,400	2,848,400	0
31	DC Interval Billing Costs	DISTRDC	916,800	916,800	0
32	DC AMI True Up	DISTRDC	1,708,400	1,708,400	0
33	Total Regulatory Assets - DC		8,830,043	8,830,043	0
34	Regulatory Assets - MD				
35	MD Hurricane Irene (August 2011)	DISTRMD	433,614	0	433,614
36	MD Approved AMI Costs 2	DISTRMD	302,220	0	302,220
37	MD Local 1900 Ratification Bonus	DISTRMD	0	0	0
38	EV Pilot Costs	DISTRMD	151,000	0	151,000
39	Approved AMI Costs	DISTRMD	5,140,900	0	5,140,900
40	MD Legacy Meters	DISTRMD	8,467,077	0	8,467,077
41	MD Tax Compensation Carrying Costs	DISTRMD	0	0	0
42	Pepco CTAs	DISTRMD	3,243,200	0	3,243,200
43	Total Regulatory Assets - MD		17,738,011	0	17,738,011
44	TOTAL AMORTIZATION EXPENSE (LESS AFUDC)		32,523,928	11,854,748	20,669,180
45	AMORIZATION EXPENSE - AFUDC				
46	AFUDC DC	DISTRDC	64,265	64,265	0
47	AFUDC MD	DISTRMD	73,431	0	73,431
48	AFUDC SM	DISTROTH	1,282	0	1,282
49	TOTAL AMORTIZATION EXPENSE - AFUDC		138,979	64,265	74,714
50	TOTAL AMORTIZATION EXPENSE		32,662,907	11,919,012	20,743,894
51	**TOTAL DEPRECIATION & AMORTIZATION**		223,380,379	115,629,821	107,750,557

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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

	OTHER TAXES & EXPENSES-26	ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	OTHER TAXES				
1	Payroll Taxes - FICA	OMLESAG	5,904,244	2,405,102	3,499,142
2	Payroll Taxes - MD EE/EA & Storm	DISTRMD	13,053	0	13,053
3	MD Property Tax - Subtransmission	STAED	4,508,323	1,894,848	2,613,475
4	DC Property Tax - Subtransmission	STAED	57,329	24,096	33,234
5	VA Property Tax - Subtransmission	STAED	408,147	171,544	236,603
6	Property Taxes - DC	DISTRDC	4,994,089	4,994,089	0
7	Property Taxes - Maryland	DISTRMD	36,142,319	0	36,142,319
8	Property Taxes - SMECO	DISTROTH	53,966	0	53,966
9	Property Taxes - VA	DISTROTH	740	0	740
10	Total Property Taxes		46,164,913	7,084,577	39,080,336
11	Federal Highway Use Tax	OMLESAG	13,330	5,430	7,900
12	DC				
13	Delivery Tax	DISTRDC	83,200,953	83,200,953	0
14	PSOS	DISTRDC	22,836,435	22,836,435	0
15	Use	DISTRDC	282,238	282,238	0
16	PSC	DISTRDC	9,549,070	9,549,070	0
17	RETF/EATF/SETF	DISTRDC	20,011,407	20,011,407	0
18	Ballpark	DISTRDC	175,011	175,011	0
19	Bus Improvement	DISTRDC	0	0	0
20	MD				
21	Environ Surch	DISTRMD	1,989,735	0	1,989,735
22	PSC	DISTRMD	2,429,906	0	2,429,906
23	Delivery Tax	DISTRMD	8,867,576	0	8,867,576
24	Univ Svc	DISTRMD	9,239,532	0	9,239,532
25	Montgomery County Surcharge	DISTRMD	146,532,511	0	146,532,511
26	Sales, Use, & Diesel Fuel Tax	DISTRMD	49,452	0	49,452
27	Gross Receipts	DISTRMD	11,527,852	0	11,527,852
28	VA				
29	Use	DISTROTH	2,346	0	2,346
30	TOTAL OTHER TAXES		368,789,564	145,550,223	223,239,341

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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	DEVELOPMENT OF INCOME TAXES-27				
	FEDERAL & STATE TAX CALCULATION				
1	**OPERATING REVENUES**		1,249,403,626	535,226,424	714,177,203
2	**OPERATING EXPENSES**				
3	Operation & Maintenance Expense		412,127,183	174,772,573	237,354,610
4	Depreciation and Amortization		223,380,379	115,629,821	107,750,557
5	Taxes Other than Income Tax		368,789,564	145,550,223	223,239,341
6	OPER INC PRE STATE TAX, INTEREST AND FED TAX		245,106,501	99,273,807	145,832,694
7	Less: Interest Expense	STDPLT	104,062,051	50,989,810	53,072,241
8	Int On Cust Deps - DC	DISTRDC	329,490	329,490	0
9	Int On Cust Deps - MD	DISTRMD	861,695	0	861,695
10	Total Interest Expense		105,253,236	51,319,300	53,933,936
11	**FIT ADJUSTMENTS (SCHEDULE M)**				
12	MD Prop Tax Adjustment - MD	DISTRMD	913,817	0	913,817
13	MD Prop Tax Adjustment Subt	STAED	113,988	47,909	66,079
14	MD Prop Tax Adjustment SMECO	DISTROTH	1,364	0	1,364
15	MD Prop Tax Adjustment - DC	DISTRDC	0	0	0
16	blank	DISTRMD	0	0	0
17	Pre-81 Removal Cost Flow-Through for Md	DISTRMD	5,388,438	0	5,388,438
18	blank	DISTRMD	0	0	0
19	Excess Tax/Book Depreciation (Pre-75)	DEPRE	(4,228,674)	(2,306,925)	(1,921,749)
20	Non-Deductible Meal Exp	OMLESAG	(1,051,597)	(428,370)	(623,227)
21	OPEB Medicare Subsidy	OMLESAGS	0	0	0
22	Control Center AFUDC DC	DISTROTH	0	0	0
23	Control Center AFUDC MD	DISTRMD	0	0	0
24	TOTAL FIT ADJUSTMENTS (SCHEDULE M)		1,137,336	(2,687,385)	3,824,721
25	TAXABLE INCOME FOR STATE		138,715,929	50,641,893	88,074,037
26	**STATE INCOME TAXES**		2,382,105	(4,499,833)	6,881,938
27	TAXABLE INCOME FOR FED		136,333,824	55,141,726	81,192,099
28	**FEDERAL INCOME TAXES**		28,630,103	11,579,762	17,050,341
29	**FEDERAL EXCESS DEFERRED AMORTIZATION**				
30	Excess Deferred Amortization-Federal (MD Distr)	DISTRMD	(11,538,708)	0	(11,538,708)
31	Excess Deferred Amortization-Federal (DC Distr)	DISTRDC	(16,740,840)	(16,740,840)	0
32	**ITC ADJUSTMENT**				
33	4% + 6% (Post 81) - DC	DISTRDC	(70,057)	(70,057)	0
34	4% + 6% (Post 81) - MD	DISTRMD	(54,816)	0	(54,816)
35	TOTAL ITC ADJUSTMENT		(124,873)	(70,057)	(54,816)
36	**TOTAL FEDERAL INCOME TAXES**		225,682	(5,231,135)	5,456,817
37	**TOTAL INCOME TAXES**		2,607,787	(9,730,968)	12,338,755
38	**TOTAL EXPENSES**		1,006,904,912	426,221,649	580,683,263
39	**NET OPERATING INCOME**		242,498,714	109,004,774	133,493,940
40	**AFUDC**	ZERO	0	0	0
41	**NET OPERATING INCOME FOR ROR CALCULATION**		242,498,714	109,004,774	133,493,940

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JURISDICTIONAL COST OF SERVICE STUDY
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ELECTRIC DISTRIBUTION

	OPERATION & MAINTENANCE EXP-28	ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	DEVELOPMENT OF OPERATION & MAINTENANCE				
	DISTRIBUTION EXPENSES				
	Storm Costs - Direct DC				
	OPERATION				
1	958100 Load dispatching	DISTRDC	0	0	0
1	958200 Station Expenses	DISTRDC	0	0	0
2	589 rents	DISTRDC	537,306	537,306	0
3	958800 Miscellaneous distribution expenses	DISTRDC	291,199	291,199	0
4	TOTAL OPERATION		537,306	537,306	0
	MAINTENANCE				
5	959200 Station expenses	DISTRDC	0	0	0
6	959300 Maintain overhead lines	DISTRDC	3,141,184	3,141,184	0
7	TOTAL MAINTENANCE		3,141,184	3,141,184	0
	Storm Costs - Direct MD				
	OPERATION				
8	958100 Load dispatching	DISTRMD	3,650	0	3,650
9	958200 Station expenses	DISTRMD	0	0	0
10	958300 Overhead line expenses	DISTRMD	0	0	0
11	958800 Miscellaneous distribution expenses	DISTRMD	374,684	0	374,684
12	TOTAL OPERATION		3,650	0	3,650
	MAINTENANCE				
13	959200 Station expenses	DISTRMD	29,383	0	29,383
14	959300 Maintain overhead lines	DISTRMD	19,500,925	0	19,500,925
15	TOTAL MAINTENANCE		19,530,308	0	19,530,308

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ELECTRIC DISTRIBUTION

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	OPERATION & MAINTENANCE EXP-29				
	DISTRIBUTION EXPENSES LESS STORM COSTS				
	OPERATION				
1	958000 Operation Supervision & Engineering	OMOPER	3,725,016	2,085,608	1,639,409
2	Direct to Maryland	DISTRMD	232,286	0	232,286
3	Direct to DC	DISTRDC	67,828	67,828	0
4	Total 958000		4,025,130	2,153,436	1,871,695
5	958100 Load dispatching				
6	Allocable	PLTDACTS	6,524,881	3,314,545	3,210,336
7	Direct to Maryland	DISTRMD	0	0	0
8	Total 958100		6,524,881	3,314,545	3,210,336
9	958200 Station expenses				
10	Subtransmission	PLTSUBT	320,129	133,718	186,411
11	Substations	PLTSUBS	903,021	487,513	415,508
12	Direct to Maryland	DISTRMD	137,888	0	137,888
13	Direct to DC	DISTRDC	341,559	341,559	0
14	Total 958200		1,702,597	962,789	739,808
15	958300 Overhead line expenses				
16	Direct to DC	DISTRDC	1,382,659	1,382,659	0
17	Direct to Maryland	DISTRMD	400,359	0	400,359
18	Subtransmission	STAED	27,876	11,716	16,160
19	Subtransmission - SMECO	DISTROTH	268	0	268
20	OH Lines	PLTOH	342,751	82,365	260,385
21	Total 958300		2,153,912	1,476,740	677,172
22	958400 Underground line expenses				
23	Subtransmission	STAED	89,210	37,495	51,715
24	Subtransmission - SMECO	DISTROTH	150	0	150
25	UG Lines	PLTUG	756,637	476,849	279,788
26	UG Services	PLTUGS	141,110	86,237	54,873
27	UG Line expenses- DC	DISTRDC	6,979,522	6,979,522	0
28	UG Line expenses- MD	DISTRMD	2,185,489	0	2,185,489
29	Total 958400		10,152,118	7,580,103	2,572,015
30	958500 Street lighting - MD	DISTRMD	1,021,505	0	1,021,505
31	958600 Meter expenses	PLANT370	2,159,771	921,030	1,238,741
32	958600 Meter expenses - MD	DISTRMD	2,585,258	0	2,585,258
33	958600 Meter expenses - DC	DISTRDC	2,518,785	2,518,785	0
34	Total 958600		7,263,815	3,439,815	3,823,999
35	958700 Customer installations expenses	PLANT371	120,001	62,004	57,996
36	958700 Customer installations expenses -MD	DISTRMD	5,006,330	0	5,006,330
37	958700 Customer installations expenses -DC	DISTRDC	3,352,873	3,352,873	0
38	Total 958700		8,479,203	3,414,877	5,064,326
39	958800 Miscellaneous distribution expenses	OMOPER	6,460,658	3,617,272	2,843,386
40	958801 Miscellaneous dist- MD- debit/credit	DISTRMD	0	0	0
41	958800 Miscellaneous distr - Maryland	DISTRMD	1,463,701	0	1,463,701
42	958800 Miscellaneous distr - DC	DISTRDC	2,691,724	2,691,724	0
43	Total 958800		10,616,083	6,308,997	4,307,086
44	958900 Rents				
45	Distribution	STDPLT	7,693,408	3,907,115	3,786,292
46	Substations	DISTRDC	2,777,068	2,777,068	0
47	95890C Rents- DC	DISTRDC	146,901	146,901	0
48	95890M Rents- MD	DISTRMD	343,797	0	343,797
49	Total 958900		10,961,173	6,831,083	4,130,089
50	TOTAL OPERATION		62,900,417	35,482,385	27,418,032

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ELECTRIC DISTRIBUTION

	OPERATION & MAINTENANCE EXP-30	ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	MAINTENANCE				
1	959000 Maintenance Supervision & Engineering	OMMAINTN	637,900	281,685	356,215
2	Direct to Maryland	DISTRMD	35,221	0	35,221
3	959100 Maintain Structures	PLTSUBS	100,127	54,056	46,072
4	959200 Station expenses				
5	Subtransmission	PLTSUBT	2,005,225	837,581	1,167,644
6	Substations	PLTSUBS	5,656,340	3,053,682	2,602,658
7	Direct to Maryland	DISTRMD	5,248,281	0	5,248,281
8	Direct to DC	DISTRDC	4,611,754	4,611,754	0
9	Total 959200		17,521,601	8,503,018	9,018,583
	959300 Maintain overhead lines				
10	Subtransmission	STAED	2,806	1,179	1,627
11	Subtransmission - SMECO	DISTROTH	27	0	27
12	OH Lines	PLTOH	34,499	8,290	26,208
13	OH Services	PLTOHS	2,200	600	1,600
14	Direct to Maryland	DISTRMD	8,687,653	0	8,687,653
15	Direct to DC	DISTRDC	4,259,654	4,259,654	0
16	Total 959300		12,986,839	4,269,723	8,717,115
	959400 Maintain underground line				
17	Subtransmission	STAED	585,816	246,219	339,598
18	Subtransmission - SMECO	DISTROTH	987	0	987
19	UG Lines	PLTUG	4,968,625	3,131,334	1,837,291
20	UG Services	PLTUGS	926,628	566,292	360,336
21	Direct to Maryland	DISTRMD	4,498,672	0	4,498,672
22	Direct to DC	DISTRDC	6,999,716	6,999,716	0
23	Total 959400		17,980,445	10,943,561	7,036,883
	959500 Maintain line transformers				
24	Allocable	PLANT368	1,723,244	879,435	843,809
25	Direct to Maryland	DISTRMD	1,087,296	0	1,087,296
26	Direct to DC	DISTRDC	929,688	929,688	0
27	Total 959500		3,740,228	1,809,123	1,931,105
	959600 Maintain street lighting & signal systems				
28	Allocable	OM596SL	(97,059)	(5,339)	(91,720)
29	Direct to Maryland	DISTRMD	5,634,991	0	5,634,991
30	Direct to DC	DISTRDC	1,348	1,348	0
31	Total 959600		5,539,280	(3,991)	5,543,271
32	959700 Maintain meters	PLANT370	629,568	268,478	361,090
33	Direct to Maryland	DISTRMD	33,443	0	33,443
34	Direct to DC	DISTRDC	4,450	4,450	0
35	Total 959700		667,461	272,928	394,533
36	959800 Maintain distribution plant	OMMAINTN	3,105,353	1,371,267	1,734,086
37	95980M Maintain distribution plant- MD	DISTRMD	257,367	0	257,367
38	95980C Maintain distribution plant- DC	DISTRDC	301,535	301,535	0
39	95980Y Maintain Distribution Plant-Acctg Policy Harmon	OMMAINTN	0	0	0
40	Total 959800		3,664,254	1,672,801	1,991,452
41	TOTAL MAINTENANCE		62,873,355	27,802,904	35,070,451
42	TOTAL DISTR. EXPENSE LESS STORM & TREE		125,773,772	63,285,289	62,488,482

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JURISDICTIONAL COST OF SERVICE STUDY
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ELECTRIC DISTRIBUTION

	OPERATION & MAINTENANCE EXP-31	ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	DISTRIBUTION EXPENSES - TOTAL				
	OPERATION				
1	958000 Operation Supervision & Engineering		4,025,130	2,153,436	1,871,695
2	958100 Load dispatching		6,528,531	3,314,545	3,213,986
3	958200 Station expenses		1,702,597	962,789	739,808
4	958300 Overhead line expenses		2,153,912	1,476,740	677,172
5	958400 Underground line expenses		10,152,118	7,580,103	2,572,015
6	958500 Street lighting		1,021,505	0	1,021,505
7	958600 Meter expenses		7,263,815	3,439,815	3,823,999
8	958700 Customer installations expenses		8,479,203	3,414,877	5,064,326
9	958800 Miscellaneous distribution expenses		11,281,966	6,600,195	4,681,771
10	958900 Rents Control Center		11,498,479	7,368,390	4,130,089
11	TOTAL OPERATION		64,107,256	36,310,890	27,796,366
12	**MAINTENANCE**				
13	959000 Maintenance Supervision & Engineering		673,121	281,685	391,436
14	959100 Maintenance Structures		100,127	54,056	46,072
15	959200 Maintain equipment		17,550,984	8,503,018	9,047,966
16	959300 Maintain overhead lines		35,628,948	7,410,908	28,218,040
17	959400 Maintain underground line		17,980,445	10,943,561	7,036,883
18	959500 Maintain line transformers		3,740,228	1,809,123	1,931,105
19	959600 Maintain street lighting & signal sys		5,539,280	(3,991)	5,543,271
20	959700 Maintain meters		667,461	272,928	394,533
21	959800 Maintain distribution plant		3,664,254	1,672,801	1,991,452
22	TOTAL MAINTENANCE		85,544,847	30,944,089	54,600,758
23	TOTAL DISTRIBUTION EXPENSES		149,652,103	67,254,979	82,397,125

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ELECTRIC DISTRIBUTION

OPERATION & MAINTENANCE EXP-32
CUSTOMER ACCOUNTS & SALES EXP - STORM COSTS DIRECTS

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	CUSTOMER ACCOUNTS EXPENSE				
	990300 Cust records and collection exp				
1	DC	DISTRDC	548,200	548,200	0
2	MD	DISTRMD	1,607,700	0	1,607,700
3	TOTAL CUSTOMER ACCOUNTS EXPENSE		2,155,900	548,200	1,607,700
	CUSTOMER SERVICE EXPENSE				
	990800 Customer assistance expenses				
4	DC	DISTRDC	0	0	0
5	MD	DISTRMD	21,981	0	21,981
6	TOTAL CUSTOMER SERVICE EXPENSE		21,981	0	21,981

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ELECTRIC DISTRIBUTION

OPERATION & MAINTENANCE EXP-33
CUSTOMER ACCOUNTS & SALES EXPENSE LESS STORM COSTS

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	CUSTOMER ACCOUNTS EXPENSE				
	990200 Meter reading expenses				
1	DC	DISTRDC	382,133	382,133	0
2	MD	DISTRMD	674,699	0	674,699
3	Other	DISTROTH	8	0	8
	990300 Cust records and collection exp				
4	DC	DISTRDC	27,039,559	27,039,559	0
5	MD	DISTRMD	52,005,211	0	52,005,211
6	Other	DISTROTH	42	0	42
	990500 Miscellaneous cust accounts exp				
	990400 Uncollectible accounts				
7	DC	DISTRDC	2,516,865	2,516,865	0
8	MD	DISTRMD	3,504,637	0	3,504,637
9	Total Account 990400		6,021,503	2,516,865	3,504,637
10	TOTAL CUSTOMER ACCOUNTS EXPENSE		86,123,155	29,938,558	56,184,597
	CUSTOMER SERVICE EXPENSE				
	990700 Supervision				
11	DC	DISTRDC	0	0	0
12	MD	DISTRMD	0	0	0
	990800 Customer assistance expenses				
13	DC	DISTRDC	1,382,212	1,382,212	0
14	MD	DISTRMD	3,785,267	0	3,785,267
15	Other	DISTROTH	0	0	0
	990900 Informational & instructional adv				
16	DC	DISTRDC	398,755	398,755	0
17	MD	DISTRMD	797,192	0	797,192
	991000 Miscellaneous customer service & informational exp				
18	DC	DISTRDC	0	0	0
19	MD	DISTRMD	0	0	0
20	TOTAL CUSTOMER SERVICE EXPENSE		6,363,426	1,780,968	4,582,459
	SALES EXPENSE				
21	991200 Demonstrating & selling expenses				
	991300 Advertising expense				
22	DC	DISTRDC	0	0	0
23	MD	DISTRMD	0	0	0
24	TOTAL SALES EXPENSE		0	0	0

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ELECTRIC DISTRIBUTION

OPERATION & MAINTENANCE EXP-34
TOTAL CUSTOMER ACCOUNTS & SALES EXPENSE

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	CUSTOMER ACCOUNTS EXPENSE				
	990200 Meter reading expenses				
1	DC		382,133	382,133	0
2	MD		674,699	0	674,699
3	Other		8	0	8
	990300 Cust records and collection exp				
4	DC		27,587,759	27,587,759	0
5	MD		53,612,912	0	53,612,912
6	Other		42	0	42
	990500 Miscellaneous cust accounts exp				
	990400 Uncollectible accounts				
7	DC		2,516,865	2,516,865	0
8	MD		3,504,637	0	3,504,637
9	Total Account 990400		6,021,503	2,516,865	3,504,637
10	TOTAL CUSTOMER ACCOUNTS EXPENSE		88,279,055	30,486,758	57,792,298
			88,279,055		
	CUSTOMER SERVICE EXPENSE				
	990700 Supervision				
11	DC		0	0	0
12	MD		0	0	0
	990800 Customer assistance expenses				
13	DC		1,382,212	1,382,212	0
14	MD		3,807,248	0	3,807,248
15	Other		0	0	0
	990900 Informational & instructional adv				
16	DC		398,755	398,755	0
17	MD		797,192	0	797,192
	991000 Miscellaneous customer service & informational exp				
18	DC		0	0	0
19	MD		0	0	0
20	TOTAL CUSTOMER SERVICE EXPENSE		6,385,407	1,780,968	4,604,440
			6,385,407		
	SALES EXPENSE				
21	991200 Demonstrating & selling expenses				
	991300 Advertising expense				
22	DC		0	0	0
23	MD		0	0	0
24	TOTAL SALES EXPENSE		0	0	0
25	**Total Storm Costs**		25,390,330	4,226,691	21,163,639
26	**O&M Less A&G & Storm Costs**		218,260,353	95,004,815	123,255,538
27	**O&M Less A&G**		244,316,566	99,522,704	144,793,862

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Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

	ALLOCATION FACTOR TABLE-35 CAPACITY-DISTRIBUTION RELATED	ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
1	Direct Maryland Distribution	DISTRMD	1	0	1
2	Direct Other Distribution	DISTROTH	1	0	1
3					
4	Direct DC Distribution	DISTRDC	1	1	0
5	ZERO ALLOCATION	ZERO	0	0	0
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Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

		Jun 2019 6+6		
	ALLOC	Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)

ALLOCATION FACTOR TABLE-36
CAPACITY-DISTR RELATED CON'T

ENERGY RELATED

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Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	ALLOCATION FACTOR TABLE-37 CUSTOMER RELATED				
1					
2	596 Street Lights -Aug 17	OM596SL	1,864,031	102,539	1,761,492
3					
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5					
6	OTHER ALLOCATORS				
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JURISDICTIONAL COST OF SERVICE STUDY
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ELECTRIC DISTRIBUTION

ALLOCATION FACTOR TABLE-38
INTERNALLY DEVELOPED

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
1	Plant Subtransmission	PLTSUBT	646,508,863	270,046,339	376,462,524
2	Subt & Distr Total	STDPLT	6,984,744,849	3,547,219,220	3,437,525,629
3	OM Less A&G	OMLESAG	244,316,567	99,522,704	144,793,862
4	Depre Exp Less AFUDC	DEPRE	188,361,376	102,759,293	85,602,083
5					
	INTERNALLY DEVELOPED CON'T				
6	Plant - MD & Other Only (NO DC)	PLTMDOTH	3,092,312,807	26,929,023	3,065,383,784
7	CWIP ST&D LESS AFUDC	CWIPSTD	0	0	0
8	Demand Plant (Dist Only)	PLTDEM	5,588,277,698	2,897,134,873	2,691,142,825
9	Customer Plant (Dist Only)	PLTCUST	749,958,288	380,038,007	369,920,281
10	Plant 360-368 (ST&D) (Excl. 3627 Control Center)	PLTDACTS	6,234,786,562	3,167,181,211	3,067,605,351
11	Plant 368	PLANT368	1,058,885,449	540,388,296	518,497,153
12	Plant 370	PLANT370	154,845,889	66,033,710	88,812,180
13	Plant 371	PLANT371	2,646,032	1,367,203	1,278,829
14	OM Operations	OMOPER	48,259,203	27,019,953	21,239,251
15	Substations (Dist Only)	PLTSUBS	962,250,868	519,489,289	442,761,580
16	OM Maintenance	OMMAINTN	58,535,980	25,848,418	32,687,562
17	Customer Deposits	CDEP	(54,178,256)	(8,837,078)	(45,341,178)
18	Depre Related Def Tax	PLTDEF	759,625,872	414,742,436	344,883,437
19	O&M Less A&G and Storm Costs	OMLESAGS	218,260,353	95,004,815	123,255,538
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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

ALLOCATION FACTOR TABLE-39
INTERNALLY DEVELOPED CON'T

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
1	PLT OH Lines (Dist Only)	PLTOH	1,053,644,807	253,197,617	800,447,189
2	PLT UG Lines (Dist Only)	PLTUG	2,513,496,574	1,584,059,671	929,436,903
3	PLT OH Services (Dist Only)	PLTOHS	66,446,668	18,123,096	48,323,572
4	PLT UG Services (Dist Only)	PLTUGS	465,378,415	284,407,488	180,970,927
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6					
7					
8					
9					
10					
11	958000 Operation Supervision & Engineering	OMEXP580	4,025,130	2,153,436	1,871,695
12	958100 Load dispatching	OMEXP581	6,528,531	3,314,545	3,213,986
13	958200 Station expenses	OMEXP582	1,702,597	962,789	739,808
14	958300 Overhead line expenses	OMEXP583	2,153,912	1,476,740	677,172
15	958400 Underground line expenses	OMEXP584	10,152,118	7,580,103	2,572,015
16	958500 Street lighting	OMEXP585	1,021,505	0	1,021,505
17	958600 Meter expenses	OMEXP586	7,263,815	3,439,815	3,823,999
18	958700 Customer installations expenses	OMEXP587	8,479,203	3,414,877	5,064,326
19	958800 Miscellaneous distribution expenses	OMEXP588	11,281,966	6,600,195	4,681,771
23	958900 Rents Control Center	OMEXP589	11,498,479	7,368,390	4,130,089
24	959000 Maintenance Supervision & Engineering	OMEXP590	673,121	281,685	391,436
25	959100 Maintenance Structures	OMEXP591	100,127	54,056	46,072
26	959200 Maintain equipment	OMEXP592	17,550,984	8,503,018	9,047,966
27	959300 Maintain overhead lines	OMEXP593	35,628,948	7,410,908	28,218,040
28	959400 Maintain underground line	OMEXP594	17,980,445	10,943,561	7,036,883
29	959500 Maintain line transformers	OMEXP595	3,740,228	1,809,123	1,931,105
30	959600 Maintain street lighting & signal sys	OMEXP596	5,539,280	(3,991)	5,543,271
31	959700 Maintain meters	OMEXP597	667,461	272,928	394,533
32	959800 Maintain distribution plant	OMEXP598	3,664,254	1,672,801	1,991,452
33	990200 Meter reading expenses	OMEXP902	1,056,841	382,133	674,707
34	990300 Cust records and collection exp	OMEXP903	81,200,712	27,587,759	53,612,953
35	990500 Miscellaneous cust accounts exp	OMEXP905	0	0	0
36	990400 Uncollectible accounts	OMEXP904	6,021,503	2,516,865	3,504,637
37	990700 Supervision	OMEXP907	0	0	0
38	990800 Customer assistance expenses	OMEXP908	5,189,460	1,382,212	3,807,248
39	990900 Informational & instructional adv	OMEXP909	1,195,947	398,755	797,192
40	991000 Miscellaneous customer service & informational exp	OMEXP910	0	0	0
41	991200 Demonstrating & selling expenses	OMEXP912	0	0	0
42	991300 Advertising expense	OMEXP913	0	0	0
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PEPCO - DC
JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

RATIO TABLE-40
CAPACITY-DISTRIBUTION RELATED

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
1	Direct Maryland Distribution	DISTRMD	1.000000	0.000000	1.000000
2	Direct Other Distribution	DISTROTH	1.000000	0.000000	1.000000
3	Subtransmission Average & Excess (NCP)	STAED	1.000000	0.420300	0.579700
4	Subtransmission Average & Excess (NCP) - VA	STAEDOTH	0.042530	0.042030	0.000500
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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
	RATIO TABLE-41				
	CAPACITY-DISTR RELATED CON'T-				
1					
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19	ENERGY RELATED				
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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

	RATIO TABLE-42 CUSTOMER RELATED-25	ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
1					
2	596 Street Lights	OM596SL	1.000000	0.055009	0.944991
3					
4					
5					
6	OTHER ALLOCATORS				
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PEPCO - DC
JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

	RATIO TABLE-43 INTERNALLY DEVELOPED	ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
1	Plant Subtransmission	PLTSUBT	1.000000	0.417699	0.582301
2	Subt & Distr Total	STDPLT	1.000000	0.507852	0.492148
3	OM Less A&G	OMLESAG	1.000000	0.407351	0.592649
4	Depre Exp Less AFUDC	DEPRE	1.000000	0.545543	0.454457
5					
	INTERNALLY DEVELOPED CON'T				
6	Plant MD & Other Only NO DC	PLTMDOTH	1.000000	0.008708	0.991292
7	CWIP ST&D LESS AFUDC	CWIPSTD	0.000000	0.000000	0.000000
8	Demand Plant	PLTDEM	1.000000	0.518431	0.481569
9	Customer Plant	PLTCUST	1.000000	0.506746	0.493254
10	Plant 360-368	PLTDACTS	1.000000	0.507986	0.492014
11	Plant 368	PLANT368	1.000000	0.510337	0.489663
12	Plant 370	PLANT370	1.000000	0.426448	0.573552
13	Plant 371	PLANT371	1.000000	0.516699	0.483301
14	OM Operations	OMOPER	1.000000	0.559892	0.440108
15	Plant Substations	PLTSUBS	1.000000	0.539869	0.460131
16	OM Maintenance	OMMAINTN	1.000000	0.441582	0.558418
17	Customer Deposits	CDEP	1.000000	0.163111	0.836889
18	Depre Related Def Tax	PLTDEF	1.000000	0.545983	0.454017
19	O&M Less A&G and Storm Costs	OMLESAGS	1.000000	0.435282	0.564718
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JURISDICTIONAL COST OF SERVICE STUDY
Traditional Test Period Compliance Filing
ELECTRIC DISTRIBUTION

RATIO TABLE-44
INTERNALLY DEVELOPED CON'T-

		ALLOC	Jun 2019 6+6 Total DISTRIBUTION (1)	DC DISTRIBUTION (2)	Other DISTRIBUTION (3)
1	PLT OH Lines	PLTOH	1.000000	0.240306	0.759694
2	PLT UG Lines	PLTUG	1.000000	0.630222	0.369778
3	PLT OH Services	PLTOHS	1.000000	0.272746	0.727254
4	PLT UG Services	PLTUGS	1.000000	0.611132	0.388868
5					
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11	958000 Operation Supervision & Engineering	OMEXP580	1.000000	0.534998	0.465002
12	958100 Load dispatching	OMEXP581	1.000000	0.507701	0.492299
13	958200 Station expenses	OMEXP582	1.000000	0.565483	0.434517
14	958300 Overhead line expenses	OMEXP583	1.000000	0.685608	0.314392
15	958400 Underground line expenses	OMEXP584	1.000000	0.746652	0.253348
16	958500 Street lighting	OMEXP585	1.000000	0.000000	1.000000
17	958600 Meter expenses	OMEXP586	1.000000	0.473555	0.526445
18	958700 Customer installations expenses	OMEXP587	1.000000	0.402736	0.597264
19	958800 Miscellaneous distribution expenses	OMEXP588	1.000000	0.585022	0.414978
23	958900 Rents Control Center	OMEXP589	1.000000	0.640814	0.359186
24	959000 Maintenance Supervision & Engineering	OMEXP590	1.000000	0.418476	0.581524
25	959100 Maintenance Structures	OMEXP591	1.000000	0.539869	0.460131
26	959200 Maintain equipment	OMEXP592	1.000000	0.484475	0.515525
27	959300 Maintain overhead lines	OMEXP593	1.000000	0.208002	0.791998
28	959400 Maintain underground line	OMEXP594	1.000000	0.608637	0.391363
29	959500 Maintain line transformers	OMEXP595	1.000000	0.483693	0.516307
30	959600 Maintain street lighting & signal sys	OMEXP596	1.000000	-0.000720	1.000720
31	959700 Maintain meters	OMEXP597	1.000000	0.408905	0.591095
32	959800 Maintain distribution plant	OMEXP598	1.000000	0.456519	0.543481
33	990200 Meter reading expenses	OMEXP902	1.000000	0.361581	0.638419
34	990300 Cust records and collection exp	OMEXP903	1.000000	0.339748	0.660252
35	990500 Miscellaneous cust accounts exp	OMEXP905	0.000000	0.000000	0.000000
36	990400 Uncollectible accounts	OMEXP904	1.000000	0.417980	0.582020
37	990700 Supervision	OMEXP907	0.000000	0.000000	0.000000
38	990800 Customer assistance expenses	OMEXP908	1.000000	0.266350	0.733650
39	990900 Informational & instructional adv	OMEXP909	1.000000	0.333422	0.666578
40	991000 Miscellaneous customer service & informational exp	OMEXP910	0.000000	0.000000	0.000000
41	991200 Demonstrating & selling expenses	OMEXP912	0.000000	0.000000	0.000000
42	991300 Advertising expense	OMEXP913	0.000000	0.000000	0.000000
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Potomac Electric Power Company

Analysis of Changes in Average Unadjusted District of Columbia Jurisdictional Rate Base and Operating Income
Between the Twelve Months Ended December 31, 2018
and the Twelve Months Ending June 30, 2019 (6+6)

(Thousands of Dollars)

Line No.		Dec-18 Average Unadjusted (1)	Jun-19 Average Unadjusted (2)	Variance (3)	Notes
	Rate Base				
1	Electric Plant in Service	$ 3,634,746	$ 3,762,607	$ 127,861	Increased cut-in's reflected in Jan-June 2019
2	Accumulated Depreciation	(1,131,594)	(1,168,178)	(36,584)	Additional Depreciation Expense reflected in Jan- June 2019
3	Accumulated Amortization	(11,489)	(12,498)	(1,009)	
4	Materials and Supplies	37,395	38,541	1,146	
5	Cash Working Capital	9,302	9,631	329	
6	Accumulated Deferred Income Taxes	(817,866)	(800,844)	17,022	Amortization of Federal Excess Deferred Income Tax Liability reduced ADIT liability balance
7	Prepaid Pension/OPEB Liab. (net of tax)	72,039	72,903	864	
8	Customer Deposits	(8,507)	(8,771)	(264)	
9	Pepco Portion of Servco Assets	27,579	28,017	438	
10	Regulatory Assets	50,113	44,475	(5,638)	Reflects amortization of Regulatory Assets
11	Unamortized Credit Facility Costs	374	364	(10)	
12	Total Rate Base	$ 1,862,091	$ 1,966,247	$ 104,156	
	Operating Revenues				
13	Sale of Electricity	$ 528,278	$ 528,438	$ 160	
14	Other Revenues	6,561	6,789	228	
15	Operating Revenues	$ 534,838	$ 535,227	$ 389	
	Operating Expenses				
16	Operation and Maintenance	$ 162,574	$ 174,773	$ 12,199	December 2018 period includes credits to establish regulatory assets per FC 1150. Increase in amortization for regulatory assets approved in FC 1150. Increase in distribution operations expenses.
17	Depreciation	99,493	103,711	4,218	Additional depreciation expense on higher EPIS
18	Amortization	10,055	11,919	1,864	Increase in software amortization related to EPIS software additions.
19	Other Taxes	147,713	145,550	(2,163)	Decrease in DC delivery tax and PSOS.
20	D.C. Income Tax	(3,829)	(4,500)	(671)	Reflects amortization of DC Excess Deferred Taxes
21	Federal Income Tax	530	(5,232)	(5,762)	Reflects decreased taxable income and greater amortization of federal excess deferred income tax liability
22	Total Operating Expenses	$ 416,536	$ 426,221	$ 9,685	
23	Operating Income	$ 118,302	$ 109,006	$ (9,296)	

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POTOMAC ELECTRIC POWER COMPANY
Cost of Capital
District of Columbia
Requested at December 31, 2018

Type of Capital	Percent of Total Capital	Embedded Cost Rate	Weighted Cost Rate
Long Term Debt	49.54%	5.27%	2.61%
Common Equity	50.46%	10.30%	5.20%
Total	100.00%		7.81%

Potomac Electric Power Company
Capital Structure
Requested at December 31, 2018

Type of Capital	Amount ($)	Ratios
Long-Term Debt	2,734,500,000	
Unamortized Net Discount	2,094,105	
Unamortized Debt Issuance Expense	(33,838,032)	
Unamortized Debt Reacquisition Costs	(13,337,623)	
Total Long-Term Debt	2,689,418,450	49.54%
Common Equity	2,739,552,929	50.46%
Total	5,428,971,379	100.00%

Potomac Electric Power Company
Weighted Cost of Long-term Debt
Long-Term Debt
Requested at December 31, 2018

Security Type	Coupon Rate	Date of Offering	Date of Maturity	Current Principal Amount	Current Unamortized (Premium)/ Discount	Current Unamortized Debt Issuance Expense	Net Amount Outstanding	Effective Cost Rate	Annual Net Cost
First Mortgage Bonds									
	5.75%	3/24/04	4/15/34	$100,000,000	$38,648	$619,200	$99,342,153	5.84%	$5,801,582
	5.40%	6/1/05	6/1/35	$175,000,000	$338,953	$1,185,663	$173,475,384	5.51%	$9,558,494
	6.50%	11/16/07	11/15/37	$250,000,000	$391,612	$2,059,765	$247,548,623	6.62%	$16,387,719
	6.50%	3/24/08	11/15/37	$250,000,000	$6,405,258	$2,520,469	$241,074,273	6.84%	$16,489,480
	7.90%	12/10/08	12/15/38	$250,000,000		$3,848,720	$246,151,280	8.06%	$19,839,793
	3.05%	4/4/12	4/1/22	$200,000,000	$208,603	$1,283,767	$198,507,630	3.29%	$6,530,901
	4.15%	3/15/13	3/15/43	$250,000,000	$871,201	$3,865,765	$245,263,034	4.28%	$10,497,258
	4.15%	3/16/15	3/15/43	$200,000,000	($7,754,891)	$3,903,450	$203,851,440	4.02%	$8,194,828
	4.15%	5/22/17	3/15/43	$200,000,000	($3,914,998)	$4,010,689	$199,904,310	4.15%	$8,296,029
	4.95%	11/14/13	11/15/43	$150,000,000	$1,018,835	$2,527,944	$146,453,221	5.12%	$7,498,405
	3.60%	3/11/14	3/15/24	$400,000,000	$302,674	$3,859,268	$395,838,058	3.82%	$15,121,014
	4.27%	6/21/18	6/15/48	$100,000,000		$3,692,115	$96,307,885	4.50%	$4,333,855
	4.31%	11/1/18	11/1/48	$100,000,000		(A)	$100,000,000	4.31%	$4,310,000
Total First Mortgage Bonds				$2,625,000,000	($2,094,105)	$33,376,815	$2,593,717,290		$132,859,357
Tax Exempt Fixed Rate Bonds									
	6.20%	3/17/09	9/1/22	$109,500,000		$461,218	$109,038,782	6.33%	$6,902,155
Total Tax Exempt Fixed Rate Bonds				$109,500,000	$0	$461,218	$109,038,782		$6,902,155
Long-Term Debt Balance				$2,734,500,000	($2,094,105)	$33,838,032	$2,702,756,073		$139,761,512
Unamortized Debt Reacquisition Costs							($13,337,623)		$1,857,621
Total Long-Term Debt Balance				$2,734,500,000	($2,094,105)	$33,838,032	$2,689,418,450	5.27%	$141,619,133

(A) The debt issuance costs in relation to the total of the $200M FMB were paid and are being amortized with the first tranche, which occurred on 6/21/2018

Potomac Electric Power Company
Calculation of the Effective Cost Rate of Long-Term Debt
Requested at December 31, 2018

Security Type	Coupon Rate	Date of Offering	Date of Maturity	Original Principal Amount	Original (Premium)/ Discount	Original Debt Issuance Expense	Original Net Amount to Company	Net Amount Per Unit	Yield to Maturity
First Mortgage Bonds									
	5.75%	3/24/04	4/15/34	$100,000,000	$76,000	$1,235,073	$98,688,927	$98.69	5.84%
	5.40%	6/1/05	6/1/35	$175,000,000	$619,500	$2,098,961	$172,281,539	$98.45	5.51%
	6.50%	11/16/07	11/15/37	$250,000,000	$622,500	$3,285,507	$246,091,993	$98.44	6.62%
	6.50%	3/24/08	11/15/37	$250,000,000	$7,707,500	$3,042,166	$239,250,334	$95.70	6.84%
	7.90%	12/10/08	12/15/38	$250,000,000	$0	$4,400,205	$245,599,795	$98.24	8.06%
	3.05%	4/4/12	4/1/22	$200,000,000	$580,000	$3,561,235	$195,858,765	$97.93	3.29%
	4.15%	3/15/13	3/15/43	$250,000,000	$977,500	$4,333,912	$244,688,588	$97.88	4.28%
	4.15%	3/16/15	3/15/43	$200,000,000	($8,422,000)	$4,244,304	$204,177,696	$102.09	4.02%
	4.15%	5/22/17	3/15/43	$200,000,000	($4,064,000)	$4,165,446	$199,898,554	$99.95	4.15%
	4.95%	11/14/13	11/15/43	$150,000,000	$1,111,500	$2,756,579	$146,131,921	$97.42	5.12%
	3.60%	3/11/14	3/15/24	$400,000,000	$532,000	$6,769,182	$392,698,818	$98.17	3.82%
	4.27%	6/21/18	6/15/48	$100,000,000	$0	$3,724,076	$96,275,924	$96.28	4.50%
	4.31%	11/1/18	11/1/48	$100,000,000	$0	$0 (A)	$100,000,000	$100.00	4.31%
Tax Exempt Fixed Rate Bonds:									
	6.20%	3/17/09	9/1/22	$109,500,000	$0	$1,274,100	$108,225,900	$98.84	6.33%

(A) The debt issuance costs in relation to the total of the $200M FMB were paid and are being amortized with the first tranche, which occurred on 6/21/2018

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Potomac Electric Power Company
District of Columbia Recordation Tax
Sections 42-1103
District of Columbia Code 1981, Division VII Property, Title 42 Real Property
Tax on Proposed Issuance of $200,000,000 First Mortgage Bonds
May 2018

	12/31/2017	
BV Property Located in District of Columbia based on 12/17 information	3,921,954,090	Update for ending 2017
Total Cost of BV Property Everywhere based on 12/17 information	8,494,209,866	Update for ending 2017
Ratio of Property Located in District of Columbia to Total Property	46.17%	
Mortgage Bond Amount	200,000,000	
Less: PEPCO"s FMB outstanding per memo	0	
Net Amount	$ 200,000,000	
Net Amount Allocated to District of Columbia	92,340,000	
Recordation Tax at 1.45%	$ 1,338,930	

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2017 PEPCO LEAD-LAG STUDY

For the District of Columbia

POTOMAC ELECTRIC POWER COMPANY

Index to Cash Working Capital Workpapers

	Workpaper Reference
Revenue Lag Summary	A-1
Expense Lag Summary	A-2
Billing Lag	B
Collection Lag	C
Other Revenue Lag – Rent from Electric Property	D
Other Revenue Lag – Billing Services	E
Other Revenue Lag – Miscellaneous Services	F
Pepco Wages Lag	G-1
Pepco Annual Incentive Payment Lag	G-19
Control Center Leaser Lag	H
Weighted Other O&M Expense Lag	I
Taxes Other than Income, Property & Payroll Lag	J
Property Tax Lag	K
Income Tax Lag	L

Potomac Electric Power Company
Calculation of Number of Days from Service to Collection

DC
Retail Electric Revenues
For the twelve months ended June 30, 2019 (6+6)

(1) Line No.	(2) Revenue Lag	(3) Billed Revenues	(4) (Lead)/Lag Days	(5) Source	(6) Dollar Weighted Amount
1	Service Lag		15.21	See Note 1	
2					
3	Billing Lag		3.65	Workpaper B	
4					
5	Collection Lag		25.38	Workpaper C	
6					
7	Total Billed Electric Distribution	$ 528,437,658	44.24		$ 23,378,082,010
8					
9					
10					
11	Late Payment Penalty	1,367,791	44.24	Line 7	60,511,076
12					
13	Reconnect/Return Check	329,798	44.24	Line 7	14,590,252
14					
15	Rent from Electric Property	1,574,845	(46.28)	Workpaper D	(72,877,104)
16					
17	Billing Services / Other	3,517,005	99.52	Workpaper E	350,028,950
18					
19	Miscellaneous Services	(673)	21.52	Workpaper F	(14,495)
20					
21	**Total Revenue Lag**	**$ 535,226,424**	**44.34**		**$ 23,730,320,689**

Potomac Electric Power Company
Distribution Cash Working Capital
Twelve Months Ended June 30, 2019

LINE NO.	ITEM	(1) Test Year D.C. Distribution Amount	(2) 2017 Study (Lead)/Lag Days	(3) Test Year D.C. Distribution Lag Dollars
	D.C. Operating Revenues			
1	Billed Sale of Electric	$ 528,437,658	44.24	$ 23,378,082,010
2	Late Payment Penalty	1,367,791	44.24	60,511,076
3	Reconnect/Return Check	329,798	44.24	14,590,252
4	CEO Online	-	44.24	-
5	Rent from Electric Property	1,574,845	(46.28)	(72,877,104)
6	Miscellaneous Services	(673)	21.52	(14,495)
7	Other	3,517,005	99.52	350,028,950
8	**Composite Revenue Lag - D.C.**	**$ 535,226,424**	**44.34**	**$ 23,730,320,689**
	D.C. Operating Expenses			
9	Pepco Gross Wages	$ 29,144,689	8.70	$ 253,558,795
10	Pepco AIP	1,561,378	241.00	376,292,116
11	Pepco D.C. - Major Storm Expense	921,854	137.47	126,727,298
12	Control Center Lease	3,868,105	88.25	341,360,298
13	Other O&M Expense	129,183,773	35.79	4,622,970,601
14	Property tax - District of Columbia	5,018,184	97.21	487,817,681
15	Property tax - Montgomery County	928,357	(4.10)	(3,806,265)
16	Property tax - PG County	837,823	(59.76)	(50,068,312)
17	Property tax - Charles County	29,967	(59.60)	(1,786,017)
18	Property tax - Other MD Counties	98,701	(76.77)	(7,577,276)
19	Property tax - Alexandria	149,985	151.09	22,661,181
20	Property tax - Arlington	18,435	234.50	4,323,097
21	Property tax - Fairfax	-	-	-
22	Property tax - Pr William	3,124	153.68	480,151
23	D.C. Delivery Tax	83,200,953	35.41	2,946,145,732
24	D.C. Public Space Occupancy Fee	22,836,435	(49.13)	(1,121,954,047)
25	D.C. RETF, SETF, EATF	20,011,407	36.27	725,813,748
26	D.C. PSC Reimbursement	9,549,070	172.50	1,647,214,575
27	D.C. Business Improvement District Tax	175,011	(99.94)	(17,490,587)
28	D.C. Ball Park Fee	-	197.50	-
29	D.C. Sales & Use Tax	282,238	35.69	10,073,074
30	Federal Heavy Highway Vehicle Use Tax (FHUT)	15,676	(138.50)	(2,171,100)
31	FICA	2,377,268	9.15	21,752,004
32	FUTA/SUTA	27,834	9.03	251,343
33	DCIT currently payable	-	59.05	-
34	FIT currently payable	-	59.05	-
35	**Total D.C. Distribution Expenses**	**$ 310,240,269**		**$ 10,382,588,090**
36	**Composite Expense Lag**		**33.47**	
37	**Net Lag**		**10.87**	
38	D.C Average Daily Expenses (ln 35, col 1 ÷ 365 days)			$ 849,973.34
39	Cash Working Capital allowance before Imprest Funds			9,239,800
40	D.C. Imprest Funds			390,785
41	D.C. CWC			$ 9,630,585

Potomac Electric Power Company
Calculation of Revenue Billing Lag Based on Meter Reading to Bill Mailing Date

SYSTEM
For the twelve months December 31, 2017

Month	Rendition Group #	Meter Reading Date	Scheduled Mail Date	Number of Days
January	1	01/03/17	01/06/17	3
January	2	01/04/17	01/07/17	3
January	3	01/05/17	01/09/17	4
January	4	01/06/17	01/11/17	5
January	5	01/07/17	01/11/17	4
January	6	01/09/17	01/12/17	3
January	7	01/10/17	01/13/17	3
January	8	01/11/17	01/14/17	3
January	9	01/12/17	01/17/17	5
January	10	01/13/17	01/18/17	5
January	11	01/14/17	01/18/17	4
January	12	01/17/17	01/20/17	3
January	13	01/18/17	01/21/17	3
January	14	01/19/17	01/23/17	4
January	15	01/23/17	01/26/17	3
January	16	01/24/17	01/27/17	3
January	17	01/25/17	01/28/17	3
January	18	01/26/17	01/30/17	4
January	19	01/27/17	02/01/17	5
January	20	01/30/17	02/02/17	3
January	21	01/31/17	02/03/17	3
			January Average	3.62

Potomac Electric Power Company
Calculation of Revenue Billing Lag Based on Meter Reading to Bill Mailing Date

SYSTEM
For the twelve months December 31, 2017

Month	Rendition Group #	Meter Reading Date	Scheduled Mail Date	Number of Days
February	1	02/01/17	02/04/17	3
February	2	02/02/17	02/06/17	4
February	3	02/03/17	02/08/17	5
February	4	02/06/17	02/09/17	3
February	5	02/07/17	02/10/17	3
February	6	02/08/17	02/11/17	3
February	7	02/09/17	02/13/17	4
February	8	02/10/17	02/15/17	5
February	9	02/11/17	02/15/17	4
February	10	02/13/17	02/16/17	3
February	11	02/14/17	02/17/17	3
February	12	02/15/17	02/18/17	3
February	13	02/16/17	02/21/17	5
February	14	02/17/17	02/22/17	5
February	15	02/21/17	02/24/17	3
February	16	02/22/17	02/25/17	3
February	17	02/23/17	02/27/17	4
February	18	02/24/17	03/01/17	5
February	19	02/25/17	03/01/17	4
February	20	02/27/17	03/02/17	3
February	21	02/28/17	03/03/17	3
			February Average	3.71

Potomac Electric Power Company
Calculation of Revenue Billing Lag Based on Meter Reading to Bill Mailing Date

SYSTEM
For the twelve months December 31, 2017

Month	Rendition Group #	Meter Reading Date	Scheduled Mail Date	Number of Days
March	1	03/01/17	03/04/17	3
March	2	03/02/17	03/06/17	4
March	3	03/03/17	03/08/17	5
March	4	03/06/17	03/09/17	3
March	5	03/07/17	03/10/17	3
March	6	03/08/17	03/11/17	3
March	7	03/09/17	03/13/17	4
March	8	03/10/17	03/15/17	5
March	9	03/13/17	03/16/17	3
March	10	03/14/17	03/17/17	3
March	11	03/15/17	03/18/17	3
March	12	03/16/17	03/20/17	4
March	13	03/17/17	03/22/17	5
March	14	03/20/17	03/23/17	3
March	15	03/21/17	03/24/17	3
March	16	03/22/17	03/25/17	3
March	17	03/23/17	03/27/17	4
March	18	03/24/17	03/29/17	5
March	19	03/27/17	03/30/17	3
March	20	03/28/17	03/31/17	3
March	21	03/29/17	04/01/17	3
			March Average	3.57

Potomac Electric Power Company
Calculation of Revenue Billing Lag Based on Meter Reading to Bill Mailing Date

SYSTEM
For the twelve months December 31, 2017

Month	Rendition Group #	Meter Reading Date	Scheduled Mail Date	Number of Days
April	1	04/03/17	04/06/17	3
April	2	04/04/17	04/07/17	3
April	3	04/05/17	04/08/17	3
April	4	04/06/17	04/10/17	4
April	5	04/07/17	04/12/17	5
April	6	04/08/17	04/12/17	4
April	7	04/10/17	04/13/17	3
April	8	04/11/17	04/14/17	3
April	9	04/12/17	04/15/17	3
April	10	04/13/17	04/17/17	4
April	11	04/14/17	04/19/17	5
April	12	04/17/17	04/20/17	3
April	13	04/18/17	04/21/17	3
April	14	04/19/17	04/22/17	3
April	15	04/20/17	04/24/17	4
April	16	04/21/17	04/26/17	5
April	17	04/24/17	04/27/17	3
April	18	04/25/17	04/28/17	3
April	19	04/26/17	04/29/17	3
April	20	04/27/17	05/01/17	4
April	21	04/28/17	05/03/17	5
			April Average	3.62

Potomac Electric Power Company
Calculation of Revenue Billing Lag Based on Meter Reading to Bill Mailing Date

SYSTEM
For the twelve months December 31, 2017

Month	Rendition Group #	Meter Reading Date	Scheduled Mail Date	Number of Days
May	1	05/01/17	05/04/17	3
May	2	05/02/17	05/05/17	3
May	3	05/03/17	05/06/17	3
May	4	05/04/17	05/08/17	4
May	5	05/05/17	05/10/17	5
May	6	05/08/17	05/11/17	3
May	7	05/09/17	05/12/17	3
May	8	05/10/17	05/13/17	3
May	9	05/11/17	05/15/17	4
May	10	05/12/17	05/17/17	5
May	11	05/15/17	05/18/17	3
May	12	05/16/17	05/19/17	3
May	13	05/17/17	05/20/17	3
May	14	05/18/17	05/22/17	4
May	15	05/19/17	05/24/17	5
May	16	05/22/17	05/25/17	3
May	17	05/23/17	05/26/17	3
May	18	05/24/17	05/27/17	3
May	19	05/25/17	05/30/17	5
May	20	05/26/17	05/31/17	5
May	21	05/30/17	06/02/17	3
			May Average	3.62

Potomac Electric Power Company
Calculation of Revenue Billing Lag Based on Meter Reading to Bill Mailing Date

SYSTEM
For the twelve months December 31, 2017

Month	Rendition Group #	Meter Reading Date	Scheduled Mail Date	Number of Days
June	1	06/01/17	06/05/17	4
June	2	06/02/17	06/07/17	5
June	3	06/05/17	06/08/17	3
June	4	06/06/17	06/09/17	3
June	5	06/07/17	06/10/17	3
June	6	06/08/17	06/12/17	4
June	7	06/09/17	06/14/17	5
June	8	06/12/17	06/15/17	3
June	9	06/13/17	06/16/17	3
June	10	06/14/17	06/17/17	3
June	11	06/15/17	06/19/17	4
June	12	06/16/17	06/21/17	5
June	13	06/19/17	06/22/17	3
June	14	06/20/17	06/23/17	3
June	15	06/21/17	06/24/17	3
June	16	06/22/17	06/26/17	4
June	17	06/23/17	06/28/17	5
June	18	06/26/17	06/29/17	3
June	19	06/27/17	06/30/17	3
June	20	06/28/17	07/01/17	3
June	21	06/29/17	07/03/17	4
			June Average	3.62

Potomac Electric Power Company
Calculation of Revenue Billing Lag Based on Meter Reading to Bill Mailing Date

SYSTEM
For the twelve months December 31, 2017

Month	Rendition Group #	Meter Reading Date	Scheduled Mail Date	Number of Days
July	1	07/03/17	07/06/17	3
July	2	07/05/17	07/08/17	3
July	3	07/06/17	07/10/17	4
July	4	07/07/17	07/12/17	5
July	5	07/10/17	07/13/17	3
July	6	07/11/17	07/14/17	3
July	7	07/12/17	07/15/17	3
July	8	07/13/17	07/17/17	4
July	9	07/14/17	07/19/17	5
July	10	07/15/17	07/19/17	4
July	11	07/17/17	07/20/17	3
July	12	07/18/17	07/21/17	3
July	13	07/19/17	07/22/17	3
July	14	07/20/17	07/24/17	4
July	15	07/21/17	07/26/17	5
July	16	07/24/17	07/27/17	3
July	17	07/25/17	07/28/17	3
July	18	07/26/17	07/29/17	3
July	19	07/27/17	07/31/17	4
July	20	07/28/17	08/02/17	5
July	21	07/31/17	08/03/17	3
			July Average	3.62

Potomac Electric Power Company
Calculation of Revenue Billing Lag Based on Meter Reading to Bill Mailing Date

SYSTEM
For the twelve months December 31, 2017

Month	Rendition Group #	Meter Reading Date	Scheduled Mail Date	Number of Days
August	1	08/01/17	08/04/17	3
August	2	08/02/17	08/05/17	3
August	3	08/03/17	08/07/17	4
August	4	08/04/17	08/09/17	5
August	5	08/07/17	08/10/17	3
August	6	08/08/17	08/11/17	3
August	7	08/09/17	08/12/17	3
August	8	08/10/17	08/14/17	4
August	9	08/11/17	08/16/17	5
August	10	08/14/17	08/17/17	3
August	11	08/15/17	08/18/17	3
August	12	08/16/17	08/19/17	3
August	13	08/17/17	08/21/17	4
August	14	08/18/17	08/23/17	5
August	15	08/21/17	08/24/17	3
August	16	08/22/17	08/25/17	3
August	17	08/23/17	08/26/17	3
August	18	08/24/17	08/28/17	4
August	19	08/25/17	08/30/17	5
August	20	08/28/17	08/31/17	3
August	21	08/29/17	09/01/17	3
			August Average	3.57

Potomac Electric Power Company
Calculation of Revenue Billing Lag Based on Meter Reading to Bill Mailing Date

SYSTEM
For the twelve months December 31, 2017

Month	Rendition Group #	Meter Reading Date	Scheduled Mail Date	Number of Days
September	1	09/01/17	09/06/17	5
September	2	09/05/17	09/08/17	3
September	3	09/06/17	09/09/17	3
September	4	09/07/17	09/11/17	4
September	5	09/08/17	09/13/17	5
September	6	09/11/17	09/14/17	3
September	7	09/12/17	09/15/17	3
September	8	09/13/17	09/16/17	3
September	9	09/14/17	09/18/17	4
September	10	09/15/17	09/20/17	5
September	11	09/16/17	09/20/17	4
September	12	09/18/17	09/21/17	3
September	13	09/19/17	09/22/17	3
September	14	09/20/17	09/23/17	3
September	15	09/21/17	09/25/17	4
September	16	09/22/17	09/27/17	5
September	17	09/25/17	09/28/17	3
September	18	09/26/17	09/29/17	3
September	19	09/27/17	09/30/17	3
September	20	09/28/17	10/02/17	4
September	21	09/29/17	10/04/17	5
			September Average	3.71

Potomac Electric Power Company
Calculation of Revenue Billing Lag Based on Meter Reading to Bill Mailing Date

SYSTEM
For the twelve months December 31, 2017

Month	Rendition Group #	Meter Reading Date	Scheduled Mail Date	Number of Days
October	1	10/02/17	10/05/17	3
October	2	10/03/17	10/06/17	3
October	3	10/04/17	10/07/17	3
October	4	10/05/17	10/10/17	5
October	5	10/06/17	10/11/17	5
October	6	10/09/17	10/12/17	3
October	7	10/10/17	10/13/17	3
October	8	10/11/17	10/14/17	3
October	9	10/12/17	10/16/17	4
October	10	10/13/17	10/18/17	5
October	11	10/16/17	10/19/17	3
October	12	10/17/17	10/20/17	3
October	13	10/18/17	10/21/17	3
October	14	10/19/17	10/23/17	4
October	15	10/20/17	10/25/17	5
October	16	10/23/17	10/26/17	3
October	17	10/24/17	10/27/17	3
October	18	10/25/17	10/28/17	3
October	19	10/26/17	10/30/17	4
October	20	10/27/17	11/01/17	5
October	21	10/30/17	11/02/17	3
			October Average	3.62

Potomac Electric Power Company
Calculation of Revenue Billing Lag Based on Meter Reading to Bill Mailing Date

SYSTEM
For the twelve months December 31, 2017

Month	Rendition Group #	Meter Reading Date	Scheduled Mail Date	Number of Days
November	1	11/01/17	11/04/17	3
November	2	11/02/17	11/06/17	4
November	3	11/03/17	11/08/17	5
November	4	11/06/17	11/09/17	3
November	5	11/07/17	11/10/17	3
November	6	11/08/17	11/11/17	3
November	7	11/09/17	11/14/17	5
November	8	11/10/17	11/15/17	5
November	9	11/11/17	11/15/17	4
November	10	11/13/17	11/16/17	3
November	11	11/14/17	11/17/17	3
November	12	11/15/17	11/18/17	3
November	13	11/16/17	11/20/17	4
November	14	11/17/17	11/22/17	5
November	15	11/20/17	11/24/17	4
November	16	11/21/17	11/24/17	3
November	17	11/22/17	11/25/17	3
November	18	11/27/17	11/30/17	3
November	19	11/28/17	12/01/17	3
November	20	11/29/17	12/02/17	3
November	21	11/30/17	12/04/17	4
			November Average	3.62

Potomac Electric Power Company
Calculation of Revenue Billing Lag Based on Meter Reading to Bill Mailing Date

SYSTEM
For the twelve months December 31, 2017

Month	Rendition Group #	Meter Reading Date	Scheduled Mail Date	Number of Days
December	1	12/01/17	12/06/17	5
December	2	12/02/17	12/06/17	4
December	3	12/04/17	12/07/17	3
December	4	12/05/17	12/08/17	3
December	5	12/06/17	12/09/17	3
December	6	12/07/17	12/11/17	4
December	7	12/08/17	12/13/17	5
December	8	12/11/17	12/14/17	3
December	9	12/12/17	12/15/17	3
December	10	12/13/17	12/16/17	3
December	11	12/14/17	12/18/17	4
December	12	12/15/17	12/20/17	5
December	13	12/16/17	12/20/17	4
December	14	12/18/17	12/21/17	3
December	15	12/19/17	12/22/17	3
December	16	12/20/17	12/23/17	3
December	17	12/21/17	12/26/17	5
December	18	12/22/17	12/27/17	5
December	19	12/27/17	12/30/17	3
December	20	12/28/17	01/01/18	4
December	21	12/29/17	01/03/18	5
			December Average	3.81
2017 AVERAGE DAYS				**3.65**

Potomac Electric Power Company
Billing Date to Collection Lag Based on Receivable Turnover

District of Columbia
For the twelve months ended December 31, 2017

Period	Beginning A/R	Billings	Payments	Adjustments	Ending A/R	A/R Turnover
1-Jan-17	48,066,123.17	-	-	-	48,066,123.17	
2-Jan-17	48,066,123.17	13,979.60	-	(9.85)	48,080,112.62	
3-Jan-17	48,080,112.62	3,604,288.78	3,135,784.97	(134,330.36)	48,682,946.79	
4-Jan-17	48,682,946.79	2,581,514.64	3,166,457.02	34,740.55	48,063,263.87	
5-Jan-17	48,063,263.87	2,059,441.43	2,307,331.69	8,728.18	47,806,645.43	
6-Jan-17	47,806,645.43	1,961,915.96	2,912,522.89	8,571.52	46,847,466.99	
7-Jan-17	46,847,466.99	1,994,004.59	410,598.04	(32,771.69)	48,463,645.23	
8-Jan-17	48,463,645.23	-	-	-	48,463,645.23	
9-Jan-17	48,463,645.23	5,408,177.87	3,755,315.34	(96,203.77)	50,212,711.53	
10-Jan-17	50,212,711.53	2,485,307.44	2,594,500.16	(35,981.89)	50,139,500.71	
11-Jan-17	50,139,500.71	1,494,580.49	2,973,086.80	(7,330.22)	48,668,324.62	
12-Jan-17	48,668,324.62	1,801,179.03	2,387,108.76	(31,854.92)	48,114,249.80	
13-Jan-17	48,114,249.80	2,901,308.00	2,238,406.28	(22,940.92)	48,800,092.44	
14-Jan-17	48,800,092.44	2,199,704.71	500,640.71	(73,617.28)	50,572,773.72	
15-Jan-17	50,572,773.72	-	-	-	50,572,773.72	
16-Jan-17	50,572,773.72	2,399,071.45	160,777.15	(85,687.70)	52,896,755.73	
17-Jan-17	52,896,755.73	2,339,725.27	3,112,522.64	(69,353.88)	52,193,312.24	
18-Jan-17	52,193,312.24	3,186,857.30	3,246,000.01	(86,669.81)	52,220,839.34	
19-Jan-17	52,220,839.34	2,177,749.74	2,340,572.56	(13,689.47)	52,071,706.00	
20-Jan-17	52,071,706.00	2,145,780.56	1,644,547.99	505.76	52,572,432.81	
21-Jan-17	52,572,432.81	-	-	(35.00)	52,572,467.81	
22-Jan-17	52,572,467.81	-	-	-	52,572,467.81	
23-Jan-17	52,572,467.81	1,797,343.27	2,402,703.84	(58,620.18)	52,025,727.43	
24-Jan-17	52,025,727.43	3,966,672.45	3,006,541.85	(176,575.57)	53,162,433.59	
25-Jan-17	53,162,433.59	2,320,419.96	3,179,204.40	(10,881.81)	52,314,530.96	
26-Jan-17	52,314,530.96	2,091,591.95	2,193,767.04	(31,399.20)	52,243,755.06	
27-Jan-17	52,243,755.06	3,080,589.16	2,322,580.02	(74,144.82)	53,075,909.03	
28-Jan-17	53,075,909.03	2,445.62	-	(238.26)	53,078,592.91	
29-Jan-17	53,078,592.91	778.62	-	(37.99)	53,079,409.51	
30-Jan-17	53,079,409.51	3,771,432.09	4,128,426.49	(134,894.37)	52,857,309.49	
31-Jan-17	52,857,309.49	2,423,130.97	3,211,058.36	(30,242.43)	52,099,624.53	
January	**1,568,558,048.77**	**60,208,990.95**	**57,330,455.00**	**(1,154,965.41)**	**1,572,591,550.13**	**27.43**

Potomac Electric Power Company
Billing Date to Collection Lag Based on Receivable Turnover

District of Columbia
For the twelve months ended December 31, 2017

Period	Beginning A/R	Billings	Payments	Adjustments	Ending A/R	A/R Turnover
1-Feb-17	52,099,624.53	3,103,188.22	2,768,707.02	(23,021.61)	52,457,127.34	
2-Feb-17	52,457,127.34	2,382,995.07	2,324,751.43	801.91	52,514,569.07	
3-Feb-17	52,514,569.07	2,371,595.94	3,203,557.30	(64,289.31)	51,746,897.02	
4-Feb-17	51,746,897.02	(212.93)	-	289.88	51,746,394.20	
5-Feb-17	51,746,394.20	9,205.87	-	(35.00)	51,755,635.07	
6-Feb-17	51,755,635.07	1,672,819.44	3,919,355.15	(12,055.19)	49,521,154.55	
7-Feb-17	49,521,154.55	3,919,514.44	2,412,802.72	(56,083.68)	51,083,949.95	
8-Feb-17	51,083,949.95	3,619,470.41	2,839,618.02	(54,759.37)	51,918,561.71	
9-Feb-17	51,918,561.71	2,219,544.92	2,753,185.44	(28,375.28)	51,413,296.48	
10-Feb-17	51,413,296.48	2,336,896.31	2,589,403.51	(59,034.01)	51,219,823.29	
11-Feb-17	51,219,823.29	1,633,821.62	490,281.60	(32,935.58)	52,396,298.89	
12-Feb-17	52,396,298.89	(21,694.50)	-	(13.83)	52,374,618.21	
13-Feb-17	52,374,618.21	3,000,168.50	2,490,944.71	(109,351.98)	52,993,193.99	
14-Feb-17	52,993,193.99	3,109,311.86	3,065,756.86	(84,447.89)	53,121,196.88	
15-Feb-17	53,121,196.88	2,666,141.43	3,042,389.14	35,824.90	52,709,124.27	
16-Feb-17	52,709,124.27	2,617,869.04	3,351,030.69	(31,631.09)	52,007,593.71	
17-Feb-17	52,007,593.71	3,310,662.12	3,080,961.18	(111,144.36)	52,348,439.01	
18-Feb-17	52,348,439.01	-	-	-	52,348,439.01	
19-Feb-17	52,348,439.01	-	-	-	52,348,439.01	
20-Feb-17	52,348,439.01	2,181,047.33	582,073.90	21,069.28	53,926,343.17	
21-Feb-17	53,926,343.17	2,710,585.40	3,339,257.43	(66,091.23)	53,363,762.37	
22-Feb-17	53,363,762.37	2,615,530.95	2,665,701.12	(55,140.18)	53,368,732.38	
23-Feb-17	53,368,732.38	2,394,234.70	3,590,654.88	(146,640.49)	52,318,952.69	
24-Feb-17	52,318,952.69	2,987,909.46	2,311,472.24	(41,760.02)	53,037,149.93	
25-Feb-17	53,037,149.93	1,143,455.99	473,592.71	(55,269.05)	53,762,282.26	
26-Feb-17	53,762,282.26	(1,821.03)	-	(22.93)	53,760,484.17	
27-Feb-17	53,760,484.17	3,531,132.57	2,750,040.17	(164,613.32)	54,706,189.89	
28-Feb-17	54,706,189.89	2,616,466.20	3,737,094.13	1,240.33	53,584,321.63	
	53,584,321.63	-	-	-	53,584,321.63	
February	**1,521,952,594.71**	**58,129,839.33**	**57,782,631.34**	**(1,137,489.11)**	**1,523,437,291.81**	**26.36**

Potomac Electric Power Company
Billing Date to Collection Lag Based on Receivable Turnover

District of Columbia
For the twelve months ended December 31, 2017

Period	Beginning A/R	Billings	Payments	Adjustments	Ending A/R	A/R Turnover
1-Mar-17	53,584,321.63	1,850,763.12	2,650,584.39	(19,656.40)	52,804,156.76	
2-Mar-17	52,804,156.76	2,079,173.39	2,619,780.03	50,845.57	52,212,704.55	
3-Mar-17	52,212,704.55	1,627,202.79	2,562,538.09	32,900.94	51,244,468.31	
4-Mar-17	51,244,468.31	927.59	-	(35.00)	51,245,430.90	
5-Mar-17	51,245,430.90	1,204.49	-	(35.00)	51,246,670.39	
6-Mar-17	51,246,670.39	2,036,642.22	4,085,962.72	(59,822.31)	49,257,172.20	
7-Mar-17	49,257,172.20	3,097,530.30	2,350,854.68	(12,794.46)	50,016,642.29	
8-Mar-17	50,016,642.29	4,158,977.20	3,313,160.06	(33,977.65)	50,896,437.08	
9-Mar-17	50,896,437.08	2,238,788.59	3,319,712.09	89,719.16	49,725,794.42	
10-Mar-17	49,725,794.42	1,793,128.01	2,517,520.51	(35,557.67)	49,036,959.60	
11-Mar-17	49,036,959.60	(171.68)	-	(70.00)	49,036,857.92	
12-Mar-17	49,036,857.92	518.05	-	(36.43)	49,037,412.40	
13-Mar-17	49,037,412.40	2,668,962.95	3,397,003.45	(37,682.66)	48,347,054.55	
14-Mar-17	48,347,054.55	1,538,192.11	2,167,138.21	(35,503.28)	47,753,611.72	
15-Mar-17	47,753,611.72	3,057,516.57	2,957,808.55	(36,213.96)	47,889,533.70	
16-Mar-17	47,889,533.70	2,075,321.24	2,552,149.77	(39,800.13)	47,452,505.30	
17-Mar-17	47,452,505.30	3,204,167.58	3,053,190.35	(89,635.53)	47,693,118.05	
18-Mar-17	47,693,118.05	857.45	-	339.07	47,693,636.44	
19-Mar-17	47,693,636.44	7,104.72	-	-	47,700,741.16	
20-Mar-17	47,700,741.16	3,006,054.03	3,403,408.94	(126,862.23)	47,430,248.48	
21-Mar-17	47,430,248.48	3,081,323.03	2,587,563.91	(106,121.45)	48,030,129.05	
22-Mar-17	48,030,129.05	2,204,299.35	2,243,527.25	(57,999.71)	48,048,900.86	
23-Mar-17	48,048,900.86	2,832,517.83	2,069,185.00	(123,893.81)	48,936,127.51	
24-Mar-17	48,936,127.51	1,928,279.75	2,731,717.22	(90,696.54)	48,223,386.58	
25-Mar-17	48,223,386.58	-	-	-	48,223,386.58	
26-Mar-17	48,223,386.58	1,456.33	-	(51.74)	48,224,894.66	
27-Mar-17	48,224,894.66	3,176,930.18	2,864,327.05	(152,629.38)	48,690,127.16	
28-Mar-17	48,690,127.16	2,449,769.46	2,902,336.32	(36,031.03)	48,273,591.33	
29-Mar-17	48,273,591.33	2,390,120.61	2,848,441.71	(75,326.77)	47,890,597.00	
30-Mar-17	47,890,597.00	1,970,274.25	2,094,603.13	(35,151.70)	47,801,419.82	
31-Mar-17	47,801,419.82	1,374,740.69	2,685,072.01	(45,874.98)	46,536,963.48	
March	**1,523,648,038.39**	**55,852,572.20**	**63,977,585.45**	**(1,077,655.10)**	**1,516,600,680.24**	**23.71**

Potomac Electric Power Company
Billing Date to Collection Lag Based on Receivable Turnover

District of Columbia
For the twelve months ended December 31, 2017

Period	Beginning A/R	Billings	Payments	Adjustments	Ending A/R	A/R Turnover
1-Apr-17	46,536,963.48	-	-	(34.13)	46,536,997.61	
2-Apr-17	46,536,997.61	1,762.70	-	3.01	46,538,757.30	
3-Apr-17	46,538,757.30	2,409,202.18	2,320,056.72	(175,120.87)	46,803,023.63	
4-Apr-17	46,803,023.63	1,988,841.60	3,365,050.75	(22,202.42)	45,449,016.90	
5-Apr-17	45,449,016.90	1,923,823.06	3,145,499.22	6,263.62	44,221,077.12	
6-Apr-17	44,221,077.12	1,798,548.21	2,561,071.17	(37,450.70)	43,496,004.86	
7-Apr-17	43,496,004.86	1,988,028.13	1,996,222.71	(35,070.61)	43,522,880.89	
8-Apr-17	43,522,880.89	2,803,921.73	425,395.91	(50,052.99)	45,951,459.70	
9-Apr-17	45,951,459.70	447.24	-	(27.52)	45,951,934.46	
10-Apr-17	45,951,934.46	2,621,597.64	2,581,756.91	(63,001.50)	46,054,776.69	
11-Apr-17	46,054,776.69	2,033,801.02	2,981,003.08	(51,665.41)	45,159,240.04	
12-Apr-17	45,159,240.04	2,001,788.50	2,888,546.03	(114,976.61)	44,387,459.11	
13-Apr-17	44,387,459.11	1,974,105.58	2,292,650.70	(62,782.46)	44,131,696.45	
14-Apr-17	44,131,696.45	2,849,138.94	2,561,788.42	(114,166.15)	44,533,213.12	
15-Apr-17	44,533,213.12	-	-	-	44,533,213.12	
16-Apr-17	44,533,213.12	30,903.48	-	(1,732.11)	44,565,848.71	
17-Apr-17	44,565,848.71	3,134,796.46	2,758,914.14	(126,082.64)	45,067,813.67	
18-Apr-17	45,067,813.67	2,244,229.14	2,525,808.82	(81,529.57)	44,867,763.56	
19-Apr-17	44,867,763.56	3,459,651.06	1,617,258.80	(70,969.84)	46,781,125.66	
20-Apr-17	46,781,125.66	19,397,375.52	1,882,383.54	(1,035,450.36)	65,331,568.00	
21-Apr-17	65,331,568.00	(13,804,025.41)	1,487,093.60	863,399.62	49,177,049.38	
22-Apr-17	49,177,049.38	1,374,584.18	422,764.85	(48,138.71)	50,177,007.42	
23-Apr-17	50,177,007.42	(55.56)	-	(35.00)	50,176,986.86	
24-Apr-17	50,176,986.86	1,385,655.75	1,045,953.27	(113,700.54)	50,630,389.89	
25-Apr-17	50,630,389.89	2,686,690.13	3,143,231.66	(104,688.26)	50,278,536.62	
26-Apr-17	50,278,536.62	2,096,767.21	2,656,680.85	(37,026.31)	49,755,649.29	
27-Apr-17	49,755,649.29	2,057,104.10	2,238,237.77	(55,265.19)	49,629,780.81	
28-Apr-17	49,629,780.81	1,731,312.65	2,493,333.86	(52,286.15)	48,920,045.75	
29-Apr-17	48,920,045.75	397.02	-	-	48,920,442.77	
30-Apr-17	48,920,442.77	-	-	-	48,920,442.77	
April	**1,418,087,722.91**	**50,190,392.26**	**49,390,702.77**	**(1,580,019.77)**	**1,420,471,202.20**	**28.76**

Potomac Electric Power Company
Billing Date to Collection Lag Based on Receivable Turnover

District of Columbia
For the twelve months ended December 31, 2017

Period	Beginning A/R	Billings	Payments	Adjustments	Ending A/R	A/R Turnover
1-May-17	48,920,442.77	3,597,008.09	3,598,295.48	(98,983.33)	49,018,138.71	
2-May-17	49,018,138.71	1,841,009.74	3,037,298.80	(85,646.76)	47,907,496.41	
3-May-17	47,907,496.41	2,493,699.18	2,817,926.71	58,372.49	47,524,896.39	
4-May-17	47,524,896.39	2,643,695.88	1,755,479.52	(19,205.20)	48,432,317.96	
5-May-17	48,432,317.96	2,148,664.40	3,221,770.41	(29,410.05)	47,388,622.00	
6-May-17	47,388,622.00	668.83	-	(35.00)	47,389,325.83	
7-May-17	47,389,325.83	1,384.56	-	(9.57)	47,390,719.96	
8-May-17	47,390,719.96	3,791,736.26	2,568,363.62	(131,273.01)	48,745,365.61	
9-May-17	48,745,365.61	2,298,430.12	2,937,554.01	(854.59)	48,107,096.31	
10-May-17	48,107,096.31	1,485,075.48	3,385,643.14	(20,280.44)	46,226,809.08	
11-May-17	46,226,809.08	2,103,060.40	3,490,920.14	(40,845.73)	44,879,795.07	
12-May-17	44,879,795.07	2,069,250.72	2,342,207.60	(63,932.40)	44,670,770.59	
13-May-17	44,670,770.59	-	-	(35.00)	44,670,805.59	
14-May-17	44,670,805.59	72.71	-	-	44,670,878.30	
15-May-17	44,670,878.30	2,763,067.63	2,943,791.18	(130,587.07)	44,620,741.83	
16-May-17	44,620,741.83	1,962,450.82	3,454,898.38	(66,581.94)	43,194,876.21	
17-May-17	43,194,876.21	2,306,782.30	2,159,609.53	(61,409.36)	43,403,458.34	
18-May-17	43,403,458.34	2,829,352.51	1,897,959.80	(106,499.97)	44,441,351.02	
19-May-17	44,441,351.02	2,805,781.55	2,360,022.03	(78,130.09)	44,965,240.63	
20-May-17	44,965,240.63	-	-	(67.61)	44,965,308.24	
21-May-17	44,965,308.24	1,255.09	-	(14.38)	44,966,577.71	
22-May-17	44,966,577.71	3,264,190.40	2,824,473.98	(80,179.72)	45,486,473.86	
23-May-17	45,486,473.86	3,323,076.86	3,523,485.26	(105,844.60)	45,391,910.06	
24-May-17	45,391,910.06	1,586,837.45	2,255,586.77	(24,219.12)	44,747,379.87	
25-May-17	44,747,379.87	2,082,128.98	2,132,586.70	(44,430.91)	44,741,353.07	
26-May-17	44,741,353.07	2,240,169.57	2,966,888.89	(100,030.37)	44,114,664.11	
27-May-17	44,114,664.11	-	-	(105.00)	44,114,769.11	
28-May-17	44,114,769.11	-	-	-	44,114,769.11	
29-May-17	44,114,769.11	23,212.52	-	(2.10)	44,137,983.73	
30-May-17	44,137,983.73	2,738,819.71	2,475,953.09	(211,622.02)	44,612,472.36	
31-May-17	44,612,472.36	3,618,790.97	3,220,029.88	(44,270.92)	45,055,504.37	
May	**1,417,962,809.83**	**56,019,672.73**	**61,370,744.91**	**(1,486,133.78)**	**1,414,097,871.43**	**23.04**

Potomac Electric Power Company
Billing Date to Collection Lag Based on Receivable Turnover

District of Columbia
For the twelve months ended December 31, 2017

Period	Beginning A/R	Billings	Payments	Adjustments	Ending A/R	A/R Turnover
1-Jun-17	45,055,504.37	1,537,858.99	1,759,937.37	429,044.01	44,404,381.98	
2-Jun-17	44,404,381.98	2,973,725.53	2,880,527.38	562,468.72	43,935,111.41	
3-Jun-17	43,935,111.41	(863.42)	-	(155.70)	43,934,403.69	
4-Jun-17	43,934,403.69	323.79	-	-	43,934,727.48	
5-Jun-17	43,934,727.48	1,397,176.47	3,147,602.76	2,562,923.11	39,621,378.08	
6-Jun-17	39,621,378.08	1,919,997.31	3,263,008.42	(885,852.47)	39,164,219.44	
7-Jun-17	39,164,219.44	2,619,908.14	2,143,689.04	(1,897,357.80)	41,537,796.33	
8-Jun-17	41,537,796.33	3,234,663.75	2,442,129.39	91,279.92	42,239,050.77	
9-Jun-17	42,239,050.77	2,314,862.43	2,422,333.85	(2,273,231.07)	44,404,810.42	
10-Jun-17	44,404,810.42	(677.58)	-	(35.04)	44,404,167.88	
11-Jun-17	44,404,167.88	879.17	-	(11.25)	44,405,058.30	
12-Jun-17	44,405,058.30	2,362,387.83	3,457,753.45	443,518.12	42,866,174.56	
13-Jun-17	42,866,174.56	2,014,001.52	2,843,756.35	419,306.36	41,617,113.37	
14-Jun-17	41,617,113.37	2,172,511.60	1,870,152.34	1,233,871.70	40,685,600.93	
15-Jun-17	40,685,600.93	2,826,219.51	2,239,484.54	(752,458.59)	42,024,794.49	
16-Jun-17	42,024,794.49	2,853,841.28	2,317,532.42	(2,057,477.36)	44,618,580.71	
17-Jun-17	44,618,580.71	(217.38)	(11.73)	(0.01)	44,618,375.07	
18-Jun-17	44,618,375.07	(16,278.07)	-	(43.01)	44,602,140.01	
19-Jun-17	44,602,140.01	2,601,742.62	2,030,417.00	(1,517,848.02)	46,691,313.65	
20-Jun-17	46,691,313.65	3,539,639.65	2,765,507.48	4,749,011.92	42,716,433.90	
21-Jun-17	42,716,433.90	3,466,454.04	1,872,129.96	(82,582.52)	44,393,340.51	
22-Jun-17	44,393,340.51	2,476,245.87	1,515,324.27	131,081.97	45,223,180.14	
23-Jun-17	45,223,180.14	2,797,004.23	2,220,741.19	(213,602.80)	46,013,045.98	
24-Jun-17	46,013,045.98	-	-	-	46,013,045.98	
25-Jun-17	46,013,045.98	564.32	-	(33.66)	46,013,643.96	
26-Jun-17	46,013,643.96	2,424,560.68	2,687,709.10	(409,495.83)	46,159,991.37	
27-Jun-17	46,159,991.37	3,156,267.07	2,689,183.96	363,721.62	46,263,352.85	
28-Jun-17	46,263,352.85	2,491,093.02	2,519,147.27	66,085.71	46,169,212.90	
29-Jun-17	46,169,212.90	3,564,442.65	2,386,491.21	(1,138,031.59)	48,485,195.92	
30-Jun-17	48,485,195.92	3,669,158.85	2,699,514.85	(1,500,042.80)	50,954,882.72	
June	**1,322,215,146.42**	**58,397,493.87**	**54,174,061.88**	**(1,675,946.36)**	**1,328,114,524.77**	**24.52**

Potomac Electric Power Company
Billing Date to Collection Lag Based on Receivable Turnover

District of Columbia
For the twelve months ended December 31, 2017

Period	Beginning A/R	Billings	Payments	Adjustments	Ending A/R	A/R Turnover
1-Jul-17	50,954,882.72	(92.41)	-	-	50,954,790.31	
2-Jul-17	50,954,790.31	104.60	-	(4.20)	50,954,899.11	
3-Jul-17	50,954,899.11	1,993,141.36	2,509,744.19	(24,940.77)	50,463,237.06	
4-Jul-17	50,463,237.06	-	-	-	50,463,237.06	
5-Jul-17	50,463,237.06	2,081,549.29	2,694,119.13	(36,484.28)	49,887,151.50	
6-Jul-17	49,887,151.50	2,041,955.52	3,496,002.36	(24,796.24)	48,457,900.90	
7-Jul-17	48,457,900.90	3,009,871.81	2,775,885.45	1,615.39	48,690,271.87	
8-Jul-17	48,690,271.87	(1,826.38)	-	(33.85)	48,688,479.34	
9-Jul-17	48,688,479.34	-	-	-	48,688,479.34	
10-Jul-17	48,688,479.34	3,542,763.08	3,315,592.26	(58,635.01)	48,974,285.17	
11-Jul-17	48,974,285.17	4,790,585.92	2,050,547.91	(68,628.37)	51,782,951.55	
12-Jul-17	51,782,951.55	2,904,325.37	2,002,877.77	(52,315.26)	52,736,714.40	
13-Jul-17	52,736,714.40	2,654,370.63	2,210,534.39	(37,908.42)	53,218,459.06	
14-Jul-17	53,218,459.06	3,059,721.59	3,078,888.80	(75,396.63)	53,274,688.48	
15-Jul-17	53,274,688.48	1,655,350.03	500,238.50	(33,058.87)	54,462,858.88	
16-Jul-17	54,462,858.88	-	-	-	54,462,858.88	
17-Jul-17	54,462,858.88	5,026,898.85	3,603,265.72	(197,228.11)	56,083,720.12	
18-Jul-17	56,083,720.12	2,978,516.63	2,914,170.15	(63,909.41)	56,211,976.01	
19-Jul-17	56,211,976.01	3,308,460.81	2,920,037.80	(101,709.48)	56,702,108.50	
20-Jul-17	56,702,108.50	3,417,392.86	1,990,095.47	(68,388.05)	58,197,793.95	
21-Jul-17	58,197,793.95	3,669,565.54	1,825,726.02	(95,288.24)	60,136,921.70	
22-Jul-17	60,136,921.70	(941.73)	-	(0.04)	60,135,980.01	
23-Jul-17	60,135,980.01	-	-	-	60,135,980.01	
24-Jul-17	60,135,980.01	4,305,457.83	3,678,428.84	(178,209.20)	60,941,218.20	
25-Jul-17	60,941,218.20	3,103,191.11	2,242,534.21	(74,527.43)	61,876,402.53	
26-Jul-17	61,876,402.53	2,683,542.33	3,029,038.09	(31,216.62)	61,562,123.39	
27-Jul-17	61,562,123.39	3,502,752.67	3,568,627.22	(77,279.34)	61,573,528.18	
28-Jul-17	61,573,528.18	3,003,162.55	1,577,607.02	(63,094.46)	63,062,178.18	
29-Jul-17	63,062,178.18	(4,617.54)	-	(38.37)	63,057,599.01	
30-Jul-17	63,057,599.01	-	-	-	63,057,599.01	
31-Jul-17	63,057,599.01	2,429,605.37	3,555,893.63	(54,792.10)	61,986,102.85	
July	**1,709,851,274.40**	**65,154,807.69**	**55,539,854.92**	**(1,416,267.36)**	**1,720,882,494.53**	**30.98**

Potomac Electric Power Company
Billing Date to Collection Lag Based on Receivable Turnover

District of Columbia
For the twelve months ended December 31, 2017

Period	Beginning A/R	Billings	Payments	Adjustments	Ending A/R	A/R Turnover
1-Aug-17	61,986,102.85	4,117,113.23	3,551,356.67	(68,100.74)	62,619,960.15	
2-Aug-17	62,619,960.15	3,655,683.11	3,316,063.49	(22,685.58)	62,982,265.34	
3-Aug-17	62,982,265.34	2,534,698.52	3,328,943.03	(29,659.68)	62,217,680.51	
4-Aug-17	62,217,680.51	3,409,662.17	3,272,388.09	(128,691.21)	62,483,645.81	
5-Aug-17	62,483,645.81	(440.29)	-	23.71	62,483,181.81	
6-Aug-17	62,483,181.81	-	-	-	62,483,181.81	
7-Aug-17	62,483,181.81	3,994,277.72	4,347,420.48	(84,681.51)	62,214,720.56	
8-Aug-17	62,214,720.56	18,649,832.83	3,935,335.21	(7,685.57)	76,936,903.75	
9-Aug-17	76,936,903.75	(11,033,128.39)	3,435,297.43	(121,885.27)	62,590,363.20	
10-Aug-17	62,590,363.20	2,738,900.80	2,778,388.11	(63,971.77)	62,614,847.65	
11-Aug-17	62,614,847.65	2,676,960.61	3,128,182.36	(96,339.33)	62,259,965.23	
12-Aug-17	62,259,965.23	175.01	-	0.10	62,260,140.14	
13-Aug-17	62,260,140.14	-	-	-	62,260,140.14	
14-Aug-17	62,260,140.14	2,358,273.70	4,327,366.19	(56,659.22)	60,347,706.88	
15-Aug-17	60,347,706.88	3,384,983.58	3,089,505.35	(193,601.01)	60,836,786.12	
16-Aug-17	60,836,786.12	2,730,066.22	4,276,112.19	(28,319.36)	59,319,059.51	
17-Aug-17	59,319,059.51	2,860,382.17	2,167,765.60	(31,001.50)	60,042,677.59	
18-Aug-17	60,042,677.59	3,302,740.14	2,598,087.66	(125,188.47)	60,872,518.54	
19-Aug-17	60,872,518.54	(2,934.42)	-	(0.01)	60,869,584.13	
20-Aug-17	60,869,584.13	-	-	-	60,869,584.13	
21-Aug-17	60,869,584.13	3,970,276.09	5,245,617.76	(119,100.56)	59,713,343.01	
22-Aug-17	59,713,343.01	3,629,472.82	3,557,673.72	(150,953.60)	59,936,095.71	
23-Aug-17	59,936,095.71	2,432,335.97	2,773,222.97	(53,302.27)	59,648,510.98	
24-Aug-17	59,648,510.98	2,463,148.17	3,313,832.73	(96,517.44)	58,894,343.86	
25-Aug-17	58,894,343.86	3,015,842.37	2,528,074.05	48,563.87	59,333,548.30	
26-Aug-17	59,333,548.30	-	-	-	59,333,548.30	
27-Aug-17	59,333,548.30	-	-	-	59,333,548.30	
28-Aug-17	59,333,548.30	2,764,418.53	3,809,945.44	(113,961.42)	58,401,982.81	
29-Aug-17	58,401,982.81	2,933,736.59	2,978,815.63	(61,379.75)	58,418,283.52	
30-Aug-17	58,418,283.52	3,018,160.01	2,198,025.60	(15,493.55)	59,253,911.47	
31-Aug-17	59,253,911.47	1,577,690.76	4,271,469.55	(33,348.33)	56,593,481.02	
August	**1,903,818,132.12**	**71,182,328.02**	**78,228,889.33**	**(1,653,939.48)**	**1,898,425,510.29**	**24.27**

Potomac Electric Power Company
Billing Date to Collection Lag Based on Receivable Turnover

District of Columbia
For the twelve months ended December 31, 2017

Period	Beginning A/R	Billings	Payments	Adjustments	Ending A/R	A/R Turnover
1-Sep-17	56,593,481.02	2,383,324.76	2,469,069.85	(15,926.04)	56,523,661.97	
2-Sep-17	56,523,661.97	15,625.24	-	(719.38)	56,540,006.58	
3-Sep-17	56,540,006.58	-	-	-	56,540,006.58	
4-Sep-17	56,540,006.58	-	-	(34.94)	56,540,041.52	
5-Sep-17	56,540,041.52	2,199,876.20	4,939,618.07	(92,601.94)	53,892,901.58	
6-Sep-17	53,892,901.58	3,573,788.36	3,283,824.58	(58,627.76)	54,241,493.13	
7-Sep-17	54,241,493.13	2,288,867.50	3,182,896.72	(63,300.17)	53,410,764.08	
8-Sep-17	53,410,764.08	2,585,166.58	2,748,531.95	(37,889.93)	53,285,288.63	
9-Sep-17	53,285,288.63	(337.33)	-	8.00	53,284,943.30	
10-Sep-17	53,284,943.30	-	-	-	53,284,943.30	
11-Sep-17	53,284,943.30	4,285,784.07	3,956,073.24	(108,317.01)	53,722,971.14	
12-Sep-17	53,722,971.14	2,761,519.03	3,257,924.94	(174,353.28)	53,400,918.52	
13-Sep-17	53,400,918.52	2,535,825.47	2,944,606.18	(27,968.81)	53,020,106.61	
14-Sep-17	53,020,106.61	2,538,775.21	2,514,351.50	(43,035.42)	53,087,565.74	
15-Sep-17	53,087,565.74	2,218,023.07	2,919,513.70	(57,282.74)	52,443,357.85	
16-Sep-17	52,443,357.85	2,537,060.87	600,424.12	(31,956.60)	54,411,951.20	
17-Sep-17	54,411,951.20	-	-	-	54,411,951.20	
18-Sep-17	54,411,951.20	4,607,823.56	2,533,355.14	(208,486.82)	56,694,906.44	
19-Sep-17	56,694,906.44	3,382,917.27	2,873,595.89	(100,932.99)	57,305,160.81	
20-Sep-17	57,305,160.81	3,347,720.15	3,357,267.74	(79,976.73)	57,375,589.95	
21-Sep-17	57,375,589.95	3,239,374.20	2,559,577.16	(3,781.79)	58,059,168.78	
22-Sep-17	58,059,168.78	3,812,293.54	1,793,008.43	(86,465.16)	60,164,919.05	
23-Sep-17	60,164,919.05	(262.47)	-	-	60,164,656.58	
24-Sep-17	60,164,656.58	-	-	-	60,164,656.58	
25-Sep-17	60,164,656.58	3,347,035.83	3,327,479.23	(129,345.24)	60,313,558.43	
26-Sep-17	60,313,558.43	2,865,419.76	3,604,029.22	(45,066.01)	59,620,014.98	
27-Sep-17	59,620,014.98	2,665,617.29	2,621,981.20	72,600.16	59,591,050.91	
28-Sep-17	59,591,050.91	3,741,091.91	2,307,460.75	(70,178.87)	61,094,860.94	
29-Sep-17	61,094,860.94	2,435,799.63	2,549,185.01	13,559.42	60,967,916.13	
30-Sep-17	60,967,916.13	-	-	-	60,967,916.13	
September	**1,690,152,813.59**	**63,368,129.70**	**60,343,774.63**	**(1,350,080.04)**	**1,694,527,248.70**	**28.08**

Potomac Electric Power Company
Billing Date to Collection Lag Based on Receivable Turnover

District of Columbia
For the twelve months ended December 31, 2017

Period	Beginning A/R	Billings	Payments	Adjustments	Ending A/R	A/R Turnover
1-Oct-17	60,967,916.13	-	-	-	60,967,916.13	
2-Oct-17	60,967,916.13	2,844,297.30	3,983,603.14	(111,593.26)	59,940,203.55	
3-Oct-17	59,940,203.55	4,580,056.86	3,183,022.29	(102,713.81)	61,439,951.93	
4-Oct-17	61,439,951.93	2,477,992.37	2,862,678.65	38,042.47	61,017,223.18	
5-Oct-17	61,017,223.18	2,790,672.17	2,444,319.55	(40,729.19)	61,404,304.99	
6-Oct-17	61,404,304.99	2,646,511.58	3,840,586.31	(57,828.59)	60,268,058.84	
7-Oct-17	60,268,058.84	-	-	-	60,268,058.84	
8-Oct-17	60,268,058.84	-	-	-	60,268,058.84	
9-Oct-17	60,268,058.84	4,292,551.25	3,419,410.23	(81,617.99)	61,222,817.86	
10-Oct-17	61,222,817.86	2,244,764.45	3,053,174.04	(21,649.99)	60,436,058.25	
11-Oct-17	60,436,058.25	2,344,630.98	3,757,291.47	(65,733.36)	59,089,131.13	
12-Oct-17	59,089,131.13	2,602,068.35	2,268,454.39	(48,872.23)	59,471,617.32	
13-Oct-17	59,471,617.32	2,077,231.50	3,620,046.39	(56,724.45)	57,985,526.88	
14-Oct-17	57,985,526.88	55,223.21	-	(2,455.03)	58,043,205.12	
15-Oct-17	58,043,205.12	-	-	-	58,043,205.12	
16-Oct-17	58,043,205.12	3,479,352.18	2,990,940.46	(155,955.40)	58,687,572.24	
17-Oct-17	58,687,572.24	2,888,615.33	3,658,582.33	(66,659.39)	57,984,264.64	
18-Oct-17	57,984,264.64	2,645,066.75	3,957,474.13	(51,557.89)	56,723,415.14	
19-Oct-17	56,723,415.14	2,680,662.50	2,703,164.74	(65,748.65)	56,766,661.54	
20-Oct-17	56,766,661.54	2,550,634.46	2,863,361.06	(48,214.02)	56,502,148.96	
21-Oct-17	56,502,148.96	-	-	(2,235.37)	56,504,384.33	
22-Oct-17	56,504,384.33	-	-	-	56,504,384.33	
23-Oct-17	56,504,384.33	4,629,135.47	3,753,481.03	(193,451.74)	57,573,490.50	
24-Oct-17	57,573,490.50	3,804,154.72	4,886,298.84	(130,315.16)	56,621,661.53	
25-Oct-17	56,621,661.53	2,588,431.37	2,746,795.33	(55,561.47)	56,518,859.05	
26-Oct-17	56,518,859.05	2,473,643.78	2,272,964.60	(3,110.11)	56,722,648.33	
27-Oct-17	56,722,648.33	2,551,134.15	2,933,577.53	(68,230.93)	56,408,435.88	
28-Oct-17	56,408,435.88	(217.39)	-	(0.25)	56,408,218.74	
29-Oct-17	56,408,218.74	-	-	-	56,408,218.74	
30-Oct-17	56,408,218.74	3,250,951.77	2,960,114.81	(151,070.93)	56,850,126.62	
31-Oct-17	56,850,126.62	2,944,024.32	4,082,313.98	(25,869.34)	55,737,706.31	
October	**1,814,017,744.68**	**65,441,589.43**	**72,241,655.31**	**(1,569,856.06)**	**1,808,787,534.86**	**25.04**

Potomac Electric Power Company
Billing Date to Collection Lag Based on Receivable Turnover

District of Columbia
For the twelve months ended December 31, 2017

Period	Beginning A/R	Billings	Payments	Adjustments	Ending A/R	A/R Turnover
1-Nov-17	55,737,706.31	1,511,942.95	2,015,423.82	(22,120.36)	55,256,345.80	
2-Nov-17	55,256,345.80	2,134,305.68	2,242,319.33	(16,014.94)	55,164,347.09	
3-Nov-17	55,164,347.09	1,450,741.20	2,895,988.15	(32,971.58)	53,752,071.72	
4-Nov-17	53,752,071.72	-	-	(35.00)	53,752,106.72	
5-Nov-17	53,752,106.72	-	-	-	53,752,106.72	
6-Nov-17	53,752,106.72	2,162,326.83	3,647,812.02	(65,201.83)	52,331,823.36	
7-Nov-17	52,331,823.36	2,607,117.34	3,277,780.03	(53,418.72)	51,714,579.39	
8-Nov-17	51,714,579.39	3,485,582.94	2,898,303.63	(53,885.60)	52,355,744.30	
9-Nov-17	52,355,744.30	2,108,927.19	2,670,762.09	(33,249.22)	51,827,158.62	
10-Nov-17	51,827,158.62	2,453,609.84	3,473,423.21	(69,414.86)	50,876,760.11	
11-Nov-17	50,876,760.11	1,380,109.33	463,824.89	(54,437.44)	51,847,481.99	
12-Nov-17	51,847,481.99	-	-	-	51,847,481.99	
13-Nov-17	51,847,481.99	2,256,800.49	3,383,916.77	(52,907.59)	50,773,273.30	
14-Nov-17	50,773,273.30	3,267,860.53	2,726,670.45	(116,106.62)	51,430,569.99	
15-Nov-17	51,430,569.99	1,725,551.24	2,186,267.34	(106,566.78)	51,076,420.67	
16-Nov-17	51,076,420.67	3,063,445.11	2,738,075.07	(71,687.15)	51,473,477.85	
17-Nov-17	51,473,477.85	3,118,157.05	3,099,741.02	(94,801.02)	51,586,694.90	
18-Nov-17	51,586,694.90	-	-	(2,240.00)	51,588,934.90	
19-Nov-17	51,588,934.90	-	-	(560.00)	51,589,494.90	
20-Nov-17	51,589,494.90	3,911,360.73	3,387,038.45	(124,010.52)	52,237,827.71	
21-Nov-17	52,237,827.71	2,808,998.67	3,472,149.18	(65,249.74)	51,639,926.94	
22-Nov-17	51,639,926.94	2,883,872.10	2,696,012.11	(83,390.83)	51,911,177.76	
23-Nov-17	51,911,177.76	-	-	(4,865.00)	51,916,042.76	
24-Nov-17	51,916,042.76	-	-	(595.00)	51,916,637.76	
25-Nov-17	51,916,637.76	-	-	(175.00)	51,916,812.76	
26-Nov-17	51,916,812.76	-	-	(560.00)	51,917,372.76	
27-Nov-17	51,917,372.76	3,341,559.03	4,647,345.87	(106,834.21)	50,718,420.13	
28-Nov-17	50,718,420.13	2,221,627.22	3,119,962.58	(38,043.68)	49,858,128.45	
29-Nov-17	49,858,128.45	2,634,746.47	2,067,886.98	(60,220.49)	50,485,208.43	
30-Nov-17	50,485,208.43	2,255,301.97	1,771,932.44	(7,401.01)	50,975,978.96	
November	**1,564,252,136.08**	**52,783,943.91**	**58,882,635.45**	**(1,336,964.19)**	**1,559,490,408.73**	**26.48**

Potomac Electric Power Company
Billing Date to Collection Lag Based on Receivable Turnover

District of Columbia
For the twelve months ended December 31, 2017

Period	Beginning A/R	Billings	Payments	Adjustments	Ending A/R	A/R Turnover
1-Dec-17	50,975,978.96	2,186,451.74	2,228,227.99	(157,311.16)	51,091,513.87	
2-Dec-17	51,091,513.87	1,090,149.33	573,059.14	(26,595.22)	51,635,199.28	
3-Dec-17	51,635,199.28	-	-	-	51,635,199.28	
4-Dec-17	51,635,199.28	2,249,296.19	3,200,842.19	(83,538.01)	50,767,191.30	
5-Dec-17	50,767,191.30	3,001,711.32	4,965,924.56	(82,546.20)	48,885,524.25	
6-Dec-17	48,885,524.25	2,162,268.53	2,133,451.88	(132.27)	48,914,473.16	
7-Dec-17	48,914,473.16	2,385,409.49	2,131,417.89	(44,467.60)	49,212,932.37	
8-Dec-17	49,212,932.37	1,568,694.96	2,556,932.94	(37,157.21)	48,261,851.59	
9-Dec-17	48,261,851.59	(876.75)	-	40.01	48,260,934.84	
10-Dec-17	48,260,934.84	(82.13)	-	-	48,260,852.71	
11-Dec-17	48,260,852.71	1,094,204.66	3,932,822.08	(80,169.46)	45,502,404.75	
12-Dec-17	45,502,404.75	1,271,068.36	2,939,044.57	(46,689.26)	43,881,117.80	
13-Dec-17	43,881,117.80	1,286,918.22	2,979,384.80	(41,661.10)	42,230,312.32	
14-Dec-17	42,230,312.32	1,496,362.13	2,216,211.07	(91,148.02)	41,601,611.40	
15-Dec-17	41,601,611.40	1,284,766.35	1,418,451.47	(109,084.54)	41,577,010.81	
16-Dec-17	41,577,010.81	1,255,350.59	1,256,817.59	(50,830.95)	41,626,374.76	
17-Dec-17	41,626,374.76	-	-	-	41,626,374.76	
18-Dec-17	41,626,374.76	1,383,287.75	3,519,137.81	(73,359.20)	39,563,883.91	
19-Dec-17	39,563,883.91	2,005,236.49	3,182,894.07	(119,274.01)	38,505,500.34	
20-Dec-17	38,505,500.34	1,382,415.60	2,941,717.70	(56,455.72)	37,002,653.96	
21-Dec-17	37,002,653.96	1,251,877.04	2,013,461.51	(73,326.65)	36,314,396.13	
22-Dec-17	36,314,396.13	1,272,618.81	3,315,787.85	(84,170.86)	34,355,397.95	
23-Dec-17	34,355,397.95	-	-	-	34,355,397.95	
24-Dec-17	34,355,397.95	-	-	-	34,355,397.95	
25-Dec-17	34,355,397.95	-	-	-	34,355,397.95	
26-Dec-17	34,355,397.95	1,062,445.57	3,306,799.80	(59,921.93)	32,170,965.65	
27-Dec-17	32,170,965.65	254,818.23	3,007,090.37	(58,411.67)	29,477,105.18	
28-Dec-17	29,477,105.18	1,383,066.42	4,635,177.43	(37,371.40)	26,262,365.57	
29-Dec-17	26,262,365.57	1,352,434.18	2,995,675.62	(9,600.01)	24,628,724.14	
30-Dec-17	24,628,724.14	-	-	-	24,628,724.14	
31-Dec-17	24,628,724.14	-	-	59,910.74	24,568,813.40	
December	**1,271,922,769.04**	**33,679,893.08**	**61,450,330.34**	**(1,363,271.70)**	**1,245,515,603.48**	**20.27**

Potomac Electric Power Company
Billing Date to Collection Lag Based on Receivable Turnover

District of Columbia
For the twelve months ended December 31, 2017

Period	Beginning A/R	Billings	Payments	Adjustments	Ending A/R	A/R Turnover
January	1,568,558,048.77	60,208,990.95	57,330,455.00	(1,154,965.41)	1,572,591,550.13	27.43
February	1,521,952,594.71	58,129,839.33	57,782,631.34	(1,137,489.11)	1,523,437,291.81	26.36
March	1,523,648,038.39	55,852,572.20	63,977,585.45	(1,077,655.10)	1,516,600,680.24	23.71
April	1,418,087,722.91	50,190,392.26	49,390,702.77	(1,580,019.77)	1,420,471,202.20	28.76
May	1,417,962,809.83	56,019,672.73	61,370,744.91	(1,486,133.78)	1,414,097,871.43	23.04
June	1,322,215,146.42	58,397,493.87	54,174,061.88	(1,675,946.36)	1,328,114,524.77	24.52
July	1,709,851,274.40	65,154,807.69	55,539,854.92	(1,416,267.36)	1,720,882,494.53	30.98
August	1,903,818,132.12	71,182,328.02	78,228,889.33	(1,653,939.48)	1,898,425,510.29	24.27
September	1,690,152,813.59	63,368,129.70	60,343,774.63	(1,350,080.04)	1,694,527,248.70	28.08
October	1,814,017,744.68	65,441,589.43	72,241,655.31	(1,569,856.06)	1,808,787,534.86	25.04
November	1,564,252,136.08	52,783,943.91	58,882,635.45	(1,336,964.19)	1,559,490,408.73	26.48
December	1,271,922,769.04	33,679,893.08	61,450,330.34	(1,363,271.70)	1,245,515,603.48	20.27
Total 2017	**$ 18,726,439,231**	**$ 690,409,653**	**$ 730,713,321**	**$ (16,802,588)**	**$ 18,702,941,921**	**25.38**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital Study
For the Period January 2017 through December 2017
Other Revenue Lag
Rent from Electric Property

Document Number	Document Type	Account	Offsetting acct no.	Document Date	Clearing date	Assignment	Amount in local currency	Service period Beginning	Service period Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300000114	RV	520100	1012586	1/5/17	5/4/2017	09	(2,111)	1/1/2017	12/31/2017	182.50	5/4/2017	(59.50)	2,111	(125,605)
3300000229	RV	520100	1002856	1/10/17	2/15/2017	09	(74,993)	1/1/2017	12/31/2017	182.50	2/15/2017	(137.50)	74,993	(10,311,543)
3300000230	RV	520100	1002856	1/10/17	2/15/2017	09	(4,254)	1/1/2017	12/31/2017	182.50	2/15/2017	(137.50)	4,254	(584,966)
3300000231	RV	520100	1002872	1/10/17	1/27/2017	09	(428,688)	1/1/2017	12/31/2017	182.50	1/27/2017	(156.50)	428,688	(67,089,672)
3300000294	RV	520100	1008099	1/11/17	1/13/2017	02	(552)	1/1/2017	12/31/2017	182.50	1/13/2017	(170.50)	552	(94,172)
3300000295	RV	520100	1008099	1/11/17	1/13/2017	02	(552)	1/1/2017	12/31/2017	182.50	1/13/2017	(170.50)	552	(94,172)
3300000296	RV	520100	1008099	1/11/17	1/13/2017	02	(552)	1/1/2017	12/31/2017	182.50	1/13/2017	(170.50)	552	(94,172)
3300000298	RV	520100	1008099	1/11/17	1/13/2017	02	(552)	1/1/2017	12/31/2017	182.50	1/13/2017	(170.50)	552	(94,172)
3300000299	RV	520100	1008099	1/11/17	1/13/2017	02	(552)	1/1/2017	12/31/2017	182.50	1/13/2017	(170.50)	552	(94,172)
3300000302	RV	520100	1008099	1/11/17	8/23/2017	02	(552)	1/1/2017	12/31/2017	182.50	8/23/2017	51.50	552	28,445
3300001040	RV	520100	1002871	1/30/17	2/23/2017	02	(4,100)	2/1/2017	2/28/2017	14.00	2/23/2017	8.00	4,100	32,800
3300001053	RV	520100	1002871	1/30/17	2/23/2017	02	(4,100)	2/1/2017	2/28/2017	14.00	2/23/2017	8.00	4,100	32,800
3300001168	RV	520100	1002874	1/31/17	2/22/2017	02	(2,200)	2/1/2017	2/28/2017	14.00	2/22/2017	7.00	2,200	15,400
3300001170	RV	520100	1002874	1/31/17	2/22/2017	02	(4,100)	2/1/2017	2/28/2017	14.00	2/22/2017	7.00	4,100	28,700
3300001178	RV	520100	1002874	1/31/17	2/22/2017	02	(1,650)	2/1/2017	2/28/2017	14.00	2/22/2017	7.00	1,650	11,550
3300001183	RV	520100	1002874	1/31/17	2/22/2017	02	(1,650)	2/1/2017	2/28/2017	14.00	2/22/2017	7.00	1,650	11,550
3300001184	RV	520100	1002874	1/31/17	2/22/2017	02	(1,650)	2/1/2017	2/28/2017	14.00	2/22/2017	7.00	1,650	11,550
3300001655	RV	520100	1002856	2/15/17	5/12/2017	09	(1,534)	1/1/2017	12/31/2017	182.50	5/12/2017	(51.50)	1,534	(78,980)
3300001656	RV	520100	1002856	2/15/17	5/12/2017	09	(87)	1/1/2017	12/31/2017	182.50	5/12/2017	(51.50)	87	(4,481)
3300001720	RV	520100	1003053	2/16/17	3/7/2017	02	(1,139)	3/1/2017	3/31/2017	15.50	3/7/2017	(9.50)	1,139	(10,821)
3300001724	RV	520100	1012586	2/16/17	5/22/2017	09	(2,111)	3/1/2017	3/31/2017	15.50	5/22/2017	66.50	2,111	140,382
3300001827	RV	520100	1002872	2/21/17	3/13/2017	09	(2,677)	3/1/2017	3/31/2017	15.50	3/13/2017	(3.50)	2,677	(9,370)
3300001857	RV	520100	1002854	2/21/17	4/14/2017	09	(4,600)	3/1/2017	3/31/2017	15.50	4/14/2017	28.50	4,600	131,100
3300002024	RV	520100	1002871	2/24/17	4/14/2017	02	(4,100)	3/1/2017	3/31/2017	15.50	4/14/2017	28.50	4,100	116,850
3300002077	RV	520100	1002871	2/27/17	4/14/2017	02	(4,100)	3/1/2017	3/31/2017	15.50	4/14/2017	28.50	4,100	116,850
3300002119	RV	520100	1002874	2/27/17	3/3/2017	02	(2,200)	3/1/2017	3/31/2017	15.50	3/3/2017	(13.50)	2,200	(29,700)
3300002120	RV	520100	1002874	2/27/17	3/3/2017	02	(4,100)	3/1/2017	3/31/2017	15.50	3/3/2017	(13.50)	4,100	(55,350)
3300002128	RV	520100	1002874	2/27/17	3/3/2017	02	(1,650)	3/1/2017	3/31/2017	15.50	3/3/2017	(13.50)	1,650	(22,275)
3300002133	RV	520100	1002874	2/27/17	3/3/2017	02	(1,650)	3/1/2017	3/31/2017	15.50	3/3/2017	(13.50)	1,650	(22,275)
3300002134	RV	520100	1002874	2/27/17	3/3/2017	02	(1,650)	3/1/2017	3/31/2017	15.50	3/3/2017	(13.50)	1,650	(22,275)
3300002187	RV	520100	1002874	2/27/17	3/3/2017	02	(1,650)	3/1/2017	3/31/2017	15.50	3/3/2017	(13.50)	1,650	(22,275)
3300002259	RV	520100	1002880	2/28/17	12/20/2017	09	(688)	3/1/2017	2/28/2018	182.50	12/20/2017	111.50	688	76,723
3300002260	RV	520100	1008069	2/28/17	2/27/2018	02	(538)	5/1/2017	5/31/2017	15.50	2/27/2018	286.50	538	154,022
3300002263	RV	520100	1002869	2/28/17	6/6/2018	02	(100)	3/1/2017	3/31/2017	15.50	6/6/2018	446.50	100	44,650
3300002265	RV	520100	1002859	2/28/17	4/12/2017	09	(258,983)	3/1/2017	2/28/2018	182.50	4/12/2017	(140.50)	258,983	(36,387,083)
3300002266	RV	520100	1006933	2/28/17	3/27/2017	09	(304,005)	3/1/2017	2/28/2018	182.50	3/27/2017	(156.50)	304,005	(47,576,783)
3300002267	RV	520100	1002858	2/28/17	6/9/2017	02	(538,505)	1/1/2017	1/31/2017	15.50	6/9/2017	143.50	538,505	77,275,485
3300002268	RV	520100	1006933	2/28/17	3/27/2017	02	(172,897)	1/1/2017	12/31/2017	182.50	3/27/2017	(97.50)	172,897	(16,857,433)
3300002270	RV	520100	1002873	2/28/17	6/14/2017	02	(1,583)	5/1/2017	5/31/2017	15.50	6/14/2017	28.50	1,583	45,105
3300002271	RV	520100	1002860	2/28/17	11/14/2017	02	(291,619)	1/1/2017	12/31/2017	182.50	11/14/2017	134.50	291,619	39,222,707
3300002272	RV	520100	1002875	2/28/17	4/4/2017	09	(91,273)	3/1/2017	2/28/2018	182.50	4/4/2017	(148.50)	91,273	(13,554,041)
3300002273	RV	520100	1003217	2/28/17	4/19/2017	09	(100)	3/1/2017	2/28/2018	182.50	4/19/2017	(133.50)	100	(13,350)
3300002274	RV	520100	1002875	2/28/17	4/4/2017	02	(768,027)	1/1/2017	12/31/2017	182.50	4/4/2017	(89.50)	768,027	(68,738,434)
3300002275	RV	520100	1002861	2/28/17	6/16/2017	09	(1,071)	3/1/2017	2/28/2018	182.50	6/16/2017	(75.50)	1,071	(80,896)
3300002276	RV	520100	1005953	2/28/17	3/28/2017	02	(100)	1/1/2017	12/31/2017	182.50	3/28/2017	(96.50)	100	(9,650)
3300002277	RV	520100	1002861	2/28/17	4/20/2017	02	(63,407)	1/1/2017	12/31/2017	182.50	4/20/2017	(73.50)	63,407	(4,660,398)
3300002278	RV	520100	1006934	2/28/17	4/6/2017	09	(169)	3/1/2017	2/28/2018	182.50	4/6/2017	(146.50)	169	(24,700)
3300002279	RV	520100	1002863	2/28/17	4/7/2017	02	(18,392)	1/1/2017	12/31/2017	182.50	4/7/2017	(86.50)	18,392	(1,590,902)
3300002280	RV	520100	1006251	2/28/17	4/7/2017	02	(62,719)	1/1/2017	12/31/2017	182.50	4/7/2017	(86.50)	62,719	(5,425,198)
3300002281	RV	520100	1002864	2/28/17	5/24/2017	02	(5,058)	1/1/2017	12/31/2017	182.50	5/24/2017	(39.50)	5,058	(199,798)
3300002282	RV	520100	1002851	2/28/17	2/27/2018	02	(1,560)	1/1/2017	12/31/2017	182.50	2/27/2018	239.50	1,560	373,620
3300002283	RV	520100	1006502	2/28/17	4/12/2017	02	(23,664)	1/1/2017	12/31/2017	182.50	4/12/2017	(81.50)	23,664	(1,928,616)
3300002284	RV	520100	1006502	2/28/17	4/12/2017	02	(12,035)	1/1/2017	12/31/2017	182.50	4/12/2017	(81.50)	12,035	(980,853)

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital Study
For the Period January 2017 through December 2017
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Document Number	Document Type	Account	Offsetting acct no.	Document Date	Clearing date	Assignment	Amount in local currency	Service period Beginning	Service period Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300002285	RV	520100	1002865	2/28/17	4/11/2017	02	(17,852)	1/1/2017	12/31/2017	182.50	4/11/2017	(82.50)	17,852	(1,472,759)
3300002286	RV	520100	1008107	2/28/17	3/28/2017	02	(713)	1/1/2017	12/31/2017	182.50	3/28/2017	(96.50)	713	(68,847)
3300002287	RV	520100	1009856	2/28/17	4/3/2017	02	(1,548)	1/1/2017	12/31/2017	182.50	4/3/2017	(90.50)	1,548	(140,105)
3300002290	RV	520100	1003082	2/28/17	2/28/2017	09	(17,604)	3/1/2017	2/28/2018	182.50	2/28/2017	(183.50)	17,604	(3,230,334)
3300002291	RV	520100	1003082	2/28/17	4/24/2017	09	(360)	1/1/2017	12/31/2017	182.50	4/24/2017	(69.50)	360	(25,020)
3300002292	RV	520100	1011164	2/28/17	3/28/2017	02	(140)	1/1/2017	12/31/2017	182.50	3/28/2017	(96.50)	140	(13,515)
3300002430	RV	520100	1002872	3/5/17	5/5/2017	02	(6,041)	1/1/2017	12/31/2017	182.50	5/5/2017	(58.50)	6,041	(353,399)
3300003137	RV	520100	1003053	3/23/17	4/7/2017	02	(1,139)	4/1/2017	4/30/2017	15.00	4/7/2017	(9.00)	1,139	(10,251)
3300003142	RV	520100	1002879	3/23/17	4/3/2017	02	(5,538)	4/1/2017	4/30/2017	15.00	4/3/2017	(13.00)	5,538	(71,997)
3300003143	RV	520100	1012586	3/23/17	5/22/2017	09	(2,111)	4/1/2017	4/30/2017	15.00	5/22/2017	36.00	2,111	75,996
3300003232	RV	520100	1002854	3/27/17	5/23/2017	09	(4,700)	4/1/2017	4/30/2017	15.00	5/23/2017	37.00	4,700	173,900
3300003274	RV	520100	1002871	3/28/17	3/29/2017	02	(574)	4/1/2017	4/30/2017	15.00	3/29/2017	(18.00)	574	(10,331)
3300003295	RV	520100	1002871	3/28/17	4/21/2017	09	(4,600)	4/1/2017	4/30/2017	15.00	4/21/2017	5.00	4,600	23,000
3300003301	RV	520100	1002871	3/28/17	4/21/2017	02	(4,200)	4/1/2017	4/30/2017	15.00	4/21/2017	5.00	4,200	21,000
3300003318	RV	520100	1002871	3/28/17	4/21/2017	02	(4,200)	4/1/2017	4/30/2017	15.00	4/21/2017	5.00	4,200	21,000
3300003573	RV	520100	1002874	3/29/17	5/5/2017	02	(2,300)	4/1/2017	4/30/2017	15.00	5/5/2017	19.00	2,300	43,700
3300003575	RV	520100	1002874	3/29/17	5/5/2017	02	(4,200)	4/1/2017	4/30/2017	15.00	5/5/2017	19.00	4,200	79,800
3300003586	RV	520100	1002874	3/29/17	5/5/2017	02	(1,700)	4/1/2017	4/30/2017	15.00	5/5/2017	19.00	1,700	32,300
3300003592	RV	520100	1002874	3/29/17	5/5/2017	02	(1,700)	4/1/2017	4/30/2017	15.00	5/5/2017	19.00	1,700	32,300
3300003594	RV	520100	1002874	3/29/17	5/5/2017	02	(1,700)	4/1/2017	4/30/2017	15.00	5/5/2017	19.00	1,700	32,300
3300003652	RV	520100	1002874	3/29/17	5/5/2017	02	(1,700)	4/1/2017	4/30/2017	15.00	5/5/2017	19.00	1,700	32,300
3300004502	RV	520100	1002854	4/19/17	6/27/2017	09	(4,700)	5/1/2017	5/31/2017	15.50	6/27/2017	41.50	4,700	195,050
3300004767	RV	520100	1003053	4/25/17	5/8/2017	02	(1,139)	5/1/2017	5/31/2017	15.50	5/8/2017	(8.50)	1,139	(9,682)
3300004771	RV	520100	1012586	4/25/17	7/3/2017	09	(2,111)	5/1/2017	5/31/2017	15.50	7/3/2017	47.50	2,111	100,273
3300004799	RV	520100	1002854	4/26/17	7/25/2017	02	(1,000)	5/1/2017	5/31/2017	15.50	7/25/2017	69.50	1,000	69,500
3300004801	RV	520100	1002854	4/26/17	7/25/2017	02	(1,000)	5/1/2017	5/31/2017	15.50	7/25/2017	69.50	1,000	69,500
3300004820	RV	520100	1002876	4/26/17	4/27/2017	02	(3,129)	5/1/2017	5/31/2017	15.50	4/27/2017	(19.50)	3,129	(61,019)
3300004834	RV	520100	1002871	4/26/17	5/5/2017	02	(750)	1/1/2017	12/31/2017	182.50	5/5/2017	(58.50)	750	(43,875)
3300004836	RV	520100	1002871	4/26/17	5/5/2017	02	(500)	1/1/2017	12/31/2017	182.50	5/5/2017	(58.50)	500	(29,250)
3300004837	RV	520100	1002871	4/26/17	5/5/2017	02	(500)	1/1/2017	12/31/2017	182.50	5/5/2017	(58.50)	500	(29,250)
3300004841	RV	520100	1002871	4/26/17	5/5/2017	02	(500)	1/1/2017	12/31/2017	182.50	5/5/2017	(58.50)	500	(29,250)
3300004853	RV	520100	1002871	4/26/17	5/25/2017	02	(4,200)	5/1/2017	5/31/2017	15.50	5/25/2017	8.50	4,200	35,700
3300004870	RV	520100	1002871	4/26/17	5/5/2017	02	(1,000)	5/1/2017	5/31/2017	15.50	5/5/2017	(11.50)	1,000	(11,500)
3300004871	RV	520100	1002871	4/26/17	5/25/2017	02	(4,200)	5/1/2017	5/31/2017	15.50	5/25/2017	8.50	4,200	35,700
3300004880	RV	520100	1002871	4/26/17	5/5/2017	02	(750)	5/1/2017	5/31/2017	15.50	5/5/2017	(11.50)	750	(8,625)
3300004884	RV	520100	1002871	4/26/17	5/5/2017	02	(750)	5/1/2017	5/31/2017	15.50	5/5/2017	(11.50)	750	(8,625)
3300005005	RV	520100	1002874	4/27/17	5/5/2017	02	(2,300)	5/1/2017	5/31/2017	15.50	5/5/2017	(11.50)	2,300	(26,450)
3300005006	RV	520100	1002874	4/27/17	5/5/2017	02	(4,200)	5/1/2017	5/31/2017	15.50	5/5/2017	(11.50)	4,200	(48,300)
3300005014	RV	520100	1002874	4/27/17	5/5/2017	02	(1,700)	5/1/2017	5/31/2017	15.50	5/5/2017	(11.50)	1,700	(19,550)
3300005019	RV	520100	1002874	4/27/17	5/5/2017	02	(1,700)	5/1/2017	5/31/2017	15.50	5/5/2017	(11.50)	1,700	(19,550)
3300005020	RV	520100	1002874	4/27/17	5/5/2017	02	(1,700)	5/1/2017	5/31/2017	15.50	5/5/2017	(11.50)	1,700	(19,550)
3300005321	RV	520100	1003053	4/25/17	5/8/2017	02	1,139	1/1/2017	12/31/2017	182.50	5/8/2017	(55.50)	(1,139)	63,215
3300005322	RV	520100	1003053	5/8/17	5/17/2017	02	(1,178)	6/1/2017	5/31/2017	-	5/17/2017	(15.00)	1,178	(17,670)
3300005558	RV	520100	1002854	5/12/17	7/3/2017	09	(4,700)	5/1/2017	5/31/2017	15.50	7/3/2017	47.50	4,700	223,250
3300005817	RV	520100	1003053	5/22/17	6/9/2017	02	(1,178)	6/1/2017	6/30/2017	15.00	6/9/2017	(7.00)	1,178	(8,246)
3300005821	RV	520100	1012586	5/22/17	8/22/2017	09	(2,111)	5/1/2017	5/31/2017	15.50	8/22/2017	97.50	2,111	205,823
3300005849	RV	520100	1002871	5/23/17	7/3/2017	02	(4,200)	6/1/2017	6/30/2017	15.00	7/3/2017	17.00	4,200	71,400
3300005895	RV	520100	1002871	5/24/17	7/3/2017	02	(4,200)	6/1/2017	6/30/2017	15.00	7/3/2017	17.00	4,200	71,400
3300005977	RV	520100	1002874	5/25/17	6/5/2017	02	(2,300)	6/1/2017	6/30/2017	15.00	6/5/2017	(11.00)	2,300	(25,300)
3300005978	RV	520100	1002874	5/25/17	6/5/2017	02	(4,200)	6/1/2017	6/30/2017	15.00	6/5/2017	(11.00)	4,200	(46,200)
3300006046	RV	520100	1002874	5/26/17	6/5/2017	02	(1,700)	6/1/2017	6/30/2017	15.00	6/5/2017	(11.00)	1,700	(18,700)
3300006051	RV	520100	1002874	5/26/17	6/5/2017	02	(1,700)	6/1/2017	6/30/2017	15.00	6/5/2017	(11.00)	1,700	(18,700)
3300006052	RV	520100	1002874	5/26/17	6/5/2017	02	(1,700)	6/1/2017	6/30/2017	15.00	6/5/2017	(11.00)	1,700	(18,700)

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital Study
For the Period January 2017 through December 2017
Other Revenue Lag
Rent from Electric Property

Document Number	Document Type	Account	Offsetting acct no.	Document Date	Clearing date	Assignment	Amount in local currency	Service period Beginning	Service period Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300006104	RV	520100	1002874	5/26/17	6/5/2017	02	(1,700)	6/1/2017	6/30/2017	15.00	6/5/2017	(11.00)	1,700	(18,700)
3300006588	RV	520100	1002854	6/14/17	6/27/2017	02	(500)	1/1/2017	12/31/2017	182.50	6/27/2017	(5.50)	500	(2,750)
3300006686	RV	520100	1002854	6/15/17	7/11/2017	09	(4,700)	7/1/2017	7/31/2017	15.50	7/11/2017	(5.50)	4,700	(25,850)
3300006804	RV	520100	1003053	6/20/17	7/19/2017	02	(1,178)	7/1/2017	7/31/2017	15.50	7/19/2017	2.50	1,178	2,945
3300007024	RV	520100	1002871	6/26/17	7/12/2017	02	(4,200)	7/1/2017	7/31/2017	15.50	7/12/2017	(4.50)	4,200	(18,900)
3300007274	RV	520100	1002871	6/29/17	7/12/2017	02	(4,200)	7/1/2017	7/31/2017	15.50	7/12/2017	(4.50)	4,200	(18,900)
3300007742	RV	520100	1002854	7/13/17	8/4/2017	09	(4,700)	8/1/2017	8/31/2017	15.50	8/4/2017	(12.50)	4,700	(58,750)
3300008130	RV	520100	1003053	7/25/17	8/7/2017	02	(1,178)	8/1/2017	8/31/2017	15.50	8/7/2017	(9.50)	1,178	(11,191)
3300008150	RV	520100	1002871	7/25/17	3/14/2018	02	(4,200)	8/1/2017	8/31/2017	15.50	3/14/2018	209.50	4,200	879,900
3300008215	RV	520100	1002871	7/26/17	8/10/2017	02	(4,200)	8/1/2017	8/31/2017	15.50	8/10/2017	(6.50)	4,200	(27,300)
3300008869	RV	520100	1003053	8/21/17	9/12/2017	02	(1,178)	9/1/2017	9/30/2017	15.00	9/12/2017	(4.00)	1,178	(4,712)
3300008899	RV	520100	1002871	8/22/17	8/23/2017	02	(589)	1/1/2017	12/31/2017	182.50	8/23/2017	51.50	589	30,336
3300008983	RV	520100	1002854	8/23/17	9/7/2017	09	(4,700)	9/1/2017	9/30/2017	15.00	9/7/2017	(9.00)	4,700	(42,300)
3300009152	RV	520100	1002871	8/25/17	9/8/2017	02	(4,200)	9/1/2017	9/30/2017	15.00	9/8/2017	(8.00)	4,200	(33,600)
3300009168	RV	520100	1002871	8/25/17	9/8/2017	02	(4,200)	9/1/2017	9/30/2017	15.00	9/8/2017	(8.00)	4,200	(33,600)
3300010007	RV	520100	1002854	9/20/17	10/27/2017	09	(4,700)	10/1/2017	10/31/2017	15.50	10/27/2017	10.50	4,700	49,350
3300010147	RV	520100	1003053	9/25/17	10/16/2017	02	(1,178)	10/1/2017	10/31/2017	15.50	10/16/2017	(0.50)	1,178	(589)
3300010191	RV	520100	1002871	9/27/17	11/17/2017	02	(4,200)	10/1/2017	10/31/2017	15.50	11/17/2017	31.50	4,200	132,300
3300010305	RV	520100	1002871	9/28/17	11/17/2017	02	(4,200)	10/1/2017	10/31/2017	15.50	11/17/2017	31.50	4,200	132,300
3300010319	RV	520100	1002871	9/28/17	11/17/2017	02	(4,000)	10/1/2017	10/31/2017	15.50	11/17/2017	31.50	4,000	126,000
3300011060	RV	520100	1002854	10/19/17	12/5/2017	09	(4,700)	11/1/2017	11/30/2017	15.00	12/5/2017	19.00	4,700	89,300
3300011164	RV	520100	1003053	10/23/17	11/14/2017	02	(1,178)	11/1/2017	11/30/2017	15.00	11/14/2017	(2.00)	1,178	(2,356)
3300011422	RV	520100	1002868	10/27/17	10/30/2017	02	(3,900)	11/1/2017	11/30/2017	15.00	10/30/2017	(17.00)	3,900	(66,300)
3300011423	RV	520100	1002868	10/27/17	3/22/2018	02	(4,000)	11/1/2017	11/30/2017	15.00	3/22/2018	126.00	4,000	504,000
3300011439	RV	520100	1002871	10/27/17	11/17/2017	02	(4,200)	11/1/2017	11/30/2017	15.00	11/17/2017	1.00	4,200	4,200
3300011455	RV	520100	1002871	10/27/17	11/17/2017	02	(4,200)	11/1/2017	11/30/2017	15.00	11/17/2017	1.00	4,200	4,200
3300012309	RV	520100	1002854	11/28/17	12/8/2017	09	(4,700)	12/1/2017	12/31/2017	15.50	12/8/2017	(8.50)	4,700	(39,950)
3300012376	RV	520100	1003053	11/28/17	12/19/2017	02	(1,178)	12/1/2017	12/31/2017	15.50	12/19/2017	2.50	1,178	2,945
3300012512	RV	520100	1002871	11/29/17	12/6/2017	02	(4,200)	12/1/2017	12/31/2017	15.50	12/6/2017	(10.50)	4,200	(44,100)
3300012533	RV	520100	1002871	11/29/17	12/6/2017	02	(4,200)	12/1/2017	12/31/2017	15.50	12/6/2017	(10.50)	4,200	(44,100)
3300012725	RV	520100	1002871	12/1/17	12/5/2017	09	(500)	1/1/2017	12/1/2017	167.50	12/5/2017	170.50	500	85,250
3300013462	RV	520100	1003053	12/15/17	1/4/2018	02	(1,178)	1/1/2017	1/31/2017	15.50	1/4/2018	352.50	1,178	415,245
3300013654	RV	520100	1002854	12/20/17	3/7/2018	09	(4,700)	12/1/2017	12/31/2017	15.50	3/7/2018	80.50	4,700	378,350
3300013786	RV	520100	1002871	12/21/17	1/11/2018	02	(4,200)	1/1/2017	1/31/2017	15.50	1/11/2018	359.50	4,200	1,509,900
													3,443,962.45	(159,371,864.89)
												Lag Days		**(46.28)**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital Study
For the Period January 2017 through December 2017
Other Revenue Lag
Billing Services and Account Management for Third Party Suppliers

											Service period					
Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Third party name	Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300001148	RV	3900001660	520500	1009585	1/31/2017	3/9/2017	-879.54	02	Other	1/1/2017	12/31/2017	182.50	3/9/2017	(114.50)	879.54	(100,707.33)
3300005421	RV	3900003443	520500	1013178	5/10/2017	5/24/2017	-100.00	02	Other	1/1/2017	12/31/2017	182.50	5/24/2017	(38.50)	100.00	(3,850.00)
3300005423	RV	3300005424	520500	1013179	5/10/2017	5/10/2017	-100.00	02	Other	1/1/2017	12/31/2017	182.50	5/10/2017	(52.50)	100.00	(5,250.00)
3300005424	RV	3300005424	520500	1013179	5/10/2017	5/10/2017	100.00	02	Other	1/1/2017	12/31/2017	182.50	5/10/2017	(52.50)	(100.00)	5,250.00
3300005425	RV	3900005405	520500	1013179	5/11/2017	8/22/2017	-100.00	02	Other	1/1/2017	12/31/2017	182.50	8/22/2017	51.50	100.00	5,150.00
3300012026	RV	3300012027	520500	1012016	11/17/2017	11/17/2017	-112.56	02,AM	TALEN ENERGY	9/1/17	9/30/17	15.00	11/17/2017	63.00	112.56	7,091.28
3300012027	RV	3300012027	520500	1012016	11/17/2017	11/17/2017	112.56	02,AM	TALEN ENERGY	9/1/17	9/30/17	15.00	11/17/2017	63.00	(112.56)	(7,091.28)
3300012028	RV	3900000132	520500	1012016	11/17/2017	1/9/2018	-138.43	02,AM	TALEN ENERGY	9/1/17	9/30/17	15.00	1/9/2018	116.00	138.43	16,057.88
3300012134	RV	3900000288	520500	1007587	11/20/2017	1/17/2018	-112.56	02,AM	AEP ENERGY	9/1/17	9/30/17	15.00	1/17/2018	124.00	112.56	13,957.44
3300012137	RV	3900000262	520500	1009421	11/20/2017	1/17/2018	-107.87	02,AM	ETHICAL ELECTRIC	9/1/17	9/30/17	15.00	1/17/2018	124.00	107.87	13,375.88
3300012159	RV	3900000079	520500	1005415	11/21/2017	1/5/2018	-11.24	02,AM	FIRST ENERGY SOLUTIONS	9/1/17	9/30/17	15.00	1/5/2018	112.00	11.24	1,258.88
3300012161	RV	3900000426	520500	1012351	11/21/2017	1/26/2018	-17.47	02,AM	ENTRUST ENERGY NORTH	9/1/17	9/30/17	15.00	1/26/2018	133.00	17.47	2,323.51
3300012164	RV	3900000082	520500	1010473	11/21/2017	1/8/2018	-41.13	02,AM	SFE ENERGY	9/1/17	9/30/17	15.00	1/8/2018	115.00	41.13	4,729.95
3300012374	RV	3900000032	520500	1008458	11/28/2017	1/3/2018	-163.05	02,AM	XOOM ENERGY	9/1/17	9/30/17	15.00	1/3/2018	110.00	163.05	17,935.50
3300012382	RV	3900000067	520500	1010474	11/28/2017	1/5/2018	-151.12	02,AM	INSPIRED ENERGY HOLDINGS, LLC	9/1/17	9/30/17	15.00	1/5/2018	112.00	151.12	16,925.44
3300012388	RV	3900007964	520500	1012511	11/28/2017	12/21/2017	-1,325.99	02,AM	AGERA ENERGY	9/1/17	9/30/17	15.00	12/21/2017	97.00	1,325.99	128,621.03
3300012389	RV	3900007802	520500	1012688	11/28/2017	12/18/2017	-233.69	02,AM	Other	9/1/17	9/30/17	15.00	12/18/2017	94.00	233.69	21,966.86
3300012390	RV	3900000147	520500	1012690	11/28/2017	1/9/2018	-11.44	02,AM	Other	9/1/17	9/30/17	15.00	1/9/2018	116.00	11.44	1,327.04
3300012391	RV	3900000031	520500	1012681	11/28/2017	1/3/2018	-7.96	02,AM	Other	9/1/17	9/30/17	15.00	1/3/2018	110.00	7.96	875.60
3300012392	RV	3900007983	520500	1012957	11/28/2017	12/21/2017	-0.70	02,AM	Other	9/1/17	9/30/17	15.00	12/21/2017	97.00	0.70	67.90
3300012393	RV	3900007959	520500	1013112	11/28/2017	12/21/2017	-1,010.66	02,AM	Other	9/1/17	9/30/17	15.00	12/21/2017	97.00	1,010.66	98,034.02
3300012394	RV	3900007631	520500	1010814	11/28/2017	12/12/2017	-27.70	02,AM	NORDIC ENERGY SERVICES, LLC	9/1/17	9/30/17	15.00	12/12/2017	88.00	27.70	2,437.60
3300012395	RV	3900007961	520500	1005335	11/28/2017	12/21/2017	-545.52	02,AM	DIRECT ENERGY SERVICE	9/1/17	9/30/17	15.00	12/21/2017	97.00	545.52	52,915.44
3300012396	RV	3900000060	520500	1006334	11/29/2017	1/4/2018	-153.12	02,AM	NEXTERA ENERGY	9/1/17	9/30/17	15.00	1/4/2018	111.00	153.12	16,996.32
3300012397	RV	3900000060	520500	1006334	11/29/2017	1/4/2018	-0.89	02,AM	NEXTERA ENERGY	9/1/17	9/30/17	15.00	1/4/2018	111.00	0.89	98.79
3300012400	RV	3900000675	520500	1013158	11/29/2017	2/7/2018	-54.63	02,AM	Other	9/1/17	9/30/17	15.00	2/7/2018	145.00	54.63	7,921.35
3300012401	RV	3900000431	520500	1011510	11/29/2017	1/26/2018	-6.22	02,AM	GREEN MOUNTAIN ENERGY CO.	9/1/17	9/30/17	15.00	1/26/2018	133.00	6.22	827.26
3300012402	RV	3900000009	520500	1005867	11/29/2017	1/2/2018	-340.96	02,AM	HORIZON POWER AND LIGHT	9/1/17	9/30/17	15.00	1/2/2018	109.00	340.96	37,164.64
3300012402	RV	3900000009	520500	1005867	11/29/2017	1/2/2018	-55.74	02,AM	HORIZON POWER AND LIGHT	9/1/17	9/30/17	15.00	1/2/2018	109.00	55.74	6,075.66
3300012403	RV	3900000767	520500	1007992	11/29/2017	2/12/2018	-94.63	02,AM	AMBIT ENERGY	9/1/17	9/30/17	15.00	2/12/2018	150.00	94.63	14,194.50
3300012404	RV	3900000235	520500	1005660	11/29/2017	1/12/2018	-67.18	02,AM	LIBERTY POWER HOLDINGS	9/1/17	9/30/17	15.00	1/12/2018	119.00	67.18	7,994.42
3300012407	RV	3900007673	520500	1007588	11/29/2017	12/12/2017	-40.76	02,AM	CLEARVIEW ENERGY	9/1/17	9/30/17	15.00	12/12/2017	88.00	40.76	3,586.88
3300012411	RV	3900000001	520500	1009857	11/29/2017	1/2/2018	-1.94	02,AM	ELIGO ENERGY DC, LLC	9/1/17	9/30/17	15.00	1/2/2018	109.00	1.94	211.46
3300012423	RV	3900007467	520500	1009259	11/29/2017	12/6/2017	-124.71	02,AM	Champion Energy Services LLC	9/1/17	9/30/17	15.00	12/6/2017	82.00	124.71	10,226.22
3300012444	RV	3900000428	520500	1007420	11/29/2017	1/26/2018	-58.20	02,AM	ENERGY PLUS HOLDING	9/1/17	9/30/17	15.00	1/26/2018	133.00	58.20	7,740.60
3300012445	RV	3900007698	520500	1009271	11/29/2017	12/14/2017	-17.79	02,AM	MAJOR ENERGY	9/1/17	9/30/17	15.00	12/14/2017	90.00	17.79	1,601.10
3300012447	RV	3900000639	520500	1008816	11/29/2017	2/6/2018	-45.94	02,AM	IDT ENERGY INC	9/1/17	9/30/17	15.00	2/6/2018	144.00	45.94	6,615.36
3300012449	RV	3900000142	520500	1011199	11/29/2017	1/9/2018	-9.84	02,AM	PLYMOUTH ROCK ENERGY	9/1/17	9/30/17	15.00	1/9/2018	116.00	9.84	1,141.44
3300012450	RV	3900007914	520500	1012081	11/29/2017	12/19/2017	-0.76	02,AM	Other	9/1/17	9/30/17	15.00	12/19/2017	95.00	0.76	72.20
3300012451	RV	3900007675	520500	1008419	11/29/2017	12/12/2017	-39.23	02,AM	PALMCO POWER MD LLC	9/1/17	9/30/17	15.00	12/12/2017	88.00	39.23	3,452.24
3300012452	RV	3900007938	520500	1013113	11/29/2017	12/20/2017	-46.98	02,AM	Other	9/1/17	9/30/17	15.00	12/20/2017	96.00	46.98	4,510.08
3300012453	RV	3900007933	520500	1007590	11/29/2017	12/20/2017	-43.34	02,AM	NORTH AMERICAN	9/1/17	9/30/17	15.00	12/20/2017	96.00	43.34	4,160.64
3300012455	RV	3900007606	520500	1009802	11/29/2017	12/11/2017	-0.34	02,AM	HIKO ENERGY, LLC	9/1/17	9/30/17	15.00	12/11/2017	87.00	0.34	29.58
3300012467	RV	3900008070	520500	1013114	11/29/2017	12/28/2017	-4,837.70	02,AM	Other	9/1/17	9/30/17	15.00	12/28/2017	104.00	4,837.70	503,120.80
3300012467	RV	3900008070	520500	1013114	11/29/2017	12/28/2017	-1,085.74	02,AM	Other	9/1/17	9/30/17	15.00	12/28/2017	104.00	1,085.74	112,916.96
3300012471	RV	3900007636	520500	1007751	11/29/2017	12/12/2017	-33.68	02,AM	STARION ENERGY	9/1/17	9/30/17	15.00	12/12/2017	88.00	33.68	2,963.84
3300012472	RV	3900000701	520500	1007744	11/29/2017	2/8/2018	-172.60	02,AM	RELIANT ENERGY	9/1/17	9/30/17	15.00	2/8/2018	146.00	172.60	25,199.60
3300012473	RV	3900008004	520500	1007745	11/29/2017	12/28/2017	-94.90	02,AM	STREAM ENERGY	9/1/17	9/30/17	15.00	12/28/2017	104.00	94.90	9,869.60
3300012480	RV	3900000673	520500	1012790	11/29/2017	2/7/2018	-3.14	02,AM	Other	9/1/17	9/30/17	15.00	2/7/2018	145.00	3.14	455.30
3300012482	RV	3900008053	520500	1010701	11/29/2017	12/28/2017	-33.25	02,AM	ENERGY ME	9/1/17	9/30/17	15.00	12/28/2017	104.00	33.25	3,458.00
3300012484	RV	3900000033	520500	1013290	11/29/2017	1/3/2018	-26.60	02,AM	Other	9/1/17	9/30/17	15.00	1/3/2018	110.00	26.60	2,926.00
3300012487	RV	3900000020	520500	1009721	11/29/2017	1/3/2018	-188.04	02,AM	SOURCE POWER & GAS	9/1/17	9/30/17	15.00	1/3/2018	110.00	188.04	20,684.40
3300012489	RV	3900000052	520500	1012820	11/29/2017	1/4/2018	-8.73	02,AM	Other	9/1/17	9/30/17	15.00	1/4/2018	111.00	8.73	969.03
3300012491	RV	3900000399	520500	1009260	11/29/2017	1/24/2018	-28.05	02,AM	UGI ENERGY SERVICES INC	9/1/17	9/30/17	15.00	1/24/2018	131.00	28.05	3,674.55
3300012498	RV	3900000649	520500	1012698	11/29/2017	2/7/2018	-87.46	02,AM	Other	9/1/17	9/30/17	15.00	2/7/2018	145.00	87.46	12,681.70
3300012499	RV	3900000061	520500	1012700	11/29/2017	1/4/2018	-931.57	02,AM	Other	9/1/17	9/30/17	15.00	1/4/2018	111.00	931.57	103,404.27
3300012501	RV	3900000349	520500	1012701	11/29/2017	1/22/2018	-18.36	02,AM	Other	9/1/17	9/30/17	15.00	1/22/2018	129.00	18.36	2,368.44
3300013210	RV	3900000959	520500	1007587	12/11/2017	2/27/2018	-101.64	02,AM	AEP ENERGY	10/1/17	10/31/17	15.50	2/27/2018	134.50	101.64	13,670.58
3300013211	RV	3900000703	520500	1012511	12/11/2017	2/8/2018	-1,246.38	02,AM	AGERA ENERGY	10/1/17	10/31/17	15.50	2/8/2018	115.50	1,246.38	143,956.89
3300013319	RV	3900000294	520500	1012820	12/12/2017	1/17/2018	-8.61	02,AM	Other	10/1/17	10/31/17	15.50	1/17/2018	93.50	8.61	805.04
3300013320	RV	3900000316	520500	1009259	12/12/2017	1/18/2018	-101.43	02,AM	Champion Energy Services LLC	10/1/17	10/31/17	15.50	1/18/2018	94.50	101.43	9,585.14
3300013321	RV	3900008030	520500	1009421	12/12/2017	12/28/2017	-102.43	02,AM	ETHICAL ELECTRIC	10/1/17	10/31/17	15.50	12/28/2017	73.50	102.43	7,528.61

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											Service period					
Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Third party name	Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300013322	RV	3900000013	520500	1007588	12/12/2017	1/2/2018	-36.63	02,AM	CLEARVIEW ENERGY	10/1/17	10/31/17	15.50	1/2/2018	78.50	36.63	2,875.46
3300013323	RV	3900000464	520500	1008181	12/12/2017	1/29/2018	-57.94	02,AM	CONSOLIDATED EDISON	10/1/17	10/31/17	15.50	1/29/2018	105.50	57.94	6,112.67
3300013327	RV	3300013361	520500	1005335	12/12/2017	12/13/2017	-60.26	02,AM	DIRECT ENERGY SERVICE	10/1/17	10/31/17	15.50	12/13/2017	58.50	60.26	3,525.21
3300013329	RV	3900000058	520500	1005335	12/12/2017	1/4/2018	-2,876.35	02,AM	DIRECT ENERGY SERVICE	10/1/17	10/31/17	15.50	1/4/2018	80.50	2,876.35	231,546.18
3300013331	RV	3900008064	520500	1012081	12/12/2017	12/28/2017	-0.66	02,AM	Other	10/1/17	10/31/17	15.50	12/28/2017	73.50	0.66	48.51
3300013332	RV	3900000649	520500	1012698	12/12/2017	2/7/2018	-155.37	02,AM	Other	10/1/17	10/31/17	15.50	2/7/2018	114.50	155.37	17,789.87
3300013333	RV	3900000003	520500	1009857	12/12/2017	1/2/2018	-3.79	02,AM	ELIGO ENERGY DC, LLC	10/1/17	10/31/17	15.50	1/2/2018	78.50	3.79	297.52
3300013334	RV	3900000704	520500	1007420	12/12/2017	2/8/2018	-51.37	02,AM	ENERGY PLUS HOLDING	10/1/17	10/31/17	15.50	2/8/2018	115.50	51.37	5,933.24
3300013335	RV	3900000312	520500	1010701	12/12/2017	1/18/2018	-30.54	02,AM	ENERGY ME	10/1/17	10/31/17	15.50	1/18/2018	94.50	30.54	2,886.03
3300013336	RV	3900000698	520500	1013112	12/12/2017	2/8/2018	-870.90	02,AM	Other	10/1/17	10/31/17	15.50	2/8/2018	115.50	870.90	100,588.95
3300013337	RV	3900001030	520500	1013290	12/12/2017	2/27/2018	-23.15	02,AM	Other	10/1/17	10/31/17	15.50	2/27/2018	134.50	23.15	3,113.68
3300013338	RV	3900000956	520500	1012351	12/12/2017	2/27/2018	-18.13	02,AM	ENTRUST ENERGY NORTH	10/1/17	10/31/17	15.50	2/27/2018	134.50	18.13	2,438.49
3300013340	RV	3900000128	520500	1005415	12/13/2017	1/9/2018	-8.88	02,AM	FIRST ENERGY SOLUTIONS	10/1/17	10/31/17	15.50	1/9/2018	85.50	8.88	759.24
3300013341	RV	3900001013	520500	1008568	12/13/2017	2/27/2018	-5.34	02,AM	GREAT AMERICAN POWER	10/1/17	10/31/17	15.50	2/27/2018	134.50	5.34	718.23
3300013342	RV	3300013343	520500	1011510	12/13/2017	12/13/2017	-0.27	02,AM	GREEN MOUNTAIN ENERGY CO.	10/1/17	10/31/17	15.50	12/13/2017	58.50	0.27	15.80
3300013343	RV	3300013343	520500	1011510	12/13/2017	12/13/2017	0.27	02,AM	GREEN MOUNTAIN ENERGY CO.	10/1/17	10/31/17	15.50	12/13/2017	58.50	(0.27)	(15.80)
3300013344	RV	3900000077	520500	1009802	12/13/2017	1/5/2018	-0.27	02,AM	HIKO ENERGY, LLC	10/1/17	10/31/17	15.50	1/5/2018	81.50	0.27	22.01
3300013345	RV	3900000327	520500	1005867	12/13/2017	1/18/2018	-163.97	02,AM	HORIZON POWER AND LIGHT	10/1/17	10/31/17	15.50	1/18/2018	94.50	163.97	15,495.17
3300013355	RV	3300013355	520500	1005335	10/13/2017	12/13/2017	9,466.37	02,AM	DIRECT ENERGY SERVICE	10/1/17	10/31/17	15.50	12/13/2017	58.50	(9,466.37)	(553,782.65)
3300013356	RV	3900000151	520500	1010004	12/13/2017	1/9/2018	-9,466.37	02,AM	DIRECT ENERGY BUSINESS MARKETING	10/1/17	10/31/17	15.50	1/9/2018	85.50	9,466.37	809,374.64
3300013357	RV	3300013357	520500	1005335	10/13/2017	12/13/2017	519.05	02,AM	DIRECT ENERGY SERVICE	10/1/17	10/31/17	15.50	12/13/2017	58.50	(519.05)	(30,364.43)
3300013358	RV	3300013358	520500	1005335	10/13/2017	12/13/2017	21,763.29	02,AM	DIRECT ENERGY SERVICE	10/1/17	10/31/17	15.50	12/13/2017	58.50	(21,763.29)	(1,273,152.47)
3300013359	RV	3900000284	520500	1012697	12/13/2017	1/17/2018	-21,763.29	02,AM	Other	10/1/17	10/31/17	15.50	1/17/2018	93.50	21,763.29	2,034,867.62
3300013360	RV	3900000283	520500	1012697	12/13/2017	1/17/2018	-519.05	02,AM	Other	10/1/17	10/31/17	15.50	1/17/2018	93.50	519.05	48,531.18
3300013361	RV	3300013361	520500	1005335	12/12/2017	12/13/2017	60.26	02,AM	DIRECT ENERGY SERVICE	10/1/17	10/31/17	15.50	12/13/2017	58.50	(60.26)	(3,525.21)
3300013362	RV	3900000900	520500	1012697	12/12/2017	2/22/2018	-60.26	02,AM	Other	10/1/17	10/31/17	15.50	2/22/2018	129.50	60.26	7,803.67
3300013424	RV	3900000261	520500	1008816	12/15/2017	1/17/2018	-36.99	02,AM	IDT ENERGY INC	10/1/17	10/31/17	15.50	1/17/2018	93.50	36.99	3,458.57
3300013425	RV	3900000078	520500	1010474	12/15/2017	1/5/2018	-134.36	02,AM	INSPIRED ENERGY HOLDINGS, LLC	10/1/17	10/31/17	15.50	1/5/2018	81.50	134.36	10,950.34
3300013426	RV	3900001112	520500	1013158	12/15/2017	3/6/2018	-45.63	02,AM	Other	10/1/17	10/31/17	15.50	3/6/2018	141.50	45.63	6,456.65
3300013427	RV	3900000350	520500	1005660	12/15/2017	1/22/2018	-265.87	02,AM	LIBERTY POWER HOLDINGS	10/1/17	10/31/17	15.50	1/22/2018	98.50	265.87	26,188.20
3300013428	RV	3900000295	520500	1012957	12/15/2017	1/17/2018	-0.56	02,AM	Other	10/1/17	10/31/17	15.50	1/17/2018	93.50	0.56	52.36
3300013429	RV	3900000015	520500	1009271	12/15/2017	1/2/2018	-21.38	02,AM	MAJOR ENERGY	10/1/17	10/31/17	15.50	1/2/2018	78.50	21.38	1,678.33
3300013431	RV	3900000955	520500	1012688	12/15/2017	2/27/2018	-228.46	02,AM	Other	10/1/17	10/31/17	15.50	2/27/2018	134.50	228.46	30,727.87
3300013432	RV	3900000320	520500	1012681	12/15/2017	1/18/2018	-9.88	02,AM	Other	10/1/17	10/31/17	15.50	1/18/2018	94.50	9.88	933.66
3300013433	RV	3900000584	520500	1006334	12/15/2017	2/2/2018	-141.00	02,AM	NEXTERA ENERGY	10/1/17	10/31/17	15.50	2/2/2018	109.50	141.00	15,439.50
3300013434	RV	3900001264	520500	1006334	12/15/2017	3/9/2018	-0.93	02,AM	NEXTERA ENERGY	10/1/17	10/31/17	15.50	3/9/2018	144.50	0.93	134.39
3300013457	RV	3900001009	520500	1012700	12/15/2017	2/27/2018	-880.07	02,AM	Other	10/1/17	10/31/17	15.50	2/27/2018	134.50	880.07	118,369.42
3300013459	RV	3900001027	520500	1010814	12/15/2017	2/27/2018	-23.75	02,AM	NORDIC ENERGY SERVICES, LLC	10/1/17	10/31/17	15.50	2/27/2018	134.50	23.75	3,194.38
3300013460	RV	3900001127	520500	1007590	12/15/2017	3/6/2018	-39.75	02,AM	NORTH AMERICAN	10/1/17	10/31/17	15.50	3/6/2018	141.50	39.75	5,624.63
3300013465	RV	3900001045	520500	1013113	12/15/2017	2/27/2018	-40.59	02,AM	Other	10/1/17	10/31/17	15.50	2/27/2018	134.50	40.59	5,459.36
3300013468	RV	3900000066	520500	1008419	12/15/2017	1/5/2018	-23.52	02,AM	PALMCO POWER MD LLC	10/1/17	10/31/17	15.50	1/5/2018	81.50	23.52	1,916.88
3300013469	RV	3900000049	520500	1011199	12/15/2017	1/4/2018	-10.01	02,AM	PLYMOUTH ROCK ENERGY	10/1/17	10/31/17	15.50	1/4/2018	80.50	10.01	805.81
3300013635	RV	3900000837	520500	1007744	12/20/2017	2/15/2018	-160.19	02,AM	RELIANT ENERGY	10/1/17	10/31/17	15.50	2/15/2018	122.50	160.19	19,623.28
3300013638	RV	3900000250	520500	1010473	12/20/2017	1/16/2018	-45.36	02,AM	SFE ENERGY	10/1/17	10/31/17	15.50	1/16/2018	92.50	45.36	4,195.80
3300013639	RV	3900000925	520500	1013289	12/20/2017	2/23/2018	-11.12	02,AM	Other	10/1/17	10/31/17	15.50	2/23/2018	130.50	11.12	1,451.16
3300013640	RV	3900000020	520500	1009721	12/20/2017	1/3/2018	-175.49	02,AM	SOURCE POWER & GAS	10/1/17	10/31/17	15.50	1/3/2018	79.50	175.49	13,951.46
3300013641	RV	3900000494	520500	1012790	12/20/2017	1/30/2018	-2.61	02,AM	Other	10/1/17	10/31/17	15.50	1/30/2018	106.50	2.61	277.97
3300013643	RV	3900000299	520500	1007751	12/20/2017	1/17/2018	-27.20	02,AM	STARION ENERGY	10/1/17	10/31/17	15.50	1/17/2018	93.50	27.20	2,543.20
3300013645	RV	3900000156	520500	1007745	12/20/2017	1/10/2018	-84.90	02,AM	STREAM ENERGY	10/1/17	10/31/17	15.50	1/10/2018	86.50	84.90	7,343.85
3300013646	RV	3900000415	520500	1012016	12/20/2017	1/25/2018	-128.61	02,AM	TALEN ENERGY	10/1/17	10/31/17	15.50	1/25/2018	101.50	128.61	13,053.92
3300013647	RV	3900000393	520500	1012701	12/20/2017	1/23/2018	-25.04	02,AM	Other	10/1/17	10/31/17	15.50	1/23/2018	99.50	25.04	2,491.48
3300013648	RV	3900000323	520500	1012690	12/20/2017	1/18/2018	-10.67	02,AM	Other	10/1/17	10/31/17	15.50	1/18/2018	94.50	10.67	1,008.32
3300013649	RV	3900000399	520500	1009260	12/20/2017	1/24/2018	-22.34	02,AM	UGI ENERGY SERVICES INC	10/1/17	10/31/17	15.50	1/24/2018	100.50	22.34	2,245.17
3300013683	RV	3900000465	520500	1013114	12/20/2017	1/29/2018	-1,278.29	02,AM	Other	10/1/17	10/31/17	15.50	1/29/2018	105.50	1,278.29	134,859.60
3300013684	RV	3900000465	520500	1013114	12/20/2017	1/29/2018	-4,638.66	02,AM	Other	10/1/17	10/31/17	15.50	1/29/2018	105.50	4,638.66	489,378.63
3300013686	RV	3900000669	520500	1008458	12/20/2017	2/7/2018	-147.07	02,AM	XOOM ENERGY	10/1/17	10/31/17	15.50	2/7/2018	114.50	147.07	16,839.52
3300002718	RV	3800000039	520500	1012686	3/15/2017	2/27/2018	-1,745.30	02,BS	Other	11/1/17	12/31/17	30.50	2/27/2018	88.50	1,745.30	154,459.05
3300002718	RV	3800000039	520500	1012686	3/15/2017	2/27/2018	-1,873.02	02,BS	Other	11/1/17	12/31/17	30.50	2/27/2018	88.50	1,873.02	165,762.27
3300002883	RV	3800000038	520500	1012699	3/20/2017	2/27/2018	-95.94	02,BS	Other	11/1/17	12/31/17	30.50	2/27/2018	88.50	95.94	8,490.69
3300002883	RV	3800000038	520500	1012699	3/20/2017	2/27/2018	-105.31	02,BS	Other	11/1/17	12/31/17	30.50	2/27/2018	88.50	105.31	9,319.94
3300003194	RV	3900007216	520500	1008419	3/24/2017	11/17/2017	-756.66	02,BS	PALMCO POWER MD LLC	11/1/17	12/31/17	30.50	11/17/2017	(13.50)	756.66	(10,214.91)
3300003194	RV	3900007216	520500	1008419	3/24/2017	11/17/2017	-772.78	02,BS	PALMCO POWER MD LLC	11/1/17	12/31/17	30.50	11/17/2017	(13.50)	772.78	(10,432.53)

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3300003542	RV	3900004962	520500	1012860	3/29/2017	7/31/2017	-0.62	02,BS	Other	11/1/17	12/31/17	30.50	7/31/2017	(122.50)	0.62	(75.95)
3300004774	RV	3900004913	520500	1012685	4/26/2017	7/28/2017	-101.09	02,BS	Other	11/1/17	12/31/17	30.50	7/28/2017	(125.50)	101.09	(12,686.80)
3300004774	RV	3900004913	520500	1012685	4/26/2017	7/28/2017	-96.59	02,BS	Other	11/1/17	12/31/17	30.50	7/28/2017	(125.50)	96.59	(12,122.05)
3300005085	RV	3900004448	520500	1013114	4/27/2017	7/7/2017	-21,695.63	02,BS	Other	11/1/17	12/31/17	30.50	7/7/2017	(146.50)	21,695.63	(3,178,409.80)
3300005085	RV	3900004448	520500	1013114	4/27/2017	7/7/2017	-21,350.34	02,BS	Other	11/1/17	12/31/17	30.50	7/7/2017	(146.50)	21,350.34	(3,127,824.81)
3300005112	RV	3300000098	520500	1009859	4/27/2017	1/5/2018	-21.37	02,BS	Other	11/1/17	12/31/17	30.50	1/5/2018	35.50	21.37	758.64
3300005112	RV	3300000098	520500	1009859	4/27/2017	1/5/2018	-11.94	02,BS	Other	11/1/17	12/31/17	30.50	1/5/2018	35.50	11.94	423.87
3300006475	RV	3300006476	520500	1012511	6/11/2017	6/11/2017	-44.25	02,BS	AGERA ENERGY	1/1/17	4/30/17	60.00	6/11/2017	102.00	44.25	4,513.50
3300006475	RV	3300006476	520500	1012511	6/11/2017	6/11/2017	-469.96	02,BS	AGERA ENERGY	1/1/17	4/30/17	60.00	6/11/2017	102.00	469.96	47,935.92
3300006476	RV	3300006476	520500	1012511	6/11/2017	6/11/2017	44.25	02,BS	AGERA ENERGY	1/1/17	4/30/17	60.00	6/11/2017	102.00	(44.25)	(4,513.50)
3300006476	RV	3300006476	520500	1012511	6/11/2017	6/11/2017	469.96	02,BS	AGERA ENERGY	1/1/17	4/30/17	60.00	6/11/2017	102.00	(469.96)	(47,935.92)
3300006478	RV	3900004449	520500	1012511	6/11/2017	7/7/2017	-1,088.04	02,BS	AGERA ENERGY	1/1/17	4/30/17	60.00	7/7/2017	128.00	1,088.04	139,269.12
3300006482	RV	3300006483	520500	1007588	6/11/2017	6/11/2017	-13,418.50	02,BS	CLEARVIEW ENERGY	1/1/17	4/30/17	60.00	6/11/2017	102.00	13,418.50	1,368,687.00
3300006483	RV	3300006483	520500	1007588	6/11/2017	6/11/2017	13,418.50	02,BS	CLEARVIEW ENERGY	1/1/17	4/30/17	60.00	6/11/2017	102.00	(13,418.50)	(1,368,687.00)
3300006484	RV	3900004201	520500	1009421	6/11/2017	6/30/2017	-13,418.50	02,BS	ETHICAL ELECTRIC	1/1/17	4/30/17	60.00	6/30/2017	121.00	13,418.50	1,623,638.50
3300006485	RV	3900004202	520500	1007588	6/11/2017	6/30/2017	-6,424.27	02,BS	CLEARVIEW ENERGY	1/1/17	4/30/17	60.00	6/30/2017	121.00	6,424.27	777,336.67
3300006489	RV	3900004317	520500	1007321	6/11/2017	7/3/2017	-4,974.32	02,BS	CONSTELLATION ELECTRIC	1/1/17	4/30/17	60.00	7/3/2017	124.00	4,974.32	616,815.68
3300006494	RV	3900004307	520500	1010004	6/11/2017	7/3/2017	-147.00	02,BS	DIRECT ENERGY BUSINESS MARKETING	1/1/17	4/30/17	60.00	7/3/2017	124.00	147.00	18,228.00
3300006562	RV	3900004261	520500	1013222	6/14/2017	7/3/2017	-100.00	02,BS	Other	1/1/17	4/30/17	60.00	7/3/2017	124.00	100.00	12,400.00
3300006757	RV	3900004606	520500	1012697	6/19/2017	7/14/2017	-2,321.68	02,BS	Other	1/1/17	4/30/17	60.00	7/14/2017	135.00	2,321.68	313,426.80
3300006758	RV	3900004605	520500	1005335	6/19/2017	7/14/2017	-47,326.38	02,BS	DIRECT ENERGY SERVICE	1/1/17	4/30/17	60.00	7/14/2017	135.00	47,326.38	6,389,061.30
3300006759	RV	3900004630	520500	1012081	6/19/2017	7/14/2017	-94.14	02,BS	Other	1/1/17	4/30/17	60.00	7/14/2017	135.00	94.14	12,708.90
3300006882	RV	3900004670	520500	1009857	6/22/2017	7/18/2017	-49.82	02,BS	ELIGO ENERGY DC, LLC	1/1/17	4/30/17	60.00	7/18/2017	139.00	49.82	6,924.98
3300006883	RV	3900004884	520500	1010701	6/22/2017	7/27/2017	-845.09	02,BS	ENERGY ME	1/1/17	4/30/17	60.00	7/27/2017	148.00	845.09	125,073.32
3300006883	RV	3900004884	520500	1010701	6/22/2017	7/27/2017	-141.34	02,BS	ENERGY ME	1/1/17	4/30/17	60.00	7/27/2017	148.00	141.34	20,918.32
3300006885	RV	3900004714	520500	1013112	6/22/2017	7/19/2017	-412.74	02,BS	Other	1/1/17	4/30/17	60.00	7/19/2017	140.00	412.74	57,783.60
3300006885	RV	3900004714	520500	1013112	6/22/2017	7/19/2017	-172.78	02,BS	Other	1/1/17	4/30/17	60.00	7/19/2017	140.00	172.78	24,189.20
3300006887	RV	3900004727	520500	1012351	6/22/2017	7/19/2017	-190.96	02,BS	ENTRUST ENERGY NORTH	1/1/17	4/30/17	60.00	7/19/2017	140.00	190.96	26,734.40
3300006936	RV	3900004864	520500	1005415	6/26/2017	7/26/2017	-57.00	02,BS	FIRST ENERGY SOLUTIONS	1/1/17	4/30/17	60.00	7/26/2017	147.00	57.00	8,379.00
3300006939	RV	3900004628	520500	1009802	6/26/2017	7/14/2017	-51.46	02,BS	HIKO ENERGY, LLC	1/1/17	4/30/17	60.00	7/14/2017	135.00	51.46	6,947.10
3300006940	RV	3900004829	520500	1005867	6/26/2017	7/25/2017	-1,688.58	02,BS	HORIZON POWER AND LIGHT	1/1/17	4/30/17	60.00	7/25/2017	146.00	1,688.58	246,532.68
3300006941	RV	3900004674	520500	1008816	6/26/2017	7/18/2017	-7,939.72	02,BS	IDT ENERGY INC	1/1/17	4/30/17	60.00	7/18/2017	139.00	7,939.72	1,103,621.08
3300006942	RV	3900004726	520500	1010474	6/26/2017	7/19/2017	-13,455.79	02,BS	INSPIRED ENERGY HOLDINGS, LLC	1/1/17	4/30/17	60.00	7/19/2017	140.00	13,455.79	1,883,810.60
3300006945	RV	3300007198	520500	1012957	6/26/2017	6/28/2017	-3.72	02,BS	Other	1/1/17	4/30/17	60.00	6/28/2017	119.00	3.72	442.68
3300006946	RV	3900004717	520500	1009271	6/26/2017	7/19/2017	-1,972.83	02,BS	MAJOR ENERGY	1/1/17	4/30/17	60.00	7/19/2017	140.00	1,972.83	276,196.20
3300006946	RV	3900004717	520500	1009271	6/26/2017	7/19/2017	-4,809.99	02,BS	MAJOR ENERGY	1/1/17	4/30/17	60.00	7/19/2017	140.00	4,809.99	673,398.60
3300006947	RV	3900004915	520500	1008815	6/26/2017	7/28/2017	-11,235.68	02,BS	MARYLAND GAS & ELECTRIC	1/1/17	4/30/17	60.00	7/28/2017	149.00	11,235.68	1,674,116.32
3300006948	RV	3300007202	520500	1012688	6/26/2017	6/28/2017	-413.40	02,BS	Other	1/1/17	4/30/17	60.00	6/28/2017	119.00	413.40	49,194.60
3300006948	RV	3300007202	520500	1012688	6/26/2017	6/28/2017	-242.61	02,BS	Other	1/1/17	4/30/17	60.00	6/28/2017	119.00	242.61	28,870.59
3300006951	RV	3900004627	520500	1010814	6/26/2017	7/14/2017	-120.63	02,BS	NORDIC ENERGY SERVICES, LLC	1/1/17	4/30/17	60.00	7/14/2017	135.00	120.63	16,285.05
3300006955	RV	3900004645	520500	1011199	6/26/2017	7/17/2017	-964.68	02,BS	PLYMOUTH ROCK ENERGY	1/1/17	4/30/17	60.00	7/17/2017	138.00	964.68	133,125.84
3300006956	RV	3900004912	520500	1007589	6/26/2017	7/28/2017	-7,999.54	02,BS	PUBLIC POWER	1/1/17	4/30/17	60.00	7/28/2017	149.00	7,999.54	1,191,931.46
3300006963	RV	3900004851	520500	1010182	6/26/2017	7/25/2017	-249.14	02,BS	SOURCE POWER & GAS	1/1/17	4/30/17	60.00	7/25/2017	146.00	249.14	36,374.44
3300006986	RV	3900004629	520500	1007751	6/26/2017	7/14/2017	-3,533.92	02,BS	STARION ENERGY	1/1/17	4/30/17	60.00	7/14/2017	135.00	3,533.92	477,079.20
3300006986	RV	3900004629	520500	1007751	6/26/2017	7/14/2017	-2,421.16	02,BS	STARION ENERGY	1/1/17	4/30/17	60.00	7/14/2017	135.00	2,421.16	326,856.60
3300006989	RV	3900004536	520500	1007745	6/26/2017	7/12/2017	-8,105.81	02,BS	STREAM ENERGY	1/1/17	4/30/17	60.00	7/12/2017	133.00	8,105.81	1,078,072.73
3300006991	RV	3900004644	520500	1012690	6/26/2017	7/17/2017	-233.51	02,BS	Other	1/1/17	4/30/17	60.00	7/17/2017	138.00	233.51	32,224.38
3300007041	RV	3900004841	520500	1008458	6/26/2017	7/25/2017	-3,432.56	02,BS	XOOM ENERGY	1/1/17	4/30/17	60.00	7/25/2017	146.00	3,432.56	501,153.76
3300007198	RV	3300007198	520500	1012957	6/26/2017	6/28/2017	3.72	02,BS	Other	1/1/17	4/30/17	60.00	6/28/2017	119.00	(3.72)	(442.68)
3300007199	RV	3900004728	520500	1012957	6/28/2017	7/19/2017	-3.10	02,BS	Other	1/1/17	4/30/17	60.00	7/19/2017	140.00	3.10	434.00
3300007199	RV	3900004728	520500	1012957	6/28/2017	7/19/2017	-0.62	02,BS	Other	1/1/17	4/30/17	60.00	7/19/2017	140.00	0.62	86.80
3300007202	RV	3300007202	520500	1012688	6/26/2017	6/28/2017	413.40	02,BS	Other	1/1/17	4/30/17	60.00	6/28/2017	119.00	(413.40)	(49,194.60)
3300007202	RV	3300007202	520500	1012688	6/26/2017	6/28/2017	242.61	02,BS	Other	1/1/17	4/30/17	60.00	6/28/2017	119.00	(242.61)	(28,870.59)
3300007203	RV	3900004643	520500	1012688	6/28/2017	7/17/2017	-413.42	02,BS	Other	1/1/17	4/30/17	60.00	7/17/2017	138.00	413.42	57,051.96
3300007203	RV	3900004643	520500	1012688	6/28/2017	7/17/2017	-242.61	02,BS	Other	1/1/17	4/30/17	60.00	7/17/2017	138.00	242.61	33,480.18
3300008611	RV	3900005982	520500	1012016	8/13/2017	9/20/2017	-53.74	02,BS	TALEN ENERGY	6/1/17	6/30/17	15.00	9/20/2017	97.00	53.74	5,212.78
3300008612	RV	3900006363	520500	1007587	8/13/2017	10/10/2017	-112.96	02,BS	AEP ENERGY	6/1/17	6/30/17	15.00	10/10/2017	117.00	112.96	13,216.32
3300008613	RV	3900005951	520500	1009421	8/13/2017	9/20/2017	-3,399.42	02,BS	ETHICAL ELECTRIC	6/1/17	6/30/17	15.00	9/20/2017	97.00	3,399.42	329,743.74
3300008617	RV	3900005672	520500	1010473	8/13/2017	9/5/2017	-537.32	02,BS	SFE ENERGY	6/1/17	6/30/17	15.00	9/5/2017	82.00	537.32	44,060.24
3300008618	RV	3900005402	520500	1008458	8/13/2017	8/22/2017	-2,952.82	02,BS	XOOM ENERGY	6/1/17	6/30/17	15.00	8/22/2017	68.00	2,952.82	200,791.76
3300008619	RV	3900005580	520500	1010474	8/13/2017	8/30/2017	-4,211.23	02,BS	INSPIRED ENERGY HOLDINGS, LLC	6/1/17	6/30/17	15.00	8/30/2017	76.00	4,211.23	320,053.48
3300008620	RV	3900005574	520500	1012511	8/13/2017	8/30/2017	-383.36	02,BS	AGERA ENERGY	6/1/17	6/30/17	15.00	8/30/2017	76.00	383.36	29,135.36

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital Study
For the Period January 2017 through December 2017
Other Revenue Lag
Billing Services and Account Management for Third Party Suppliers

											Service period					
Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Third party name	Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300008621	RV	3900006401	520500	1012688	8/13/2017	10/12/2017	-137.97	02,BS	Other	6/1/17	6/30/17	15.00	10/12/2017	119.00	137.97	16,418.43
3300008622	RV	3900005690	520500	1012690	8/13/2017	9/6/2017	-276.65	02,BS	Other	6/1/17	6/30/17	15.00	9/6/2017	83.00	276.65	22,961.95
3300008623	RV	3900006249	520500	1012681	8/13/2017	10/4/2017	-70.94	02,BS	Other	6/1/17	6/30/17	15.00	10/4/2017	111.00	70.94	7,874.34
3300008624	RV	3900006003	520500	1012957	8/13/2017	9/21/2017	-8.06	02,BS	Other	6/1/17	6/30/17	15.00	9/21/2017	98.00	8.06	789.88
3300008625	RV	3900006057	520500	1013112	8/13/2017	9/22/2017	-111.59	02,BS	Other	6/1/17	6/30/17	15.00	9/22/2017	99.00	111.59	11,047.41
3300008626	RV	3900006119	520500	1010814	8/13/2017	9/27/2017	-32.71	02,BS	NORDIC ENERGY SERVICES, LLC	6/1/17	6/30/17	15.00	9/27/2017	104.00	32.71	3,401.84
3300008627	RV	3900005688	520500	1005335	8/13/2017	9/6/2017	-12,020.06	02,BS	DIRECT ENERGY SERVICE	6/1/17	6/30/17	15.00	9/6/2017	83.00	12,020.06	997,664.98
3300008644	RV	3900006015	520500	1006334	8/14/2017	9/21/2017	-160.60	02,BS	NEXTERA ENERGY	6/1/17	6/30/17	15.00	9/21/2017	98.00	160.60	15,738.80
3300008645	RV	3900006015	520500	1006334	8/14/2017	9/21/2017	-23.56	02,BS	NEXTERA ENERGY	6/1/17	6/30/17	15.00	9/21/2017	98.00	23.56	2,308.88
3300008648	RV	3900006250	520500	1011510	8/14/2017	10/4/2017	-184.14	02,BS	GREEN MOUNTAIN ENERGY CO.	6/1/17	6/30/17	15.00	10/4/2017	111.00	184.14	20,439.54
3300008649	RV	3900005798	520500	1005867	8/14/2017	9/12/2017	-429.30	02,BS	HORIZON POWER AND LIGHT	6/1/17	6/30/17	15.00	9/12/2017	89.00	429.30	38,207.70
3300008651	RV	3900007036	520500	1007992	8/14/2017	11/8/2017	-2,218.70	02,BS	AMBIT ENERGY	6/1/17	6/30/17	15.00	11/8/2017	146.00	2,218.70	323,930.20
3300008652	RV	3900006538	520500	1005660	8/14/2017	10/19/2017	-662.89	02,BS	LIBERTY POWER HOLDINGS	6/1/17	6/30/17	15.00	10/19/2017	126.00	662.89	83,524.14
3300008654	RV	3300008753	520500	1007588	8/14/2017	8/18/2017	-1,616.96	02,BS	CLEARVIEW ENERGY	6/1/17	6/30/17	15.00	8/18/2017	64.00	1,616.96	103,485.44
3300008663	RV	3900005478	520500	1009857	8/14/2017	8/25/2017	-24.73	02,BS	ELIGO ENERGY DC, LLC	6/1/17	6/30/17	15.00	8/25/2017	71.00	24.73	1,755.83
3300008664	RV	3900006247	520500	1009259	8/14/2017	10/4/2017	-230.82	02,BS	Champion Energy Services LLC	6/1/17	6/30/17	15.00	10/4/2017	111.00	230.82	25,621.02
3300008667	RV	3900005849	520500	1012697	8/14/2017	9/13/2017	-664.96	02,BS	Other	6/1/17	6/30/17	15.00	9/13/2017	90.00	664.96	59,846.40
3300008669	RV	3900006674	520500	1007420	8/14/2017	10/25/2017	-1,336.37	02,BS	ENERGY PLUS HOLDING	6/1/17	6/30/17	15.00	10/25/2017	132.00	1,336.37	176,400.84
3300008670	RV	3900005900	520500	1009271	8/14/2017	9/18/2017	-570.84	02,BS	MAJOR ENERGY	6/1/17	6/30/17	15.00	9/18/2017	95.00	570.84	54,229.80
3300008671	RV	3900005532	520500	1008816	8/14/2017	8/29/2017	-1,721.73	02,BS	IDT ENERGY INC	6/1/17	6/30/17	15.00	8/29/2017	75.00	1,721.73	129,129.75
3300008672	RV	3900007023	520500	1008181	8/14/2017	11/8/2017	-137.25	02,BS	CONSOLIDATED EDISON	6/1/17	6/30/17	15.00	11/8/2017	146.00	137.25	20,038.50
3300008673	RV	3900006035	520500	1011199	8/14/2017	9/21/2017	-239.18	02,BS	PLYMOUTH ROCK ENERGY	6/1/17	6/30/17	15.00	9/21/2017	98.00	239.18	23,439.64
3300008711	RV	3900005627	520500	1009802	8/16/2017	8/31/2017	-12.40	02,BS	HIKO ENERGY, LLC	6/1/17	6/30/17	15.00	8/31/2017	77.00	12.40	954.80
3300008725	RV	3900006276	520500	1009260	8/17/2017	10/6/2017	-6.00	02,BS	UGI ENERGY SERVICES INC	6/1/17	6/30/17	15.00	10/6/2017	113.00	6.00	678.00
3300008729	RV	3900006405	520500	1008568	8/17/2017	10/12/2017	-493.03	02,BS	GREAT AMERICAN POWER	6/1/17	6/30/17	15.00	10/12/2017	119.00	493.03	58,670.57
3300008730	RV	3300008834	520500	1012351	8/17/2017	8/21/2017	-828.56	02,BS	ENTRUST ENERGY NORTH	6/1/17	6/30/17	15.00	8/21/2017	67.00	828.56	55,513.52
3300008731	RV	3900006399	520500	1007744	8/17/2017	10/12/2017	-988.63	02,BS	RELIANT ENERGY	6/1/17	6/30/17	15.00	10/12/2017	119.00	988.63	117,646.97
3300008732	RV	3900005422	520500	1007745	8/17/2017	8/23/2017	-1,985.97	02,BS	STREAM ENERGY	6/1/17	6/30/17	15.00	8/23/2017	69.00	1,985.97	137,031.93
3300008733	RV	3900006628	520500	1008878	8/17/2017	10/23/2017	-165.58	02,BS	AP GAS AND ELECTRIC	6/1/17	6/30/17	15.00	10/23/2017	130.00	165.58	21,525.40
3300008734	RV	3900006362	520500	1012790	8/17/2017	10/10/2017	-93.00	02,BS	Other	6/1/17	6/30/17	15.00	10/10/2017	117.00	93.00	10,881.00
3300008735	RV	3900005832	520500	1010701	8/17/2017	9/13/2017	-253.00	02,BS	ENERGY ME	6/1/17	6/30/17	15.00	9/13/2017	90.00	253.00	22,770.00
3300008736	RV	3900006057	520500	1013112	8/17/2017	9/22/2017	-172.79	02,BS	Other	6/1/17	6/30/17	15.00	9/22/2017	99.00	172.79	17,106.21
3300008737	RV	3900006602	520500	1009721	8/17/2017	10/23/2017	-84.31	02,BS	SOURCE POWER & GAS	6/1/17	6/30/17	15.00	10/23/2017	130.00	84.31	10,960.30
3300008748	RV	3900006041	520500	1012081	8/18/2017	9/21/2017	-32.37	02,BS	Other	6/1/17	6/30/17	15.00	9/21/2017	98.00	32.37	3,172.26
3300008750	RV	3900006168	520500	1008131	8/18/2017	9/29/2017	-1,172.23	02,BS	OASIS ENERGY	6/1/17	6/30/17	15.00	9/29/2017	106.00	1,172.23	124,256.38
3300008751	RV	3900005801	520500	1007590	8/18/2017	9/12/2017	-920.01	02,BS	NORTH AMERICAN	6/1/17	6/30/17	15.00	9/12/2017	89.00	920.01	81,880.89
3300008753	RV	3300008753	520500	1007588	8/14/2017	8/18/2017	1,616.96	02,BS	CLEARVIEW ENERGY	6/1/17	6/30/17	15.00	8/18/2017	64.00	(1,616.96)	(103,485.44)
3300008754	RV	3900006051	520500	1007588	8/14/2017	9/22/2017	-1,619.96	02,BS	CLEARVIEW ENERGY	6/1/17	6/30/17	15.00	9/22/2017	99.00	1,619.96	160,376.04
3300008834	RV	3300008834	520500	1012351	8/17/2017	8/21/2017	828.56	02,BS	ENTRUST ENERGY NORTH	6/1/17	6/30/17	15.00	8/21/2017	67.00	(828.56)	(55,513.52)
3300008835	RV	3900006034	520500	1007751	8/17/2017	9/21/2017	-611.80	02,BS	STARION ENERGY	6/1/17	6/30/17	15.00	9/21/2017	98.00	611.80	59,956.40
3300008835	RV	3900006034	520500	1007751	8/17/2017	9/21/2017	-828.56	02,BS	STARION ENERGY	6/1/17	6/30/17	15.00	9/21/2017	98.00	828.56	81,198.88
3300009257	RV	3900006251	520500	1012016	8/29/2017	10/4/2017	-50.74	02,BS	TALEN ENERGY	6/1/17	6/30/17	15.00	10/4/2017	111.00	50.74	5,632.14
3300009258	RV	3900006059	520500	1007587	8/29/2017	9/22/2017	-115.96	02,BS	AEP ENERGY	6/1/17	6/30/17	15.00	9/22/2017	99.00	115.96	11,480.04
3300009259	RV	3900006104	520500	1009421	8/29/2017	9/26/2017	-3,455.84	02,BS	ETHICAL ELECTRIC	6/1/17	6/30/17	15.00	9/26/2017	103.00	3,455.84	355,951.52
3300009261	RV	3900006257	520500	1012351	8/29/2017	10/4/2017	-51.36	02,BS	ENTRUST ENERGY NORTH	6/1/17	6/30/17	15.00	10/4/2017	111.00	51.36	5,700.96
3300009263	RV	3900005901	520500	1010473	8/29/2017	9/18/2017	-512.57	02,BS	SFE ENERGY	6/1/17	6/30/17	15.00	9/18/2017	95.00	512.57	48,694.15
3300009265	RV	3900006154	520500	1010474	8/29/2017	9/28/2017	-3,965.48	02,BS	INSPIRED ENERGY HOLDINGS, LLC	6/1/17	6/30/17	15.00	9/28/2017	105.00	3,965.48	416,375.40
3300009266	RV	3900005968	520500	1012511	8/29/2017	9/20/2017	-325.28	02,BS	AGERA ENERGY	6/1/17	6/30/17	15.00	9/20/2017	97.00	325.28	31,552.16
3300009267	RV	3900006894	520500	1012688	8/29/2017	11/1/2017	-141.85	02,BS	Other	6/1/17	6/30/17	15.00	11/1/2017	139.00	141.85	19,717.15
3300009268	RV	3900005975	520500	1012690	8/29/2017	9/20/2017	-224.57	02,BS	Other	6/1/17	6/30/17	15.00	9/20/2017	97.00	224.57	21,783.29
3300009271	RV	3900006117	520500	1013112	8/29/2017	9/27/2017	-109.34	02,BS	Other	6/1/17	6/30/17	15.00	9/27/2017	104.00	109.34	11,371.36
3300009272	RV	3900006876	520500	1010814	8/29/2017	11/1/2017	-31.47	02,BS	NORDIC ENERGY SERVICES, LLC	6/1/17	6/30/17	15.00	11/1/2017	139.00	31.47	4,374.33
3300009273	RV	3900006970	520500	1005335	8/29/2017	11/6/2017	-11,620.91	02,BS	DIRECT ENERGY SERVICE	6/1/17	6/30/17	15.00	11/6/2017	144.00	11,620.91	1,673,411.04
3300009274	RV	3900006294	520500	1006334	8/29/2017	10/6/2017	-137.17	02,BS	NEXTERA ENERGY	6/1/17	6/30/17	15.00	10/6/2017	113.00	137.17	15,500.21
3300009276	RV	3900006294	520500	1006334	8/29/2017	10/6/2017	-21.08	02,BS	NEXTERA ENERGY	6/1/17	6/30/17	15.00	10/6/2017	113.00	21.08	2,382.04
3300009284	RV	3900006673	520500	1011510	8/29/2017	10/25/2017	-160.58	02,BS	GREEN MOUNTAIN ENERGY CO.	6/1/17	6/30/17	15.00	10/25/2017	132.00	160.58	21,196.56
3300009286	RV	3900006040	520500	1005867	8/29/2017	9/21/2017	-413.38	02,BS	HORIZON POWER AND LIGHT	6/1/17	6/30/17	15.00	9/21/2017	98.00	413.38	40,511.24
3300009298	RV	3900007036	520500	1007992	8/29/2017	11/8/2017	-2,151.71	02,BS	AMBIT ENERGY	6/1/17	6/30/17	15.00	11/8/2017	146.00	2,151.71	314,149.66
3300009301	RV	3900006007	520500	1005660	8/29/2017	9/21/2017	-666.77	02,BS	LIBERTY POWER HOLDINGS	6/1/17	6/30/17	15.00	9/21/2017	98.00	666.77	65,343.46
3300009312	RV	3900005981	520500	1007588	8/29/2017	9/20/2017	-1,680.72	02,BS	CLEARVIEW ENERGY	6/1/17	6/30/17	15.00	9/20/2017	97.00	1,680.72	163,029.84
3300009315	RV	3900005737	520500	1009857	8/29/2017	9/8/2017	-21.99	02,BS	ELIGO ENERGY DC, LLC	6/1/17	6/30/17	15.00	9/8/2017	85.00	21.99	1,869.15
3300009316	RV	3900005901	520500	1010473	8/29/2017	9/18/2017	-37.84	02,BS	SFE ENERGY	6/1/17	6/30/17	15.00	9/18/2017	95.00	37.84	3,594.80

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											Service period					
Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Third party name	Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300009317	RV	3900005973	520500	1009259	8/29/2017	9/20/2017	-229.19	02,BS	Champion Energy Services LLC	6/1/17	6/30/17	15.00	9/20/2017	97.00	229.19	22,231.43
3300009325	RV	3900006013	520500	1012697	8/30/2017	9/21/2017	-626.35	02,BS	Other	6/1/17	6/30/17	15.00	9/21/2017	98.00	626.35	61,382.30
3300009329	RV	3900006831	520500	1007420	8/30/2017	10/30/2017	-1,301.39	02,BS	ENERGY PLUS HOLDING	6/1/17	6/30/17	15.00	10/30/2017	137.00	1,301.39	178,290.43
3300009330	RV	3900005900	520500	1009271	8/30/2017	9/18/2017	-485.41	02,BS	MAJOR ENERGY	6/1/17	6/30/17	15.00	9/18/2017	95.00	485.41	46,113.95
3300009331	RV	3900006697	520500	1008816	8/30/2017	10/26/2017	-1,856.27	02,BS	IDT ENERGY INC	6/1/17	6/30/17	15.00	10/26/2017	133.00	1,856.27	246,883.91
3300009332	RV	3900007023	520500	1008181	8/30/2017	11/8/2017	-566.21	02,BS	CONSOLIDATED EDISON	6/1/17	6/30/17	15.00	11/8/2017	146.00	566.21	82,666.66
3300009333	RV	3900006101	520500	1011199	8/30/2017	9/25/2017	-241.92	02,BS	PLYMOUTH ROCK ENERGY	6/1/17	6/30/17	15.00	9/25/2017	102.00	241.92	24,675.84
3300009334	RV	3900006041	520500	1012081	8/30/2017	9/21/2017	-30.51	02,BS	Other	6/1/17	6/30/17	15.00	9/21/2017	98.00	30.51	2,989.98
3300009335	RV	3900005854	520500	1008419	8/30/2017	9/14/2017	-1,633.34	02,BS	PALMCO POWER MD LLC	6/1/17	6/30/17	15.00	9/14/2017	91.00	1,633.34	148,633.94
3300009336	RV	3900006819	520500	1008131	8/30/2017	10/30/2017	-791.29	02,BS	OASIS ENERGY	6/1/17	6/30/17	15.00	10/30/2017	137.00	791.29	108,406.73
3300009337	RV	3900006100	520500	1007590	8/30/2017	9/25/2017	-871.03	02,BS	NORTH AMERICAN	6/1/17	6/30/17	15.00	9/25/2017	102.00	871.03	88,845.06
3300009339	RV	3900005967	520500	1009802	8/30/2017	9/20/2017	-12.40	02,BS	HIKO ENERGY, LLC	6/1/17	6/30/17	15.00	9/20/2017	97.00	12.40	1,202.80
3300009343	RV	3900006828	520500	1009260	8/30/2017	10/30/2017	-6.00	02,BS	UGI ENERGY SERVICES INC	6/1/17	6/30/17	15.00	10/30/2017	137.00	6.00	822.00
3300009346	RV	3900006892	520500	1008568	8/30/2017	11/1/2017	-494.89	02,BS	GREAT AMERICAN POWER	6/1/17	6/30/17	15.00	11/1/2017	139.00	494.89	68,789.71
3300009347	RV	3900006038	520500	1007751	8/30/2017	9/21/2017	-828.56	02,BS	STARION ENERGY	6/1/17	6/30/17	15.00	9/21/2017	98.00	828.56	81,198.88
3300009348	RV	3900006675	520500	1007744	8/30/2017	10/25/2017	-952.54	02,BS	RELIANT ENERGY	6/1/17	6/30/17	15.00	10/25/2017	132.00	952.54	125,735.28
3300009349	RV	3900005698	520500	1007745	8/30/2017	9/7/2017	-602.35	02,BS	STREAM ENERGY	6/1/17	6/30/17	15.00	9/7/2017	84.00	602.35	50,597.40
3300009351	RV	3900007054	520500	1012790	8/30/2017	11/10/2017	-65.72	02,BS	Other	6/1/17	6/30/17	15.00	11/10/2017	148.00	65.72	9,726.56
3300009352	RV	3900005977	520500	1010701	8/30/2017	9/20/2017	-246.87	02,BS	ENERGY ME	6/1/17	6/30/17	15.00	9/20/2017	97.00	246.87	23,946.39
3300009353	RV	3900006117	520500	1013112	8/30/2017	9/27/2017	-163.69	02,BS	Other	6/1/17	6/30/17	15.00	9/27/2017	104.00	163.69	17,023.76
3300009354	RV	3900006011	520500	1008458	8/30/2017	9/21/2017	-2,847.98	02,BS	XOOM ENERGY	6/1/17	6/30/17	15.00	9/21/2017	98.00	2,847.98	279,102.04
3300009355	RV	3900005899	520500	1009721	8/30/2017	9/18/2017	-63.50	02,BS	SOURCE POWER & GAS	6/1/17	6/30/17	15.00	9/18/2017	95.00	63.50	6,032.50
3300009569	RV	3900007134	520500	1012016	9/8/2017	11/14/2017	-52.24	02,BS	TALEN ENERGY	7/1/17	7/31/17	15.50	11/14/2017	121.50	52.24	6,347.16
3300009575	RV	3900007558	520500	1007587	9/11/2017	12/8/2017	-124.96	02,BS	AEP ENERGY	7/1/17	7/31/17	15.50	12/8/2017	145.50	124.96	18,181.68
3300009578	RV	3900006104	520500	1009421	9/11/2017	9/26/2017	-3,189.99	02,BS	ETHICAL ELECTRIC	7/1/17	7/31/17	15.50	9/26/2017	72.50	3,189.99	231,274.28
3300009588	RV	3900006497	520500	1012351	9/11/2017	10/17/2017	-45.49	02,BS	ENTRUST ENERGY NORTH	7/1/17	7/31/17	15.50	10/17/2017	93.50	45.49	4,253.32
3300009590	RV	3900006625	520500	1010473	9/11/2017	10/23/2017	-528.08	02,BS	SFE ENERGY	7/1/17	7/31/17	15.50	10/23/2017	99.50	528.08	52,543.96
3300009592	RV	3900006222	520500	1010474	9/11/2017	10/4/2017	-4,074.08	02,BS	INSPIRED ENERGY HOLDINGS, LLC	7/1/17	7/31/17	15.50	10/4/2017	80.50	4,074.08	327,963.44
3300009593	RV	3300009595	520500	1012688	9/11/2017	9/11/2017	-378.49	02,BS	Other	7/1/17	7/31/17	15.50	9/11/2017	57.50	378.49	21,763.18
3300009595	RV	3300009595	520500	1012688	9/11/2017	9/11/2017	378.49	02,BS	Other	7/1/17	7/31/17	15.50	9/11/2017	57.50	(378.49)	(21,763.18)
3300009597	RV	3900007253	520500	1012511	9/11/2017	11/20/2017	-378.49	02,BS	AGERA ENERGY	7/1/17	7/31/17	15.50	11/20/2017	127.50	378.49	48,257.48
3300009598	RV	3900006893	520500	1012688	9/11/2017	11/1/2017	-164.84	02,BS	Other	7/1/17	7/31/17	15.50	11/1/2017	108.50	164.84	17,885.14
3300009599	RV	3900006832	520500	1012690	9/11/2017	10/30/2017	-302.07	02,BS	Other	7/1/17	7/31/17	15.50	10/30/2017	106.50	302.07	32,170.46
3300009600	RV	3900007491	520500	1012681	9/11/2017	12/6/2017	-204.86	02,BS	Other	7/1/17	7/31/17	15.50	12/6/2017	143.50	204.86	29,397.41
3300009601	RV	3900007557	520500	1012957	9/11/2017	12/8/2017	-8.68	02,BS	Other	7/1/17	7/31/17	15.50	12/8/2017	145.50	8.68	1,262.94
3300009603	RV	3900006876	520500	1010814	9/11/2017	11/1/2017	-32.35	02,BS	NORDIC ENERGY SERVICES, LLC	7/1/17	7/31/17	15.50	11/1/2017	108.50	32.35	3,509.98
3300009608	RV	3900007265	520500	1011228	9/11/2017	11/21/2017	-1,438.40	02,BS	COMMERCE ENERGY, INC	7/1/17	7/31/17	15.50	11/21/2017	128.50	1,438.40	184,834.40
3300009609	RV	3900006830	520500	1011510	9/11/2017	10/30/2017	-172.36	02,BS	GREEN MOUNTAIN ENERGY CO.	7/1/17	7/31/17	15.50	10/30/2017	106.50	172.36	18,356.34
3300009618	RV	3900006256	520500	1005867	9/12/2017	10/4/2017	-386.40	02,BS	HORIZON POWER AND LIGHT	7/1/17	7/31/17	15.50	10/4/2017	80.50	386.40	31,105.20
3300009619	RV	3900006496	520500	1005415	9/12/2017	10/17/2017	-11.25	02,BS	FIRST ENERGY SOLUTIONS	7/1/17	7/31/17	15.50	10/17/2017	93.50	11.25	1,051.88
3300009771	RV	3900006221	520500	1007588	9/18/2017	10/4/2017	-1,557.34	02,BS	CLEARVIEW ENERGY	7/1/17	7/31/17	15.50	10/4/2017	80.50	1,557.34	125,365.87
3300009772	RV	3900006047	520500	1009857	9/18/2017	9/22/2017	-23.98	02,BS	ELIGO ENERGY DC, LLC	7/1/17	7/31/17	15.50	9/22/2017	68.50	23.98	1,642.63
3300009773	RV	3900006402	520500	1013289	9/18/2017	10/12/2017	-13.02	02,BS	Other	7/1/17	7/31/17	15.50	10/12/2017	88.50	13.02	1,152.27
3300009774	RV	3900007037	520500	1009259	9/18/2017	11/8/2017	-4.50	02,BS	Champion Energy Services LLC	7/1/17	7/31/17	15.50	11/8/2017	115.50	4.50	519.75
3300009777	RV	3300010010	520500	1012697	9/18/2017	9/21/2017	-1,460.54	02,BS	Other	7/1/17	7/31/17	15.50	9/21/2017	67.50	1,460.54	98,586.45
3300009790	RV	3900006145	520500	1009271	9/18/2017	9/28/2017	-524.21	02,BS	MAJOR ENERGY	7/1/17	7/31/17	15.50	9/28/2017	74.50	524.21	39,053.65
3300009791	RV	3900006499	520500	1008816	9/18/2017	10/17/2017	-1,529.27	02,BS	IDT ENERGY INC	7/1/17	7/31/17	15.50	10/17/2017	93.50	1,529.27	142,986.75
3300009793	RV	3900007412	520500	1011199	9/18/2017	12/1/2017	-239.31	02,BS	PLYMOUTH ROCK ENERGY	7/1/17	7/31/17	15.50	12/1/2017	138.50	239.31	33,144.44
3300009794	RV	3900006636	520500	1012081	9/18/2017	10/23/2017	-25.42	02,BS	Other	7/1/17	7/31/17	15.50	10/23/2017	99.50	25.42	2,529.29
3300009795	RV	3900006171	520500	1008419	9/18/2017	9/29/2017	-1,715.93	02,BS	PALMCO POWER MD LLC	7/1/17	7/31/17	15.50	9/29/2017	75.50	1,715.93	129,552.72
3300009796	RV	3900007389	520500	1008131	9/18/2017	12/1/2017	-1,171.58	02,BS	OASIS ENERGY	7/1/17	7/31/17	15.50	12/1/2017	138.50	1,171.58	162,263.83
3300009813	RV	3900006253	520500	1009802	9/18/2017	10/4/2017	-11.16	02,BS	HIKO ENERGY, LLC	7/1/17	7/31/17	15.50	10/4/2017	80.50	11.16	898.38
3300009816	RV	3900007672	520500	1009260	9/18/2017	12/12/2017	-6.00	02,BS	UGI ENERGY SERVICES INC	7/1/17	7/31/17	15.50	12/12/2017	149.50	6.00	897.00
3300009840	RV	3900006906	520500	1013114	9/18/2017	11/2/2017	-17,820.82	02,BS	Other	7/1/17	7/31/17	15.50	11/2/2017	109.50	17,820.82	1,951,379.79
3300009848	RV	3900006406	520500	1008568	9/18/2017	10/12/2017	-80.60	02,BS	GREAT AMERICAN POWER	7/1/17	7/31/17	15.50	10/12/2017	88.50	80.60	7,133.10
3300009850	RV	3900006120	520500	1007751	9/18/2017	9/27/2017	-762.06	02,BS	STARION ENERGY	7/1/17	7/31/17	15.50	9/27/2017	73.50	762.06	56,011.41
3300009851	RV	3900006962	520500	1007744	9/18/2017	11/6/2017	-907.12	02,BS	RELIANT ENERGY	7/1/17	7/31/17	15.50	11/6/2017	113.50	907.12	102,958.12
3300009852	RV	3900006721	520500	1007745	9/18/2017	10/27/2017	-1,879.40	02,BS	STREAM ENERGY	7/1/17	7/31/17	15.50	10/27/2017	103.50	1,879.40	194,517.90
3300009855	RV	3900006362	520500	1012790	9/18/2017	10/10/2017	-86.80	02,BS	Other	7/1/17	7/31/17	15.50	10/10/2017	86.50	86.80	7,508.20
3300009856	RV	3900006412	520500	1010701	9/18/2017	10/12/2017	-26.71	02,BS	ENERGY ME	7/1/17	7/31/17	15.50	10/12/2017	88.50	26.71	2,363.84
3300009856	RV	3900006412	520500	1010701	9/18/2017	10/12/2017	-247.75	02,BS	ENERGY ME	7/1/17	7/31/17	15.50	10/12/2017	88.50	247.75	21,925.88
3300009857	RV	3900007131	520500	1013290	9/18/2017	11/14/2017	-273.39	02,BS	Other	7/1/17	7/31/17	15.50	11/14/2017	121.50	273.39	33,216.89

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										Service period						
Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Third party name	Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300009858	RV	3900006220	520500	1008458	9/18/2017	10/4/2017	-2,591.40	02,BS	XOOM ENERGY	7/1/17	7/31/17	15.50	10/4/2017	80.50	2,591.40	208,607.70
3300009859	RV	3900006172	520500	1009721	9/18/2017	9/29/2017	-122.40	02,BS	SOURCE POWER & GAS	7/1/17	7/31/17	15.50	9/29/2017	75.50	122.40	9,241.20
3300009860	RV	3900006404	520500	1012820	9/18/2017	10/12/2017	-56.25	02,BS	Other	7/1/17	7/31/17	15.50	10/12/2017	88.50	56.25	4,978.13
3300010010	RV	3300010010	520500	1012697	9/18/2017	9/21/2017	1,460.54	02,BS	Other	7/1/17	7/31/17	15.50	9/21/2017	67.50	(1,460.54)	(98,586.45)
3300010011	RV	3900006498	520500	1012697	9/18/2017	10/17/2017	-669.10	02,BS	Other	7/1/17	7/31/17	15.50	10/17/2017	93.50	669.10	62,560.85
3300010108	RV	3900006747	520500	1012016	9/24/2017	10/27/2017	-54.49	02,BS	TALEN ENERGY	7/1/17	7/31/17	15.50	10/27/2017	103.50	54.49	5,639.72
3300010109	RV	3900007558	520500	1007587	9/24/2017	12/8/2017	-122.09	02,BS	AEP ENERGY	7/1/17	7/31/17	15.50	12/8/2017	145.50	122.09	17,764.10
3300010110	RV	3900006500	520500	1009421	9/24/2017	10/17/2017	-3,622.65	02,BS	ETHICAL ELECTRIC	7/1/17	7/31/17	15.50	10/17/2017	93.50	3,622.65	338,717.78
3300010112	RV	3900006749	520500	1012351	9/24/2017	10/27/2017	-53.74	02,BS	ENTRUST ENERGY NORTH	7/1/17	7/31/17	15.50	10/27/2017	103.50	53.74	5,562.09
3300010114	RV	3900006567	520500	1013289	9/24/2017	10/20/2017	-320.05	02,BS	Other	7/1/17	7/31/17	15.50	10/20/2017	96.50	320.05	30,884.83
3300010115	RV	3900006725	520500	1010473	9/24/2017	10/27/2017	-542.65	02,BS	SFE ENERGY	7/1/17	7/31/17	15.50	10/27/2017	103.50	542.65	56,164.28
3300010117	RV	3900006403	520500	1010474	9/24/2017	10/12/2017	-4,406.66	02,BS	INSPIRED ENERGY HOLDINGS, LLC	7/1/17	7/31/17	15.50	10/12/2017	88.50	4,406.66	389,989.41
3300010118	RV	3900006566	520500	1012511	9/24/2017	10/20/2017	-423.98	02,BS	AGERA ENERGY	7/1/17	7/31/17	15.50	10/20/2017	96.50	423.98	40,914.07
3300010119	RV	3900007614	520500	1012688	9/24/2017	12/11/2017	-182.84	02,BS	Other	7/1/17	7/31/17	15.50	12/11/2017	148.50	182.84	27,151.74
3300010120	RV	3900006622	520500	1012690	9/24/2017	10/23/2017	-392.59	02,BS	Other	7/1/17	7/31/17	15.50	10/23/2017	99.50	392.59	39,062.71
3300010121	RV	3900006827	520500	1012681	9/24/2017	10/30/2017	-326.25	02,BS	Other	7/1/17	7/31/17	15.50	10/30/2017	106.50	326.25	34,745.63
3300010122	RV	3900006895	520500	1012957	9/24/2017	11/1/2017	-11.78	02,BS	Other	7/1/17	7/31/17	15.50	11/1/2017	108.50	11.78	1,278.13
3300010123	RV	3900007556	520500	1013112	9/24/2017	12/8/2017	-136.96	02,BS	Other	7/1/17	7/31/17	15.50	12/8/2017	145.50	136.96	19,927.68
3300010124	RV	3900006488	520500	1010814	9/24/2017	10/17/2017	-38.97	02,BS	NORDIC ENERGY SERVICES, LLC	7/1/17	7/31/17	15.50	10/17/2017	93.50	38.97	3,643.70
3300010125	RV	3900006400	520500	1005335	9/24/2017	10/12/2017	-12,114.78	02,BS	DIRECT ENERGY SERVICE	7/1/17	7/31/17	15.50	10/12/2017	88.50	12,114.78	1,072,158.03
3300010212	RV	3300010230	520500	1006334	9/28/2017	9/28/2017	-322.90	02,BS	NEXTERA ENERGY	7/1/17	7/31/17	15.50	9/28/2017	74.50	322.90	24,056.05
3300010215	RV	3900007555	520500	1011510	9/28/2017	12/8/2017	-180.42	02,BS	GREEN MOUNTAIN ENERGY CO.	7/1/17	7/31/17	15.50	12/8/2017	145.50	180.42	26,251.11
3300010216	RV	3900006395	520500	1005867	9/28/2017	10/12/2017	-432.53	02,BS	HORIZON POWER AND LIGHT	7/1/17	7/31/17	15.50	10/12/2017	88.50	432.53	38,278.91
3300010220	RV	3900006538	520500	1005660	9/28/2017	10/19/2017	-639.46	02,BS	LIBERTY POWER HOLDINGS	7/1/17	7/31/17	15.50	10/19/2017	95.50	639.46	61,068.43
3300010221	RV	3900006464	520500	1007588	9/28/2017	10/16/2017	-1,707.74	02,BS	CLEARVIEW ENERGY	7/1/17	7/31/17	15.50	10/16/2017	92.50	1,707.74	157,965.95
3300010222	RV	3900006562	520500	1009857	9/28/2017	10/20/2017	-26.10	02,BS	ELIGO ENERGY DC, LLC	7/1/17	7/31/17	15.50	10/20/2017	96.50	26.10	2,518.65
3300010224	RV	3300010225	520500	1009259	9/28/2017	9/28/2017	-3,600.67	02,BS	Champion Energy Services LLC	7/1/17	7/31/17	15.50	9/28/2017	74.50	3,600.67	268,249.92
3300010225	RV	3300010225	520500	1009259	9/28/2017	9/28/2017	3,600.67	02,BS	Champion Energy Services LLC	7/1/17	7/31/17	15.50	9/28/2017	74.50	(3,600.67)	(268,249.92)
3300010228	RV	3900006624	520500	1012697	9/28/2017	10/23/2017	-942.82	02,BS	Other	7/1/17	7/31/17	15.50	10/23/2017	99.50	942.82	93,810.59
3300010230	RV	3300010230	520500	1006334	9/28/2017	9/28/2017	322.90	02,BS	NEXTERA ENERGY	7/1/17	7/31/17	15.50	9/28/2017	74.50	(322.90)	(24,056.05)
3300010231	RV	3900006967	520500	1006334	9/28/2017	11/6/2017	-250.00	02,BS	NEXTERA ENERGY	7/1/17	7/31/17	15.50	11/6/2017	113.50	250.00	28,375.00
3300010245	RV	3900006216	520500	1009271	9/28/2017	10/4/2017	-550.64	02,BS	MAJOR ENERGY	7/1/17	7/31/17	15.50	10/4/2017	80.50	550.64	44,326.52
3300010259	RV	3900006852	520500	1008816	9/28/2017	10/31/2017	-1,600.34	02,BS	IDT ENERGY INC	7/1/17	7/31/17	15.50	10/31/2017	107.50	1,600.34	172,036.55
3300010265	RV	3900006487	520500	1011199	9/28/2017	10/17/2017	-240.68	02,BS	PLYMOUTH ROCK ENERGY	7/1/17	7/31/17	15.50	10/17/2017	93.50	240.68	22,503.58
3300010273	RV	3900006357	520500	1008419	9/28/2017	10/10/2017	-1,806.45	02,BS	PALMCO POWER MD LLC	7/1/17	7/31/17	15.50	10/10/2017	86.50	1,806.45	156,257.93
3300010274	RV	3900007389	520500	1008131	9/28/2017	12/1/2017	-1,269.31	02,BS	OASIS ENERGY	7/1/17	7/31/17	15.50	12/1/2017	138.50	1,269.31	175,799.44
3300010277	RV	3900006825	520500	1007590	9/28/2017	10/30/2017	-1,041.53	02,BS	NORTH AMERICAN	7/1/17	7/31/17	15.50	10/30/2017	106.50	1,041.53	110,922.95
3300010288	RV	3900006486	520500	1009802	9/28/2017	10/17/2017	-11.78	02,BS	HIKO ENERGY, LLC	7/1/17	7/31/17	15.50	10/17/2017	93.50	11.78	1,101.43
3300010340	RV	3900006540	520500	1009260	9/28/2017	10/19/2017	-6.75	02,BS	UGI ENERGY SERVICES INC	7/1/17	7/31/17	15.50	10/19/2017	95.50	6.75	644.63
3300010341	RV	3900007251	520500	1013114	9/28/2017	11/20/2017	-20,830.42	02,BS	Other	7/1/17	7/31/17	15.50	11/20/2017	127.50	20,830.42	2,655,878.55
3300010343	RV	3900007135	520500	1008568	9/28/2017	11/14/2017	-4.34	02,BS	GREAT AMERICAN POWER	7/1/17	7/31/17	15.50	11/14/2017	121.50	4.34	527.31
3300010344	RV	3900006358	520500	1007751	9/28/2017	10/10/2017	-789.50	02,BS	STARION ENERGY	7/1/17	7/31/17	15.50	10/10/2017	86.50	789.50	68,291.75
3300010346	RV	3900007541	520500	1007744	9/28/2017	12/7/2017	-1,013.76	02,BS	RELIANT ENERGY	7/1/17	7/31/17	15.50	12/7/2017	144.50	1,013.76	146,488.32
3300010347	RV	3900006723	520500	1007745	9/28/2017	10/27/2017	-2,104.38	02,BS	STREAM ENERGY	7/1/17	7/31/17	15.50	10/27/2017	103.50	2,104.38	217,803.33
3300010349	RV	3900006859	520500	1012790	9/28/2017	11/1/2017	-98.58	02,BS	Other	7/1/17	7/31/17	15.50	11/1/2017	108.50	98.58	10,695.93
3300010350	RV	3900006626	520500	1010701	9/28/2017	10/23/2017	-252.25	02,BS	ENERGY ME	7/1/17	7/31/17	15.50	10/23/2017	99.50	252.25	25,098.88
3300010351	RV	3900007131	520500	1013290	9/28/2017	11/14/2017	-461.31	02,BS	Other	7/1/17	7/31/17	15.50	11/14/2017	121.50	461.31	56,049.17
3300010352	RV	3900006621	520500	1008458	9/28/2017	10/23/2017	-3,156.41	02,BS	XOOM ENERGY	7/1/17	7/31/17	15.50	10/23/2017	99.50	3,156.41	314,062.80
3300010353	RV	3900006475	520500	1009721	9/28/2017	10/16/2017	-127.94	02,BS	SOURCE POWER & GAS	7/1/17	7/31/17	15.50	10/16/2017	92.50	127.94	11,834.45
3300010354	RV	3900007111	520500	1012820	9/28/2017	11/14/2017	-59.74	02,BS	Other	7/1/17	7/31/17	15.50	11/14/2017	121.50	59.74	7,258.41
3300012026	RV	3300012027	520500	1012016	11/17/2017	11/17/2017	-52.99	02,BS	TALEN ENERGY	9/1/17	9/30/17	15.00	11/17/2017	63.00	52.99	3,338.37
3300012027	RV	3300012027	520500	1012016	11/17/2017	11/17/2017	52.99	02,BS	TALEN ENERGY	9/1/17	9/30/17	15.00	11/17/2017	63.00	(52.99)	(3,338.37)
3300012028	RV	3900000132	520500	1012016	11/17/2017	1/9/2018	-52.99	02,BS	TALEN ENERGY	9/1/17	9/30/17	15.00	1/9/2018	116.00	52.99	6,146.84
3300012134	RV	3900000288	520500	1007587	11/20/2017	1/17/2018	-116.84	02,BS	AEP ENERGY	9/1/17	9/30/17	15.00	1/17/2018	124.00	116.84	14,488.16
3300012137	RV	3900000262	520500	1009421	11/20/2017	1/17/2018	-2,945.45	02,BS	ETHICAL ELECTRIC	9/1/17	9/30/17	15.00	1/17/2018	124.00	2,945.45	365,235.80
3300012159	RV	3900000079	520500	1005415	11/21/2017	1/5/2018	-3.75	02,BS	FIRST ENERGY SOLUTIONS	9/1/17	9/30/17	15.00	1/5/2018	112.00	3.75	420.00
3300012161	RV	3900000426	520500	1012351	11/21/2017	1/26/2018	-43.24	02,BS	ENTRUST ENERGY NORTH	9/1/17	9/30/17	15.00	1/26/2018	133.00	43.24	5,750.92
3300012164	RV	3900000082	520500	1010473	11/21/2017	1/8/2018	-511.24	02,BS	SFE ENERGY	9/1/17	9/30/17	15.00	1/8/2018	115.00	511.24	58,792.60
3300012374	RV	3900000032	520500	1008458	11/28/2017	1/3/2018	-2,635.28	02,BS	XOOM ENERGY	9/1/17	9/30/17	15.00	1/3/2018	110.00	2,635.28	289,880.80
3300012382	RV	3900000067	520500	1010474	11/28/2017	1/5/2018	-3,986.04	02,BS	INSPIRED ENERGY HOLDINGS, LLC	9/1/17	9/30/17	15.00	1/5/2018	112.00	3,986.04	446,436.48
3300012388	RV	3900007964	520500	1012511	11/28/2017	12/21/2017	-335.91	02,BS	AGERA ENERGY	9/1/17	9/30/17	15.00	12/21/2017	97.00	335.91	32,583.27
3300012389	RV	3900007802	520500	1012688	11/28/2017	12/18/2017	-153.85	02,BS	Other	9/1/17	9/30/17	15.00	12/18/2017	94.00	153.85	14,461.90

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital Study
For the Period January 2017 through December 2017
Other Revenue Lag
Billing Services and Account Management for Third Party Suppliers

										Service period						
Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Third party name	Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300012390	RV	3900000147	520500	1012690	11/28/2017	1/9/2018	-338.03	02,BS	Other	9/1/17	9/30/17	15.00	1/9/2018	116.00	338.03	39,211.48
3300012391	RV	3900000031	520500	1012681	11/28/2017	1/3/2018	-329.84	02,BS	Other	9/1/17	9/30/17	15.00	1/3/2018	110.00	329.84	36,282.40
3300012392	RV	3900007983	520500	1012957	11/28/2017	12/21/2017	-11.78	02,BS	Other	9/1/17	9/30/17	15.00	12/21/2017	97.00	11.78	1,142.66
3300012393	RV	3900007959	520500	1013112	11/28/2017	12/21/2017	-121.21	02,BS	Other	9/1/17	9/30/17	15.00	12/21/2017	97.00	121.21	11,757.37
3300012394	RV	3900007631	520500	1010814	11/28/2017	12/12/2017	-33.85	02,BS	NORDIC ENERGY SERVICES, LLC	9/1/17	9/30/17	15.00	12/12/2017	88.00	33.85	2,978.80
3300012395	RV	3900007961	520500	1005335	11/28/2017	12/21/2017	-9,819.80	02,BS	DIRECT ENERGY SERVICE	9/1/17	9/30/17	15.00	12/21/2017	97.00	9,819.80	952,520.60
3300012396	RV	3900000060	520500	1006334	11/29/2017	1/4/2018	-185.97	02,BS	NEXTERA ENERGY	9/1/17	9/30/17	15.00	1/4/2018	111.00	185.97	20,642.67
3300012397	RV	3900000060	520500	1006334	11/29/2017	1/4/2018	-17.98	02,BS	NEXTERA ENERGY	9/1/17	9/30/17	15.00	1/4/2018	111.00	17.98	1,995.78
3300012400	RV	3900000675	520500	1013158	11/29/2017	2/7/2018	-1,321.22	02,BS	Other	9/1/17	9/30/17	15.00	2/7/2018	145.00	1,321.22	191,576.90
3300012401	RV	3900000431	520500	1011510	11/29/2017	1/26/2018	-164.92	02,BS	GREEN MOUNTAIN ENERGY CO.	9/1/17	9/30/17	15.00	1/26/2018	133.00	164.92	21,934.36
3300012403	RV	3900000767	520500	1007992	11/29/2017	2/12/2018	-1,852.04	02,BS	AMBIT ENERGY	9/1/17	9/30/17	15.00	2/12/2018	150.00	1,852.04	277,806.00
3300012404	RV	3900000235	520500	1005660	11/29/2017	1/12/2018	-523.64	02,BS	LIBERTY POWER HOLDINGS	9/1/17	9/30/17	15.00	1/12/2018	119.00	523.64	62,313.16
3300012407	RV	3900007673	520500	1007588	11/29/2017	12/12/2017	-1,404.56	02,BS	CLEARVIEW ENERGY	9/1/17	9/30/17	15.00	12/12/2017	88.00	1,404.56	123,601.28
3300012411	RV	3900000001	520500	1009857	11/29/2017	1/2/2018	-24.60	02,BS	ELIGO ENERGY DC, LLC	9/1/17	9/30/17	15.00	1/2/2018	109.00	24.60	2,681.40
3300012423	RV	3900007467	520500	1009259	11/29/2017	12/6/2017	-206.72	02,BS	Champion Energy Services LLC	9/1/17	9/30/17	15.00	12/6/2017	82.00	206.72	16,951.04
3300012444	RV	3900000428	520500	1007420	11/29/2017	1/26/2018	-1,055.86	02,BS	ENERGY PLUS HOLDING	9/1/17	9/30/17	15.00	1/26/2018	133.00	1,055.86	140,429.38
3300012445	RV	3900007698	520500	1009271	11/29/2017	12/14/2017	-452.29	02,BS	MAJOR ENERGY	9/1/17	9/30/17	15.00	12/14/2017	90.00	452.29	40,706.10
3300012447	RV	3900000639	520500	1008816	11/29/2017	2/6/2018	-1,318.34	02,BS	IDT ENERGY INC	9/1/17	9/30/17	15.00	2/6/2018	144.00	1,318.34	189,840.96
3300012449	RV	3900000142	520500	1011199	11/29/2017	1/9/2018	-205.22	02,BS	PLYMOUTH ROCK ENERGY	9/1/17	9/30/17	15.00	1/9/2018	116.00	205.22	23,805.52
3300012450	RV	3900007914	520500	1012081	11/29/2017	12/19/2017	-22.32	02,BS	Other	9/1/17	9/30/17	15.00	12/19/2017	95.00	22.32	2,120.40
3300012451	RV	3900007675	520500	1008419	11/29/2017	12/12/2017	-1,528.69	02,BS	PALMCO POWER MD LLC	9/1/17	9/30/17	15.00	12/12/2017	88.00	1,528.69	134,524.72
3300012452	RV	3900007938	520500	1013113	11/29/2017	12/20/2017	-1,076.07	02,BS	Other	9/1/17	9/30/17	15.00	12/20/2017	96.00	1,076.07	103,302.72
3300012453	RV	3900007933	520500	1007590	11/29/2017	12/20/2017	-825.38	02,BS	NORTH AMERICAN	9/1/17	9/30/17	15.00	12/20/2017	96.00	825.38	79,236.48
3300012455	RV	3900007606	520500	1009802	11/29/2017	12/11/2017	-9.30	02,BS	HIKO ENERGY, LLC	9/1/17	9/30/17	15.00	12/11/2017	87.00	9.30	809.10
3300012460	RV	3900007809	520500	1012685	11/29/2017	12/18/2017	-77.09	02,BS	Other	9/1/17	9/30/17	15.00	12/18/2017	94.00	77.09	7,246.46
3300012467	RV	3900008070	520500	1013114	11/29/2017	12/28/2017	-18,038.99	02,BS	Other	9/1/17	9/30/17	15.00	12/28/2017	104.00	18,038.99	1,876,054.96
3300012470	RV	3900007982	520500	1008568	11/29/2017	12/21/2017	-4.34	02,BS	GREAT AMERICAN POWER	9/1/17	9/30/17	15.00	12/21/2017	97.00	4.34	420.98
3300012471	RV	3900007636	520500	1007751	11/29/2017	12/12/2017	-710.60	02,BS	STARION ENERGY	9/1/17	9/30/17	15.00	12/12/2017	88.00	710.60	62,532.80
3300012472	RV	3900000701	520500	1007744	11/29/2017	2/8/2018	-887.28	02,BS	RELIANT ENERGY	9/1/17	9/30/17	15.00	2/8/2018	146.00	887.28	129,542.88
3300012473	RV	3900008004	520500	1007745	11/29/2017	12/28/2017	-1,747.21	02,BS	STREAM ENERGY	9/1/17	9/30/17	15.00	12/28/2017	104.00	1,747.21	181,709.84
3300012480	RV	3900000673	520500	1012790	11/29/2017	2/7/2018	-94.86	02,BS	Other	9/1/17	9/30/17	15.00	2/7/2018	145.00	94.86	13,754.70
3300012482	RV	3900008053	520500	1010701	11/29/2017	12/28/2017	-246.25	02,BS	ENERGY ME	9/1/17	9/30/17	15.00	12/28/2017	104.00	246.25	25,610.00
3300012484	RV	3900000033	520500	1013290	11/29/2017	1/3/2018	-386.53	02,BS	Other	9/1/17	9/30/17	15.00	1/3/2018	110.00	386.53	42,518.30
3300012487	RV	3900000020	520500	1009721	11/29/2017	1/3/2018	-107.26	02,BS	SOURCE POWER & GAS	9/1/17	9/30/17	15.00	1/3/2018	110.00	107.26	11,798.60
3300012489	RV	3900000052	520500	1012820	11/29/2017	1/4/2018	-43.50	02,BS	Other	9/1/17	9/30/17	15.00	1/4/2018	111.00	43.50	4,828.50
3300012491	RV	3900000399	520500	1009260	11/29/2017	1/24/2018	-5.25	02,BS	UGI ENERGY SERVICES INC	9/1/17	9/30/17	15.00	1/24/2018	131.00	5.25	687.75
3300012882	RV	3900000791	520500	1012016	12/7/2017	2/13/2018	-53.74	02,BS	TALEN ENERGY	10/1/17	10/31/17	15.50	2/13/2018	120.50	53.74	6,475.67
3300012883	RV	3900000958	520500	1007587	12/7/2017	2/27/2018	-124.34	02,BS	AEP ENERGY	10/1/17	10/31/17	15.50	2/27/2018	134.50	124.34	16,723.73
3300012884	RV	3900007990	520500	1009421	12/7/2017	12/22/2017	-3,423.89	02,BS	ETHICAL ELECTRIC	10/1/17	10/31/17	15.50	12/22/2017	67.50	3,423.89	231,112.58
3300012887	RV	3900000321	520500	1005415	12/7/2017	1/18/2018	-3.75	02,BS	FIRST ENERGY SOLUTIONS	10/1/17	10/31/17	15.50	1/18/2018	94.50	3.75	354.38
3300012892	RV	3900000956	520500	1012351	12/7/2017	2/27/2018	-56.87	02,BS	ENTRUST ENERGY NORTH	10/1/17	10/31/17	15.50	2/27/2018	134.50	56.87	7,649.02
3300012900	RV	3900000250	520500	1010473	12/7/2017	1/16/2018	-507.37	02,BS	SFE ENERGY	10/1/17	10/31/17	15.50	1/16/2018	92.50	507.37	46,931.73
3300012901	RV	3300013041	520500	1008458	12/7/2017	12/11/2017	-2,470.08	02,BS	XOOM ENERGY	10/1/17	10/31/17	15.50	12/11/2017	56.50	2,470.08	139,559.52
3300012902	RV	3900000078	520500	1010474	12/7/2017	1/5/2018	-4,320.97	02,BS	INSPIRED ENERGY HOLDINGS, LLC	10/1/17	10/31/17	15.50	1/5/2018	81.50	4,320.97	352,159.06
3300012905	RV	3900000051	520500	1012511	12/7/2017	1/4/2018	-424.78	02,BS	AGERA ENERGY	10/1/17	10/31/17	15.50	1/4/2018	80.50	424.78	34,194.79
3300012906	RV	3900000429	520500	1012688	12/7/2017	1/26/2018	-180.59	02,BS	Other	10/1/17	10/31/17	15.50	1/26/2018	102.50	180.59	18,510.48
3300012907	RV	3900000129	520500	1012690	12/7/2017	1/9/2018	-371.64	02,BS	Other	10/1/17	10/31/17	15.50	1/9/2018	85.50	371.64	31,775.22
3300012909	RV	3900000076	520500	1012681	12/7/2017	1/5/2018	-349.68	02,BS	Other	10/1/17	10/31/17	15.50	1/5/2018	81.50	349.68	28,498.92
3300012916	RV	3900000130	520500	1012957	12/7/2017	1/9/2018	-12.40	02,BS	Other	10/1/17	10/31/17	15.50	1/9/2018	85.50	12.40	1,060.20
3300012924	RV	3900000311	520500	1013112	12/7/2017	1/18/2018	-131.71	02,BS	Other	10/1/17	10/31/17	15.50	1/18/2018	94.50	131.71	12,446.60
3300012927	RV	3900000021	520500	1010814	12/7/2017	1/3/2018	-35.48	02,BS	NORDIC ENERGY SERVICES, LLC	10/1/17	10/31/17	15.50	1/3/2018	79.50	35.48	2,820.66
3300012929	RV	3900000057	520500	1005335	12/7/2017	1/4/2018	-10,937.42	02,BS	DIRECT ENERGY SERVICE	10/1/17	10/31/17	15.50	1/4/2018	80.50	10,937.42	880,462.31
3300012930	RV	3900000281	520500	1006334	12/7/2017	1/17/2018	-214.47	02,BS	NEXTERA ENERGY	10/1/17	10/31/17	15.50	1/17/2018	93.50	214.47	20,052.95
3300012931	RV	3900000281	520500	1006334	12/7/2017	1/17/2018	-24.18	02,BS	NEXTERA ENERGY	10/1/17	10/31/17	15.50	1/17/2018	93.50	24.18	2,260.83
3300012932	RV	3900001112	520500	1013158	12/7/2017	3/6/2018	-1,323.70	02,BS	Other	10/1/17	10/31/17	15.50	3/6/2018	141.50	1,323.70	187,303.55
3300012933	RV	3900000700	520500	1011510	12/7/2017	2/8/2018	-166.78	02,BS	GREEN MOUNTAIN ENERGY CO.	10/1/17	10/31/17	15.50	2/8/2018	115.50	166.78	19,263.09
3300012934	RV	3900008054	520500	1005867	12/7/2017	12/28/2017	-403.10	02,BS	HORIZON POWER AND LIGHT	10/1/17	10/31/17	15.50	12/28/2017	73.50	403.10	29,627.85
3300012937	RV	3900000767	520500	1007992	12/8/2017	2/12/2018	-1,990.91	02,BS	AMBIT ENERGY	10/1/17	10/31/17	15.50	2/12/2018	119.50	1,990.91	237,913.75
3300012938	RV	3900000350	520500	1005660	12/8/2017	1/22/2018	-597.89	02,BS	LIBERTY POWER HOLDINGS	10/1/17	10/31/17	15.50	1/22/2018	98.50	597.89	58,892.17
3300012941	RV	3900000013	520500	1007588	12/8/2017	1/2/2018	-1,485.78	02,BS	CLEARVIEW ENERGY	10/1/17	10/31/17	15.50	1/2/2018	78.50	1,485.78	116,633.73
3300012945	RV	3900000002	520500	1009857	12/8/2017	1/2/2018	-24.73	02,BS	ELIGO ENERGY DC, LLC	10/1/17	10/31/17	15.50	1/2/2018	78.50	24.73	1,941.31
3300012957	RV	3900000316	520500	1009259	12/8/2017	1/18/2018	-258.44	02,BS	Champion Energy Services LLC	10/1/17	10/31/17	15.50	1/18/2018	94.50	258.44	24,422.58

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											Service period					
Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Third party name	Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300012960	RV	3900000313	520500	1005335	12/8/2017	1/18/2018	-932.68	02,BS	DIRECT ENERGY SERVICE	10/1/17	10/31/17	15.50	1/18/2018	94.50	932.68	88,138.26
3300012962	RV	3900000704	520500	1007420	12/8/2017	2/8/2018	-1,211.98	02,BS	ENERGY PLUS HOLDING	10/1/17	10/31/17	15.50	2/8/2018	115.50	1,211.98	139,983.69
3300012963	RV	3900000015	520500	1009271	12/8/2017	1/2/2018	-491.48	02,BS	MAJOR ENERGY	10/1/17	10/31/17	15.50	1/2/2018	78.50	491.48	38,581.18
3300012964	RV	3900000117	520500	1008816	12/8/2017	1/9/2018	-1,285.74	02,BS	IDT ENERGY INC	10/1/17	10/31/17	15.50	1/9/2018	85.50	1,285.74	109,930.77
3300012965	RV	3900000464	520500	1008181	12/8/2017	1/29/2018	-15.98	02,BS	CONSOLIDATED EDISON	10/1/17	10/31/17	15.50	1/29/2018	105.50	15.98	1,685.89
3300012967	RV	3900000297	520500	1011199	12/8/2017	1/17/2018	-246.16	02,BS	PLYMOUTH ROCK ENERGY	10/1/17	10/31/17	15.50	1/17/2018	93.50	246.16	23,015.96
3300012970	RV	3900008064	520500	1012081	12/8/2017	12/28/2017	-22.32	02,BS	Other	10/1/17	10/31/17	15.50	12/28/2017	73.50	22.32	1,640.52
3300012976	RV	3900001046	520500	1013113	12/8/2017	2/27/2018	-1,146.29	02,BS	Other	10/1/17	10/31/17	15.50	2/27/2018	134.50	1,146.29	154,176.01
3300012978	RV	3900001127	520500	1007590	12/8/2017	3/6/2018	-953.49	02,BS	NORTH AMERICAN	10/1/17	10/31/17	15.50	3/6/2018	141.50	953.49	134,918.84
3300013041	RV	3300013041	520500	1008458	12/7/2017	12/11/2017	2,470.08	02,BS	XOOM ENERGY	10/1/17	10/31/17	15.50	12/11/2017	56.50	(2,470.08)	(139,559.52)
3300013047	RV	3900000322	520500	1008458	12/7/2017	1/18/2018	-2,914.08	02,BS	XOOM ENERGY	10/1/17	10/31/17	15.50	1/18/2018	94.50	2,914.08	275,380.56
3300013147	RV	3900000077	520500	1009802	12/11/2017	1/5/2018	-10.54	02,BS	HIKO ENERGY, LLC	10/1/17	10/31/17	15.50	1/5/2018	81.50	10.54	859.01
3300013150	RV	3900000467	520500	1013114	12/11/2017	1/29/2018	-18,605.65	02,BS	Other	10/1/17	10/31/17	15.50	1/29/2018	105.50	18,605.65	1,962,896.08
3300013161	RV	3900001013	520500	1008568	12/11/2017	2/27/2018	-0.62	02,BS	GREAT AMERICAN POWER	10/1/17	10/31/17	15.50	2/27/2018	134.50	0.62	83.39
3300013171	RV	3900000053	520500	1007751	12/11/2017	1/4/2018	-729.85	02,BS	STARION ENERGY	10/1/17	10/31/17	15.50	1/4/2018	80.50	729.85	58,752.93
3300013178	RV	3900000702	520500	1007744	12/11/2017	2/8/2018	-965.53	02,BS	RELIANT ENERGY	10/1/17	10/31/17	15.50	2/8/2018	115.50	965.53	111,518.72
3300013181	RV	3900000155	520500	1007745	12/11/2017	1/10/2018	-1,954.02	02,BS	STREAM ENERGY	10/1/17	10/31/17	15.50	1/10/2018	86.50	1,954.02	169,022.73
3300013185	RV	3900000314	520500	1008878	12/11/2017	1/18/2018	-161.11	02,BS	AP GAS AND ELECTRIC	10/1/17	10/31/17	15.50	1/18/2018	94.50	161.11	15,224.90
3300013186	RV	3900000673	520500	1012790	12/11/2017	2/7/2018	-103.54	02,BS	Other	10/1/17	10/31/17	15.50	2/7/2018	114.50	103.54	11,855.33
3300013187	RV	3900000292	520500	1010701	12/11/2017	1/17/2018	-250.75	02,BS	ENERGY ME	10/1/17	10/31/17	15.50	1/17/2018	93.50	250.75	23,445.13
3300013188	RV	3900000430	520500	1013290	12/11/2017	1/26/2018	-345.08	02,BS	Other	10/1/17	10/31/17	15.50	1/26/2018	102.50	345.08	35,370.70
3300013189	RV	3900000020	520500	1009721	12/11/2017	1/3/2018	-127.94	02,BS	SOURCE POWER & GAS	10/1/17	10/31/17	15.50	1/3/2018	79.50	127.94	10,171.23
3300013190	RV	3900000294	520500	1012820	12/11/2017	1/17/2018	-47.12	02,BS	Other	10/1/17	10/31/17	15.50	1/17/2018	93.50	47.12	4,405.72
3300013191	RV	3900000399	520500	1009260	12/11/2017	1/24/2018	-5.25	02,BS	UGI ENERGY SERVICES INC	10/1/17	10/31/17	15.50	1/24/2018	100.50	5.25	527.63
3300012026	RV	3300012027	520500	1012016	11/17/2017	11/17/2017	-131.71	09,AM	TALEN ENERGY	9/1/17	9/30/17	15.00	11/17/2017	63.00	131.71	8,297.73
3300012027	RV	3300012027	520500	1012016	11/17/2017	11/17/2017	131.71	09,AM	TALEN ENERGY	9/1/17	9/30/17	15.00	11/17/2017	63.00	(131.71)	(8,297.73)
3300012028	RV	3900000132	520500	1012016	11/17/2017	1/9/2018	-1,802.94	09,AM	TALEN ENERGY	9/1/17	9/30/17	15.00	1/9/2018	116.00	1,802.94	209,141.04
3300012134	RV	3900000288	520500	1007587	11/20/2017	1/17/2018	-131.71	09,AM	AEP ENERGY	9/1/17	9/30/17	15.00	1/17/2018	124.00	131.71	16,332.04
3300012137	RV	3900000262	520500	1009421	11/20/2017	1/17/2018	-460.16	09,AM	ETHICAL ELECTRIC	9/1/17	9/30/17	15.00	1/17/2018	124.00	460.16	57,059.84
3300012160	RV	3900000225	520500	1011511	11/21/2017	1/12/2018	-31.51	09,AM	RENAISSANCE POWER & GAS	9/1/17	9/30/17	15.00	1/12/2018	119.00	31.51	3,749.69
3300012374	RV	3900000032	520500	1008458	11/28/2017	1/3/2018	-154.85	09,AM	XOOM ENERGY	9/1/17	9/30/17	15.00	1/3/2018	110.00	154.85	17,033.50
3300012388	RV	3900007964	520500	1012511	11/28/2017	12/21/2017	-1,085.05	09,AM	AGERA ENERGY	9/1/17	9/30/17	15.00	12/21/2017	97.00	1,085.05	105,249.85
3300012389	RV	3900007802	520500	1012688	11/28/2017	12/18/2017	-522.64	09,AM	Other	9/1/17	9/30/17	15.00	12/18/2017	94.00	522.64	49,128.16
3300012392	RV	3900007983	520500	1012957	11/28/2017	12/21/2017	-11.63	09,AM	Other	9/1/17	9/30/17	15.00	12/21/2017	97.00	11.63	1,128.11
3300012393	RV	3900007959	520500	1013112	11/28/2017	12/21/2017	-829.05	09,AM	Other	9/1/17	9/30/17	15.00	12/21/2017	97.00	829.05	80,417.85
3300012395	RV	3900007961	520500	1005335	11/28/2017	12/21/2017	-65.11	09,AM	DIRECT ENERGY SERVICE	9/1/17	9/30/17	15.00	12/21/2017	97.00	65.11	6,315.67
3300012396	RV	3900000060	520500	1006334	11/29/2017	1/4/2018	-620.91	09,AM	NEXTERA ENERGY	9/1/17	9/30/17	15.00	1/4/2018	111.00	620.91	68,921.01
3300012397	RV	3900000060	520500	1006334	11/29/2017	1/4/2018	-17.92	09,AM	NEXTERA ENERGY	9/1/17	9/30/17	15.00	1/4/2018	111.00	17.92	1,989.12
3300012402	RV	3900000009	520500	1005867	11/29/2017	1/2/2018	-189.34	09,AM	HORIZON POWER AND LIGHT	9/1/17	9/30/17	15.00	1/2/2018	109.00	189.34	20,638.06
3300012403	RV	3900000767	520500	1007992	11/29/2017	2/12/2018	-78.43	09,AM	AMBIT ENERGY	9/1/17	9/30/17	15.00	2/12/2018	150.00	78.43	11,764.50
3300012404	RV	3900000235	520500	1005660	11/29/2017	1/12/2018	-305.17	09,AM	LIBERTY POWER HOLDINGS	9/1/17	9/30/17	15.00	1/12/2018	119.00	305.17	36,315.23
3300012407	RV	3900007673	520500	1007588	11/29/2017	12/12/2017	-52.93	09,AM	CLEARVIEW ENERGY	9/1/17	9/30/17	15.00	12/12/2017	88.00	52.93	4,657.84
3300012411	RV	3900000001	520500	1009857	11/29/2017	1/2/2018	-26.78	09,AM	ELIGO ENERGY DC, LLC	9/1/17	9/30/17	15.00	1/2/2018	109.00	26.78	2,919.02
3300012423	RV	3900007467	520500	1009259	11/29/2017	12/6/2017	-214.26	09,AM	Champion Energy Services LLC	9/1/17	9/30/17	15.00	12/6/2017	82.00	214.26	17,569.32
3300012445	RV	3900007698	520500	1009271	11/29/2017	12/14/2017	-73.76	09,AM	MAJOR ENERGY	9/1/17	9/30/17	15.00	12/14/2017	90.00	73.76	6,638.40
3300012447	RV	3900000639	520500	1008816	11/29/2017	2/6/2018	-231.80	09,AM	IDT ENERGY INC	9/1/17	9/30/17	15.00	2/6/2018	144.00	231.80	33,379.20
3300012451	RV	3900007675	520500	1008419	11/29/2017	12/12/2017	-14.69	09,AM	PALMCO POWER MD LLC	9/1/17	9/30/17	15.00	12/12/2017	88.00	14.69	1,292.72
3300012460	RV	3900007809	520500	1012685	11/29/2017	12/18/2017	-3.07	09,AM	Other	9/1/17	9/30/17	15.00	12/18/2017	94.00	3.07	288.58
3300012467	RV	3900008070	520500	1013114	11/29/2017	12/28/2017	-6,964.87	09,AM	Other	9/1/17	9/30/17	15.00	12/28/2017	104.00	6,964.87	724,346.48
3300012469	RV	3900000465	520500	1013114	11/29/2017	1/29/2018	-5,738.23	09,AM	Other	9/1/17	9/30/17	15.00	1/29/2018	136.00	5,738.23	780,399.28
3300012471	RV	3900007636	520500	1007751	11/29/2017	12/12/2017	-57.09	09,AM	STARION ENERGY	9/1/17	9/30/17	15.00	12/12/2017	88.00	57.09	5,023.92
3300012472	RV	3900000701	520500	1007744	11/29/2017	2/8/2018	-22.63	09,AM	RELIANT ENERGY	9/1/17	9/30/17	15.00	2/8/2018	146.00	22.63	3,303.98
3300012473	RV	3900008004	520500	1007745	11/29/2017	12/28/2017	-113.18	09,AM	STREAM ENERGY	9/1/17	9/30/17	15.00	12/28/2017	104.00	113.18	11,770.72
3300012482	RV	3900008053	520500	1010701	11/29/2017	12/28/2017	-97.88	09,AM	ENERGY ME	9/1/17	9/30/17	15.00	12/28/2017	104.00	97.88	10,179.52
3300012484	RV	3900000033	520500	1013290	11/29/2017	1/3/2018	-9.90	09,AM	Other	9/1/17	9/30/17	15.00	1/3/2018	110.00	9.90	1,089.00
3300012487	RV	3900000020	520500	1009721	11/29/2017	1/3/2018	-3,229.49	09,AM	SOURCE POWER & GAS	9/1/17	9/30/17	15.00	1/3/2018	110.00	3,229.49	355,243.90
3300012489	RV	3900000052	520500	1012820	11/29/2017	1/4/2018	-65.82	09,AM	Other	9/1/17	9/30/17	15.00	1/4/2018	111.00	65.82	7,306.02
3300012491	RV	3900000399	520500	1009260	11/29/2017	1/24/2018	-41.77	09,AM	UGI ENERGY SERVICES INC	9/1/17	9/30/17	15.00	1/24/2018	131.00	41.77	5,471.87
3300012499	RV	3900000061	520500	1012700	11/29/2017	1/4/2018	-1,107.25	09,AM	Other	9/1/17	9/30/17	15.00	1/4/2018	111.00	1,107.25	122,904.75
3300013210	RV	3900000959	520500	1007587	12/11/2017	2/27/2018	-79.37	09,AM	AEP ENERGY	10/1/17	10/31/17	15.50	2/27/2018	134.50	79.37	10,675.27
3300013211	RV	3900000703	520500	1012511	12/11/2017	2/8/2018	-1,566.92	09,AM	AGERA ENERGY	10/1/17	10/31/17	15.50	2/8/2018	115.50	1,566.92	180,979.26
3300013319	RV	3900000294	520500	1012820	12/12/2017	1/17/2018	-57.30	09,AM	Other	10/1/17	10/31/17	15.50	1/17/2018	93.50	57.30	5,357.55

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Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Third party name	Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300013320	RV	3900000316	520500	1009259	12/12/2017	1/18/2018	-209.86	09,AM	Champion Energy Services LLC	10/1/17	10/31/17	15.50	1/18/2018	94.50	209.86	19,831.77
3300013321	RV	3900008030	520500	1009421	12/12/2017	12/28/2017	-401.26	09,AM	ETHICAL ELECTRIC	10/1/17	10/31/17	15.50	12/28/2017	73.50	401.26	29,492.61
3300013322	RV	3900000013	520500	1007588	12/12/2017	1/2/2018	-58.64	09,AM	CLEARVIEW ENERGY	10/1/17	10/31/17	15.50	1/2/2018	78.50	58.64	4,603.24
3300013323	RV	3900000464	520500	1008181	12/12/2017	1/29/2018	-2,801.47	09,AM	CONSOLIDATED EDISON	10/1/17	10/31/17	15.50	1/29/2018	105.50	2,801.47	295,555.09
3300013327	RV	3300013361	520500	1005335	12/12/2017	12/13/2017	-1,435.97	09,AM	DIRECT ENERGY SERVICE	10/1/17	10/31/17	15.50	12/13/2017	58.50	1,435.97	84,004.25
3300013328	RV	3900007960	520500	1005335	12/12/2017	12/21/2017	-251.46	09,AM	DIRECT ENERGY SERVICE	10/1/17	10/31/17	15.50	12/21/2017	66.50	251.46	16,722.09
3300013329	RV	3900000058	520500	1005335	12/12/2017	1/4/2018	-24,611.80	09,AM	DIRECT ENERGY SERVICE	10/1/17	10/31/17	15.50	1/4/2018	80.50	24,611.80	1,981,249.90
3300013333	RV	3900000003	520500	1009857	12/12/2017	1/2/2018	-24.98	09,AM	ELIGO ENERGY DC, LLC	10/1/17	10/31/17	15.50	1/2/2018	78.50	24.98	1,960.93
3300013335	RV	3900000312	520500	1010701	12/12/2017	1/18/2018	-83.69	09,AM	ENERGY ME	10/1/17	10/31/17	15.50	1/18/2018	94.50	83.69	7,908.71
3300013336	RV	3900000698	520500	1013112	12/12/2017	2/8/2018	-1,013.72	09,AM	Other	10/1/17	10/31/17	15.50	2/8/2018	115.50	1,013.72	117,084.66
3300013337	RV	3900001030	520500	1013290	12/12/2017	2/27/2018	-9.22	09,AM	Other	10/1/17	10/31/17	15.50	2/27/2018	134.50	9.22	1,240.09
3300013345	RV	3900000327	520500	1005867	12/13/2017	1/18/2018	-44.74	09,AM	HORIZON POWER AND LIGHT	10/1/17	10/31/17	15.50	1/18/2018	94.50	44.74	4,227.93
3300002686	RV	3900002297	520500	1007587	3/15/2017	4/6/2017	-33.46	09,BS	AEP ENERGY	11/1/2016	12/31/16	30.50	4/6/2017	126.50	33.46	4,232.69
3300002686	RV	3900002297	520500	1007587	3/15/2017	4/6/2017	-32.09	09,BS	AEP ENERGY	11/1/2016	12/31/16	30.50	4/6/2017	126.50	32.09	4,059.39
3300002692	RV	3900002326	520500	1012511	3/15/2017	4/7/2017	-14.97	09,BS	AGERA ENERGY	11/1/2016	12/31/16	30.50	4/7/2017	127.50	14.97	1,908.68
3300002692	RV	3900002326	520500	1012511	3/15/2017	4/7/2017	-21.59	09,BS	AGERA ENERGY	11/1/2016	12/31/16	30.50	4/7/2017	127.50	21.59	2,752.73
3300002693	RV	3900002392	520500	1007992	3/15/2017	4/11/2017	-505.60	09,BS	AMBIT ENERGY	11/1/2016	12/31/16	30.50	4/11/2017	131.50	505.60	66,486.40
3300002693	RV	3900002392	520500	1007992	3/15/2017	4/11/2017	-508.08	09,BS	AMBIT ENERGY	11/1/2016	12/31/16	30.50	4/11/2017	131.50	508.08	66,812.52
3300002695	RV	3900002319	520500	1009259	3/15/2017	4/7/2017	-3.75	09,BS	Champion Energy Services LLC	11/1/2016	12/31/16	30.50	4/7/2017	127.50	3.75	478.13
3300002695	RV	3900002319	520500	1009259	3/15/2017	4/7/2017	-3.75	09,BS	Champion Energy Services LLC	11/1/2016	12/31/16	30.50	4/7/2017	127.50	3.75	478.13
3300002696	RV	3900002552	520500	1009421	3/15/2017	4/17/2017	-3,797.45	09,BS	ETHICAL ELECTRIC	11/1/2016	12/31/16	30.50	4/17/2017	137.50	3,797.45	522,149.38
3300002696	RV	3900002552	520500	1009421	3/15/2017	4/17/2017	-3,770.69	09,BS	ETHICAL ELECTRIC	11/1/2016	12/31/16	30.50	4/17/2017	137.50	3,770.69	518,469.88
3300002712	RV	3900002215	520500	1007588	3/15/2017	4/4/2017	-364.98	09,BS	CLEARVIEW ENERGY	11/1/2016	12/31/16	30.50	4/4/2017	124.50	364.98	45,440.01
3300002712	RV	3900002215	520500	1007588	3/15/2017	4/4/2017	-412.23	09,BS	CLEARVIEW ENERGY	11/1/2016	12/31/16	30.50	4/4/2017	124.50	412.23	51,322.64
3300002719	RV	3900002745	520500	1008181	3/15/2017	4/24/2017	-140.35	09,BS	CONSOLIDATED EDISON	11/1/2016	12/31/16	30.50	4/24/2017	144.50	140.35	20,280.58
3300002719	RV	3900002745	520500	1008181	3/15/2017	4/24/2017	-144.56	09,BS	CONSOLIDATED EDISON	11/1/2016	12/31/16	30.50	4/24/2017	144.50	144.56	20,888.92
3300002875	RV	3900002744	520500	1010004	3/19/2017	4/24/2017	-92.38	09,BS	DIRECT ENERGY BUSINESS MARKETING	11/1/2016	12/31/16	30.50	4/24/2017	144.50	92.38	13,348.91
3300002875	RV	3900002744	520500	1010004	3/19/2017	4/24/2017	-52.26	09,BS	DIRECT ENERGY BUSINESS MARKETING	11/1/2016	12/31/16	30.50	4/24/2017	144.50	52.26	7,551.57
3300002876	RV	3900002743	520500	1012697	3/20/2017	4/24/2017	-1.50	09,BS	Other	11/1/2016	12/31/16	30.50	4/24/2017	144.50	1.50	216.75
3300002876	RV	3900002743	520500	1012697	3/20/2017	4/24/2017	-1.50	09,BS	Other	11/1/2016	12/31/16	30.50	4/24/2017	144.50	1.50	216.75
3300002879	RV	3900002730	520500	1009857	3/20/2017	4/24/2017	-188.80	09,BS	ELIGO ENERGY DC, LLC	11/1/2016	12/31/16	30.50	4/24/2017	144.50	188.80	27,281.60
3300002879	RV	3900002730	520500	1009857	3/20/2017	4/24/2017	-138.42	09,BS	ELIGO ENERGY DC, LLC	11/1/2016	12/31/16	30.50	4/24/2017	144.50	138.42	20,001.69
3300002912	RV	3900002452	520500	1005867	3/20/2017	4/12/2017	-412.62	09,BS	HORIZON POWER AND LIGHT	11/1/2016	12/31/16	30.50	4/12/2017	132.50	412.62	54,672.15
3300002912	RV	3900002452	520500	1005867	3/20/2017	4/12/2017	-429.72	09,BS	HORIZON POWER AND LIGHT	11/1/2016	12/31/16	30.50	4/12/2017	132.50	429.72	56,937.90
3300002917	RV	3900002317	520500	1008816	3/20/2017	4/7/2017	-3,542.31	09,BS	IDT ENERGY INC	11/1/2016	12/31/16	30.50	4/7/2017	127.50	3,542.31	451,644.53
3300002917	RV	3900002317	520500	1008816	3/20/2017	4/7/2017	-3,483.80	09,BS	IDT ENERGY INC	11/1/2016	12/31/16	30.50	4/7/2017	127.50	3,483.80	444,184.50
3300003197	RV	3900002746	520500	1007744	3/24/2017	4/24/2017	-118.58	09,BS	RELIANT ENERGY	11/1/2016	12/31/16	30.50	4/24/2017	144.50	118.58	17,134.81
3300003197	RV	3900002746	520500	1007744	3/24/2017	4/24/2017	-122.92	09,BS	RELIANT ENERGY	11/1/2016	12/31/16	30.50	4/24/2017	144.50	122.92	17,761.94
3300003198	RV	3900002766	520500	1011511	3/24/2017	4/24/2017	-318.81	09,BS	RENAISSANCE POWER & GAS	11/1/2016	12/31/16	30.50	4/24/2017	144.50	318.81	46,068.05
3300003198	RV	3900002766	520500	1011511	3/24/2017	4/24/2017	-352.91	09,BS	RENAISSANCE POWER & GAS	11/1/2016	12/31/16	30.50	4/24/2017	144.50	352.91	50,995.50
3300003540	RV	3900002725	520500	1010182	3/29/2017	4/24/2017	-1.50	09,BS	SOURCE POWER & GAS	11/1/2016	12/31/16	30.50	4/24/2017	144.50	1.50	216.75
3300003540	RV	3900002725	520500	1010182	3/29/2017	4/24/2017	-1.50	09,BS	SOURCE POWER & GAS	11/1/2016	12/31/16	30.50	4/24/2017	144.50	1.50	216.75
3300003550	RV	3900002768	520500	1007751	3/29/2017	4/24/2017	-661.04	09,BS	STARION ENERGY	11/1/2016	12/31/16	30.50	4/24/2017	144.50	661.04	95,520.28
3300003550	RV	3900002768	520500	1007751	3/29/2017	4/24/2017	-642.44	09,BS	STARION ENERGY	11/1/2016	12/31/16	30.50	4/24/2017	144.50	642.44	92,832.58
3300003555	RV	3900002438	520500	1007745	3/29/2017	4/12/2017	-497.22	09,BS	STREAM ENERGY	11/1/2016	12/31/16	30.50	4/12/2017	132.50	497.22	65,881.65
3300003555	RV	3900002438	520500	1007745	3/29/2017	4/12/2017	-560.39	09,BS	STREAM ENERGY	11/1/2016	12/31/16	30.50	4/12/2017	132.50	560.39	74,251.68
3300003654	RV	3900002734	520500	1010225	3/29/2017	4/24/2017	-829.55	09,BS	Other	11/1/2016	12/31/16	30.50	4/24/2017	144.50	829.55	119,869.98
3300003654	RV	3900002734	520500	1010225	3/29/2017	4/24/2017	-771.86	09,BS	Other	11/1/2016	12/31/16	30.50	4/24/2017	144.50	771.86	111,533.77
3300006478	RV	3900004449	520500	1012511	6/11/2017	7/7/2017	-476.87	09,BS	AGERA ENERGY	1/1/17	4/30/17	60.00	7/7/2017	128.00	476.87	61,039.36
3300006482	RV	3300006483	520500	1007588	6/11/2017	6/11/2017	-15,584.70	09,BS	CLEARVIEW ENERGY	1/1/17	4/30/17	60.00	6/11/2017	102.00	15,584.70	1,589,639.40
3300006483	RV	3300006483	520500	1007588	6/11/2017	6/11/2017	15,584.70	09,BS	CLEARVIEW ENERGY	1/1/17	4/30/17	60.00	6/11/2017	102.00	(15,584.70)	(1,589,639.40)
3300006484	RV	3900004201	520500	1009421	6/11/2017	6/30/2017	-15,584.70	09,BS	ETHICAL ELECTRIC	1/1/17	4/30/17	60.00	6/30/2017	121.00	15,584.70	1,885,748.70
3300006485	RV	3900004202	520500	1007588	6/11/2017	6/30/2017	-1,635.44	09,BS	CLEARVIEW ENERGY	1/1/17	4/30/17	60.00	6/30/2017	121.00	1,635.44	197,888.24
3300006488	RV	3300006490	520500	1007321	6/11/2017	6/11/2017	-1,755.18	09,BS	CONSTELLATION ELECTRIC	1/1/17	4/30/17	60.00	6/11/2017	102.00	1,755.18	179,028.36
3300006490	RV	3300006490	520500	1007321	6/11/2017	6/11/2017	1,755.18	09,BS	CONSTELLATION ELECTRIC	1/1/17	4/30/17	60.00	6/11/2017	102.00	(1,755.18)	(179,028.36)
3300006491	RV	3900004303	520500	1012684	6/11/2017	7/3/2017	-1,755.18	09,BS	Other	1/1/17	4/30/17	60.00	7/3/2017	124.00	1,755.18	217,642.32
3300006494	RV	3900004307	520500	1010004	6/11/2017	7/3/2017	-289.60	09,BS	DIRECT ENERGY BUSINESS MARKETING	1/1/17	4/30/17	60.00	7/3/2017	124.00	289.60	35,910.40
3300006757	RV	3900004606	520500	1012697	6/19/2017	7/14/2017	-54.94	09,BS	Other	1/1/17	4/30/17	60.00	7/14/2017	135.00	54.94	7,416.90
3300006758	RV	3900004605	520500	1005335	6/19/2017	7/14/2017	-1,939.01	09,BS	DIRECT ENERGY SERVICE	1/1/17	4/30/17	60.00	7/14/2017	135.00	1,939.01	261,766.35
3300006760	RV	3900004669	520500	1009857	6/19/2017	7/18/2017	-436.72	09,BS	ELIGO ENERGY DC, LLC	1/1/17	4/30/17	60.00	7/18/2017	139.00	436.72	60,704.08
3300006940	RV	3900004829	520500	1005867	6/26/2017	7/25/2017	-1,585.75	09,BS	HORIZON POWER AND LIGHT	1/1/17	4/30/17	60.00	7/25/2017	146.00	1,585.75	231,519.50
3300006941	RV	3900004674	520500	1008816	6/26/2017	7/18/2017	-12,930.41	09,BS	IDT ENERGY INC	1/1/17	4/30/17	60.00	7/18/2017	139.00	12,930.41	1,797,326.99

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital Study
For the Period January 2017 through December 2017
Other Revenue Lag
Billing Services and Account Management for Third Party Suppliers

											Service period					
Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Third party name	Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300006945	RV	3300007198	520500	1012957	6/26/2017	6/28/2017	-0.62	09,BS	Other	1/1/17	4/30/17	60.00	6/28/2017	119.00	0.62	73.78
3300006957	RV	3900004912	520500	1007589	6/26/2017	7/28/2017	-4,517.66	09,BS	PUBLIC POWER	1/1/17	4/30/17	60.00	7/28/2017	149.00	4,517.66	673,131.34
3300006960	RV	3900004718	520500	1011511	6/26/2017	7/19/2017	-1,575.61	09,BS	RENAISSANCE POWER & GAS	1/1/17	4/30/17	60.00	7/19/2017	140.00	1,575.61	220,585.40
3300006963	RV	3900004851	520500	1010182	6/26/2017	7/25/2017	-47.45	09,BS	SOURCE POWER & GAS	1/1/17	4/30/17	60.00	7/25/2017	146.00	47.45	6,927.70
3300006988	RV	3900004535	520500	1007745	6/26/2017	7/12/2017	-2,267.56	09,BS	STREAM ENERGY	1/1/17	4/30/17	60.00	7/12/2017	133.00	2,267.56	301,585.48
3300006995	RV	3900004916	520500	1008458	6/26/2017	7/28/2017	-11,357.58	09,BS	XOOM ENERGY	1/1/17	4/30/17	60.00	7/28/2017	149.00	11,357.58	1,692,279.42
3300007198	RV	3300007198	520500	1012957	6/26/2017	6/28/2017	0.62	09,BS	Other	1/1/17	4/30/17	60.00	6/28/2017	119.00	(0.62)	(73.78)
3300008611	RV	3900005982	520500	1012016	8/13/2017	9/20/2017	-70.73	09,BS	TALEN ENERGY	6/1/17	6/30/17	15.00	9/20/2017	97.00	70.73	6,860.81
3300008612	RV	3900006363	520500	1007587	8/13/2017	10/10/2017	-33.46	09,BS	AEP ENERGY	6/1/17	6/30/17	15.00	10/10/2017	117.00	33.46	3,914.82
3300008613	RV	3900005951	520500	1009421	8/13/2017	9/20/2017	-4,231.64	09,BS	ETHICAL ELECTRIC	6/1/17	6/30/17	15.00	9/20/2017	97.00	4,231.64	410,469.08
3300008614	RV	3900005692	520500	1011511	8/13/2017	9/6/2017	-327.13	09,BS	RENAISSANCE POWER & GAS	6/1/17	6/30/17	15.00	9/6/2017	83.00	327.13	27,151.79
3300008618	RV	3900005402	520500	1008458	8/13/2017	8/22/2017	-992.34	09,BS	XOOM ENERGY	6/1/17	6/30/17	15.00	8/22/2017	68.00	992.34	67,479.12
3300008620	RV	3900005574	520500	1012511	8/13/2017	8/30/2017	-168.25	09,BS	AGERA ENERGY	6/1/17	6/30/17	15.00	8/30/2017	76.00	168.25	12,787.00
3300008621	RV	3900006401	520500	1012688	8/13/2017	10/12/2017	-63.62	09,BS	Other	6/1/17	6/30/17	15.00	10/12/2017	119.00	63.62	7,570.78
3300008624	RV	3900006003	520500	1012957	8/13/2017	9/21/2017	-109.25	09,BS	Other	6/1/17	6/30/17	15.00	9/21/2017	98.00	109.25	10,706.50
3300008625	RV	3900006057	520500	1013112	8/13/2017	9/22/2017	-46.84	09,BS	Other	6/1/17	6/30/17	15.00	9/22/2017	99.00	46.84	4,637.16
3300008627	RV	3900005688	520500	1005335	8/13/2017	9/6/2017	-743.13	09,BS	DIRECT ENERGY SERVICE	6/1/17	6/30/17	15.00	9/6/2017	83.00	743.13	61,679.79
3300008644	RV	3900006015	520500	1006334	8/14/2017	9/21/2017	-251.80	09,BS	NEXTERA ENERGY	6/1/17	6/30/17	15.00	9/21/2017	98.00	251.80	24,676.40
3300008645	RV	3900006015	520500	1006334	8/14/2017	9/21/2017	-98.58	09,BS	NEXTERA ENERGY	6/1/17	6/30/17	15.00	9/21/2017	98.00	98.58	9,660.84
3300008649	RV	3900005798	520500	1005867	8/14/2017	9/12/2017	-381.98	09,BS	HORIZON POWER AND LIGHT	6/1/17	6/30/17	15.00	9/12/2017	89.00	381.98	33,996.22
3300008651	RV	3900007036	520500	1007992	8/14/2017	11/8/2017	-534.15	09,BS	AMBIT ENERGY	6/1/17	6/30/17	15.00	11/8/2017	146.00	534.15	77,985.90
3300008652	RV	3900006538	520500	1005660	8/14/2017	10/19/2017	-480.03	09,BS	LIBERTY POWER HOLDINGS	6/1/17	6/30/17	15.00	10/19/2017	126.00	480.03	60,483.78
3300008654	RV	3300008753	520500	1007588	8/14/2017	8/18/2017	-546.28	09,BS	CLEARVIEW ENERGY	6/1/17	6/30/17	15.00	8/18/2017	64.00	546.28	34,961.92
3300008663	RV	3900005478	520500	1009857	8/14/2017	8/25/2017	-165.63	09,BS	ELIGO ENERGY DC, LLC	6/1/17	6/30/17	15.00	8/25/2017	71.00	165.63	11,759.73
3300008664	RV	3900006247	520500	1009259	8/14/2017	10/4/2017	-3.75	09,BS	Champion Energy Services LLC	6/1/17	6/30/17	15.00	10/4/2017	111.00	3.75	416.25
3300008666	RV	3900006000	520500	1009599	8/14/2017	9/21/2017	-708.44	09,BS	Other	6/1/17	6/30/17	15.00	9/21/2017	98.00	708.44	69,427.12
3300008667	RV	3900005849	520500	1012697	8/14/2017	9/13/2017	-80.77	09,BS	Other	6/1/17	6/30/17	15.00	9/13/2017	90.00	80.77	7,269.30
3300008670	RV	3900005900	520500	1009271	8/14/2017	9/18/2017	-1,450.08	09,BS	MAJOR ENERGY	6/1/17	6/30/17	15.00	9/18/2017	95.00	1,450.08	137,757.60
3300008671	RV	3900005532	520500	1008816	8/14/2017	8/29/2017	-3,347.27	09,BS	IDT ENERGY INC	6/1/17	6/30/17	15.00	8/29/2017	75.00	3,347.27	251,045.25
3300008672	RV	3900007023	520500	1008181	8/14/2017	11/8/2017	-532.73	09,BS	CONSOLIDATED EDISON	6/1/17	6/30/17	15.00	11/8/2017	146.00	532.73	77,778.58
3300008725	RV	3900006276	520500	1009260	8/17/2017	10/6/2017	-9.75	09,BS	UGI ENERGY SERVICES INC	6/1/17	6/30/17	15.00	10/6/2017	113.00	9.75	1,101.75
3300008728	RV	3900006906	520500	1013114	8/17/2017	11/2/2017	-531.61	09,BS	Other	6/1/17	6/30/17	15.00	11/2/2017	140.00	531.61	74,425.40
3300008730	RV	3300008834	520500	1012351	8/17/2017	8/21/2017	-611.80	09,BS	ENTRUST ENERGY NORTH	6/1/17	6/30/17	15.00	8/21/2017	67.00	611.80	40,990.60
3300008731	RV	3900006399	520500	1007744	8/17/2017	10/12/2017	-153.17	09,BS	RELIANT ENERGY	6/1/17	6/30/17	15.00	10/12/2017	119.00	153.17	18,227.23
3300008732	RV	3900005422	520500	1007745	8/17/2017	8/23/2017	-595.76	09,BS	STREAM ENERGY	6/1/17	6/30/17	15.00	8/23/2017	69.00	595.76	41,107.44
3300008735	RV	3900005832	520500	1010701	8/17/2017	9/13/2017	-34.21	09,BS	ENERGY ME	6/1/17	6/30/17	15.00	9/13/2017	90.00	34.21	3,078.90
3300008736	RV	3900006057	520500	1013112	8/17/2017	9/22/2017	-6.33	09,BS	Other	6/1/17	6/30/17	15.00	9/22/2017	99.00	6.33	626.67
3300008737	RV	3900006602	520500	1009721	8/17/2017	10/23/2017	-61.18	09,BS	SOURCE POWER & GAS	6/1/17	6/30/17	15.00	10/23/2017	130.00	61.18	7,953.40
3300008749	RV	3900005631	520500	1008419	8/18/2017	9/1/2017	-26.66	09,BS	PALMCO POWER MD LLC	6/1/17	6/30/17	15.00	9/1/2017	78.00	26.66	2,079.48
3300008749	RV	3900005631	520500	1008419	8/18/2017	9/1/2017	-1,664.34	09,BS	PALMCO POWER MD LLC	6/1/17	6/30/17	15.00	9/1/2017	78.00	1,664.34	129,818.52
3300008753	RV	3300008753	520500	1007588	8/14/2017	8/18/2017	546.28	09,BS	CLEARVIEW ENERGY	6/1/17	6/30/17	15.00	8/18/2017	64.00	(546.28)	(34,961.92)
3300008754	RV	3900006051	520500	1007588	8/14/2017	9/22/2017	-546.28	09,BS	CLEARVIEW ENERGY	6/1/17	6/30/17	15.00	9/22/2017	99.00	546.28	54,081.72
3300008834	RV	3300008834	520500	1012351	8/17/2017	8/21/2017	611.80	09,BS	ENTRUST ENERGY NORTH	6/1/17	6/30/17	15.00	8/21/2017	67.00	(611.80)	(40,990.60)
3300009257	RV	3900006251	520500	1012016	8/29/2017	10/4/2017	-63.98	09,BS	TALEN ENERGY	6/1/17	6/30/17	15.00	10/4/2017	111.00	63.98	7,101.78
3300009258	RV	3900006059	520500	1007587	8/29/2017	9/22/2017	-32.71	09,BS	AEP ENERGY	6/1/17	6/30/17	15.00	9/22/2017	99.00	32.71	3,238.29
3300009259	RV	3900006104	520500	1009421	8/29/2017	9/26/2017	-4,310.25	09,BS	ETHICAL ELECTRIC	6/1/17	6/30/17	15.00	9/26/2017	103.00	4,310.25	443,955.75
3300009260	RV	3900006121	520500	1011511	8/29/2017	9/27/2017	-373.63	09,BS	RENAISSANCE POWER & GAS	6/1/17	6/30/17	15.00	9/27/2017	104.00	373.63	38,857.52
3300009264	RV	3900006011	520500	1008458	8/29/2017	9/21/2017	-909.49	09,BS	XOOM ENERGY	6/1/17	6/30/17	15.00	9/21/2017	98.00	909.49	89,130.02
3300009266	RV	3900005968	520500	1012511	8/29/2017	9/20/2017	-160.26	09,BS	AGERA ENERGY	6/1/17	6/30/17	15.00	9/20/2017	97.00	160.26	15,545.22
3300009267	RV	3900006894	520500	1012688	8/29/2017	11/1/2017	-65.12	09,BS	Other	6/1/17	6/30/17	15.00	11/1/2017	139.00	65.12	9,051.68
3300009271	RV	3900006117	520500	1013112	8/29/2017	9/27/2017	-46.22	09,BS	Other	6/1/17	6/30/17	15.00	9/27/2017	104.00	46.22	4,806.88
3300009273	RV	3900006970	520500	1005335	8/29/2017	11/6/2017	-594.33	09,BS	DIRECT ENERGY SERVICE	6/1/17	6/30/17	15.00	11/6/2017	144.00	594.33	85,583.52
3300009274	RV	3900006294	520500	1006334	8/29/2017	10/6/2017	-331.99	09,BS	NEXTERA ENERGY	6/1/17	6/30/17	15.00	10/6/2017	113.00	331.99	37,514.87
3300009276	RV	3900006294	520500	1006334	8/29/2017	10/6/2017	-94.24	09,BS	NEXTERA ENERGY	6/1/17	6/30/17	15.00	10/6/2017	113.00	94.24	10,649.12
3300009286	RV	3900006040	520500	1005867	8/29/2017	9/21/2017	-405.80	09,BS	HORIZON POWER AND LIGHT	6/1/17	6/30/17	15.00	9/21/2017	98.00	405.80	39,768.40
3300009298	RV	3900007036	520500	1007992	8/29/2017	11/8/2017	-501.03	09,BS	AMBIT ENERGY	6/1/17	6/30/17	15.00	11/8/2017	146.00	501.03	73,150.38
3300009301	RV	3900006007	520500	1005660	8/29/2017	9/21/2017	-475.23	09,BS	LIBERTY POWER HOLDINGS	6/1/17	6/30/17	15.00	9/21/2017	98.00	475.23	46,572.54
3300009312	RV	3900005981	520500	1007588	8/29/2017	9/20/2017	-521.87	09,BS	CLEARVIEW ENERGY	6/1/17	6/30/17	15.00	9/20/2017	97.00	521.87	50,621.39
3300009315	RV	3900005737	520500	1009857	8/29/2017	9/8/2017	-160.93	09,BS	ELIGO ENERGY DC, LLC	6/1/17	6/30/17	15.00	9/8/2017	85.00	160.93	13,679.05
3300009318	RV	3900005973	520500	1009259	8/29/2017	9/20/2017	-4.50	09,BS	Champion Energy Services LLC	6/1/17	6/30/17	15.00	9/20/2017	97.00	4.50	436.50
3300009325	RV	3900006013	520500	1012697	8/30/2017	9/21/2017	-90.10	09,BS	Other	6/1/17	6/30/17	15.00	9/21/2017	98.00	90.10	8,829.80
3300009330	RV	3900005900	520500	1009271	8/30/2017	9/18/2017	-1,109.93	09,BS	MAJOR ENERGY	6/1/17	6/30/17	15.00	9/18/2017	95.00	1,109.93	105,443.35

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											Service period					
Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Third party name	Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300009331	RV	3900006697	520500	1008816	8/30/2017	10/26/2017	-3,456.75	09,BS	IDT ENERGY INC	6/1/17	6/30/17	15.00	10/26/2017	133.00	3,456.75	459,747.75
3300009332	RV	3900007023	520500	1008181	8/30/2017	11/8/2017	-142.47	09,BS	CONSOLIDATED EDISON	6/1/17	6/30/17	15.00	11/8/2017	146.00	142.47	20,800.62
3300009343	RV	3900006828	520500	1009260	8/30/2017	10/30/2017	-10.50	09,BS	UGI ENERGY SERVICES INC	6/1/17	6/30/17	15.00	10/30/2017	137.00	10.50	1,438.50
3300009345	RV	3900006906	520500	1013114	8/30/2017	11/2/2017	-589.36	09,BS	Other	6/1/17	6/30/17	15.00	11/2/2017	140.00	589.36	82,510.40
3300009347	RV	3900006038	520500	1007751	8/30/2017	9/21/2017	-577.86	09,BS	STARION ENERGY	6/1/17	6/30/17	15.00	9/21/2017	98.00	577.86	56,630.28
3300009348	RV	3900006675	520500	1007744	8/30/2017	10/25/2017	-148.83	09,BS	RELIANT ENERGY	6/1/17	6/30/17	15.00	10/25/2017	132.00	148.83	19,645.56
3300009349	RV	3900005698	520500	1007745	8/30/2017	9/7/2017	-2,104.26	09,BS	STREAM ENERGY	6/1/17	6/30/17	15.00	9/7/2017	84.00	2,104.26	176,757.84
3300009352	RV	3900005977	520500	1010701	8/30/2017	9/20/2017	-34.21	09,BS	ENERGY ME	6/1/17	6/30/17	15.00	9/20/2017	97.00	34.21	3,318.37
3300009353	RV	3900006117	520500	1013112	8/30/2017	9/27/2017	-3.85	09,BS	Other	6/1/17	6/30/17	15.00	9/27/2017	104.00	3.85	400.40
3300009355	RV	3900005899	520500	1009721	8/30/2017	9/18/2017	-22.73	09,BS	SOURCE POWER & GAS	6/1/17	6/30/17	15.00	9/18/2017	95.00	22.73	2,159.35
3300009578	RV	3900006104	520500	1009421	9/11/2017	9/26/2017	-4,048.84	09,BS	ETHICAL ELECTRIC	5/1/17	5/31/17	15.50	9/26/2017	133.50	4,048.84	540,520.14
3300009587	RV	3900006121	520500	1011511	9/11/2017	9/27/2017	-291.66	09,BS	RENAISSANCE POWER & GAS	5/1/17	5/31/17	15.50	9/27/2017	134.50	291.66	39,228.27
3300009591	RV	3900006252	520500	1008458	9/11/2017	10/4/2017	-732.77	09,BS	XOOM ENERGY	5/1/17	5/31/17	15.50	10/4/2017	141.50	732.77	103,686.96
3300009593	RV	3300009595	520500	1012688	9/11/2017	9/11/2017	-171.74	09,BS	Other	5/1/17	5/31/17	15.50	9/11/2017	118.50	171.74	20,351.19
3300009595	RV	3300009595	520500	1012688	9/11/2017	9/11/2017	171.74	09,BS	Other	5/1/17	5/31/17	15.50	9/11/2017	118.50	(171.74)	(20,351.19)
3300009618	RV	3900006256	520500	1005867	9/12/2017	10/4/2017	-390.92	09,BS	HORIZON POWER AND LIGHT	5/1/17	5/31/17	15.50	10/4/2017	141.50	390.92	55,315.18
3300009771	RV	3900006221	520500	1007588	9/18/2017	10/4/2017	-500.89	09,BS	CLEARVIEW ENERGY	5/1/17	5/31/17	15.50	10/4/2017	141.50	500.89	70,875.94
3300009772	RV	3900006047	520500	1009857	9/18/2017	9/22/2017	-144.06	09,BS	ELIGO ENERGY DC, LLC	5/1/17	5/31/17	15.50	9/22/2017	129.50	144.06	18,655.77
3300009777	RV	3300010010	520500	1012697	9/18/2017	9/21/2017	-122.34	09,BS	Other	5/1/17	5/31/17	15.50	9/21/2017	128.50	122.34	15,720.69
3300009790	RV	3900006145	520500	1009271	9/18/2017	9/28/2017	-886.24	09,BS	MAJOR ENERGY	5/1/17	5/31/17	15.50	9/28/2017	135.50	886.24	120,085.52
3300009795	RV	3900006171	520500	1008419	9/18/2017	9/29/2017	-27.28	09,BS	PALMCO POWER MD LLC	5/1/17	5/31/17	15.50	9/29/2017	136.50	27.28	3,723.72
3300009850	RV	3900006120	520500	1007751	9/18/2017	9/27/2017	-528.59	09,BS	STARION ENERGY	5/1/17	5/31/17	15.50	9/27/2017	134.50	528.59	71,095.36
3300009859	RV	3900006172	520500	1009721	9/18/2017	9/29/2017	-55.05	09,BS	SOURCE POWER & GAS	5/1/17	5/31/17	15.50	9/29/2017	136.50	55.05	7,514.33
3300009860	RV	3900006404	520500	1012820	9/18/2017	10/12/2017	-46.24	09,BS	Other	5/1/17	5/31/17	15.50	10/12/2017	149.50	46.24	6,912.88
3300010010	RV	3300010010	520500	1012697	9/18/2017	9/21/2017	122.34	09,BS	Other	5/1/17	5/31/17	15.50	9/21/2017	128.50	(122.34)	(15,720.69)
3300010116	RV	3900006408	520500	1008458	9/24/2017	10/12/2017	-1,171.08	09,BS	XOOM ENERGY	5/1/17	5/31/17	15.50	10/12/2017	149.50	1,171.08	175,076.46
3300010125	RV	3900006400	520500	1005335	9/24/2017	10/12/2017	-865.79	09,BS	DIRECT ENERGY SERVICE	5/1/17	5/31/17	15.50	10/12/2017	149.50	865.79	129,435.61
3300010212	RV	3300010230	520500	1006334	9/28/2017	9/28/2017	-377.74	09,BS	NEXTERA ENERGY	5/1/17	5/31/17	15.50	9/28/2017	135.50	377.74	51,183.77
3300010216	RV	3900006395	520500	1005867	9/28/2017	10/12/2017	-394.67	09,BS	HORIZON POWER AND LIGHT	5/1/17	5/31/17	15.50	10/12/2017	149.50	394.67	59,003.17
3300010230	RV	3300010230	520500	1006334	9/28/2017	9/28/2017	377.74	09,BS	NEXTERA ENERGY	5/1/17	5/31/17	15.50	9/28/2017	135.50	(377.74)	(51,183.77)
3300010245	RV	3900006216	520500	1009271	9/28/2017	10/4/2017	-1,644.30	09,BS	MAJOR ENERGY	5/1/17	5/31/17	15.50	10/4/2017	141.50	1,644.30	232,668.45
3300010273	RV	3900006357	520500	1008419	9/28/2017	10/10/2017	-166.16	09,BS	PALMCO POWER MD LLC	5/1/17	5/31/17	15.50	10/10/2017	147.50	166.16	24,508.60
3300010344	RV	3900006358	520500	1007751	9/28/2017	10/10/2017	-646.78	09,BS	STARION ENERGY	5/1/17	5/31/17	15.50	10/10/2017	147.50	646.78	95,400.05
3300012026	RV	3300012027	520500	1012016	11/17/2017	11/17/2017	-66.98	09,BS	TALEN ENERGY	9/1/17	9/30/17	15.00	11/17/2017	63.00	66.98	4,219.74
3300012027	RV	3300012027	520500	1012016	11/17/2017	11/17/2017	66.98	09,BS	TALEN ENERGY	9/1/17	9/30/17	15.00	11/17/2017	63.00	(66.98)	(4,219.74)
3300012028	RV	3900000132	520500	1012016	11/17/2017	1/9/2018	-66.98	09,BS	TALEN ENERGY	9/1/17	9/30/17	15.00	1/9/2018	116.00	66.98	7,769.68
3300012134	RV	3900000288	520500	1007587	11/20/2017	1/17/2018	-33.46	09,BS	AEP ENERGY	9/1/17	9/30/17	15.00	1/17/2018	124.00	33.46	4,149.04
3300012137	RV	3900000262	520500	1009421	11/20/2017	1/17/2018	-3,768.73	09,BS	ETHICAL ELECTRIC	9/1/17	9/30/17	15.00	1/17/2018	124.00	3,768.73	467,322.52
3300012160	RV	3900000225	520500	1011511	11/21/2017	1/12/2018	-256.81	09,BS	RENAISSANCE POWER & GAS	9/1/17	9/30/17	15.00	1/12/2018	119.00	256.81	30,560.39
3300012374	RV	3900000032	520500	1008458	11/28/2017	1/3/2018	-709.89	09,BS	XOOM ENERGY	9/1/17	9/30/17	15.00	1/3/2018	110.00	709.89	78,087.90
3300012388	RV	3900007964	520500	1012511	11/28/2017	12/21/2017	-174.22	09,BS	AGERA ENERGY	9/1/17	9/30/17	15.00	12/21/2017	97.00	174.22	16,899.34
3300012389	RV	3900007802	520500	1012688	11/28/2017	12/18/2017	-60.62	09,BS	Other	9/1/17	9/30/17	15.00	12/18/2017	94.00	60.62	5,698.28
3300012392	RV	3900007983	520500	1012957	11/28/2017	12/21/2017	-85.07	09,BS	Other	9/1/17	9/30/17	15.00	12/21/2017	97.00	85.07	8,251.79
3300012393	RV	3900007959	520500	1013112	11/28/2017	12/21/2017	-60.58	09,BS	Other	9/1/17	9/30/17	15.00	12/21/2017	97.00	60.58	5,876.26
3300012395	RV	3900007961	520500	1005335	11/28/2017	12/21/2017	-476.01	09,BS	DIRECT ENERGY SERVICE	9/1/17	9/30/17	15.00	12/21/2017	97.00	476.01	46,172.97
3300012396	RV	3900000060	520500	1006334	11/29/2017	1/4/2018	-245.05	09,BS	NEXTERA ENERGY	9/1/17	9/30/17	15.00	1/4/2018	111.00	245.05	27,200.55
3300012397	RV	3900000060	520500	1006334	11/29/2017	1/4/2018	-87.42	09,BS	NEXTERA ENERGY	9/1/17	9/30/17	15.00	1/4/2018	111.00	87.42	9,703.62
3300012402	RV	3900000009	520500	1005867	11/29/2017	1/2/2018	-360.30	09,BS	HORIZON POWER AND LIGHT	9/1/17	9/30/17	15.00	1/2/2018	109.00	360.30	39,272.70
3300012403	RV	3900000767	520500	1007992	11/29/2017	2/12/2018	-396.16	09,BS	AMBIT ENERGY	9/1/17	9/30/17	15.00	2/12/2018	150.00	396.16	59,424.00
3300012404	RV	3900000235	520500	1005660	11/29/2017	1/12/2018	-392.30	09,BS	LIBERTY POWER HOLDINGS	9/1/17	9/30/17	15.00	1/12/2018	119.00	392.30	46,683.70
3300012407	RV	3900007673	520500	1007588	11/29/2017	12/12/2017	-415.07	09,BS	CLEARVIEW ENERGY	9/1/17	9/30/17	15.00	12/12/2017	88.00	415.07	36,526.16
3300012411	RV	3900000001	520500	1009857	11/29/2017	1/2/2018	-127.81	09,BS	ELIGO ENERGY DC, LLC	9/1/17	9/30/17	15.00	1/2/2018	109.00	127.81	13,931.29
3300012423	RV	3900007467	520500	1009259	11/29/2017	12/6/2017	-3.75	09,BS	Champion Energy Services LLC	9/1/17	9/30/17	15.00	12/6/2017	82.00	3.75	307.50
3300012445	RV	3900007698	520500	1009271	11/29/2017	12/14/2017	-701.97	09,BS	MAJOR ENERGY	9/1/17	9/30/17	15.00	12/14/2017	90.00	701.97	63,177.30
3300012447	RV	3900000639	520500	1008816	11/29/2017	2/6/2018	-2,091.09	09,BS	IDT ENERGY INC	9/1/17	9/30/17	15.00	2/6/2018	144.00	2,091.09	301,116.96
3300012451	RV	3900007675	520500	1008419	11/29/2017	12/12/2017	-115.94	09,BS	PALMCO POWER MD LLC	9/1/17	9/30/17	15.00	12/12/2017	88.00	115.94	10,202.72
3300012460	RV	3900007809	520500	1012685	11/29/2017	12/18/2017	-162.90	09,BS	Other	9/1/17	9/30/17	15.00	12/18/2017	94.00	162.90	15,312.60
3300012467	RV	3900008070	520500	1013114	11/29/2017	12/28/2017	-4,872.54	09,BS	Other	9/1/17	9/30/17	15.00	12/28/2017	104.00	4,872.54	506,744.16
3300012469	RV	3900000465	520500	1013114	11/29/2017	1/29/2018	-475.36	09,BS	Other	9/1/17	9/30/17	15.00	1/29/2018	136.00	475.36	64,648.96
3300012471	RV	3900007636	520500	1007751	11/29/2017	12/12/2017	-472.04	09,BS	STARION ENERGY	9/1/17	9/30/17	15.00	12/12/2017	88.00	472.04	41,539.52
3300012472	RV	3900000701	520500	1007744	11/29/2017	2/8/2018	-154.15	09,BS	RELIANT ENERGY	9/1/17	9/30/17	15.00	2/8/2018	146.00	154.15	22,505.90
3300012473	RV	3900008004	520500	1007745	11/29/2017	12/28/2017	-490.92	09,BS	STREAM ENERGY	9/1/17	9/30/17	15.00	12/28/2017	104.00	490.92	51,055.68

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Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Third party name	Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300012482	RV	3900008053	520500	1010701	11/29/2017	12/28/2017	-29.97	09,BS	ENERGY ME	9/1/17	9/30/17	15.00	12/28/2017	104.00	29.97	3,116.88
3300012484	RV	3900000033	520500	1013290	11/29/2017	1/3/2018	-2.61	09,BS	Other	9/1/17	9/30/17	15.00	1/3/2018	110.00	2.61	287.10
3300012487	RV	3900000020	520500	1009721	11/29/2017	1/3/2018	-56.68	09,BS	SOURCE POWER & GAS	9/1/17	9/30/17	15.00	1/3/2018	110.00	56.68	6,234.80
3300012489	RV	3900000052	520500	1012820	11/29/2017	1/4/2018	-56.48	09,BS	Other	9/1/17	9/30/17	15.00	1/4/2018	111.00	56.48	6,269.28
3300012491	RV	3900000399	520500	1009260	11/29/2017	1/24/2018	-9.75	09,BS	UGI ENERGY SERVICES INC	9/1/17	9/30/17	15.00	1/24/2018	131.00	9.75	1,277.25
3300012882	RV	3900000791	520500	1012016	12/7/2017	2/13/2018	-72.98	09,BS	TALEN ENERGY	10/1/17	10/31/17	15.50	2/13/2018	120.50	72.98	8,794.09
3300012883	RV	3900000958	520500	1007587	12/7/2017	2/27/2018	-32.71	09,BS	AEP ENERGY	10/1/17	10/31/17	15.50	2/27/2018	134.50	32.71	4,399.50
3300012884	RV	3900007990	520500	1009421	12/7/2017	12/22/2017	-4,078.89	09,BS	ETHICAL ELECTRIC	10/1/17	10/31/17	15.50	12/22/2017	67.50	4,078.89	275,325.08
3300012890	RV	3900008067	520500	1011511	12/7/2017	12/28/2017	-347.95	09,BS	RENAISSANCE POWER & GAS	10/1/17	10/31/17	15.50	12/28/2017	73.50	347.95	25,574.33
3300012901	RV	3300013041	520500	1008458	12/7/2017	12/11/2017	-999.48	09,BS	XOOM ENERGY	10/1/17	10/31/17	15.50	12/11/2017	56.50	999.48	56,470.62
3300012905	RV	3900000051	520500	1012511	12/7/2017	1/4/2018	-176.63	09,BS	AGERA ENERGY	10/1/17	10/31/17	15.50	1/4/2018	80.50	176.63	14,218.72
3300012906	RV	3900000429	520500	1012688	12/7/2017	1/26/2018	-71.87	09,BS	Other	10/1/17	10/31/17	15.50	1/26/2018	102.50	71.87	7,366.68
3300012916	RV	3900000130	520500	1012957	12/7/2017	1/9/2018	-107.39	09,BS	Other	10/1/17	10/31/17	15.50	1/9/2018	85.50	107.39	9,181.85
3300012924	RV	3900000311	520500	1013112	12/7/2017	1/18/2018	-68.93	09,BS	Other	10/1/17	10/31/17	15.50	1/18/2018	94.50	68.93	6,513.89
3300012930	RV	3900000281	520500	1006334	12/7/2017	1/17/2018	-278.41	09,BS	NEXTERA ENERGY	10/1/17	10/31/17	15.50	1/17/2018	93.50	278.41	26,031.34
3300012931	RV	3900000281	520500	1006334	12/7/2017	1/17/2018	-91.76	09,BS	NEXTERA ENERGY	10/1/17	10/31/17	15.50	1/17/2018	93.50	91.76	8,579.56
3300012934	RV	3900008054	520500	1005867	12/7/2017	12/28/2017	-367.52	09,BS	HORIZON POWER AND LIGHT	10/1/17	10/31/17	15.50	12/28/2017	73.50	367.52	27,012.72
3300012937	RV	3900000767	520500	1007992	12/8/2017	2/12/2018	-467.65	09,BS	AMBIT ENERGY	10/1/17	10/31/17	15.50	2/12/2018	119.50	467.65	55,884.18
3300012939	RV	3900000350	520500	1005660	12/8/2017	1/22/2018	-433.74	09,BS	LIBERTY POWER HOLDINGS	10/1/17	10/31/17	15.50	1/22/2018	98.50	433.74	42,723.39
3300012941	RV	3900000013	520500	1007588	12/8/2017	1/2/2018	-589.06	09,BS	CLEARVIEW ENERGY	10/1/17	10/31/17	15.50	1/2/2018	78.50	589.06	46,241.21
3300012945	RV	3900000002	520500	1009857	12/8/2017	1/2/2018	-158.19	09,BS	ELIGO ENERGY DC, LLC	10/1/17	10/31/17	15.50	1/2/2018	78.50	158.19	12,417.92
3300012957	RV	3900000316	520500	1009259	12/8/2017	1/18/2018	-5.25	09,BS	Champion Energy Services LLC	10/1/17	10/31/17	15.50	1/18/2018	94.50	5.25	496.13
3300012960	RV	3900000313	520500	1005335	12/8/2017	1/18/2018	-204.49	09,BS	DIRECT ENERGY SERVICE	10/1/17	10/31/17	15.50	1/18/2018	94.50	204.49	19,324.31
3300012961	RV	3300012968	520500	1008419	12/8/2017	12/8/2017	-1,065.15	09,BS	PALMCO POWER MD LLC	10/1/17	10/31/17	15.50	12/8/2017	53.50	1,065.15	56,985.53
3300012963	RV	3900000015	520500	1009271	12/8/2017	1/2/2018	-1,380.05	09,BS	MAJOR ENERGY	10/1/17	10/31/17	15.50	1/2/2018	78.50	1,380.05	108,333.93
3300012964	RV	3900000117	520500	1008816	12/8/2017	1/9/2018	-3,175.01	09,BS	IDT ENERGY INC	10/1/17	10/31/17	15.50	1/9/2018	85.50	3,175.01	271,463.36
3300012965	RV	3900000464	520500	1008181	12/8/2017	1/29/2018	-34.86	09,BS	CONSOLIDATED EDISON	10/1/17	10/31/17	15.50	1/29/2018	105.50	34.86	3,677.73
3300012968	RV	3300012968	520500	1008419	12/8/2017	12/8/2017	1,065.15	09,BS	PALMCO POWER MD LLC	10/1/17	10/31/17	15.50	12/8/2017	53.50	(1,065.15)	(56,985.53)
3300013041	RV	3300013041	520500	1008458	12/7/2017	12/11/2017	999.48	09,BS	XOOM ENERGY	10/1/17	10/31/17	15.50	12/11/2017	56.50	(999.48)	(56,470.62)
3300013047	RV	3900000322	520500	1008458	12/7/2017	1/18/2018	-999.48	09,BS	XOOM ENERGY	10/1/17	10/31/17	15.50	1/18/2018	94.50	999.48	94,450.86
3300013150	RV	3900000467	520500	1013114	12/11/2017	1/29/2018	-4,956.97	09,BS	Other	10/1/17	10/31/17	15.50	1/29/2018	105.50	4,956.97	522,960.34
3300013154	RV	3900000467	520500	1013114	12/11/2017	1/29/2018	-534.74	09,BS	Other	10/1/17	10/31/17	15.50	1/29/2018	105.50	534.74	56,415.07
3300013171	RV	3900000053	520500	1007751	12/11/2017	1/4/2018	-573.98	09,BS	STARION ENERGY	10/1/17	10/31/17	15.50	1/4/2018	80.50	573.98	46,205.39
3300013178	RV	3900000702	520500	1007744	12/11/2017	2/8/2018	-175.85	09,BS	RELIANT ENERGY	10/1/17	10/31/17	15.50	2/8/2018	115.50	175.85	20,310.68
3300013181	RV	3900000155	520500	1007745	12/11/2017	1/10/2018	-644.05	09,BS	STREAM ENERGY	10/1/17	10/31/17	15.50	1/10/2018	86.50	644.05	55,710.33
3300013187	RV	3900000292	520500	1010701	12/11/2017	1/17/2018	-34.21	09,BS	ENERGY ME	10/1/17	10/31/17	15.50	1/17/2018	93.50	34.21	3,198.64
3300013188	RV	3900000430	520500	1013290	12/11/2017	1/26/2018	-3.85	09,BS	Other	10/1/17	10/31/17	15.50	1/26/2018	102.50	3.85	394.63
3300013189	RV	3900000020	520500	1009721	12/11/2017	1/3/2018	-68.91	09,BS	SOURCE POWER & GAS	10/1/17	10/31/17	15.50	1/3/2018	79.50	68.91	5,478.35
3300013190	RV	3900000294	520500	1012820	12/11/2017	1/17/2018	-76.34	09,BS	Other	10/1/17	10/31/17	15.50	1/17/2018	93.50	76.34	7,137.79
3300013191	RV	3900000399	520500	1009260	12/11/2017	1/24/2018	-9.75	09,BS	UGI ENERGY SERVICES INC	10/1/17	10/31/17	15.50	1/24/2018	100.50	9.75	979.88
															750,928.32	74,735,933.79
														Lag Days		**99.52**

Note: Removed Lag Days greater than 150 days

POTOMAC ELECTRIC POWER COMPANY
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Other Revenue Lag
Fire & Damage Reconnect, Joint Use Escort and interconnection Application Fee

Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Service period Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300009175	RV	3900006623	519500	1006992	8/28/2017	10/23/2017	-2,629.33	09	8/28/2017	8/28/2017	0.50	10/23/2017	56.50	2,629.33	148,557.15
3300012025	RV	3900007505	519500	1006995	11/17/2017	12/6/2017	-106.48	09	11/17/2017	11/17/2017	0.50	12/6/2017	19.50	106.48	2,076.36
3300000000	RV	3900001054	633697	1012044	1/3/2017	2/17/2017	-61.40	02	1/3/2017	1/3/2017	0.50	2/17/2017	45.50	61.40	2,793.70
3300000001	RV	3900000527	633697	1012759	1/3/2017	1/26/2017	-61.40	02	1/3/2017	1/3/2017	0.50	1/26/2017	23.50	61.40	1,442.90
3300000002	RV	3900000130	633697	1012392	1/3/2017	1/9/2017	-61.50	02	1/3/2017	1/3/2017	0.50	1/9/2017	6.50	61.50	399.75
3300000003	RV	3900000179	633697	1012382	1/3/2017	1/10/2017	-63.20	02	1/3/2017	1/3/2017	0.50	1/10/2017	7.50	63.20	474.00
3300000004	RV	3900000176	633697	1012382	1/3/2017	1/10/2017	-67.00	02	1/3/2017	1/3/2017	0.50	1/10/2017	7.50	67.00	502.50
3300000041	RV	3900000358	633697	1012959	1/4/2017	1/20/2017	-3,950.00	02	1/4/2017	1/4/2017	0.50	1/20/2017	16.50	3,950.00	65,175.00
3300000075	RV	3900000300	633697	1012382	1/4/2017	1/18/2017	-62.00	02	1/4/2017	1/4/2017	0.50	1/18/2017	14.50	62.00	899.00
3300000078	RV	3900000296	633697	1012382	1/4/2017	1/18/2017	-61.10	02	1/4/2017	1/4/2017	0.50	1/18/2017	14.50	61.10	885.95
3300000084	RV	3900000297	633697	1012382	1/4/2017	1/18/2017	-60.40	02	1/4/2017	1/4/2017	0.50	1/18/2017	14.50	60.40	875.80
3300000088	RV	3900000323	633697	1012382	1/4/2017	1/19/2017	-65.20	02	1/4/2017	1/4/2017	0.50	1/19/2017	15.50	65.20	1,010.60
3300000091	RV	3900000299	633697	1012382	1/4/2017	1/18/2017	-60.40	02	1/4/2017	1/4/2017	0.50	1/18/2017	14.50	60.40	875.80
3300000094	RV	3900000298	633697	1012382	1/4/2017	1/18/2017	-61.40	02	1/4/2017	1/4/2017	0.50	1/18/2017	14.50	61.40	890.30
3300000097	RV	3900000301	633697	1012382	1/4/2017	1/18/2017	-61.80	02	1/4/2017	1/4/2017	0.50	1/18/2017	14.50	61.80	896.10
3300000100	RV	3900000326	633697	1012382	1/4/2017	1/19/2017	-61.40	02	1/4/2017	1/4/2017	0.50	1/19/2017	15.50	61.40	951.70
3300000101	RV	3900000368	633697	1012382	1/4/2017	1/23/2017	-61.40	02	1/4/2017	1/4/2017	0.50	1/23/2017	19.50	61.40	1,197.30
3300000102	RV	3900000324	633697	1012382	1/4/2017	1/19/2017	-60.40	02	1/4/2017	1/4/2017	0.50	1/19/2017	15.50	60.40	936.20
3300000128	RV	3900000314	633697	1012382	1/6/2017	1/18/2017	-60.40	02	1/6/2017	1/6/2017	0.50	1/18/2017	12.50	60.40	755.00
3300000133	RV	3900000313	633697	1012382	1/6/2017	1/18/2017	-60.40	02	1/6/2017	1/6/2017	0.50	1/18/2017	12.50	60.40	755.00
3300000135	RV	3900000322	633697	1012382	1/6/2017	1/19/2017	-62.80	02	1/6/2017	1/6/2017	0.50	1/19/2017	13.50	62.80	847.80
3300000136	RV	3900000304	633697	41717	1/6/2017	1/18/2017	-63.00	02	1/6/2017	1/6/2017	0.50	1/18/2017	12.50	63.00	787.50
3300000137	RV	3900001228	633697	1012044	1/6/2017	2/23/2017	-61.40	02	1/6/2017	1/6/2017	0.50	2/23/2017	48.50	61.40	2,977.90
3300000139	RV	3900000321	633697	1012382	1/6/2017	1/19/2017	-60.40	02	1/6/2017	1/6/2017	0.50	1/19/2017	13.50	60.40	815.40
3300000140	RV	3900001229	633697	1012044	1/6/2017	2/23/2017	-61.40	02	1/6/2017	1/6/2017	0.50	2/23/2017	48.50	61.40	2,977.90
3300000141	RV	3900001231	633697	1012044	1/6/2017	2/23/2017	-61.40	02	1/6/2017	1/6/2017	0.50	2/23/2017	48.50	61.40	2,977.90
3300000143	RV	3900001230	633697	1012044	1/6/2017	2/23/2017	-61.40	02	1/6/2017	1/6/2017	0.50	2/23/2017	48.50	61.40	2,977.90
3300000144	RV	3900000158	633697	1012044	1/6/2017	1/10/2017	-60.54	02	1/6/2017	1/6/2017	0.50	1/10/2017	4.50	60.54	272.43
3300000145	RV	3900000159	633697	1012044	1/6/2017	1/10/2017	-62.04	02	1/6/2017	1/6/2017	0.50	1/10/2017	4.50	62.04	279.18
3300000146	RV	3900000160	633697	1012044	1/6/2017	1/10/2017	-62.47	02	1/6/2017	1/6/2017	0.50	1/10/2017	4.50	62.47	281.12
3300000148	RV	3900000302	633697	1012382	1/6/2017	1/18/2017	-61.80	02	1/6/2017	1/6/2017	0.50	1/18/2017	12.50	61.80	772.50
3300000149	RV	3900000319	633697	1012382	1/6/2017	1/19/2017	-65.20	02	1/6/2017	1/6/2017	0.50	1/19/2017	13.50	65.20	880.20
3300000151	RV	3900000320	633697	1012382	1/6/2017	1/19/2017	-65.20	02	1/6/2017	1/6/2017	0.50	1/19/2017	13.50	65.20	880.20
3300000152	RV	3900000325	633697	1012382	1/6/2017	1/19/2017	-65.20	02	1/6/2017	1/6/2017	0.50	1/19/2017	13.50	65.20	880.20
3300000153	RV	3900001232	633697	1012044	1/6/2017	2/23/2017	-61.40	02	1/6/2017	1/6/2017	0.50	2/23/2017	48.50	61.40	2,977.90
3300000154	RV	3900000318	633697	1012044	1/6/2017	1/19/2017	-65.20	02	1/6/2017	1/6/2017	0.50	1/19/2017	13.50	65.20	880.20
3300000156	RV	3900001227	633697	1012044	1/6/2017	2/23/2017	-61.40	02	1/6/2017	1/6/2017	0.50	2/23/2017	48.50	61.40	2,977.90
3300000157	RV	3900000244	633697	1012423	1/6/2017	1/13/2017	-65.20	02	1/6/2017	1/6/2017	0.50	1/13/2017	7.50	65.20	489.00
3300000172	RV	3900000295	633697	1012382	1/9/2017	1/18/2017	-62.80	02	1/9/2017	1/9/2017	0.50	1/18/2017	9.50	62.80	596.60
3300000173	RV	3900000367	633697	1012382	1/9/2017	1/23/2017	-60.40	02	1/9/2017	1/9/2017	0.50	1/23/2017	14.50	60.40	875.80
3300000174	RV	3900000357	633697	1012044	1/9/2017	1/20/2017	-65.20	02	1/9/2017	1/9/2017	0.50	1/20/2017	11.50	65.20	749.80
3300000175	RV	3900000363	633697	1012382	1/9/2017	1/23/2017	-61.40	02	1/9/2017	1/9/2017	0.50	1/23/2017	14.50	61.40	890.30
3300000176	RV	3900000361	633697	1012044	1/9/2017	1/23/2017	-65.20	02	1/9/2017	1/9/2017	0.50	1/23/2017	14.50	65.20	945.40
3300000177	RV	3900000250	633697	1012423	1/9/2017	1/13/2017	-63.00	02	1/9/2017	1/9/2017	0.50	1/13/2017	4.50	63.00	283.50
3300000178	RV	3900000362	633697	1012382	1/9/2017	1/23/2017	-60.40	02	1/9/2017	1/9/2017	0.50	1/23/2017	14.50	60.40	875.80
3300000179	RV	3900000396	633697	1012044	1/9/2017	1/24/2017	-65.20	02	1/9/2017	1/9/2017	0.50	1/24/2017	15.50	65.20	1,010.60
3300000180	RV	3900000364	633697	1012382	1/9/2017	1/23/2017	-60.40	02	1/9/2017	1/9/2017	0.50	1/23/2017	14.50	60.40	875.80
3300000191	RV	3900000366	633697	1012382	1/9/2017	1/23/2017	-60.40	02	1/9/2017	1/9/2017	0.50	1/23/2017	14.50	60.40	875.80
3300000243	RV	3900000409	633697	1012382	1/10/2017	1/24/2017	-65.20	02	1/10/2017	1/10/2017	0.50	1/24/2017	14.50	65.20	945.40
3300000245	RV	3900000408	633697	1012382	1/10/2017	1/24/2017	-65.20	02	1/10/2017	1/10/2017	0.50	1/24/2017	14.50	65.20	945.40

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3300000247	RV	3900000412	633697	1012382	1/10/2017	1/24/2017	-64.20	02	1/10/2017	1/10/2017	0.50	1/24/2017	14.50	64.20	930.90
3300000249	RV	3900000413	633697	1012382	1/10/2017	1/24/2017	-62.80	02	1/10/2017	1/10/2017	0.50	1/24/2017	14.50	62.80	910.60
3300000303	RV	3900000365	633697	1012382	1/11/2017	1/23/2017	-62.80	02	1/11/2017	1/11/2017	0.50	1/23/2017	12.50	62.80	785.00
3300000304	RV	3300000332	633697	NEM	1/11/2017	1/12/2017	-63.20	02	1/11/2017	1/11/2017	0.50	1/12/2017	1.50	63.20	94.80
3300000305	RV	3900000486	633697	41717	1/11/2017	1/24/2017	-65.20	02	1/11/2017	1/11/2017	0.50	1/24/2017	13.50	65.20	880.20
3300000332	RV	3300000332	633697	NEM	1/11/2017	1/12/2017	63.20	02	1/11/2017	1/11/2017	0.50	1/12/2017	1.50	(63.20)	(94.80)
3300000333	RV	3900000694	633697	1012382	1/12/2017	2/3/2017	-63.20	02	1/12/2017	1/12/2017	0.50	2/3/2017	22.50	63.20	1,422.00
3300000334	RV	3300000340	633697	NEM	1/12/2017	1/12/2017	-62.00	02	1/12/2017	1/12/2017	0.50	1/12/2017	0.50	62.00	31.00
3300000335	RV	3900000607	633697	1012358	1/12/2017	1/31/2017	-61.40	02	1/12/2017	1/12/2017	0.50	1/31/2017	19.50	61.40	1,197.30
3300000336	RV	3900000690	633697	1012382	1/12/2017	2/3/2017	-60.40	02	1/12/2017	1/12/2017	0.50	2/3/2017	22.50	60.40	1,359.00
3300000337	RV	3300000342	633697	NEM	1/12/2017	1/12/2017	-61.80	02	1/12/2017	1/12/2017	0.50	1/12/2017	0.50	61.80	30.90
3300000338	RV	3900000287	633697	1012044	1/12/2017	1/18/2017	-66.13	02	1/12/2017	1/12/2017	0.50	1/18/2017	6.50	66.13	429.85
3300000339	RV	3900000410	633697	1012382	1/12/2017	1/24/2017	-60.40	02	1/12/2017	1/12/2017	0.50	1/24/2017	12.50	60.40	755.00
3300000340	RV	3300000340	633697	NEM	1/12/2017	1/12/2017	62.00	02	1/12/2017	1/12/2017	0.50	1/12/2017	0.50	(62.00)	(31.00)
3300000341	RV	3900000279	633697	1012423	1/12/2017	1/17/2017	-62.00	02	1/12/2017	1/12/2017	0.50	1/17/2017	5.50	62.00	341.00
3300000342	RV	3300000342	633697	NEM	1/12/2017	1/12/2017	61.80	02	1/12/2017	1/12/2017	0.50	1/12/2017	0.50	(61.80)	(30.90)
3300000343	RV	3900000693	633697	1012382	1/12/2017	2/3/2017	-61.80	02	1/12/2017	1/12/2017	0.50	2/3/2017	22.50	61.80	1,390.50
3300000344	RV	3900000278	633697	1012423	1/13/2017	1/17/2017	-61.40	02	1/13/2017	1/13/2017	0.50	1/17/2017	4.50	61.40	276.30
3300000345	RV	3900000406	633697	1012382	1/13/2017	1/24/2017	-63.20	02	1/13/2017	1/13/2017	0.50	1/24/2017	11.50	63.20	726.80
3300000350	RV	3900000271	633697	1013008	1/13/2017	1/14/2017	-63.60	02	1/13/2017	1/13/2017	0.50	1/14/2017	1.50	63.60	95.40
3300000356	RV	3900000681	633697	1012382	1/13/2017	2/3/2017	-61.40	02	1/13/2017	1/13/2017	0.50	2/3/2017	21.50	61.40	1,320.10
3300000359	RV	3300000368	633697	NEM	1/13/2017	1/13/2017	-65.20	02	1/13/2017	1/13/2017	0.50	1/13/2017	0.50	65.20	32.60
3300000364	RV	3900000677	633697	1012382	1/13/2017	2/3/2017	-65.20	02	1/13/2017	1/13/2017	0.50	2/3/2017	21.50	65.20	1,401.80
3300000368	RV	3300000368	633697	NEM	1/13/2017	1/13/2017	65.20	02	1/13/2017	1/13/2017	0.50	1/13/2017	0.50	(65.20)	(32.60)
3300000369	RV	3900001666	633697	1012382	1/13/2017	3/9/2017	-65.20	02	1/13/2017	1/13/2017	0.50	3/9/2017	55.50	65.20	3,618.60
3300000372	RV	3900000680	633697	1012382	1/13/2017	2/3/2017	-65.20	02	1/13/2017	1/13/2017	0.50	2/3/2017	21.50	65.20	1,401.80
3300000374	RV	3900000678	633697	1012382	1/13/2017	2/3/2017	-63.20	02	1/13/2017	1/13/2017	0.50	2/3/2017	21.50	63.20	1,358.80
3300000383	RV	3900000411	633697	1012382	1/13/2017	1/24/2017	-63.20	02	1/13/2017	1/13/2017	0.50	1/24/2017	11.50	63.20	726.80
3300000388	RV	3900000689	633697	1012382	1/17/2017	2/3/2017	-65.20	02	1/17/2017	1/17/2017	0.50	2/3/2017	17.50	65.20	1,141.00
3300000389	RV	3900000697	633697	1012382	1/17/2017	2/3/2017	-64.20	02	1/17/2017	1/17/2017	0.50	2/3/2017	17.50	64.20	1,123.50
3300000390	RV	3900000691	633697	1012382	1/17/2017	2/3/2017	-60.40	02	1/17/2017	1/17/2017	0.50	2/3/2017	17.50	60.40	1,057.00
3300000391	RV	3900000692	633697	1012382	1/17/2017	2/3/2017	-68.00	02	1/17/2017	1/17/2017	0.50	2/3/2017	17.50	68.00	1,190.00
3300000392	RV	3300000427	633697	1012382	1/17/2017	1/18/2017	-60.40	02	1/17/2017	1/17/2017	0.50	1/18/2017	1.50	60.40	90.60
3300000393	RV	3900000676	633697	1012382	1/17/2017	2/3/2017	-65.20	02	1/17/2017	1/17/2017	0.50	2/3/2017	17.50	65.20	1,141.00
3300000427	RV	3300000427	633697	1012382	1/17/2017	1/18/2017	60.40	02	1/17/2017	1/17/2017	0.50	1/18/2017	1.50	(60.40)	(90.60)
3300000428	RV	3900000699	633697	1012382	1/18/2017	2/3/2017	-60.40	02	1/18/2017	1/18/2017	0.50	2/3/2017	16.50	60.40	996.60
3300000432	RV	3900000369	633697	1012423	1/18/2017	1/23/2017	-63.00	02	1/18/2017	1/18/2017	0.50	1/23/2017	5.50	63.00	346.50
3300000433	RV	3300000450	633697	NEM	1/18/2017	1/18/2017	-60.20	02	1/18/2017	1/18/2017	0.50	1/18/2017	0.50	60.20	30.10
3300000434	RV	3900000695	633697	1012382	1/18/2017	2/3/2017	-63.20	02	1/18/2017	1/18/2017	0.50	2/3/2017	16.50	63.20	1,042.80
3300000435	RV	3900000696	633697	1012382	1/18/2017	2/3/2017	-63.20	02	1/18/2017	1/18/2017	0.50	2/3/2017	16.50	63.20	1,042.80
3300000436	RV	3900000698	633697	1012382	1/18/2017	2/3/2017	-64.20	02	1/18/2017	1/18/2017	0.50	2/3/2017	16.50	64.20	1,059.30
3300000437	RV	3900001034	633697	1012044	1/18/2017	2/17/2017	-60.97	02	1/18/2017	1/18/2017	0.50	2/17/2017	30.50	60.97	1,859.59
3300000438	RV	3900001233	633697	1012044	1/18/2017	2/23/2017	-65.70	02	1/18/2017	1/18/2017	0.50	2/23/2017	36.50	65.70	2,398.05
3300000439	RV	3900001114	633697	1012044	1/18/2017	2/21/2017	-61.40	02	1/18/2017	1/18/2017	0.50	2/21/2017	34.50	61.40	2,118.30
3300000440	RV	3900000702	633697	1012382	1/18/2017	2/3/2017	-80.40	02	1/18/2017	1/18/2017	0.50	2/3/2017	16.50	80.40	1,326.60
3300000441	RV	3900000701	633697	1012382	1/18/2017	2/3/2017	-60.40	02	1/18/2017	1/18/2017	0.50	2/3/2017	16.50	60.40	996.60
3300000450	RV	3300000450	633697	NEM	1/18/2017	1/18/2017	60.20	02	1/18/2017	1/18/2017	0.50	1/18/2017	0.50	(60.20)	(30.10)
3300000451	RV	3900000700	633697	1012382	1/18/2017	2/3/2017	-60.20	02	1/18/2017	1/18/2017	0.50	2/3/2017	16.50	60.20	993.30
3300000453	RV	3900001318	633697	1012044	1/19/2017	2/27/2017	-60.11	02	1/19/2017	1/19/2017	0.50	2/27/2017	39.50	60.11	2,374.35
3300000455	RV	3900000777	633697	1012382	1/19/2017	2/9/2017	-64.20	02	1/19/2017	1/19/2017	0.50	2/9/2017	21.50	64.20	1,380.30

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3300000456	RV	3900000766	633697	1012382	1/19/2017	2/8/2017	-61.80	02	1/19/2017	1/19/2017	0.50	2/8/2017	20.50	61.80	1,266.90
3300000458	RV	3900000780	633697	1012382	1/19/2017	2/9/2017	-60.40	02	1/19/2017	1/19/2017	0.50	2/9/2017	21.50	60.40	1,298.60
3300000459	RV	3300000460	633697	NEM	1/19/2017	1/19/2017	-65.20	02	1/19/2017	1/19/2017	0.50	1/19/2017	0.50	65.20	32.60
3300000460	RV	3300000460	633697	NEM	1/19/2017	1/19/2017	65.20	02	1/19/2017	1/19/2017	0.50	1/19/2017	0.50	(65.20)	(32.60)
3300000461	RV	3900000781	633697	1012382	1/19/2017	2/9/2017	-65.20	02	1/19/2017	1/19/2017	0.50	2/9/2017	21.50	65.20	1,401.80
3300000463	RV	3900000767	633697	1012382	1/19/2017	2/8/2017	-60.40	02	1/19/2017	1/19/2017	0.50	2/8/2017	20.50	60.40	1,238.20
3300000582	RV	3900000850	633697	1012382	1/25/2017	2/10/2017	-60.40	02	1/25/2017	1/25/2017	0.50	2/10/2017	16.50	60.40	996.60
3300000583	RV	3900000736	633697	1012044	1/25/2017	2/7/2017	-61.83	02	1/25/2017	1/25/2017	0.50	2/7/2017	13.50	61.83	834.71
3300000584	RV	3900000772	633697	1012382	1/25/2017	2/8/2017	-65.20	02	1/25/2017	1/25/2017	0.50	2/8/2017	14.50	65.20	945.40
3300000585	RV	3900001115	633697	1012044	1/25/2017	2/21/2017	-65.20	02	1/25/2017	1/25/2017	0.50	2/21/2017	27.50	65.20	1,793.00
3300000593	RV	3900000776	633697	1012382	1/25/2017	2/8/2017	-63.60	02	1/25/2017	1/25/2017	0.50	2/8/2017	14.50	63.60	922.20
3300000600	RV	3300000635	633697	NEM	1/25/2017	1/25/2017	-61.40	02	1/25/2017	1/25/2017	0.50	1/25/2017	0.50	61.40	30.70
3300000610	RV	3900000771	633697	1012382	1/25/2017	2/8/2017	-60.40	02	1/25/2017	1/25/2017	0.50	2/8/2017	14.50	60.40	875.80
3300000620	RV	3900001116	633697	1012044	1/25/2017	2/21/2017	-60.75	02	1/25/2017	1/25/2017	0.50	2/21/2017	27.50	60.75	1,670.63
3300000630	RV	3900000775	633697	1012382	1/25/2017	2/8/2017	-60.40	02	1/25/2017	1/25/2017	0.50	2/8/2017	14.50	60.40	875.80
3300000631	RV	3900000770	633697	1012382	1/25/2017	2/8/2017	-63.60	02	1/25/2017	1/25/2017	0.50	2/8/2017	14.50	63.60	922.20
3300000632	RV	3900000802	633697	41717	1/25/2017	2/9/2017	-70.00	02	1/25/2017	1/25/2017	0.50	2/9/2017	15.50	70.00	1,085.00
3300000633	RV	3900000842	633697	1012382	1/25/2017	2/10/2017	-60.20	02	1/25/2017	1/25/2017	0.50	2/10/2017	16.50	60.20	993.30
3300000634	RV	3900000779	633697	1012382	1/25/2017	2/9/2017	-65.00	02	1/25/2017	1/25/2017	0.50	2/9/2017	15.50	65.00	1,007.50
3300000635	RV	3300000635	633697	NEM	1/25/2017	1/25/2017	61.40	02	1/25/2017	1/25/2017	0.50	1/25/2017	0.50	(61.40)	(30.70)
3300000636	RV	3900001319	633697	1012044	1/25/2017	2/27/2017	-61.40	02	1/25/2017	1/25/2017	0.50	2/27/2017	33.50	61.40	2,056.90
3300000713	RV	3900000773	633697	1012382	1/26/2017	2/8/2017	-64.20	02	1/26/2017	1/26/2017	0.50	2/8/2017	13.50	64.20	866.70
3300000714	RV	3900000765	633697	1012382	1/26/2017	2/8/2017	-60.40	02	1/26/2017	1/26/2017	0.50	2/8/2017	13.50	60.40	815.40
3300000715	RV	3900000778	633697	1012382	1/26/2017	2/9/2017	-65.20	02	1/26/2017	1/26/2017	0.50	2/9/2017	14.50	65.20	945.40
3300000716	RV	3900000768	633697	1012382	1/26/2017	2/8/2017	-65.20	02	1/26/2017	1/26/2017	0.50	2/8/2017	13.50	65.20	880.20
3300000717	RV	3900000709	633697	1012423	1/26/2017	2/3/2017	-65.20	02	1/26/2017	1/26/2017	0.50	2/3/2017	8.50	65.20	554.20
3300000718	RV	3900001320	633697	1012044	1/26/2017	2/27/2017	-65.20	02	1/26/2017	1/26/2017	0.50	2/27/2017	32.50	65.20	2,119.00
3300000719	RV	3900001321	633697	1012044	1/26/2017	2/27/2017	-64.41	02	1/26/2017	1/26/2017	0.50	2/27/2017	32.50	64.41	2,093.33
3300000720	RV	3900000763	633697	1012382	1/26/2017	2/8/2017	-60.20	02	1/26/2017	1/26/2017	0.50	2/8/2017	13.50	60.20	812.70
3300000721	RV	3900000625	633697	1012358	1/26/2017	2/1/2017	-61.40	02	1/26/2017	1/26/2017	0.50	2/1/2017	6.50	61.40	399.10
3300000722	RV	3900000708	633697	1012423	1/26/2017	2/3/2017	-63.00	02	1/26/2017	1/26/2017	0.50	2/3/2017	8.50	63.00	535.50
3300000723	RV	3900000950	633697	1012382	1/26/2017	2/15/2017	-60.40	02	1/26/2017	1/26/2017	0.50	2/15/2017	20.50	60.40	1,238.20
3300000724	RV	3900000759	633697	1012382	1/26/2017	2/8/2017	-61.40	02	1/26/2017	1/26/2017	0.50	2/8/2017	13.50	61.40	828.90
3300000725	RV	3900000762	633697	1012382	1/26/2017	2/8/2017	-60.40	02	1/26/2017	1/26/2017	0.50	2/8/2017	13.50	60.40	815.40
3300000726	RV	3900000769	633697	1012382	1/26/2017	2/8/2017	-60.20	02	1/26/2017	1/26/2017	0.50	2/8/2017	13.50	60.20	812.70
3300000727	RV	3900000764	633697	1012382	1/26/2017	2/8/2017	-61.40	02	1/26/2017	1/26/2017	0.50	2/8/2017	13.50	61.40	828.90
3300000728	RV	3900000805	633697	41717	1/26/2017	2/9/2017	-65.20	02	1/26/2017	1/26/2017	0.50	2/9/2017	14.50	65.20	945.40
3300000729	RV	3900000774	633697	1012382	1/26/2017	2/8/2017	-63.60	02	1/26/2017	1/26/2017	0.50	2/8/2017	13.50	63.60	858.60
3300000730	RV	3900000804	633697	41717	1/26/2017	2/9/2017	-62.60	02	1/26/2017	1/26/2017	0.50	2/9/2017	14.50	62.60	907.70
3300000731	RV	3900000636	633697	1012382	1/26/2017	2/1/2017	-60.40	02	1/26/2017	1/26/2017	0.50	2/1/2017	6.50	60.40	392.60
3300000732	RV	3900000707	633697	1012423	1/26/2017	2/3/2017	-61.40	02	1/26/2017	1/26/2017	0.50	2/3/2017	8.50	61.40	521.90
3300000733	RV	3900000637	633697	1012382	1/26/2017	2/1/2017	-60.40	02	1/26/2017	1/26/2017	0.50	2/1/2017	6.50	60.40	392.60
3300000734	RV	3900000706	633697	1012423	1/26/2017	2/3/2017	-71.40	02	1/26/2017	1/26/2017	0.50	2/3/2017	8.50	71.40	606.90
3300000782	RV	3300000782	633697	1012423	10/27/2016	1/27/2017	63.80	02	10/27/2016	10/27/2016	0.50	1/27/2017	92.50	(63.80)	(5,901.50)
3300000801	RV	3900000808	633697	1012382	1/27/2017	2/9/2017	-74.00	02	1/27/2017	1/27/2017	0.50	2/9/2017	13.50	74.00	999.00
3300000802	RV	3900000951	633697	1012382	1/27/2017	2/15/2017	-71.40	02	1/27/2017	1/27/2017	0.50	2/15/2017	19.50	71.40	1,392.30
3300000804	RV	3900000956	633697	1012382	1/27/2017	2/15/2017	-63.20	02	1/27/2017	1/27/2017	0.50	2/15/2017	19.50	63.20	1,232.40
3300000812	RV	3900000806	633697	41717	1/27/2017	2/9/2017	-61.40	02	1/27/2017	1/27/2017	0.50	2/9/2017	13.50	61.40	828.90
3300000821	RV	3900001323	633697	1012044	1/27/2017	2/27/2017	-60.54	02	1/27/2017	1/27/2017	0.50	2/27/2017	31.50	60.54	1,907.01
3300000822	RV	3900001325	633697	1012044	1/27/2017	2/27/2017	-62.90	02	1/27/2017	1/27/2017	0.50	2/27/2017	31.50	62.90	1,981.35

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3300000823	RV	3300000824	633697	NEM	1/27/2017	1/27/2017	-67.60	02	1/27/2017	1/27/2017	0.50	1/27/2017	0.50	67.60	33.80
3300000824	RV	3300000824	633697	NEM	1/27/2017	1/27/2017	67.60	02	1/27/2017	1/27/2017	0.50	1/27/2017	0.50	(67.60)	(33.80)
3300000825	RV	3900000954	633697	1012382	1/27/2017	2/15/2017	-67.60	02	1/27/2017	1/27/2017	0.50	2/15/2017	19.50	67.60	1,318.20
3300000944	RV	3900000955	633697	1012382	1/30/2017	2/15/2017	-60.40	02	1/30/2017	1/30/2017	0.50	2/15/2017	16.50	60.40	996.60
3300000949	RV	3900000949	633697	1012382	1/30/2017	2/15/2017	-60.40	02	1/30/2017	1/30/2017	0.50	2/15/2017	16.50	60.40	996.60
3300000953	RV	3900000947	633697	1012382	1/30/2017	2/15/2017	-62.80	02	1/30/2017	1/30/2017	0.50	2/15/2017	16.50	62.80	1,036.20
3300000964	RV	3900001324	633697	1012044	1/30/2017	2/27/2017	-65.20	02	1/30/2017	1/30/2017	0.50	2/27/2017	28.50	65.20	1,858.20
3300000967	RV	3900000848	633697	1012382	1/30/2017	2/10/2017	-60.40	02	1/30/2017	1/30/2017	0.50	2/10/2017	11.50	60.40	694.60
3300000971	RV	3900000852	633697	1012382	1/30/2017	2/10/2017	-61.40	02	1/30/2017	1/30/2017	0.50	2/10/2017	11.50	61.40	706.10
3300000975	RV	3900000953	633697	1012382	1/30/2017	2/15/2017	-60.40	02	1/30/2017	1/30/2017	0.50	2/15/2017	16.50	60.40	996.60
3300000982	RV	3900000705	633697	1012423	1/30/2017	2/3/2017	-67.60	02	1/30/2017	1/30/2017	0.50	2/3/2017	4.50	67.60	304.20
3300000990	RV	3900001322	633697	1012044	1/30/2017	2/27/2017	-61.40	02	1/30/2017	1/30/2017	0.50	2/27/2017	28.50	61.40	1,749.90
3300001140	RV	3900001327	633697	1012044	1/31/2017	2/27/2017	-65.20	02	1/31/2017	1/31/2017	0.50	2/27/2017	27.50	65.20	1,793.00
3300001143	RV	3900001326	633697	1012044	1/31/2017	2/27/2017	-61.40	02	1/31/2017	1/31/2017	0.50	2/27/2017	27.50	61.40	1,688.50
3300001144	RV	3900000807	633697	41717	1/31/2017	2/9/2017	-65.20	02	1/31/2017	1/31/2017	0.50	2/9/2017	9.50	65.20	619.40
3300001146	RV	3900000841	633697	1012382	1/31/2017	2/10/2017	-60.40	02	1/31/2017	1/31/2017	0.50	2/10/2017	10.50	60.40	634.20
3300001246	RV	3900000846	633697	1012382	2/1/2017	2/10/2017	-60.40	02	2/1/2017	2/1/2017	0.50	2/10/2017	9.50	60.40	573.80
3300001247	RV	3900000957	633697	1012382	2/1/2017	2/15/2017	-61.40	02	2/1/2017	2/1/2017	0.50	2/15/2017	14.50	61.40	890.30
3300001250	RV	3900000952	633697	1012382	2/1/2017	2/15/2017	-64.20	02	2/1/2017	2/1/2017	0.50	2/15/2017	14.50	64.20	930.90
3300001254	RV	3300001273	633697	1012382	2/1/2017	2/1/2017	-61.40	02	2/1/2017	2/1/2017	0.50	2/1/2017	0.50	61.40	30.70
3300001257	RV	3900000930	633697	1012382	2/1/2017	2/15/2017	-61.00	02	2/1/2017	2/1/2017	0.50	2/15/2017	14.50	61.00	884.50
3300001260	RV	3900000948	633697	1012382	2/1/2017	2/15/2017	-61.40	02	2/1/2017	2/1/2017	0.50	2/15/2017	14.50	61.40	890.30
3300001261	RV	3300001276	633697	1012382	2/1/2017	2/1/2017	-61.40	02	2/1/2017	2/1/2017	0.50	2/1/2017	0.50	61.40	30.70
3300001262	RV	3900000801	633697	41717	2/1/2017	2/9/2017	-61.40	02	2/1/2017	2/1/2017	0.50	2/9/2017	8.50	61.40	521.90
3300001273	RV	3300001273	633697	1012382	2/1/2017	2/1/2017	61.40	02	2/1/2017	2/1/2017	0.50	2/1/2017	0.50	(61.40)	(30.70)
3300001275	RV	3900001545	633697	1012044	2/1/2017	3/7/2017	-61.40	02	2/1/2017	2/1/2017	0.50	3/7/2017	34.50	61.40	2,118.30
3300001276	RV	3300001276	633697	1012382	2/1/2017	2/1/2017	61.40	02	2/1/2017	2/1/2017	0.50	2/1/2017	0.50	(61.40)	(30.70)
3300001277	RV	3900001375	633697	1012044	2/1/2017	2/28/2017	-61.40	02	2/1/2017	2/1/2017	0.50	2/28/2017	27.50	61.40	1,688.50
3300001315	RV	3900001384	633697	1012358	2/2/2017	2/28/2017	-61.40	02	2/2/2017	2/2/2017	0.50	2/28/2017	26.50	61.40	1,627.10
3300001316	RV	3900000872	633697	41717	2/2/2017	2/14/2017	-61.40	02	2/2/2017	2/2/2017	0.50	2/14/2017	12.50	61.40	767.50
3300001349	RV	3900001378	633697	1012044	2/2/2017	2/28/2017	-61.61	02	2/2/2017	2/2/2017	0.50	2/28/2017	26.50	61.61	1,632.67
3300001350	RV	3900000843	633697	1012382	2/2/2017	2/10/2017	-61.40	02	2/2/2017	2/2/2017	0.50	2/10/2017	8.50	61.40	521.90
3300001351	RV	3900001379	633697	1012044	2/2/2017	2/28/2017	-69.00	02	2/2/2017	2/2/2017	0.50	2/28/2017	26.50	69.00	1,828.50
3300001352	RV	3900000844	633697	1012382	2/2/2017	2/10/2017	-61.40	02	2/2/2017	2/2/2017	0.50	2/10/2017	8.50	61.40	521.90
3300001353	RV	3900000847	633697	1012382	2/2/2017	2/10/2017	-60.40	02	2/2/2017	2/2/2017	0.50	2/10/2017	8.50	60.40	513.40
3300001354	RV	3900000851	633697	1012382	2/2/2017	2/10/2017	-60.40	02	2/2/2017	2/2/2017	0.50	2/10/2017	8.50	60.40	513.40
3300001356	RV	3300001375	633697	NEM	2/2/2017	2/3/2017	-61.40	02	2/2/2017	2/2/2017	0.50	2/3/2017	1.50	61.40	92.10
3300001357	RV	3900001377	633697	1012044	2/2/2017	2/28/2017	-61.40	02	2/2/2017	2/2/2017	0.50	2/28/2017	26.50	61.40	1,627.10
3300001375	RV	3300001375	633697	NEM	2/2/2017	2/3/2017	61.40	02	2/2/2017	2/2/2017	0.50	2/3/2017	1.50	(61.40)	(92.10)
3300001376	RV	3900001374	633697	1012044	2/3/2017	2/28/2017	-61.40	02	2/3/2017	2/3/2017	0.50	2/28/2017	25.50	61.40	1,565.70
3300001377	RV	3900000845	633697	1012382	2/3/2017	2/10/2017	-60.40	02	2/3/2017	2/3/2017	0.50	2/10/2017	7.50	60.40	453.00
3300001379	RV	3900000921	633697	1012382	2/3/2017	2/15/2017	-70.00	02	2/3/2017	2/3/2017	0.50	2/15/2017	12.50	70.00	875.00
3300001380	RV	3900000922	633697	1012382	2/3/2017	2/15/2017	-61.40	02	2/3/2017	2/3/2017	0.50	2/15/2017	12.50	61.40	767.50
3300001381	RV	3900000849	633697	1012382	2/3/2017	2/10/2017	-61.40	02	2/3/2017	2/3/2017	0.50	2/10/2017	7.50	61.40	460.50
3300001382	RV	3900001376	633697	1012044	2/3/2017	2/28/2017	-61.40	02	2/3/2017	2/3/2017	0.50	2/28/2017	25.50	61.40	1,565.70
3300001383	RV	3900001373	633697	1012044	2/3/2017	2/28/2017	-61.40	02	2/3/2017	2/3/2017	0.50	2/28/2017	25.50	61.40	1,565.70
3300001401	RV	3900001243	633697	1012382	2/6/2017	2/23/2017	-60.40	02	2/6/2017	2/6/2017	0.50	2/23/2017	17.50	60.40	1,057.00
3300001402	RV	3900001241	633697	1012382	2/6/2017	2/23/2017	-65.20	02	2/6/2017	2/6/2017	0.50	2/23/2017	17.50	65.20	1,141.00
3300001403	RV	3900001237	633697	1012382	2/6/2017	2/23/2017	-65.20	02	2/6/2017	2/6/2017	0.50	2/23/2017	17.50	65.20	1,141.00
3300001405	RV	3900001236	633697	1012382	2/6/2017	2/23/2017	-60.20	02	2/6/2017	2/6/2017	0.50	2/23/2017	17.50	60.20	1,053.50

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									Service period						
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3300001407	RV	3900001240	633697	1012382	2/6/2017	2/23/2017	-63.20	02	2/6/2017	2/6/2017	0.50	2/23/2017	17.50	63.20	1,106.00
3300001446	RV	3900001385	633697	1012358	2/7/2017	2/28/2017	-63.60	02	2/7/2017	2/7/2017	0.50	2/28/2017	21.50	63.60	1,367.40
3300001449	RV	3900001251	633697	1012382	2/7/2017	2/23/2017	-63.20	02	2/7/2017	2/7/2017	0.50	2/23/2017	16.50	63.20	1,042.80
3300001450	RV	3900001254	633697	1012382	2/7/2017	2/23/2017	-64.20	02	2/7/2017	2/7/2017	0.50	2/23/2017	16.50	64.20	1,059.30
3300001453	RV	3900001245	633697	1012382	2/7/2017	2/23/2017	-61.80	02	2/7/2017	2/7/2017	0.50	2/23/2017	16.50	61.80	1,019.70
3300001454	RV	3900001234	633697	1012382	2/7/2017	2/23/2017	-61.00	02	2/7/2017	2/7/2017	0.50	2/23/2017	16.50	61.00	1,006.50
3300001455	RV	3900001239	633697	1012382	2/7/2017	2/23/2017	-60.40	02	2/7/2017	2/7/2017	0.50	2/23/2017	16.50	60.40	996.60
3300001456	RV	3900001250	633697	1012382	2/7/2017	2/23/2017	-61.80	02	2/7/2017	2/7/2017	0.50	2/23/2017	16.50	61.80	1,019.70
3300001473	RV	3900002176	633697	1012605	2/8/2017	4/4/2017	-116.60	02	2/8/2017	2/8/2017	0.50	4/4/2017	55.50	116.60	6,471.30
3300001490	RV	3900002176	633697	1012605	2/8/2017	4/4/2017	-116.60	02	2/8/2017	2/8/2017	0.50	4/4/2017	55.50	116.60	6,471.30
3300001491	RV	3300001511	633697	NEM	2/8/2017	2/8/2017	-116.60	02	2/8/2017	2/8/2017	0.50	2/8/2017	0.50	116.60	58.30
3300001492	RV	3900002176	633697	1012605	2/8/2017	4/4/2017	-116.60	02	2/8/2017	2/8/2017	0.50	4/4/2017	55.50	116.60	6,471.30
3300001493	RV	3900002176	633697	1012605	2/8/2017	4/4/2017	-116.60	02	2/8/2017	2/8/2017	0.50	4/4/2017	55.50	116.60	6,471.30
3300001494	RV	3900002176	633697	1012605	2/8/2017	4/4/2017	-116.60	02	2/8/2017	2/8/2017	0.50	4/4/2017	55.50	116.60	6,471.30
3300001496	RV	3900002176	633697	1012605	2/8/2017	4/4/2017	-116.60	02	2/8/2017	2/8/2017	0.50	4/4/2017	55.50	116.60	6,471.30
3300001497	RV	3900001255	633697	1012382	2/8/2017	2/23/2017	-63.20	02	2/8/2017	2/8/2017	0.50	2/23/2017	15.50	63.20	979.60
3300001498	RV	3900001235	633697	1012382	2/8/2017	2/23/2017	-61.00	02	2/8/2017	2/8/2017	0.50	2/23/2017	15.50	61.00	945.50
3300001499	RV	3900001248	633697	1012382	2/8/2017	2/23/2017	-60.40	02	2/8/2017	2/8/2017	0.50	2/23/2017	15.50	60.40	936.20
3300001500	RV	3300001513	633697	NEM	2/8/2017	2/8/2017	-65.20	02	2/8/2017	2/8/2017	0.50	2/8/2017	0.50	65.20	32.60
3300001501	RV	3900001253	633697	1012382	2/8/2017	2/23/2017	-63.60	02	2/8/2017	2/8/2017	0.50	2/23/2017	15.50	63.60	985.80
3300001502	RV	3900001238	633697	1012382	2/8/2017	2/23/2017	-64.20	02	2/8/2017	2/8/2017	0.50	2/23/2017	15.50	64.20	995.10
3300001503	RV	3900001242	633697	1012382	2/8/2017	2/23/2017	-61.40	02	2/8/2017	2/8/2017	0.50	2/23/2017	15.50	61.40	951.70
3300001504	RV	3900001249	633697	1012382	2/8/2017	2/23/2017	-63.20	02	2/8/2017	2/8/2017	0.50	2/23/2017	15.50	63.20	979.60
3300001505	RV	3900001252	633697	1012382	2/8/2017	2/23/2017	-60.40	02	2/8/2017	2/8/2017	0.50	2/23/2017	15.50	60.40	936.20
3300001506	RV	3900001246	633697	1012382	2/8/2017	2/23/2017	-67.60	02	2/8/2017	2/8/2017	0.50	2/23/2017	15.50	67.60	1,047.80
3300001507	RV	3300001508	633697	NEM	2/8/2017	2/8/2017	-60.40	02	2/8/2017	2/8/2017	0.50	2/8/2017	0.50	60.40	30.20
3300001508	RV	3300001508	633697	NEM	2/8/2017	2/8/2017	60.40	02	2/8/2017	2/8/2017	0.50	2/8/2017	0.50	(60.40)	(30.20)
3300001509	RV	3900001244	633697	1012382	2/8/2017	2/23/2017	-60.40	02	2/8/2017	2/8/2017	0.50	2/23/2017	15.50	60.40	936.20
3300001511	RV	3300001511	633697	NEM	2/8/2017	2/8/2017	116.60	02	2/8/2017	2/8/2017	0.50	2/8/2017	0.50	(116.60)	(58.30)
3300001512	RV	3900002176	633697	1012605	2/8/2017	4/4/2017	-116.60	02	2/8/2017	2/8/2017	0.50	4/4/2017	55.50	116.60	6,471.30
3300001513	RV	3300001513	633697	NEM	2/8/2017	2/8/2017	65.20	02	2/8/2017	2/8/2017	0.50	2/8/2017	0.50	(65.20)	(32.60)
3300001514	RV	3900001247	633697	1012382	2/8/2017	2/23/2017	-65.20	02	2/8/2017	2/8/2017	0.50	2/23/2017	15.50	65.20	1,010.60
3300001550	RV	3900001380	633697	1012358	2/9/2017	2/28/2017	-63.80	02	2/9/2017	2/9/2017	0.50	2/28/2017	19.50	63.80	1,244.10
3300001552	RV	3900001383	633697	1012382	2/9/2017	2/28/2017	-64.20	02	2/9/2017	2/9/2017	0.50	2/28/2017	19.50	64.20	1,251.90
3300001553	RV	3900001382	633697	1012382	2/9/2017	2/28/2017	-70.00	02	2/9/2017	2/9/2017	0.50	2/28/2017	19.50	70.00	1,365.00
3300001554	RV	3900001381	633697	1012382	2/9/2017	2/28/2017	-65.20	02	2/9/2017	2/9/2017	0.50	2/28/2017	19.50	65.20	1,271.40
3300001601	RV	3900001365	633697	41717	2/14/2017	2/28/2017	-61.40	02	2/14/2017	2/14/2017	0.50	2/28/2017	14.50	61.40	890.30
3300001605	RV	3900001370	633697	1012382	2/14/2017	2/28/2017	-60.40	02	2/14/2017	2/14/2017	0.50	2/28/2017	14.50	60.40	875.80
3300001617	RV	3900002003	633697	1012044	2/14/2017	3/28/2017	-61.40	02	2/14/2017	2/14/2017	0.50	3/28/2017	42.50	61.40	2,609.50
3300001625	RV	3900002004	633697	1012044	2/14/2017	3/28/2017	-61.40	02	2/14/2017	2/14/2017	0.50	3/28/2017	42.50	61.40	2,609.50
3300001626	RV	3300001650	633697	NEM	2/14/2017	2/14/2017	-61.40	02	2/14/2017	2/14/2017	0.50	2/14/2017	0.50	61.40	30.70
3300001627	RV	3900002121	633697	1012499	2/14/2017	3/30/2017	-67.20	02	2/14/2017	2/14/2017	0.50	3/30/2017	44.50	67.20	2,990.40
3300001628	RV	3900001371	633697	1012382	2/14/2017	2/28/2017	-70.00	02	2/14/2017	2/14/2017	0.50	2/28/2017	14.50	70.00	1,015.00
3300001631	RV	3900001677	633697	1012382	2/14/2017	3/9/2017	-81.40	02	2/14/2017	2/14/2017	0.50	3/9/2017	23.50	81.40	1,912.90
3300001632	RV	3900001678	633697	1012382	2/14/2017	3/9/2017	-63.20	02	2/14/2017	2/14/2017	0.50	3/9/2017	23.50	63.20	1,485.20
3300001633	RV	3900001367	633697	1012382	2/14/2017	2/28/2017	-70.00	02	2/14/2017	2/14/2017	0.50	2/28/2017	14.50	70.00	1,015.00
3300001634	RV	3900001672	633697	1012382	2/14/2017	3/9/2017	-60.40	02	2/14/2017	2/14/2017	0.50	3/9/2017	23.50	60.40	1,419.40
3300001635	RV	3900001369	633697	1012382	2/14/2017	2/28/2017	-60.40	02	2/14/2017	2/14/2017	0.50	2/28/2017	14.50	60.40	875.80
3300001636	RV	3900001673	633697	1012382	2/14/2017	3/9/2017	-61.40	02	2/14/2017	2/14/2017	0.50	3/9/2017	23.50	61.40	1,442.90
3300001637	RV	3900002005	633697	1012044	2/14/2017	3/28/2017	-61.40	02	2/14/2017	2/14/2017	0.50	3/28/2017	42.50	61.40	2,609.50

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3300001638	RV	3900001368	633697	1012382	2/14/2017	2/28/2017	-60.40	02	2/14/2017	2/14/2017	0.50	2/28/2017	14.50	60.40	875.80
3300001639	RV	3900001674	633697	1012382	2/14/2017	3/9/2017	-62.00	02	2/14/2017	2/14/2017	0.50	3/9/2017	23.50	62.00	1,457.00
3300001640	RV	3300001641	633697	NEM	2/14/2017	2/14/2017	-63.20	02	2/14/2017	2/14/2017	0.50	2/14/2017	0.50	63.20	31.60
3300001641	RV	3300001641	633697	NEM	2/14/2017	2/14/2017	63.20	02	2/14/2017	2/14/2017	0.50	2/14/2017	0.50	(63.20)	(31.60)
3300001642	RV	3900001372	633697	1012382	2/14/2017	2/28/2017	-63.20	02	2/14/2017	2/14/2017	0.50	2/28/2017	14.50	63.20	916.40
3300001643	RV	3900001676	633697	1012382	2/14/2017	3/9/2017	-61.40	02	2/14/2017	2/14/2017	0.50	3/9/2017	23.50	61.40	1,442.90
3300001644	RV	3900001670	633697	1012382	2/14/2017	3/9/2017	-60.40	02	2/14/2017	2/14/2017	0.50	3/9/2017	23.50	60.40	1,419.40
3300001645	RV	3900002006	633697	1012382	2/14/2017	3/28/2017	-65.20	02	2/14/2017	2/14/2017	0.50	3/28/2017	42.50	65.20	2,771.00
3300001646	RV	3900002008	633697	1012044	2/14/2017	3/28/2017	-60.97	02	2/14/2017	2/14/2017	0.50	3/28/2017	42.50	60.97	2,591.23
3300001647	RV	3900002185	633697	1012044	2/14/2017	4/4/2017	-69.00	02	2/14/2017	2/14/2017	0.50	4/4/2017	49.50	69.00	3,415.50
3300001648	RV	3900001366	633697	41717	2/14/2017	2/28/2017	-70.00	02	2/14/2017	2/14/2017	0.50	2/28/2017	14.50	70.00	1,015.00
3300001649	RV	3900001669	633697	1012382	2/14/2017	3/9/2017	-62.00	02	2/14/2017	2/14/2017	0.50	3/9/2017	23.50	62.00	1,457.00
3300001650	RV	3300001650	633697	NEM	2/14/2017	2/14/2017	61.40	02	2/14/2017	2/14/2017	0.50	2/14/2017	0.50	(61.40)	(30.70)
3300001651	RV	3900002007	633697	1012044	2/14/2017	3/28/2017	-61.40	02	2/14/2017	2/14/2017	0.50	3/28/2017	42.50	61.40	2,609.50
3300001684	RV	3900001594	633697	41717	2/15/2017	3/8/2017	-80.00	02	2/15/2017	2/15/2017	0.50	3/8/2017	21.50	80.00	1,720.00
3300001686	RV	3900001743	633697	1012382	2/15/2017	3/13/2017	-69.40	02	2/15/2017	2/15/2017	0.50	3/13/2017	26.50	69.40	1,839.10
3300001687	RV	3900001757	633697	1012382	2/15/2017	3/14/2017	-60.40	02	2/15/2017	2/15/2017	0.50	3/14/2017	27.50	60.40	1,661.00
3300001690	RV	3900001472	633697	1012392	2/15/2017	3/3/2017	-64.00	02	2/15/2017	2/15/2017	0.50	3/3/2017	16.50	64.00	1,056.00
3300001726	RV	3900001540	633697	1012358	2/16/2017	3/7/2017	-61.40	02	2/16/2017	2/16/2017	0.50	3/7/2017	19.50	61.40	1,197.30
3300001727	RV	3900001299	633697	1012423	2/16/2017	2/24/2017	-61.40	02	2/16/2017	2/16/2017	0.50	2/24/2017	8.50	61.40	521.90
3300001728	RV	3900001747	633697	1012382	2/16/2017	3/14/2017	-62.60	02	2/16/2017	2/16/2017	0.50	3/14/2017	26.50	62.60	1,658.90
3300001729	RV	3900001750	633697	1012382	2/16/2017	3/14/2017	-61.40	02	2/16/2017	2/16/2017	0.50	3/14/2017	26.50	61.40	1,627.10
3300001730	RV	3900001753	633697	1012382	2/16/2017	3/14/2017	-60.40	02	2/16/2017	2/16/2017	0.50	3/14/2017	26.50	60.40	1,600.60
3300001731	RV	3900001766	633697	1012382	2/16/2017	3/14/2017	-60.40	02	2/16/2017	2/16/2017	0.50	3/14/2017	26.50	60.40	1,600.60
3300001732	RV	3900001758	633697	1012382	2/16/2017	3/14/2017	-60.40	02	2/16/2017	2/16/2017	0.50	3/14/2017	26.50	60.40	1,600.60
3300001772	RV	3900001298	633697	1012423	2/17/2017	2/24/2017	-63.80	02	2/17/2017	2/17/2017	0.50	2/24/2017	7.50	63.80	478.50
3300001781	RV	3900002179	633697	1012044	2/17/2017	4/4/2017	-61.40	02	2/17/2017	2/17/2017	0.50	4/4/2017	46.50	61.40	2,855.10
3300001816	RV	3900001671	633697	1012382	2/24/2017	3/9/2017	-60.40	02	2/24/2017	2/24/2017	0.50	3/9/2017	13.50	60.40	815.40
3300001817	RV	3900001751	633697	1012382	2/17/2017	3/14/2017	-60.40	02	2/17/2017	2/17/2017	0.50	3/14/2017	25.50	60.40	1,540.20
3300001819	RV	3900001752	633697	1012382	2/17/2017	3/14/2017	-65.20	02	2/17/2017	2/17/2017	0.50	3/14/2017	25.50	65.20	1,662.60
3300001820	RV	3900001675	633697	1012382	2/17/2017	3/9/2017	-61.40	02	2/17/2017	2/17/2017	0.50	3/9/2017	20.50	61.40	1,258.70
3300001822	RV	3900003190	633697	1012382	2/17/2017	5/11/2017	-64.20	02	2/17/2017	2/17/2017	0.50	5/11/2017	83.50	64.20	5,360.70
3300001823	RV	3900001748	633697	1012382	2/17/2017	3/14/2017	-67.60	02	2/17/2017	2/17/2017	0.50	3/14/2017	25.50	67.60	1,723.80
3300001833	RV	3900001759	633697	1012382	2/21/2017	3/14/2017	-61.40	02	2/21/2017	2/21/2017	0.50	3/14/2017	21.50	61.40	1,320.10
3300001834	RV	3900001769	633697	1012382	2/21/2017	3/14/2017	-60.40	02	2/21/2017	2/21/2017	0.50	3/14/2017	21.50	60.40	1,298.60
3300001835	RV	3900002180	633697	1012044	2/21/2017	4/4/2017	-61.40	02	2/21/2017	2/21/2017	0.50	4/4/2017	42.50	61.40	2,609.50
3300001924	RV	3300001937	633697	NEM	2/22/2017	2/22/2017	-61.61	02	2/22/2017	2/22/2017	0.50	2/22/2017	0.50	61.61	30.81
3300001932	RV	3900002396	633697	1012423	2/22/2017	4/11/2017	-63.80	02	2/22/2017	2/22/2017	0.50	4/11/2017	48.50	63.80	3,094.30
3300001933	RV	3900002181	633697	1012044	2/22/2017	4/4/2017	-65.20	02	2/22/2017	2/22/2017	0.50	4/4/2017	41.50	65.20	2,705.80
3300001934	RV	3900001754	633697	1012382	2/22/2017	3/14/2017	-63.20	02	2/22/2017	2/22/2017	0.50	3/14/2017	20.50	63.20	1,295.60
3300001935	RV	3900001763	633697	1012382	2/22/2017	3/14/2017	-63.20	02	2/22/2017	2/22/2017	0.50	3/14/2017	20.50	63.20	1,295.60
3300001936	RV	3900001746	633697	1012382	2/22/2017	3/14/2017	-60.40	02	2/22/2017	2/22/2017	0.50	3/14/2017	20.50	60.40	1,238.20
3300001937	RV	3300001937	633697	NEM	2/22/2017	2/22/2017	61.61	02	2/22/2017	2/22/2017	0.50	2/22/2017	0.50	(61.61)	(30.81)
3300001938	RV	3900002182	633697	1012044	2/22/2017	4/4/2017	-61.61	02	2/22/2017	2/22/2017	0.50	4/4/2017	41.50	61.61	2,556.82
3300001970	RV	3900001501	633697	1012703	2/24/2017	3/6/2017	-78.80	02	2/24/2017	2/24/2017	0.50	3/6/2017	10.50	78.80	827.40
3300001976	RV	3900001741	633697	1012382	2/24/2017	3/13/2017	-61.40	02	2/24/2017	2/24/2017	0.50	3/13/2017	17.50	61.40	1,074.50
3300001977	RV	3300002036	633697	NEM	2/24/2017	2/27/2017	-61.80	02	2/24/2017	2/24/2017	0.50	2/27/2017	3.50	61.80	216.30
3300001983	RV	3900001756	633697	1012382	2/24/2017	3/14/2017	-61.40	02	2/24/2017	2/24/2017	0.50	3/14/2017	18.50	61.40	1,135.90
3300002005	RV	3900001762	633697	1012382	2/24/2017	3/14/2017	-61.40	02	2/24/2017	2/24/2017	0.50	3/14/2017	18.50	61.40	1,135.90
3300002011	RV	3900001764	633697	1012382	2/24/2017	3/14/2017	-61.00	02	2/24/2017	2/24/2017	0.50	3/14/2017	18.50	61.00	1,128.50

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3300002036	RV	3300002036	633697	NEM	2/24/2017	2/27/2017	61.80	02	2/24/2017	2/24/2017	0.50	2/27/2017	3.50	(61.80)	(216.30)
3300002037	RV	3900001767	633697	1012382	2/27/2017	3/14/2017	-61.80	02	2/27/2017	2/27/2017	0.50	3/14/2017	15.50	61.80	957.90
3300002058	RV	3900001768	633697	1012382	2/27/2017	3/14/2017	-65.20	02	2/27/2017	2/27/2017	0.50	3/14/2017	15.50	65.20	1,010.60
3300002060	RV	3900001742	633697	1012382	2/27/2017	3/13/2017	-65.20	02	2/27/2017	2/27/2017	0.50	3/13/2017	14.50	65.20	945.40
3300002061	RV	3900001760	633697	1012382	2/27/2017	3/14/2017	-61.80	02	2/27/2017	2/27/2017	0.50	3/14/2017	15.50	61.80	957.90
3300002062	RV	3900002785	633697	41717	2/27/2017	4/24/2017	-63.60	02	2/27/2017	2/27/2017	0.50	4/24/2017	56.50	63.60	3,593.40
3300002063	RV	3900002183	633697	1012044	2/27/2017	4/4/2017	-69.00	02	2/27/2017	2/27/2017	0.50	4/4/2017	36.50	69.00	2,518.50
3300002064	RV	3900001745	633697	1012382	2/27/2017	3/14/2017	-65.20	02	2/27/2017	2/27/2017	0.50	3/14/2017	15.50	65.20	1,010.60
3300002065	RV	3900001761	633697	1012382	2/27/2017	3/14/2017	-60.40	02	2/27/2017	2/27/2017	0.50	3/14/2017	15.50	60.40	936.20
3300002066	RV	3900001765	633697	1012382	2/27/2017	3/14/2017	-63.44	02	2/27/2017	2/27/2017	0.50	3/14/2017	15.50	63.44	983.32
3300002189	RV	3900001593	633697	41717	2/27/2017	3/8/2017	-65.20	02	2/27/2017	2/27/2017	0.50	3/8/2017	9.50	65.20	619.40
3300002190	RV	3900001518	633697	1012423	2/27/2017	3/6/2017	-69.00	02	2/27/2017	2/27/2017	0.50	3/6/2017	7.50	69.00	517.50
3300002191	RV	3900001548	633697	1012044	2/27/2017	3/7/2017	-62.47	02	2/27/2017	2/27/2017	0.50	3/7/2017	8.50	62.47	531.00
3300002192	RV	3900001755	633697	1012382	2/27/2017	3/14/2017	-66.00	02	2/27/2017	2/27/2017	0.50	3/14/2017	15.50	66.00	1,023.00
3300002193	RV	3900002184	633697	1012044	2/27/2017	4/4/2017	-61.40	02	2/27/2017	2/27/2017	0.50	4/4/2017	36.50	61.40	2,241.10
3300002194	RV	3900001749	633697	1012382	2/27/2017	3/14/2017	-61.40	02	2/27/2017	2/27/2017	0.50	3/14/2017	15.50	61.40	951.70
3300002320	RV	3900001870	633697	1012358	3/2/2017	3/20/2017	-63.60	02	3/2/2017	3/2/2017	0.50	3/20/2017	18.50	63.60	1,176.60
3300002321	RV	3900002018	633697	1012382	3/2/2017	3/28/2017	-65.20	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	65.20	1,727.80
3300002323	RV	3900002022	633697	1012382	3/2/2017	3/28/2017	-61.40	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	61.40	1,627.10
3300002332	RV	3900002013	633697	1012382	3/2/2017	3/28/2017	-65.20	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	65.20	1,727.80
3300002348	RV	3900002187	633697	1012044	3/2/2017	4/4/2017	-61.40	02	3/2/2017	3/2/2017	0.50	4/4/2017	33.50	61.40	2,056.90
3300002349	RV	3900002017	633697	1012382	3/2/2017	3/28/2017	-60.40	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	60.40	1,600.60
3300002350	RV	3900002191	633697	1012044	3/2/2017	4/4/2017	-61.40	02	3/2/2017	3/2/2017	0.50	4/4/2017	33.50	61.40	2,056.90
3300002351	RV	3900002015	633697	1012382	3/2/2017	3/28/2017	-60.40	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	60.40	1,600.60
3300002353	RV	3900002009	633697	1012382	3/2/2017	3/28/2017	-67.40	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	67.40	1,786.10
3300002355	RV	3900002011	633697	1012382	3/2/2017	3/28/2017	-61.40	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	61.40	1,627.10
3300002356	RV	3900002014	633697	1012382	3/2/2017	3/28/2017	-60.40	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	60.40	1,600.60
3300002357	RV	3900002010	633697	1012382	3/2/2017	3/28/2017	-62.00	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	62.00	1,643.00
3300002358	RV	3900002068	633697	41717	3/2/2017	3/28/2017	-65.20	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	65.20	1,727.80
3300002359	RV	3900002186	633697	1012044	3/2/2017	4/4/2017	-61.40	02	3/2/2017	3/2/2017	0.50	4/4/2017	33.50	61.40	2,056.90
3300002360	RV	3900002196	633697	1012044	3/2/2017	4/4/2017	-63.33	02	3/2/2017	3/2/2017	0.50	4/4/2017	33.50	63.33	2,121.56
3300002361	RV	3900001867	633697	1012423	3/2/2017	3/20/2017	-61.40	02	3/2/2017	3/2/2017	0.50	3/20/2017	18.50	61.40	1,135.90
3300002362	RV	3900001866	633697	1012423	3/2/2017	3/20/2017	-61.40	02	3/2/2017	3/2/2017	0.50	3/20/2017	18.50	61.40	1,135.90
3300002363	RV	3900002019	633697	1012382	3/2/2017	3/28/2017	-65.00	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	65.00	1,722.50
3300002364	RV	3900001865	633697	1012423	3/2/2017	3/20/2017	-61.40	02	3/2/2017	3/2/2017	0.50	3/20/2017	18.50	61.40	1,135.90
3300002365	RV	3900002025	633697	1012382	3/2/2017	3/28/2017	-66.00	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	66.00	1,749.00
3300002366	RV	3900002024	633697	1012382	3/2/2017	3/28/2017	-67.60	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	67.60	1,791.40
3300002367	RV	3900002026	633697	1012382	3/2/2017	3/28/2017	-63.00	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	63.00	1,669.50
3300002368	RV	3900002012	633697	1012382	3/2/2017	3/28/2017	-63.20	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	63.20	1,674.80
3300002369	RV	3900002023	633697	1012382	3/2/2017	3/28/2017	-60.40	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	60.40	1,600.60
3300002370	RV	3900002021	633697	1012382	3/2/2017	3/28/2017	-61.80	02	3/2/2017	3/2/2017	0.50	3/28/2017	26.50	61.80	1,637.70
3300002371	RV	3900002194	633697	1012044	3/2/2017	4/4/2017	-65.20	02	3/2/2017	3/2/2017	0.50	4/4/2017	33.50	65.20	2,184.20
3300002372	RV	3900001871	633697	1012358	3/2/2017	3/20/2017	-61.40	02	3/2/2017	3/2/2017	0.50	3/20/2017	18.50	61.40	1,135.90
3300002382	RV	3900002020	633697	1012382	3/3/2017	3/28/2017	-64.20	02	3/3/2017	3/3/2017	0.50	3/28/2017	25.50	64.20	1,637.10
3300002384	RV	3300002424	633697	NEM	3/3/2017	3/3/2017	-62.00	02	3/3/2017	3/3/2017	0.50	3/3/2017	0.50	62.00	31.00
3300002394	RV	3900002055	633697	1012382	3/3/2017	3/28/2017	-62.80	02	3/3/2017	3/3/2017	0.50	3/28/2017	25.50	62.80	1,601.40
3300002414	RV	3900002039	633697	1012382	3/3/2017	3/28/2017	-64.20	02	3/3/2017	3/3/2017	0.50	3/28/2017	25.50	64.20	1,637.10
3300002422	RV	3900002195	633697	1012044	3/3/2017	4/4/2017	-61.40	02	3/3/2017	3/3/2017	0.50	4/4/2017	32.50	61.40	1,995.50
3300002423	RV	3900002051	633697	1012382	3/3/2017	3/28/2017	-61.80	02	3/3/2017	3/3/2017	0.50	3/28/2017	25.50	61.80	1,575.90
3300002424	RV	3300002424	633697	NEM	3/3/2017	3/3/2017	62.00	02	3/3/2017	3/3/2017	0.50	3/3/2017	0.50	(62.00)	(31.00)

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Fire & Damage Reconnect, Joint Use Escort and interconnection Application Fee

Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Service period Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300002425	RV	3300002427	633697	NEM	3/3/2017	3/3/2017	-62.00	02	3/3/2017	3/3/2017	0.50	3/3/2017	0.50	62.00	31.00
3300002427	RV	3300002427	633697	NEM	3/3/2017	3/3/2017	62.00	02	3/3/2017	3/3/2017	0.50	3/3/2017	0.50	(62.00)	(31.00)
3300002428	RV	3900002016	633697	1012382	3/3/2017	3/28/2017	-62.00	02	3/3/2017	3/3/2017	0.50	3/28/2017	25.50	62.00	1,581.00
3300002711	RV	3900001951	633697	1012423	3/15/2017	3/24/2017	-65.20	02	3/15/2017	3/15/2017	0.50	3/24/2017	9.50	65.20	619.40
3300002713	RV	3900002058	633697	1012382	3/15/2017	3/28/2017	-61.40	02	3/15/2017	3/15/2017	0.50	3/28/2017	13.50	61.40	828.90
3300002715	RV	3900002034	633697	1012382	3/15/2017	3/28/2017	-63.60	02	3/15/2017	3/15/2017	0.50	3/28/2017	13.50	63.60	858.60
3300002716	RV	3900001950	633697	1012423	3/15/2017	3/24/2017	-65.20	02	3/15/2017	3/15/2017	0.50	3/24/2017	9.50	65.20	619.40
3300002717	RV	3900002063	633697	1012382	3/15/2017	3/28/2017	-61.80	02	3/15/2017	3/15/2017	0.50	3/28/2017	13.50	61.80	834.30
3300002720	RV	3900002061	633697	1012382	3/15/2017	3/28/2017	-65.20	02	3/15/2017	3/15/2017	0.50	3/28/2017	13.50	65.20	880.20
3300002722	RV	3900002040	633697	1012382	3/15/2017	3/28/2017	-61.40	02	3/15/2017	3/15/2017	0.50	3/28/2017	13.50	61.40	828.90
3300002723	RV	3900002190	633697	1012044	3/15/2017	4/4/2017	-61.40	02	3/15/2017	3/15/2017	0.50	4/4/2017	20.50	61.40	1,258.70
3300002724	RV	3900002189	633697	1012382	3/15/2017	4/4/2017	-61.40	02	3/15/2017	3/15/2017	0.50	4/4/2017	20.50	61.40	1,258.70
3300002725	RV	3900002035	633697	1012382	3/15/2017	3/28/2017	-65.20	02	3/15/2017	3/15/2017	0.50	3/28/2017	13.50	65.20	880.20
3300002726	RV	3900002032	633697	1012382	3/15/2017	3/28/2017	-65.20	02	3/15/2017	3/15/2017	0.50	3/28/2017	13.50	65.20	880.20
3300002727	RV	3900003840	633697	1012382	3/15/2017	6/13/2017	-64.40	02	3/15/2017	3/15/2017	0.50	6/13/2017	90.50	64.40	5,828.20
3300002728	RV	3900002106	633697	41717	3/15/2017	3/30/2017	-62.00	02	3/15/2017	3/15/2017	0.50	3/30/2017	15.50	62.00	961.00
3300002729	RV	3900002630	633697	1012759	3/15/2017	4/21/2017	-61.40	02	3/15/2017	3/15/2017	0.50	4/21/2017	37.50	61.40	2,302.50
3300002730	RV	3900002059	633697	1012382	3/15/2017	3/28/2017	-62.80	02	3/15/2017	3/15/2017	0.50	3/28/2017	13.50	62.80	847.80
3300002731	RV	3900002054	633697	1012382	3/15/2017	3/28/2017	-62.60	02	3/15/2017	3/15/2017	0.50	3/28/2017	13.50	62.60	845.10
3300002732	RV	3900002188	633697	1012044	3/15/2017	4/4/2017	-65.20	02	3/15/2017	3/15/2017	0.50	4/4/2017	20.50	65.20	1,336.60
3300002733	RV	3900002104	633697	41717	3/15/2017	3/30/2017	-63.00	02	3/15/2017	3/15/2017	0.50	3/30/2017	15.50	63.00	976.50
3300002734	RV	3900002056	633697	1012382	3/15/2017	3/28/2017	-61.80	02	3/15/2017	3/15/2017	0.50	3/28/2017	13.50	61.80	834.30
3300002735	RV	3900002047	633697	1012382	3/15/2017	3/28/2017	-62.80	02	3/15/2017	3/15/2017	0.50	3/28/2017	13.50	62.80	847.80
3300002736	RV	3900002038	633697	1012382	3/15/2017	3/28/2017	-60.40	02	3/15/2017	3/15/2017	0.50	3/28/2017	13.50	60.40	815.40
3300002737	RV	3900002046	633697	1012382	3/15/2017	3/28/2017	-65.20	02	3/15/2017	3/15/2017	0.50	3/28/2017	13.50	65.20	880.20
3300002738	RV	3900002041	633697	1012382	3/15/2017	3/28/2017	-63.20	02	3/15/2017	3/15/2017	0.50	3/28/2017	13.50	63.20	853.20
3300002744	RV	3900002066	633697	1012386	3/16/2017	3/28/2017	-63.60	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	63.60	795.00
3300002745	RV	3900001861	633697	1012434	3/16/2017	3/17/2017	-61.61	02	3/16/2017	3/16/2017	0.50	3/17/2017	1.50	61.61	92.42
3300002748	RV	3900002062	633697	1012382	3/16/2017	3/28/2017	-60.40	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	60.40	755.00
3300002749	RV	3900002042	633697	1012382	3/16/2017	3/28/2017	-61.40	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	61.40	767.50
3300002750	RV	3900002049	633697	1012382	3/16/2017	3/28/2017	-60.40	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	60.40	755.00
3300002751	RV	3900002028	633697	1012382	3/16/2017	3/28/2017	-60.40	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	60.40	755.00
3300002763	RV	3900002248	633697	1012044	3/16/2017	4/5/2017	-61.40	02	3/16/2017	3/16/2017	0.50	4/5/2017	20.50	61.40	1,258.70
3300002776	RV	3900002033	633697	1012382	3/16/2017	3/28/2017	-60.40	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	60.40	755.00
3300002780	RV	3900002027	633697	1012382	3/16/2017	3/28/2017	-61.40	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	61.40	767.50
3300002790	RV	3300002819	633697	NEM	3/16/2017	3/16/2017	-61.40	02	3/16/2017	3/16/2017	0.50	3/16/2017	0.50	61.40	30.70
3300002791	RV	3900002057	633697	1012382	3/16/2017	3/28/2017	-61.40	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	61.40	767.50
3300002792	RV	3900002247	633697	1012044	3/16/2017	4/5/2017	-62.47	02	3/16/2017	3/16/2017	0.50	4/5/2017	20.50	62.47	1,280.64
3300002793	RV	3900002036	633697	1010371	3/16/2017	3/28/2017	-60.40	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	60.40	755.00
3300002794	RV	3900002052	633697	1010371	3/16/2017	3/28/2017	-62.80	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	62.80	785.00
3300002795	RV	3900002102	633697	1008403	3/16/2017	3/30/2017	-61.40	02	3/16/2017	3/16/2017	0.50	3/30/2017	14.50	61.40	890.30
3300002796	RV	3900002037	633697	1010371	3/16/2017	3/28/2017	-60.40	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	60.40	755.00
3300002797	RV	3900002050	633697	1010371	3/16/2017	3/28/2017	-62.80	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	62.80	785.00
3300002798	RV	3900002045	633697	1010371	3/16/2017	3/28/2017	-61.80	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	61.80	772.50
3300002799	RV	3900002200	633697	1012044	3/16/2017	4/4/2017	-65.20	02	3/16/2017	3/16/2017	0.50	4/4/2017	19.50	65.20	1,271.40
3300002800	RV	3900002193	633697	1012044	3/16/2017	4/4/2017	-62.04	02	3/16/2017	3/16/2017	0.50	4/4/2017	19.50	62.04	1,209.78
3300002801	RV	3900002192	633697	1012044	3/16/2017	4/4/2017	-61.40	02	3/16/2017	3/16/2017	0.50	4/4/2017	19.50	61.40	1,197.30
3300002802	RV	3900002030	633697	1010371	3/16/2017	3/28/2017	-65.20	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	65.20	815.00
3300002803	RV	3900002029	633697	1012382	3/16/2017	3/28/2017	-61.40	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	61.40	767.50
3300002804	RV	3900002053	633697	1012382	3/16/2017	3/28/2017	-65.20	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	65.20	815.00

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3300002808	RV	3900001869	633697	1012434	3/16/2017	3/20/2017	-60.11	02	3/16/2017	3/16/2017	0.50	3/20/2017	4.50	60.11	270.50
3300002809	RV	3900002048	633697	1012382	3/16/2017	3/28/2017	-63.20	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	63.20	790.00
3300002810	RV	3900002060	633697	1012382	3/16/2017	3/28/2017	-65.20	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	65.20	815.00
3300002811	RV	3900001952	633697	1012423	3/16/2017	3/24/2017	-63.00	02	3/16/2017	3/16/2017	0.50	3/24/2017	8.50	63.00	535.50
3300002812	RV	3900003422	633697	1012499	3/16/2017	5/23/2017	-60.25	02	3/16/2017	3/16/2017	0.50	5/23/2017	68.50	60.25	4,127.13
3300002813	RV	3900002043	633697	1012382	3/16/2017	3/28/2017	-65.20	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	65.20	815.00
3300002814	RV	3900002202	633697	1012044	3/16/2017	4/4/2017	-61.40	02	3/16/2017	3/16/2017	0.50	4/4/2017	19.50	61.40	1,197.30
3300002815	RV	3900002105	633697	41717	3/16/2017	3/30/2017	-61.40	02	3/16/2017	3/16/2017	0.50	3/30/2017	14.50	61.40	890.30
3300002816	RV	3900002044	633697	1012382	3/16/2017	3/28/2017	-67.60	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	67.60	845.00
3300002817	RV	3900002031	633697	1012382	3/16/2017	3/28/2017	-65.20	02	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	65.20	815.00
3300002818	RV	3900002245	633697	1012044	3/16/2017	4/5/2017	-60.32	02	3/16/2017	3/16/2017	0.50	4/5/2017	20.50	60.32	1,236.56
3300002819	RV	3300002819	633697	NEM	3/16/2017	3/16/2017	61.40	02	3/16/2017	3/16/2017	0.50	3/16/2017	0.50	(61.40)	(30.70)
3300002820	RV	3900002246	633697	1012044	3/16/2017	4/5/2017	-61.40	02	3/16/2017	3/16/2017	0.50	4/5/2017	20.50	61.40	1,258.70
3300002831	RV	3900002223	633697	1012382	3/17/2017	4/5/2017	-61.80	02	3/17/2017	3/17/2017	0.50	4/5/2017	19.50	61.80	1,205.10
3300002832	RV	3900002292	633697	1012382	3/17/2017	4/6/2017	-65.20	02	3/17/2017	3/17/2017	0.50	4/6/2017	20.50	65.20	1,336.60
3300002846	RV	3900002075	633697	1012358	3/17/2017	3/28/2017	-62.60	02	3/17/2017	3/17/2017	0.50	3/28/2017	11.50	62.60	719.90
3300002847	RV	3900002213	633697	1012382	3/17/2017	4/4/2017	-61.80	02	3/17/2017	3/17/2017	0.50	4/4/2017	18.50	61.80	1,143.30
3300002848	RV	3900002197	633697	1012044	3/17/2017	4/4/2017	-61.40	02	3/17/2017	3/17/2017	0.50	4/4/2017	18.50	61.40	1,135.90
3300002849	RV	3900002199	633697	1012044	3/17/2017	4/4/2017	-60.54	02	3/17/2017	3/17/2017	0.50	4/4/2017	18.50	60.54	1,119.99
3300002851	RV	3900002225	633697	1012382	3/17/2017	4/5/2017	-60.40	02	3/17/2017	3/17/2017	0.50	4/5/2017	19.50	60.40	1,177.80
3300002853	RV	3900002244	633697	1012044	3/17/2017	4/5/2017	-60.54	02	3/17/2017	3/17/2017	0.50	4/5/2017	19.50	60.54	1,180.53
3300002854	RV	3900002234	633697	1012382	3/17/2017	4/5/2017	-66.00	02	3/17/2017	3/17/2017	0.50	4/5/2017	19.50	66.00	1,287.00
3300002855	RV	3900002238	633697	1012382	3/17/2017	4/5/2017	-60.40	02	3/17/2017	3/17/2017	0.50	4/5/2017	19.50	60.40	1,177.80
3300002856	RV	3900002201	633697	1012044	3/17/2017	4/4/2017	-65.20	02	3/17/2017	3/17/2017	0.50	4/4/2017	18.50	65.20	1,206.20
3300002857	RV	3900002251	633697	1012382	3/17/2017	4/5/2017	-66.40	02	3/17/2017	3/17/2017	0.50	4/5/2017	19.50	66.40	1,294.80
3300002858	RV	3800000199	633697	1012044	3/17/2017	3/22/2017	-61.40	02	3/17/2017	3/17/2017	0.50	3/22/2017	5.50	61.40	337.70
3300002859	RV	3900002237	633697	1012382	3/17/2017	4/5/2017	-61.80	02	3/17/2017	3/17/2017	0.50	4/5/2017	19.50	61.80	1,205.10
3300002860	RV	3900002293	633697	1012382	3/17/2017	4/6/2017	-71.40	02	3/17/2017	3/17/2017	0.50	4/6/2017	20.50	71.40	1,463.70
3300002861	RV	3900002312	633697	1012382	3/17/2017	4/6/2017	-64.20	02	3/17/2017	3/17/2017	0.50	4/6/2017	20.50	64.20	1,316.10
3300002862	RV	3900002305	633697	1012382	3/17/2017	4/6/2017	-61.40	02	3/17/2017	3/17/2017	0.50	4/6/2017	20.50	61.40	1,258.70
3300002863	RV	3900002294	633697	1012382	3/17/2017	4/6/2017	-60.40	02	3/17/2017	3/17/2017	0.50	4/6/2017	20.50	60.40	1,238.20
3300002864	RV	3300002872	633697	NEM	3/17/2017	3/17/2017	-61.40	02	3/17/2017	3/17/2017	0.50	3/17/2017	0.50	61.40	30.70
3300002865	RV	3900002295	633697	1012382	3/17/2017	4/6/2017	-64.20	02	3/17/2017	3/17/2017	0.50	4/6/2017	20.50	64.20	1,316.10
3300002866	RV	3900002314	633697	1012382	3/17/2017	4/6/2017	-61.40	02	3/17/2017	3/17/2017	0.50	4/6/2017	20.50	61.40	1,258.70
3300002867	RV	3900002306	633697	1012382	3/17/2017	4/6/2017	-66.00	02	3/17/2017	3/17/2017	0.50	4/6/2017	20.50	66.00	1,353.00
3300002868	RV	3300002869	633697	NEM	3/17/2017	3/17/2017	-70.00	02	3/17/2017	3/17/2017	0.50	3/17/2017	0.50	70.00	35.00
3300002869	RV	3300002869	633697	NEM	3/17/2017	3/17/2017	70.00	02	3/17/2017	3/17/2017	0.50	3/17/2017	0.50	(70.00)	(35.00)
3300002870	RV	3900002308	633697	1012382	3/17/2017	4/6/2017	-70.00	02	3/17/2017	3/17/2017	0.50	4/6/2017	20.50	70.00	1,435.00
3300002871	RV	3900002311	633697	1012382	3/17/2017	4/6/2017	-63.20	02	3/17/2017	3/17/2017	0.50	4/6/2017	20.50	63.20	1,295.60
3300002872	RV	3300002872	633697	NEM	3/17/2017	3/17/2017	61.40	02	3/17/2017	3/17/2017	0.50	3/17/2017	0.50	(61.40)	(30.70)
3300002873	RV	3900002313	633697	1012382	3/17/2017	4/6/2017	-61.40	02	3/17/2017	3/17/2017	0.50	4/6/2017	20.50	61.40	1,258.70
3300002913	RV	3900003843	633697	1012382	3/20/2017	6/13/2017	-60.40	02	3/20/2017	3/20/2017	0.50	6/13/2017	85.50	60.40	5,164.20
3300002914	RV	3900002203	633697	1012044	3/20/2017	4/4/2017	-61.40	02	3/20/2017	3/20/2017	0.50	4/4/2017	15.50	61.40	951.70
3300002915	RV	3900002230	633697	1012382	3/20/2017	4/5/2017	-61.40	02	3/20/2017	3/20/2017	0.50	4/5/2017	16.50	61.40	1,013.10
3300002916	RV	3900001949	633697	1012637	3/20/2017	3/24/2017	-64.00	02	3/20/2017	3/20/2017	0.50	3/24/2017	4.50	64.00	288.00
3300002918	RV	3900002127	633697	41717	3/20/2017	3/30/2017	-65.20	02	3/20/2017	3/20/2017	0.50	3/30/2017	10.50	65.20	684.60
3300002921	RV	3900002231	633697	1012382	3/20/2017	4/5/2017	-61.40	02	3/20/2017	3/20/2017	0.50	4/5/2017	16.50	61.40	1,013.10
3300002922	RV	3900003841	633697	1012382	3/20/2017	6/13/2017	-63.20	02	3/20/2017	3/20/2017	0.50	6/13/2017	85.50	63.20	5,403.60
3300002923	RV	3900002236	633697	1012382	3/20/2017	4/5/2017	-65.20	02	3/20/2017	3/20/2017	0.50	4/5/2017	16.50	65.20	1,075.80
3300002924	RV	3900001898	633697	1012631	3/20/2017	3/22/2017	-63.44	02	3/20/2017	3/20/2017	0.50	3/22/2017	2.50	63.44	158.60

POTOMAC ELECTRIC POWER COMPANY
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Fire & Damage Reconnect, Joint Use Escort and interconnection Application Fee

Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Service period Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300002925	RV	3900002229	633697	1012382	3/20/2017	4/5/2017	-61.40	02	3/20/2017	3/20/2017	0.50	4/5/2017	16.50	61.40	1,013.10
3300002926	RV	3900002076	633697	1012358	3/20/2017	3/28/2017	-62.60	02	3/20/2017	3/20/2017	0.50	3/28/2017	8.50	62.60	532.10
3300002927	RV	3900002235	633697	1012382	3/20/2017	4/5/2017	-61.40	02	3/20/2017	3/20/2017	0.50	4/5/2017	16.50	61.40	1,013.10
3300002928	RV	3900002252	633697	1012382	3/20/2017	4/5/2017	-60.40	02	3/20/2017	3/20/2017	0.50	4/5/2017	16.50	60.40	996.60
3300002929	RV	3900002226	633697	1012382	3/20/2017	4/5/2017	-61.40	02	3/20/2017	3/20/2017	0.50	4/5/2017	16.50	61.40	1,013.10
3300002930	RV	3900002250	633697	1012382	3/20/2017	4/5/2017	-60.40	02	3/20/2017	3/20/2017	0.50	4/5/2017	16.50	60.40	996.60
3300002931	RV	3900002126	633697	1012645	3/20/2017	3/30/2017	-65.20	02	3/20/2017	3/20/2017	0.50	3/30/2017	10.50	65.20	684.60
3300002932	RV	3900002224	633697	1012382	3/20/2017	4/5/2017	-80.40	02	3/20/2017	3/20/2017	0.50	4/5/2017	16.50	80.40	1,326.60
3300002934	RV	3900002291	633697	1012382	3/21/2017	4/6/2017	-61.00	02	3/21/2017	3/21/2017	0.50	4/6/2017	16.50	61.00	1,006.50
3300002935	RV	3900002385	633697	1012382	3/21/2017	4/10/2017	-60.40	02	3/21/2017	3/21/2017	0.50	4/10/2017	20.50	60.40	1,238.20
3300002977	RV	3900002290	633697	1012382	3/21/2017	4/6/2017	-69.00	02	3/21/2017	3/21/2017	0.50	4/6/2017	16.50	69.00	1,138.50
3300002985	RV	3900002365	633697	1012382	3/21/2017	4/10/2017	-63.60	02	3/21/2017	3/21/2017	0.50	4/10/2017	20.50	63.60	1,303.80
3300002988	RV	3900002366	633697	1012382	3/21/2017	4/10/2017	-62.60	02	3/21/2017	3/21/2017	0.50	4/10/2017	20.50	62.60	1,283.30
3300002989	RV	3900002310	633697	1012382	3/21/2017	4/6/2017	-70.00	02	3/21/2017	3/21/2017	0.50	4/6/2017	16.50	70.00	1,155.00
3300002990	RV	3900002309	633697	1012382	3/21/2017	4/6/2017	-64.20	02	3/21/2017	3/21/2017	0.50	4/6/2017	16.50	64.20	1,059.30
3300002991	RV	3900002307	633697	1012382	3/21/2017	4/6/2017	-67.60	02	3/21/2017	3/21/2017	0.50	4/6/2017	16.50	67.60	1,115.40
3300003042	RV	3900002073	633697	1012358	3/22/2017	3/28/2017	-65.20	02	3/22/2017	3/22/2017	0.50	3/28/2017	6.50	65.20	423.80
3300003043	RV	3900002228	633697	1012382	3/22/2017	4/5/2017	-61.40	02	3/22/2017	3/22/2017	0.50	4/5/2017	14.50	61.40	890.30
3300003078	RV	3900002232	633697	1012382	3/22/2017	4/5/2017	-65.20	02	3/22/2017	3/22/2017	0.50	4/5/2017	14.50	65.20	945.40
3300003089	RV	3900002211	633697	1012382	3/22/2017	4/4/2017	-69.00	02	3/22/2017	3/22/2017	0.50	4/4/2017	13.50	69.00	931.50
3300003092	RV	3900002249	633697	1012382	3/22/2017	4/5/2017	-66.40	02	3/22/2017	3/22/2017	0.50	4/5/2017	14.50	66.40	962.80
3300003095	RV	3900002243	633697	1012044	3/22/2017	4/5/2017	-68.92	02	3/22/2017	3/22/2017	0.50	4/5/2017	14.50	68.92	999.34
3300003096	RV	3900002242	633697	1012044	3/22/2017	4/5/2017	-60.97	02	3/22/2017	3/22/2017	0.50	4/5/2017	14.50	60.97	884.07
3300003099	RV	3900002233	633697	1012382	3/22/2017	4/5/2017	-60.40	02	3/22/2017	3/22/2017	0.50	4/5/2017	14.50	60.40	875.80
3300003101	RV	3900002083	633697	1012423	3/22/2017	3/29/2017	-61.40	02	3/22/2017	3/22/2017	0.50	3/29/2017	7.50	61.40	460.50
3300003102	RV	3900002210	633697	1012044	3/22/2017	4/4/2017	-61.40	02	3/22/2017	3/22/2017	0.50	4/4/2017	13.50	61.40	828.90
3300003105	RV	3800000199	633697	1012044	3/22/2017	3/22/2017	61.40	02	3/22/2017	3/22/2017	0.50	3/22/2017	0.50	(61.40)	(30.70)
3300003132	RV	3900002212	633697	1012044	3/23/2017	4/4/2017	-65.20	02	3/23/2017	3/23/2017	0.50	4/4/2017	12.50	65.20	815.00
3300003133	RV	3900002227	633697	1012382	3/23/2017	4/5/2017	-72.80	02	3/23/2017	3/23/2017	0.50	4/5/2017	13.50	72.80	982.80
3300003134	RV	3300003148	633697	NEM	3/23/2017	3/23/2017	-61.83	02	3/23/2017	3/23/2017	0.50	3/23/2017	0.50	61.83	30.92
3300003138	RV	3900002074	633697	1012358	3/23/2017	3/28/2017	-61.40	02	3/23/2017	3/23/2017	0.50	3/28/2017	5.50	61.40	337.70
3300003141	RV	3300003149	633697	NEM	3/23/2017	3/23/2017	-61.40	02	3/23/2017	3/23/2017	0.50	3/23/2017	0.50	61.40	30.70
3300003148	RV	3300003148	633697	NEM	3/23/2017	3/23/2017	61.83	02	3/23/2017	3/23/2017	0.50	3/23/2017	0.50	(61.83)	(30.92)
3300003149	RV	3300003149	633697	NEM	3/23/2017	3/23/2017	61.40	02	3/23/2017	3/23/2017	0.50	3/23/2017	0.50	(61.40)	(30.70)
3300003150	RV	3900003844	633697	1012382	3/23/2017	6/13/2017	-61.40	02	3/23/2017	3/23/2017	0.50	6/13/2017	82.50	61.40	5,065.50
3300003151	RV	3900002209	633697	1012044	3/23/2017	4/4/2017	-61.83	02	3/23/2017	3/23/2017	0.50	4/4/2017	12.50	61.83	772.88
3300003172	RV	3900003842	633697	1012382	3/24/2017	6/13/2017	-65.20	02	3/24/2017	3/24/2017	0.50	6/13/2017	81.50	65.20	5,313.80
3300003173	RV	3900002207	633697	1012044	3/24/2017	4/4/2017	-69.00	02	3/24/2017	3/24/2017	0.50	4/4/2017	11.50	69.00	793.50
3300003174	RV	3900002457	633697	1012382	3/24/2017	4/12/2017	-65.20	02	3/24/2017	3/24/2017	0.50	4/12/2017	19.50	65.20	1,271.40
3300003285	RV	3900002466	633697	1012382	3/28/2017	4/12/2017	-61.40	02	3/28/2017	3/28/2017	0.50	4/12/2017	15.50	61.40	951.70
3300003287	RV	3900002335	633697	41717	3/28/2017	4/7/2017	-62.60	02	3/28/2017	3/28/2017	0.50	4/7/2017	10.50	62.60	657.30
3300003288	RV	3900002464	633697	1012382	3/28/2017	4/12/2017	-61.40	02	3/28/2017	3/28/2017	0.50	4/12/2017	15.50	61.40	951.70
3300003290	RV	3900002204	633697	1012044	3/28/2017	4/4/2017	-61.25	02	3/28/2017	3/28/2017	0.50	4/4/2017	7.50	61.25	459.38
3300003291	RV	3900002206	633697	1012044	3/28/2017	4/4/2017	-60.75	02	3/28/2017	3/28/2017	0.50	4/4/2017	7.50	60.75	455.63
3300003292	RV	3900002460	633697	1012382	3/28/2017	4/12/2017	-60.40	02	3/28/2017	3/28/2017	0.50	4/12/2017	15.50	60.40	936.20
3300003299	RV	3300003359	633697	NEM	3/28/2017	3/28/2017	-61.80	02	3/28/2017	3/28/2017	0.50	3/28/2017	0.50	61.80	30.90
3300003310	RV	3900002254	633697	1012382	3/28/2017	4/5/2017	-65.20	02	3/28/2017	3/28/2017	0.50	4/5/2017	8.50	65.20	554.20
3300003312	RV	3900004112	633697	1012387	3/28/2017	6/27/2017	-78.00	02	3/28/2017	3/28/2017	0.50	6/27/2017	91.50	78.00	7,137.00
3300003319	RV	3300003361	633697	NEM	3/28/2017	3/28/2017	-62.80	02	3/28/2017	3/28/2017	0.50	3/28/2017	0.50	62.80	31.40
3300003327	RV	3300003331	633697	NEM	3/28/2017	3/28/2017	-80.40	02	3/28/2017	3/28/2017	0.50	3/28/2017	0.50	80.40	40.20

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Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Service period Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300003331	RV	3300003331	633697	NEM	3/28/2017	3/28/2017	80.40	02	3/28/2017	3/28/2017	0.50	3/28/2017	0.50	(80.40)	(40.20)
3300003335	RV	3900002205	633697	1012044	3/28/2017	4/4/2017	-80.40	02	3/28/2017	3/28/2017	0.50	4/4/2017	7.50	80.40	603.00
3300003347	RV	3900002256	633697	1012044	3/28/2017	4/5/2017	-69.00	02	3/28/2017	3/28/2017	0.50	4/5/2017	8.50	69.00	586.50
3300003358	RV	3900002465	633697	1012382	3/28/2017	4/12/2017	-67.60	02	3/28/2017	3/28/2017	0.50	4/12/2017	15.50	67.60	1,047.80
3300003359	RV	3300003359	633697	NEM	3/28/2017	3/28/2017	61.80	02	3/28/2017	3/28/2017	0.50	3/28/2017	0.50	(61.80)	(30.90)
3300003360	RV	3900002253	633697	1012382	3/28/2017	4/5/2017	-61.80	02	3/28/2017	3/28/2017	0.50	4/5/2017	8.50	61.80	525.30
3300003361	RV	3300003361	633697	NEM	3/28/2017	3/28/2017	62.80	02	3/28/2017	3/28/2017	0.50	3/28/2017	0.50	(62.80)	(31.40)
3300003362	RV	3900002380	633697	1012382	3/28/2017	4/10/2017	-62.80	02	3/28/2017	3/28/2017	0.50	4/10/2017	13.50	62.80	847.80
3300003527	RV	3900002373	633697	1012382	3/29/2017	4/10/2017	-65.20	02	3/29/2017	3/29/2017	0.50	4/10/2017	12.50	65.20	815.00
3300003533	RV	3900002372	633697	1012382	3/29/2017	4/10/2017	-65.20	02	3/29/2017	3/29/2017	0.50	4/10/2017	12.50	65.20	815.00
3300003543	RV	3900002375	633697	1012382	3/29/2017	4/10/2017	-65.20	02	3/29/2017	3/29/2017	0.50	4/10/2017	12.50	65.20	815.00
3300003547	RV	3900002337	633697	41717	3/29/2017	4/7/2017	-61.40	02	3/29/2017	3/29/2017	0.50	4/7/2017	9.50	61.40	583.30
3300003551	RV	3300003659	633697	NEM	3/29/2017	3/29/2017	-60.40	02	3/29/2017	3/29/2017	0.50	3/29/2017	0.50	60.40	30.20
3300003593	RV	3900002383	633697	1012382	3/29/2017	4/10/2017	-65.20	02	3/29/2017	3/29/2017	0.50	4/10/2017	12.50	65.20	815.00
3300003635	RV	3900002255	633697	1012044	3/29/2017	4/5/2017	-61.40	02	3/29/2017	3/29/2017	0.50	4/5/2017	7.50	61.40	460.50
3300003639	RV	3300003661	633697	NEM	3/29/2017	3/29/2017	-61.80	02	3/29/2017	3/29/2017	0.50	3/29/2017	0.50	61.80	30.90
3300003647	RV	3300003663	633697	NEM	3/29/2017	3/29/2017	-65.20	02	3/29/2017	3/29/2017	0.50	3/29/2017	0.50	65.20	32.60
3300003653	RV	3900002208	633697	1012044	3/29/2017	4/4/2017	-65.20	02	3/29/2017	3/29/2017	0.50	4/4/2017	6.50	65.20	423.80
3300003655	RV	3900002336	633697	41717	3/29/2017	4/7/2017	-61.40	02	3/29/2017	3/29/2017	0.50	4/7/2017	9.50	61.40	583.30
3300003657	RV	3900002364	633697	1012382	3/29/2017	4/10/2017	-63.20	02	3/29/2017	3/29/2017	0.50	4/10/2017	12.50	63.20	790.00
3300003658	RV	3900002374	633697	1012382	3/29/2017	4/10/2017	-65.20	02	3/29/2017	3/29/2017	0.50	4/10/2017	12.50	65.20	815.00
3300003659	RV	3300003659	633697	NEM	3/29/2017	3/29/2017	60.40	02	3/29/2017	3/29/2017	0.50	3/29/2017	0.50	(60.40)	(30.20)
3300003660	RV	3900002360	633697	1012382	3/29/2017	4/10/2017	-60.40	02	3/29/2017	3/29/2017	0.50	4/10/2017	12.50	60.40	755.00
3300003661	RV	3300003661	633697	NEM	3/29/2017	3/29/2017	61.80	02	3/29/2017	3/29/2017	0.50	3/29/2017	0.50	(61.80)	(30.90)
3300003662	RV	3900002377	633697	1012382	3/29/2017	4/10/2017	-61.80	02	3/29/2017	3/29/2017	0.50	4/10/2017	12.50	61.80	772.50
3300003663	RV	3300003663	633697	NEM	3/29/2017	3/29/2017	65.20	02	3/29/2017	3/29/2017	0.50	3/29/2017	0.50	(65.20)	(32.60)
3300003664	RV	3900002371	633697	1012382	3/29/2017	4/10/2017	-65.20	02	3/29/2017	3/29/2017	0.50	4/10/2017	12.50	65.20	815.00
3300003723	RV	3900002368	633697	1012382	3/30/2017	4/10/2017	-60.40	02	3/30/2017	3/30/2017	0.50	4/10/2017	11.50	60.40	694.60
3300003724	RV	3300003739	633697	NEM	3/30/2017	3/30/2017	-72.80	02	3/30/2017	3/30/2017	0.50	3/30/2017	0.50	72.80	36.40
3300003725	RV	3300003737	633697	NEM	3/30/2017	3/30/2017	-65.20	02	3/30/2017	3/30/2017	0.50	3/30/2017	0.50	65.20	32.60
3300003726	RV	3900002376	633697	1012382	3/30/2017	4/10/2017	-60.40	02	3/30/2017	3/30/2017	0.50	4/10/2017	11.50	60.40	694.60
3300003727	RV	3900002322	633697	1012423	3/30/2017	4/7/2017	-62.60	02	3/30/2017	3/30/2017	0.50	4/7/2017	8.50	62.60	532.10
3300003728	RV	3300003735	633697	NEM	3/30/2017	3/30/2017	-62.60	02	3/30/2017	3/30/2017	0.50	3/30/2017	0.50	62.60	31.30
3300003729	RV	3900002321	633697	1012382	3/30/2017	4/7/2017	-60.20	02	3/30/2017	3/30/2017	0.50	4/7/2017	8.50	60.20	511.70
3300003730	RV	3900002381	633697	1012382	3/30/2017	4/10/2017	-70.00	02	3/30/2017	3/30/2017	0.50	4/10/2017	11.50	70.00	805.00
3300003731	RV	3900002362	633697	1012382	3/30/2017	4/10/2017	-60.40	02	3/30/2017	3/30/2017	0.50	4/10/2017	11.50	60.40	694.60
3300003732	RV	3300003733	633697	NEM	3/30/2017	3/30/2017	-60.40	02	3/30/2017	3/30/2017	0.50	3/30/2017	0.50	60.40	30.20
3300003733	RV	3300003733	633697	NEM	3/30/2017	3/30/2017	60.40	02	3/30/2017	3/30/2017	0.50	3/30/2017	0.50	(60.40)	(30.20)
3300003734	RV	3900002384	633697	1012382	3/30/2017	4/10/2017	-60.40	02	3/30/2017	3/30/2017	0.50	4/10/2017	11.50	60.40	694.60
3300003735	RV	3300003735	633697	NEM	3/30/2017	3/30/2017	62.60	02	3/30/2017	3/30/2017	0.50	3/30/2017	0.50	(62.60)	(31.30)
3300003736	RV	3900002379	633697	1012382	3/30/2017	4/10/2017	-62.60	02	3/30/2017	3/30/2017	0.50	4/10/2017	11.50	62.60	719.90
3300003737	RV	3300003737	633697	NEM	3/30/2017	3/30/2017	65.20	02	3/30/2017	3/30/2017	0.50	3/30/2017	0.50	(65.20)	(32.60)
3300003738	RV	3900002382	633697	1012382	3/30/2017	4/10/2017	-65.20	02	3/30/2017	3/30/2017	0.50	4/10/2017	11.50	65.20	749.80
3300003739	RV	3300003739	633697	NEM	3/30/2017	3/30/2017	72.80	02	3/30/2017	3/30/2017	0.50	3/30/2017	0.50	(72.80)	(36.40)
3300003740	RV	3900002367	633697	1012382	3/30/2017	4/10/2017	-72.80	02	3/30/2017	3/30/2017	0.50	4/10/2017	11.50	72.80	837.20
3300003763	RV	3900002369	633697	1012382	3/31/2017	4/10/2017	-60.40	02	3/31/2017	3/31/2017	0.50	4/10/2017	10.50	60.40	634.20
3300003774	RV	3900002323	633697	1012423	3/31/2017	4/7/2017	-69.00	02	3/31/2017	3/31/2017	0.50	4/7/2017	7.50	69.00	517.50
3300003783	RV	3300003787	633697	NEM	3/31/2017	3/31/2017	-60.40	02	3/31/2017	3/31/2017	0.50	3/31/2017	0.50	60.40	30.20
3300003784	RV	3300003791	633697	NEM	3/31/2017	3/31/2017	-60.40	02	3/31/2017	3/31/2017	0.50	3/31/2017	0.50	60.40	30.20
3300003785	RV	3300003793	633697	NEM	3/31/2017	3/31/2017	-60.40	02	3/31/2017	3/31/2017	0.50	3/31/2017	0.50	60.40	30.20

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Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Service period Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300003786	RV	3900002363	633697	1012382	3/31/2017	4/10/2017	-60.40	02	3/31/2017	3/31/2017	0.50	4/10/2017	10.50	60.40	634.20
3300003787	RV	3300003787	633697	NEM	3/31/2017	3/31/2017	60.40	02	3/31/2017	3/31/2017	0.50	3/31/2017	0.50	(60.40)	(30.20)
3300003790	RV	3900002378	633697	1012382	3/31/2017	4/10/2017	-60.40	02	3/31/2017	3/31/2017	0.50	4/10/2017	10.50	60.40	634.20
3300003791	RV	3300003791	633697	NEM	3/31/2017	3/31/2017	60.40	02	3/31/2017	3/31/2017	0.50	3/31/2017	0.50	(60.40)	(30.20)
3300003792	RV	3900002370	633697	1012382	3/31/2017	4/10/2017	-60.40	02	3/31/2017	3/31/2017	0.50	4/10/2017	10.50	60.40	634.20
3300003793	RV	3300003793	633697	NEM	3/31/2017	3/31/2017	60.40	02	3/31/2017	3/31/2017	0.50	3/31/2017	0.50	(60.40)	(30.20)
3300003794	RV	3900002361	633697	1012382	3/31/2017	4/10/2017	-60.40	02	3/31/2017	3/31/2017	0.50	4/10/2017	10.50	60.40	634.20
3300003836	RV	3900002517	633697	1012044	4/4/2017	4/14/2017	-61.61	02	4/4/2017	4/4/2017	0.50	4/14/2017	10.50	61.61	646.91
3300003837	RV	3900002614	633697	1012382	4/4/2017	4/20/2017	-72.80	02	4/4/2017	4/4/2017	0.50	4/20/2017	16.50	72.80	1,201.20
3300003838	RV	3900002529	633697	1012382	4/4/2017	4/17/2017	-61.80	02	4/4/2017	4/4/2017	0.50	4/17/2017	13.50	61.80	834.30
3300003839	RV	3900002619	633697	1012382	4/4/2017	4/20/2017	-61.20	02	4/4/2017	4/4/2017	0.50	4/20/2017	16.50	61.20	1,009.80
3300003840	RV	3900002624	633697	1012382	4/4/2017	4/20/2017	-70.00	02	4/4/2017	4/4/2017	0.50	4/20/2017	16.50	70.00	1,155.00
3300003841	RV	3900002629	633697	26961	4/4/2017	4/21/2017	-62.00	02	4/4/2017	4/4/2017	0.50	4/21/2017	17.50	62.00	1,085.00
3300003843	RV	3900002459	633697	1012382	4/4/2017	4/12/2017	-70.00	02	4/4/2017	4/4/2017	0.50	4/12/2017	8.50	70.00	595.00
3300003869	RV	3900002788	633697	41717	4/4/2017	4/24/2017	-61.40	02	4/4/2017	4/4/2017	0.50	4/24/2017	20.50	61.40	1,258.70
3300003870	RV	3900002462	633697	1012382	4/4/2017	4/12/2017	-60.40	02	4/4/2017	4/4/2017	0.50	4/12/2017	8.50	60.40	513.40
3300003871	RV	3900002621	633697	1012382	4/4/2017	4/20/2017	-61.80	02	4/4/2017	4/4/2017	0.50	4/20/2017	16.50	61.80	1,019.70
3300003872	RV	3900002458	633697	1012382	4/4/2017	4/12/2017	-64.20	02	4/4/2017	4/4/2017	0.50	4/12/2017	8.50	64.20	545.70
3300003873	RV	3900002463	633697	1012382	4/4/2017	4/12/2017	-65.20	02	4/4/2017	4/4/2017	0.50	4/12/2017	8.50	65.20	554.20
3300003874	RV	3900002461	633697	1012382	4/4/2017	4/12/2017	-62.80	02	4/4/2017	4/4/2017	0.50	4/12/2017	8.50	62.80	533.80
3300003875	RV	3300003877	633697	NEM	4/4/2017	4/5/2017	-61.40	02	4/4/2017	4/4/2017	0.50	4/5/2017	1.50	61.40	92.10
3300003877	RV	3300003877	633697	NEM	4/4/2017	4/5/2017	61.40	02	4/4/2017	4/4/2017	0.50	4/5/2017	1.50	(61.40)	(92.10)
3300003878	RV	3900002386	633697	1012382	4/5/2017	4/10/2017	-61.40	02	4/5/2017	4/5/2017	0.50	4/10/2017	5.50	61.40	337.70
3300003879	RV	3900002515	633697	1012044	4/5/2017	4/14/2017	-61.40	02	4/5/2017	4/5/2017	0.50	4/14/2017	9.50	61.40	583.30
3300003880	RV	3900002357	633697	1012382	4/5/2017	4/10/2017	-61.20	02	4/5/2017	4/5/2017	0.50	4/10/2017	5.50	61.20	336.60
3300003901	RV	3900002356	633697	1012382	4/5/2017	4/10/2017	-61.40	02	4/5/2017	4/5/2017	0.50	4/10/2017	5.50	61.40	337.70
3300003931	RV	3900002359	633697	1012382	4/5/2017	4/10/2017	-60.40	02	4/5/2017	4/5/2017	0.50	4/10/2017	5.50	60.40	332.20
3300003932	RV	3900002358	633697	1012382	4/5/2017	4/10/2017	-60.40	02	4/5/2017	4/5/2017	0.50	4/10/2017	5.50	60.40	332.20
3300003933	RV	3900002780	633697	1012382	4/5/2017	4/24/2017	-61.40	02	4/5/2017	4/5/2017	0.50	4/24/2017	19.50	61.40	1,197.30
3300003962	RV	3900002513	633697	1012044	4/6/2017	4/14/2017	-61.40	02	4/6/2017	4/6/2017	0.50	4/14/2017	8.50	61.40	521.90
3300003963	RV	3900002514	633697	1012044	4/6/2017	4/14/2017	-65.91	02	4/6/2017	4/6/2017	0.50	4/14/2017	8.50	65.91	560.24
3300003964	RV	3300003965	633697	NEM	4/6/2017	4/6/2017	-68.40	02	4/6/2017	4/6/2017	0.50	4/6/2017	0.50	68.40	34.20
3300003965	RV	3300003965	633697	NEM	4/6/2017	4/6/2017	68.40	02	4/6/2017	4/6/2017	0.50	4/6/2017	0.50	(68.40)	(34.20)
3300003966	RV	3300004032	633697	NEM	4/6/2017	4/7/2017	-68.40	02	4/6/2017	4/6/2017	0.50	4/7/2017	1.50	68.40	102.60
3300003967	RV	3300003968	633697	NEM	4/6/2017	4/6/2017	-78.80	02	4/6/2017	4/6/2017	0.50	4/6/2017	0.50	78.80	39.40
3300003968	RV	3300003968	633697	NEM	4/6/2017	4/6/2017	78.80	02	4/6/2017	4/6/2017	0.50	4/6/2017	0.50	(78.80)	(39.40)
3300003969	RV	3900002473	633697	1012423	4/6/2017	4/13/2017	-78.80	02	4/6/2017	4/6/2017	0.50	4/13/2017	7.50	78.80	591.00
3300003970	RV	3900002516	633697	1012044	4/6/2017	4/14/2017	-60.97	02	4/6/2017	4/6/2017	0.50	4/14/2017	8.50	60.97	518.25
3300003971	RV	3900002622	633697	1012382	4/6/2017	4/20/2017	-61.40	02	4/6/2017	4/6/2017	0.50	4/20/2017	14.50	61.40	890.30
3300003990	RV	3900002932	633697	1012382	4/7/2017	5/2/2017	-60.40	02	4/7/2017	4/7/2017	0.50	5/2/2017	25.50	60.40	1,540.20
3300003991	RV	3900002615	633697	1012382	4/7/2017	4/20/2017	-60.40	02	4/7/2017	4/7/2017	0.50	4/20/2017	13.50	60.40	815.40
3300003992	RV	3900002793	633697	1012382	4/7/2017	4/24/2017	-68.00	02	4/7/2017	4/7/2017	0.50	4/24/2017	17.50	68.00	1,190.00
3300003993	RV	3900002616	633697	1012382	4/7/2017	4/20/2017	-61.40	02	4/7/2017	4/7/2017	0.50	4/20/2017	13.50	61.40	828.90
3300003994	RV	3900003121	633697	1012044	4/7/2017	5/9/2017	-60.75	02	4/7/2017	4/7/2017	0.50	5/9/2017	32.50	60.75	1,974.38
3300003995	RV	3300004010	633697	NEM	4/7/2017	4/7/2017	-61.80	02	4/7/2017	4/7/2017	0.50	4/7/2017	0.50	61.80	30.90
3300003996	RV	3900002953	633697	1012382	4/7/2017	5/2/2017	-60.40	02	4/7/2017	4/7/2017	0.50	5/2/2017	25.50	60.40	1,540.20
3300003997	RV	3900002934	633697	1012382	4/7/2017	5/2/2017	-64.20	02	4/7/2017	4/7/2017	0.50	5/2/2017	25.50	64.20	1,637.10
3300003998	RV	3300004040	633697	NEM	4/7/2017	4/7/2017	-60.40	02	4/7/2017	4/7/2017	0.50	4/7/2017	0.50	60.40	30.20
3300003999	RV	3900002617	633697	1012382	4/7/2017	4/20/2017	-63.20	02	4/7/2017	4/7/2017	0.50	4/20/2017	13.50	63.20	853.20
3300004000	RV	3300004019	633697	NEM	4/7/2017	4/7/2017	-69.00	02	4/7/2017	4/7/2017	0.50	4/7/2017	0.50	69.00	34.50

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3300004002	RV	3300004003	633697	NEM	4/7/2017	4/7/2017	-60.75	02	4/7/2017	4/7/2017	0.50	4/7/2017	0.50	60.75	30.38
3300004003	RV	3300004003	633697	NEM	4/7/2017	4/7/2017	60.75	02	4/7/2017	4/7/2017	0.50	4/7/2017	0.50	(60.75)	(30.38)
3300004004	RV	3900002628	633697	26961	4/7/2017	4/21/2017	-60.75	02	4/7/2017	4/7/2017	0.50	4/21/2017	14.50	60.75	880.88
3300004010	RV	3300004010	633697	NEM	4/7/2017	4/7/2017	61.80	02	4/7/2017	4/7/2017	0.50	4/7/2017	0.50	(61.80)	(30.90)
3300004015	RV	3900002954	633697	1012382	4/7/2017	5/2/2017	-61.80	02	4/7/2017	4/7/2017	0.50	5/2/2017	25.50	61.80	1,575.90
3300004019	RV	3300004019	633697	NEM	4/7/2017	4/7/2017	69.00	02	4/7/2017	4/7/2017	0.50	4/7/2017	0.50	(69.00)	(34.50)
3300004023	RV	3900003120	633697	1012044	4/7/2017	5/9/2017	-69.00	02	4/7/2017	4/7/2017	0.50	5/9/2017	32.50	69.00	2,242.50
3300004032	RV	3300004032	633697	NEM	4/6/2017	4/7/2017	68.40	02	4/6/2017	4/6/2017	0.50	4/7/2017	1.50	(68.40)	(102.60)
3300004039	RV	3900002794	633697	1012382	4/7/2017	4/24/2017	-68.40	02	4/7/2017	4/7/2017	0.50	4/24/2017	17.50	68.40	1,197.00
3300004040	RV	3300004040	633697	NEM	4/7/2017	4/7/2017	60.40	02	4/7/2017	4/7/2017	0.50	4/7/2017	0.50	(60.40)	(30.20)
3300004041	RV	3900002952	633697	1012382	4/7/2017	5/2/2017	-60.40	02	4/7/2017	4/7/2017	0.50	5/2/2017	25.50	60.40	1,540.20
3300004058	RV	3900002791	633697	1012382	4/10/2017	4/24/2017	-65.20	02	4/10/2017	4/10/2017	0.50	4/24/2017	14.50	65.20	945.40
3300004064	RV	3900002795	633697	1012382	4/10/2017	4/24/2017	-64.00	02	4/10/2017	4/10/2017	0.50	4/24/2017	14.50	64.00	928.00
3300004069	RV	3300004080	633697	1012382	4/10/2017	4/10/2017	-61.40	02	4/10/2017	4/10/2017	0.50	4/10/2017	0.50	61.40	30.70
3300004070	RV	3900003119	633697	1012044	4/10/2017	5/9/2017	-65.20	02	4/10/2017	4/10/2017	0.50	5/9/2017	29.50	65.20	1,923.40
3300004071	RV	3900003123	633697	1012382	4/10/2017	5/9/2017	-60.11	02	4/10/2017	4/10/2017	0.50	5/9/2017	29.50	60.11	1,773.25
3300004073	RV	3900003118	633697	1012044	4/10/2017	5/9/2017	-61.40	02	4/10/2017	4/10/2017	0.50	5/9/2017	29.50	61.40	1,811.30
3300004074	RV	3900003122	633697	1012044	4/10/2017	5/9/2017	-65.20	02	4/10/2017	4/10/2017	0.50	5/9/2017	29.50	65.20	1,923.40
3300004075	RV	3900003115	633697	1012044	4/10/2017	5/9/2017	-61.40	02	4/10/2017	4/10/2017	0.50	5/9/2017	29.50	61.40	1,811.30
3300004076	RV	3900003116	633697	1012044	4/10/2017	5/9/2017	-65.20	02	4/10/2017	4/10/2017	0.50	5/9/2017	29.50	65.20	1,923.40
3300004077	RV	3900003117	633697	1012044	4/10/2017	5/9/2017	-65.20	02	4/10/2017	4/10/2017	0.50	5/9/2017	29.50	65.20	1,923.40
3300004080	RV	3300004080	633697	1012382	4/10/2017	4/10/2017	61.40	02	4/10/2017	4/10/2017	0.50	4/10/2017	0.50	(61.40)	(30.70)
3300004081	RV	3900002792	633697	1012382	4/10/2017	4/24/2017	-61.40	02	4/10/2017	4/10/2017	0.50	4/24/2017	14.50	61.40	890.30
3300004130	RV	3900003114	633697	1012044	4/11/2017	5/9/2017	-69.00	02	4/11/2017	4/11/2017	0.50	5/9/2017	28.50	69.00	1,966.50
3300004131	RV	3900002797	633697	1012382	4/11/2017	4/24/2017	-65.20	02	4/11/2017	4/11/2017	0.50	4/24/2017	13.50	65.20	880.20
3300004132	RV	3900002798	633697	1012382	4/11/2017	4/24/2017	-65.20	02	4/11/2017	4/11/2017	0.50	4/24/2017	13.50	65.20	880.20
3300004133	RV	3900002620	633697	1012382	4/11/2017	4/20/2017	-63.60	02	4/11/2017	4/11/2017	0.50	4/20/2017	9.50	63.60	604.20
3300004134	RV	3300004135	633697	NEM	4/11/2017	4/11/2017	-60.40	02	4/11/2017	4/11/2017	0.50	4/11/2017	0.50	60.40	30.20
3300004135	RV	3300004135	633697	NEM	4/11/2017	4/11/2017	60.40	02	4/11/2017	4/11/2017	0.50	4/11/2017	0.50	(60.40)	(30.20)
3300004136	RV	3900002796	633697	1012382	4/11/2017	4/24/2017	-60.40	02	4/11/2017	4/11/2017	0.50	4/24/2017	13.50	60.40	815.40
3300004137	RV	3900002618	633697	1012382	4/11/2017	4/20/2017	-60.40	02	4/11/2017	4/11/2017	0.50	4/20/2017	9.50	60.40	573.80
3300004187	RV	3300004200	633697	NEM	4/12/2017	4/12/2017	-63.80	02	4/12/2017	4/12/2017	0.50	4/12/2017	0.50	63.80	31.90
3300004188	RV	3900002787	633697	41717	4/12/2017	4/24/2017	-62.60	02	4/12/2017	4/12/2017	0.50	4/24/2017	12.50	62.60	782.50
3300004192	RV	3900003113	633697	1012044	4/12/2017	5/9/2017	-61.40	02	4/12/2017	4/12/2017	0.50	5/9/2017	27.50	61.40	1,688.50
3300004194	RV	3900002724	633697	1012423	4/12/2017	4/21/2017	-69.00	02	4/12/2017	4/12/2017	0.50	4/21/2017	9.50	69.00	655.50
3300004195	RV	3900002613	633697	1012382	4/12/2017	4/20/2017	-60.40	02	4/12/2017	4/12/2017	0.50	4/20/2017	8.50	60.40	513.40
3300004197	RV	3300004205	633697	NEM	4/12/2017	4/12/2017	-60.11	02	4/12/2017	4/12/2017	0.50	4/12/2017	0.50	60.11	30.06
3300004199	RV	3300004209	633697	NEM	4/12/2017	4/12/2017	-61.40	02	4/12/2017	4/12/2017	0.50	4/12/2017	0.50	61.40	30.70
3300004200	RV	3300004200	633697	NEM	4/12/2017	4/12/2017	63.80	02	4/12/2017	4/12/2017	0.50	4/12/2017	0.50	(63.80)	(31.90)
3300004204	RV	3900002723	633697	1012423	4/12/2017	4/21/2017	-63.80	02	4/12/2017	4/12/2017	0.50	4/21/2017	9.50	63.80	606.10
3300004205	RV	3300004205	633697	NEM	4/12/2017	4/12/2017	60.11	02	4/12/2017	4/12/2017	0.50	4/12/2017	0.50	(60.11)	(30.06)
3300004206	RV	3900003112	633697	1012044	4/12/2017	5/9/2017	-60.11	02	4/12/2017	4/12/2017	0.50	5/9/2017	27.50	60.11	1,653.03
3300004209	RV	3300004209	633697	NEM	4/12/2017	4/12/2017	61.40	02	4/12/2017	4/12/2017	0.50	4/12/2017	0.50	(61.40)	(30.70)
3300004211	RV	3300004212	633697	NEM	4/12/2017	4/12/2017	-61.40	02	4/12/2017	4/12/2017	0.50	4/12/2017	0.50	61.40	30.70
3300004212	RV	3300004212	633697	NEM	4/12/2017	4/12/2017	61.40	02	4/12/2017	4/12/2017	0.50	4/12/2017	0.50	(61.40)	(30.70)
3300004213	RV	3900002623	633697	1012382	4/12/2017	4/20/2017	-61.40	02	4/12/2017	4/12/2017	0.50	4/20/2017	8.50	61.40	521.90
3300004214	RV	3900002588	633697	1012382	4/12/2017	4/19/2017	-2,042.00	02	4/12/2017	4/12/2017	0.50	4/19/2017	7.50	2,042.00	15,315.00
3300004215	RV	3900002589	633697	1012382	4/12/2017	4/19/2017	-2,042.00	02	4/12/2017	4/12/2017	0.50	4/19/2017	7.50	2,042.00	15,315.00
3300004262	RV	3300004263	633697	NEM	4/13/2017	4/13/2017	-65.20	02	4/13/2017	4/13/2017	0.50	4/13/2017	0.50	65.20	32.60
3300004263	RV	3300004263	633697	NEM	4/13/2017	4/13/2017	65.20	02	4/13/2017	4/13/2017	0.50	4/13/2017	0.50	(65.20)	(32.60)

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital Study
For the Period January 2017 through December 2017
Other Revenue Lag
Fire & Damage Reconnect, Joint Use Escort and interconnection Application Fee

Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Service period Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300004264	RV	3900003219	633697	1012044	4/13/2017	5/12/2017	-65.20	02	4/13/2017	4/13/2017	0.50	5/12/2017	29.50	65.20	1,923.40
3300004265	RV	3900003603	633697	1012434	4/13/2017	6/2/2017	-60.97	02	4/13/2017	4/13/2017	0.50	6/2/2017	50.50	60.97	3,078.99
3300004266	RV	3900002963	633697	1012382	4/13/2017	5/2/2017	-61.80	02	4/13/2017	4/13/2017	0.50	5/2/2017	19.50	61.80	1,205.10
3300004269	RV	3300004270	633697	NEM	4/13/2017	4/13/2017	-60.40	02	4/13/2017	4/13/2017	0.50	4/13/2017	0.50	60.40	30.20
3300004270	RV	3300004270	633697	NEM	4/13/2017	4/13/2017	60.40	02	4/13/2017	4/13/2017	0.50	4/13/2017	0.50	(60.40)	(30.20)
3300004271	RV	3900002916	633697	41717	4/13/2017	5/1/2017	-61.40	02	4/13/2017	4/13/2017	0.50	5/1/2017	18.50	61.40	1,135.90
3300004272	RV	3300004275	633697	NEM	4/13/2017	4/13/2017	-61.40	02	4/13/2017	4/13/2017	0.50	4/13/2017	0.50	61.40	30.70
3300004273	RV	3300004274	633697	NEM	4/13/2017	4/13/2017	-61.40	02	4/13/2017	4/13/2017	0.50	4/13/2017	0.50	61.40	30.70
3300004274	RV	3300004274	633697	NEM	4/13/2017	4/13/2017	61.40	02	4/13/2017	4/13/2017	0.50	4/13/2017	0.50	(61.40)	(30.70)
3300004275	RV	3300004275	633697	NEM	4/13/2017	4/13/2017	61.40	02	4/13/2017	4/13/2017	0.50	4/13/2017	0.50	(61.40)	(30.70)
3300004278	RV	3900002961	633697	1012382	4/13/2017	5/2/2017	-60.40	02	4/13/2017	4/13/2017	0.50	5/2/2017	19.50	60.40	1,177.80
3300004279	RV	3900003109	633697	1012044	4/13/2017	5/9/2017	-61.40	02	4/13/2017	4/13/2017	0.50	5/9/2017	26.50	61.40	1,627.10
3300004281	RV	3900002962	633697	1012382	4/13/2017	5/2/2017	-60.40	02	4/13/2017	4/13/2017	0.50	5/2/2017	19.50	60.40	1,177.80
3300004282	RV	3900002971	633697	1012382	4/13/2017	5/2/2017	-61.40	02	4/13/2017	4/13/2017	0.50	5/2/2017	19.50	61.40	1,197.30
3300004330	RV	3900002722	633697	1012423	4/14/2017	4/21/2017	-61.40	02	4/14/2017	4/14/2017	0.50	4/21/2017	7.50	61.40	460.50
3300004331	RV	3900002721	633697	1012423	4/14/2017	4/21/2017	-61.40	02	4/14/2017	4/14/2017	0.50	4/21/2017	7.50	61.40	460.50
3300004332	RV	3900002942	633697	1012382	4/14/2017	5/2/2017	-71.40	02	4/14/2017	4/14/2017	0.50	5/2/2017	18.50	71.40	1,320.90
3300004333	RV	3900002970	633697	1012382	4/14/2017	5/2/2017	-68.00	02	4/14/2017	4/14/2017	0.50	5/2/2017	18.50	68.00	1,258.00
3300004334	RV	3300004335	633697	NEM	4/14/2017	4/14/2017	-65.20	02	4/14/2017	4/14/2017	0.50	4/14/2017	0.50	65.20	32.60
3300004335	RV	3300004335	633697	NEM	4/14/2017	4/14/2017	65.20	02	4/14/2017	4/14/2017	0.50	4/14/2017	0.50	(65.20)	(32.60)
3300004336	RV	3900002951	633697	1012382	4/14/2017	5/2/2017	-65.20	02	4/14/2017	4/14/2017	0.50	5/2/2017	18.50	65.20	1,206.20
3300004337	RV	3900002944	633697	1012382	4/14/2017	5/2/2017	-60.40	02	4/14/2017	4/14/2017	0.50	5/2/2017	18.50	60.40	1,117.40
3300004338	RV	3900002720	633697	1012423	4/14/2017	4/21/2017	-61.40	02	4/14/2017	4/14/2017	0.50	4/21/2017	7.50	61.40	460.50
3300004339	RV	3900002969	633697	1012382	4/14/2017	5/2/2017	-65.20	02	4/14/2017	4/14/2017	0.50	5/2/2017	18.50	65.20	1,206.20
3300004340	RV	3900002968	633697	1012382	4/14/2017	5/2/2017	-60.40	02	4/14/2017	4/14/2017	0.50	5/2/2017	18.50	60.40	1,117.40
3300004341	RV	3900002967	633697	1012382	4/14/2017	5/2/2017	-67.60	02	4/14/2017	4/14/2017	0.50	5/2/2017	18.50	67.60	1,250.60
3300004342	RV	3900003110	633697	1012044	4/14/2017	5/9/2017	-60.11	02	4/14/2017	4/14/2017	0.50	5/9/2017	25.50	60.11	1,532.81
3300004360	RV	3900002933	633697	1012382	4/17/2017	5/2/2017	-70.00	02	4/17/2017	4/17/2017	0.50	5/2/2017	15.50	70.00	1,085.00
3300004361	RV	3900003108	633697	1012044	4/17/2017	5/9/2017	-61.40	02	4/17/2017	4/17/2017	0.50	5/9/2017	22.50	61.40	1,381.50
3300004362	RV	3900002958	633697	1012382	4/17/2017	5/2/2017	-60.40	02	4/17/2017	4/17/2017	0.50	5/2/2017	15.50	60.40	936.20
3300004363	RV	3900002949	633697	1012382	4/17/2017	5/2/2017	-61.80	02	4/17/2017	4/17/2017	0.50	5/2/2017	15.50	61.80	957.90
3300004364	RV	3900002959	633697	1012382	4/17/2017	5/2/2017	-61.40	02	4/17/2017	4/17/2017	0.50	5/2/2017	15.50	61.40	951.70
3300004365	RV	3900002955	633697	1012382	4/17/2017	5/2/2017	-65.20	02	4/17/2017	4/17/2017	0.50	5/2/2017	15.50	65.20	1,010.60
3300004366	RV	3900002948	633697	1012382	4/17/2017	5/2/2017	-62.80	02	4/17/2017	4/17/2017	0.50	5/2/2017	15.50	62.80	973.40
3300004367	RV	3900002947	633697	1012382	4/17/2017	5/2/2017	-61.40	02	4/17/2017	4/17/2017	0.50	5/2/2017	15.50	61.40	951.70
3300004368	RV	3900002943	633697	1012382	4/17/2017	5/2/2017	-61.80	02	4/17/2017	4/17/2017	0.50	5/2/2017	15.50	61.80	957.90
3300004369	RV	3900003111	633697	1012044	4/17/2017	5/9/2017	-61.40	02	4/17/2017	4/17/2017	0.50	5/9/2017	22.50	61.40	1,381.50
3300004370	RV	3900002946	633697	1012382	4/17/2017	5/2/2017	-61.80	02	4/17/2017	4/17/2017	0.50	5/2/2017	15.50	61.80	957.90
3300004371	RV	3900002915	633697	41717	4/17/2017	5/1/2017	-61.40	02	4/17/2017	4/17/2017	0.50	5/1/2017	14.50	61.40	890.30
3300004373	RV	3900002945	633697	1012382	4/17/2017	5/2/2017	-61.40	02	4/17/2017	4/17/2017	0.50	5/2/2017	15.50	61.40	951.70
3300004376	RV	3900002966	633697	1012382	4/18/2017	5/2/2017	-61.80	02	4/18/2017	4/18/2017	0.50	5/2/2017	14.50	61.80	896.10
3300004377	RV	3900002917	633697	41717	4/18/2017	5/1/2017	-61.40	02	4/18/2017	4/18/2017	0.50	5/1/2017	13.50	61.40	828.90
3300004378	RV	3900002965	633697	1012382	4/18/2017	5/2/2017	-67.60	02	4/18/2017	4/18/2017	0.50	5/2/2017	14.50	67.60	980.20
3300004379	RV	3900002941	633697	1012382	4/18/2017	5/2/2017	-60.40	02	4/18/2017	4/18/2017	0.50	5/2/2017	14.50	60.40	875.80
3300004380	RV	3900003218	633697	1012044	4/18/2017	5/12/2017	-65.27	02	4/18/2017	4/18/2017	0.50	5/12/2017	24.50	65.27	1,599.12
3300004393	RV	3900003224	633697	1012044	4/18/2017	5/12/2017	-61.40	02	4/18/2017	4/18/2017	0.50	5/12/2017	24.50	61.40	1,504.30
3300004404	RV	3900002950	633697	1012382	4/18/2017	5/2/2017	-64.20	02	4/18/2017	4/18/2017	0.50	5/2/2017	14.50	64.20	930.90
3300004405	RV	3900002964	633697	1012382	4/18/2017	5/2/2017	-64.40	02	4/18/2017	4/18/2017	0.50	5/2/2017	14.50	64.40	933.80
3300004406	RV	3300004407	633697	NEM	4/18/2017	4/18/2017	-62.60	02	4/18/2017	4/18/2017	0.50	4/18/2017	0.50	62.60	31.30
3300004407	RV	3300004407	633697	NEM	4/18/2017	4/18/2017	62.60	02	4/18/2017	4/18/2017	0.50	4/18/2017	0.50	(62.60)	(31.30)

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3300004409	RV	3900002960	633697	1012382	4/18/2017	5/2/2017	-62.60	02	4/18/2017	4/18/2017	0.50	5/2/2017	14.50	62.60	907.70
3300004413	RV	3300004414	633697	NEM	4/18/2017	4/18/2017	-60.40	02	4/18/2017	4/18/2017	0.50	4/18/2017	0.50	60.40	30.20
3300004414	RV	3300004414	633697	NEM	4/18/2017	4/18/2017	60.40	02	4/18/2017	4/18/2017	0.50	4/18/2017	0.50	(60.40)	(30.20)
3300004415	RV	3900004666	633697	1012382	4/18/2017	7/17/2017	-60.40	02	4/18/2017	4/18/2017	0.50	7/17/2017	90.50	60.40	5,466.20
3300004416	RV	3900002956	633697	1012382	4/18/2017	5/2/2017	-65.20	02	4/18/2017	4/18/2017	0.50	5/2/2017	14.50	65.20	945.40
3300004417	RV	3300004418	633697	NEM	4/18/2017	4/18/2017	-60.40	02	4/18/2017	4/18/2017	0.50	4/18/2017	0.50	60.40	30.20
3300004418	RV	3300004418	633697	NEM	4/18/2017	4/18/2017	60.40	02	4/18/2017	4/18/2017	0.50	4/18/2017	0.50	(60.40)	(30.20)
3300004419	RV	3900003152	633697	1012382	4/18/2017	5/10/2017	-60.40	02	4/18/2017	4/18/2017	0.50	5/10/2017	22.50	60.40	1,359.00
3300004420	RV	3900002957	633697	1012382	4/18/2017	5/2/2017	-61.40	02	4/18/2017	4/18/2017	0.50	5/2/2017	14.50	61.40	890.30
3300004421	RV	3900003220	633697	1012044	4/18/2017	5/12/2017	-61.40	02	4/18/2017	4/18/2017	0.50	5/12/2017	24.50	61.40	1,504.30
3300004422	RV	3900002918	633697	41717	4/18/2017	5/1/2017	-65.20	02	4/18/2017	4/18/2017	0.50	5/1/2017	13.50	65.20	880.20
3300004451	RV	3900003587	633697	1012233	4/19/2017	5/31/2017	-68.00	02	4/19/2017	4/19/2017	0.50	5/31/2017	42.50	68.00	2,890.00
3300004454	RV	3900003423	633697	1012637	4/19/2017	5/23/2017	-60.25	02	4/19/2017	4/19/2017	0.50	5/23/2017	34.50	60.25	2,078.63
3300004455	RV	3900003153	633697	1012382	4/19/2017	5/10/2017	-61.40	02	4/19/2017	4/19/2017	0.50	5/10/2017	21.50	61.40	1,320.10
3300004456	RV	3900003154	633697	1012382	4/19/2017	5/10/2017	-65.20	02	4/19/2017	4/19/2017	0.50	5/10/2017	21.50	65.20	1,401.80
3300004596	RV	3900003155	633697	1012382	4/20/2017	5/10/2017	-65.20	02	4/20/2017	4/20/2017	0.50	5/10/2017	20.50	65.20	1,336.60
3300004597	RV	3900003350	633697	1012044	4/20/2017	5/19/2017	-60.54	02	4/20/2017	4/20/2017	0.50	5/19/2017	29.50	60.54	1,785.93
3300004598	RV	3900003349	633697	1012044	4/20/2017	5/19/2017	-64.62	02	4/20/2017	4/20/2017	0.50	5/19/2017	29.50	64.62	1,906.29
3300004604	RV	3900003149	633697	1012382	4/20/2017	5/10/2017	-61.40	02	4/20/2017	4/20/2017	0.50	5/10/2017	20.50	61.40	1,258.70
3300004607	RV	3900003148	633697	1012382	4/20/2017	5/10/2017	-65.20	02	4/20/2017	4/20/2017	0.50	5/10/2017	20.50	65.20	1,336.60
3300004608	RV	3900003147	633697	1012382	4/20/2017	5/10/2017	-62.80	02	4/20/2017	4/20/2017	0.50	5/10/2017	20.50	62.80	1,287.40
3300004609	RV	3900002830	633697	1012423	4/20/2017	4/26/2017	-61.40	02	4/20/2017	4/20/2017	0.50	4/26/2017	6.50	61.40	399.10
3300004610	RV	3900003351	633697	1012044	4/20/2017	5/19/2017	-61.40	02	4/20/2017	4/20/2017	0.50	5/19/2017	29.50	61.40	1,811.30
3300004632	RV	3900003146	633697	1012382	4/21/2017	5/10/2017	-60.40	02	4/21/2017	4/21/2017	0.50	5/10/2017	19.50	60.40	1,177.80
3300004636	RV	3900003234	633697	1012382	4/21/2017	5/12/2017	-61.40	02	4/21/2017	4/21/2017	0.50	5/12/2017	21.50	61.40	1,320.10
3300004639	RV	3900003232	633697	1012382	4/21/2017	5/12/2017	-61.80	02	4/21/2017	4/21/2017	0.50	5/12/2017	21.50	61.80	1,328.70
3300004644	RV	3300004677	633697	NEM	4/21/2017	4/21/2017	-64.20	02	4/21/2017	4/21/2017	0.50	4/21/2017	0.50	64.20	32.10
3300004647	RV	3900003225	633697	1012382	4/21/2017	5/12/2017	-66.00	02	4/21/2017	4/21/2017	0.50	5/12/2017	21.50	66.00	1,419.00
3300004649	RV	3900003352	633697	1012044	4/21/2017	5/19/2017	-65.48	02	4/21/2017	4/21/2017	0.50	5/19/2017	28.50	65.48	1,866.18
3300004672	RV	3900003894	633697	1012423	4/21/2017	6/15/2017	-63.00	02	4/21/2017	4/21/2017	0.50	6/15/2017	55.50	63.00	3,496.50
3300004676	RV	3900003231	633697	1012382	4/21/2017	5/12/2017	-61.40	02	4/21/2017	4/21/2017	0.50	5/12/2017	21.50	61.40	1,320.10
3300004677	RV	3300004677	633697	NEM	4/21/2017	4/21/2017	64.20	02	4/21/2017	4/21/2017	0.50	4/21/2017	0.50	(64.20)	(32.10)
3300004678	RV	3900003127	633697	1012382	4/21/2017	5/10/2017	-64.20	02	4/21/2017	4/21/2017	0.50	5/10/2017	19.50	64.20	1,251.90
3300004713	RV	3900003354	633697	1012044	4/24/2017	5/19/2017	-61.40	02	4/24/2017	4/24/2017	0.50	5/19/2017	25.50	61.40	1,565.70
3300004714	RV	3900003353	633697	1012044	4/24/2017	5/19/2017	-61.40	02	4/24/2017	4/24/2017	0.50	5/19/2017	25.50	61.40	1,565.70
3300004726	RV	3900003229	633697	1012382	4/24/2017	5/12/2017	-63.20	02	4/24/2017	4/24/2017	0.50	5/12/2017	18.50	63.20	1,169.20
3300004732	RV	3900003143	633697	1012382	4/24/2017	5/10/2017	-61.80	02	4/24/2017	4/24/2017	0.50	5/10/2017	16.50	61.80	1,019.70
3300004733	RV	3900003142	633697	1012382	4/24/2017	5/10/2017	-68.00	02	4/24/2017	4/24/2017	0.50	5/10/2017	16.50	68.00	1,122.00
3300004734	RV	3900003151	633697	1012382	4/24/2017	5/10/2017	-65.20	02	4/24/2017	4/24/2017	0.50	5/10/2017	16.50	65.20	1,075.80
3300004818	RV	3900003228	633697	1012382	4/26/2017	5/12/2017	-64.20	02	4/26/2017	4/26/2017	0.50	5/12/2017	16.50	64.20	1,059.30
3300004827	RV	3900003145	633697	1012382	4/26/2017	5/10/2017	-60.40	02	4/26/2017	4/26/2017	0.50	5/10/2017	14.50	60.40	875.80
3300004829	RV	3900003233	633697	1012382	4/26/2017	5/12/2017	-60.40	02	4/26/2017	4/26/2017	0.50	5/12/2017	16.50	60.40	996.60
3300004830	RV	3900003144	633697	1012382	4/26/2017	5/10/2017	-60.40	02	4/26/2017	4/26/2017	0.50	5/10/2017	14.50	60.40	875.80
3300004831	RV	3900003226	633697	1012382	4/26/2017	5/12/2017	-62.80	02	4/26/2017	4/26/2017	0.50	5/12/2017	16.50	62.80	1,036.20
3300004832	RV	3900003227	633697	1012382	4/26/2017	5/12/2017	-62.80	02	4/26/2017	4/26/2017	0.50	5/12/2017	16.50	62.80	1,036.20
3300004833	RV	3900003230	633697	1012382	4/26/2017	5/12/2017	-64.20	02	4/26/2017	4/26/2017	0.50	5/12/2017	16.50	64.20	1,059.30
3300004835	RV	3900003141	633697	1012382	4/26/2017	5/10/2017	-62.80	02	4/26/2017	4/26/2017	0.50	5/10/2017	14.50	62.80	910.60
3300004840	RV	3900003140	633697	1012382	4/26/2017	5/10/2017	-61.80	02	4/26/2017	4/26/2017	0.50	5/10/2017	14.50	61.80	896.10
3300004848	RV	3900003072	633697	41717	4/26/2017	5/8/2017	-65.20	02	4/26/2017	4/26/2017	0.50	5/8/2017	12.50	65.20	815.00
3300004861	RV	3900003139	633697	1012382	4/26/2017	5/10/2017	-61.80	02	4/26/2017	4/26/2017	0.50	5/10/2017	14.50	61.80	896.10

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3300004877	RV	3900003138	633697	1012382	4/26/2017	5/10/2017	-61.80	02	4/26/2017	4/26/2017	0.50	5/10/2017	14.50	61.80	896.10
3300004909	RV	3900003137	633697	1012382	4/26/2017	5/10/2017	-60.40	02	4/26/2017	4/26/2017	0.50	5/10/2017	14.50	60.40	875.80
3300004910	RV	3900003136	633697	1012382	4/26/2017	5/10/2017	-60.40	02	4/26/2017	4/26/2017	0.50	5/10/2017	14.50	60.40	875.80
3300004911	RV	3900003135	633697	1012382	4/26/2017	5/10/2017	-65.20	02	4/26/2017	4/26/2017	0.50	5/10/2017	14.50	65.20	945.40
3300004912	RV	3900002870	633697	1012637	4/26/2017	4/28/2017	-64.00	02	4/26/2017	4/26/2017	0.50	4/28/2017	2.50	64.00	160.00
3300004989	RV	3900003357	633697	1012044	4/27/2017	5/19/2017	-61.83	02	4/27/2017	4/27/2017	0.50	5/19/2017	22.50	61.83	1,391.18
3300004991	RV	3900003356	633697	1012044	4/27/2017	5/19/2017	-60.97	02	4/27/2017	4/27/2017	0.50	5/19/2017	22.50	60.97	1,371.83
3300004992	RV	3900003355	633697	1012044	4/27/2017	5/19/2017	-61.40	02	4/27/2017	4/27/2017	0.50	5/19/2017	22.50	61.40	1,381.50
3300004994	RV	3900003134	633697	1012382	4/27/2017	5/10/2017	-63.20	02	4/27/2017	4/27/2017	0.50	5/10/2017	13.50	63.20	853.20
3300004995	RV	3900003133	633697	1012382	4/27/2017	5/10/2017	-61.40	02	4/27/2017	4/27/2017	0.50	5/10/2017	13.50	61.40	828.90
3300004996	RV	3900003359	633697	1012044	4/27/2017	5/19/2017	-61.40	02	4/27/2017	4/27/2017	0.50	5/19/2017	22.50	61.40	1,381.50
3300004997	RV	3900003358	633697	1012044	4/27/2017	5/19/2017	-61.83	02	4/27/2017	4/27/2017	0.50	5/19/2017	22.50	61.83	1,391.18
3300004998	RV	3900003132	633697	1012382	4/27/2017	5/10/2017	-65.20	02	4/27/2017	4/27/2017	0.50	5/10/2017	13.50	65.20	880.20
3300005098	RV	3900002889	633697	1012423	4/28/2017	5/1/2017	-61.40	02	4/28/2017	4/28/2017	0.50	5/1/2017	3.50	61.40	214.90
3300005100	RV	3900003131	633697	1012382	4/28/2017	5/10/2017	-60.40	02	4/28/2017	4/28/2017	0.50	5/10/2017	12.50	60.40	755.00
3300005101	RV	3900003130	633697	1012382	4/28/2017	5/10/2017	-64.20	02	4/28/2017	4/28/2017	0.50	5/10/2017	12.50	64.20	802.50
3300005102	RV	3900003129	633697	1012382	4/28/2017	5/10/2017	-62.00	02	4/28/2017	4/28/2017	0.50	5/10/2017	12.50	62.00	775.00
3300005104	RV	3900003128	633697	1012382	4/28/2017	5/10/2017	-64.20	02	4/28/2017	4/28/2017	0.50	5/10/2017	12.50	64.20	802.50
3300005146	RV	3900003150	633697	1012382	5/1/2017	5/10/2017	-60.40	02	5/1/2017	5/1/2017	0.50	5/10/2017	9.50	60.40	573.80
3300005152	RV	3900003126	633697	1012382	5/1/2017	5/9/2017	-62.80	02	5/1/2017	5/1/2017	0.50	5/9/2017	8.50	62.80	533.80
3300005153	RV	3900003360	633697	1012044	5/1/2017	5/19/2017	-61.40	02	5/1/2017	5/1/2017	0.50	5/19/2017	18.50	61.40	1,135.90
3300005154	RV	3300005160	633697	NEM	5/1/2017	5/1/2017	-60.40	02	5/1/2017	5/1/2017	0.50	5/1/2017	0.50	60.40	30.20
3300005155	RV	3900003202	633697	1012382	5/1/2017	5/12/2017	-61.40	02	5/1/2017	5/1/2017	0.50	5/12/2017	11.50	61.40	706.10
3300005156	RV	3900003125	633697	1012382	5/1/2017	5/9/2017	-63.20	02	5/1/2017	5/1/2017	0.50	5/9/2017	8.50	63.20	537.20
3300005157	RV	3900003361	633697	1012044	5/1/2017	5/19/2017	-61.40	02	5/1/2017	5/1/2017	0.50	5/19/2017	18.50	61.40	1,135.90
3300005158	RV	3900003785	633697	1012382	5/1/2017	6/8/2017	-61.40	02	5/1/2017	5/1/2017	0.50	6/8/2017	38.50	61.40	2,363.90
3300005159	RV	3900003039	633697	1012423	5/1/2017	5/5/2017	-61.40	02	5/1/2017	5/1/2017	0.50	5/5/2017	4.50	61.40	276.30
3300005160	RV	3300005160	633697	NEM	5/1/2017	5/1/2017	60.40	02	5/1/2017	5/1/2017	0.50	5/1/2017	0.50	(60.40)	(30.20)
3300005161	RV	3900003124	633697	1012382	5/1/2017	5/9/2017	-60.40	02	5/1/2017	5/1/2017	0.50	5/9/2017	8.50	60.40	513.40
3300005162	RV	3900003907	633697	1012358	5/2/2017	6/15/2017	-61.00	02	5/2/2017	5/2/2017	0.50	6/15/2017	44.50	61.00	2,714.50
3300005163	RV	3900003763	633697	1012382	5/2/2017	6/7/2017	-65.20	02	5/2/2017	5/2/2017	0.50	6/7/2017	36.50	65.20	2,379.80
3300005164	RV	3900003693	633697	1012382	5/2/2017	6/5/2017	-60.40	02	5/2/2017	5/2/2017	0.50	6/5/2017	34.50	60.40	2,083.80
3300005165	RV	3300005197	633697	NEM	5/2/2017	5/2/2017	-63.20	02	5/2/2017	5/2/2017	0.50	5/2/2017	0.50	63.20	31.60
3300005166	RV	3900003775	633697	1012382	5/2/2017	6/7/2017	-60.40	02	5/2/2017	5/2/2017	0.50	6/7/2017	36.50	60.40	2,204.60
3300005186	RV	3300005189	633697	NEM	5/2/2017	5/2/2017	-60.40	02	5/2/2017	5/2/2017	0.50	5/2/2017	0.50	60.40	30.20
3300005189	RV	3300005189	633697	NEM	5/2/2017	5/2/2017	60.40	02	5/2/2017	5/2/2017	0.50	5/2/2017	0.50	(60.40)	(30.20)
3300005190	RV	3900003771	633697	1012382	5/2/2017	6/7/2017	-60.40	02	5/2/2017	5/2/2017	0.50	6/7/2017	36.50	60.40	2,204.60
3300005191	RV	3900003847	633697	1012044	5/2/2017	6/13/2017	-61.40	02	5/2/2017	5/2/2017	0.50	6/13/2017	42.50	61.40	2,609.50
3300005192	RV	3900003772	633697	1012382	5/2/2017	6/7/2017	-63.20	02	5/2/2017	5/2/2017	0.50	6/7/2017	36.50	63.20	2,306.80
3300005193	RV	3900003764	633697	1012382	5/2/2017	6/7/2017	-60.40	02	5/2/2017	5/2/2017	0.50	6/7/2017	36.50	60.40	2,204.60
3300005194	RV	3900003777	633697	1012382	5/2/2017	6/7/2017	-60.40	02	5/2/2017	5/2/2017	0.50	6/7/2017	36.50	60.40	2,204.60
3300005195	RV	3900003766	633697	1012382	5/2/2017	6/7/2017	-60.40	02	5/2/2017	5/2/2017	0.50	6/7/2017	36.50	60.40	2,204.60
3300005196	RV	3900003697	633697	1012382	5/2/2017	6/5/2017	-60.40	02	5/2/2017	5/2/2017	0.50	6/5/2017	34.50	60.40	2,083.80
3300005197	RV	3300005197	633697	NEM	5/2/2017	5/2/2017	63.20	02	5/2/2017	5/2/2017	0.50	5/2/2017	0.50	(63.20)	(31.60)
3300005198	RV	3900003767	633697	1012382	5/2/2017	6/7/2017	-63.20	02	5/2/2017	5/2/2017	0.50	6/7/2017	36.50	63.20	2,306.80
3300005222	RV	3900003684	633697	1012382	5/3/2017	6/5/2017	-63.20	02	5/3/2017	5/3/2017	0.50	6/5/2017	33.50	63.20	2,117.20
3300005223	RV	3900003848	633697	1012044	5/3/2017	6/13/2017	-61.83	02	5/3/2017	5/3/2017	0.50	6/13/2017	41.50	61.83	2,565.95
3300005225	RV	3900003695	633697	1012382	5/3/2017	6/5/2017	-60.40	02	5/3/2017	5/3/2017	0.50	6/5/2017	33.50	60.40	2,023.40
3300005256	RV	3900003575	633697	1012382	5/4/2017	5/31/2017	-62.00	02	5/4/2017	5/4/2017	0.50	5/31/2017	27.50	62.00	1,705.00
3300005261	RV	3900003362	633697	1012044	5/4/2017	5/19/2017	-65.20	02	5/4/2017	5/4/2017	0.50	5/19/2017	15.50	65.20	1,010.60

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3300005262	RV	3900003268	633697	1012382	5/4/2017	5/17/2017	-61.40	02	5/4/2017	5/4/2017	0.50	5/17/2017	13.50	61.40	828.90
3300005263	RV	3900003191	633697	1012382	5/4/2017	5/11/2017	-60.40	02	5/4/2017	5/4/2017	0.50	5/11/2017	7.50	60.40	453.00
3300005264	RV	3900003193	633697	1012382	5/4/2017	5/11/2017	-60.40	02	5/4/2017	5/4/2017	0.50	5/11/2017	7.50	60.40	453.00
3300005265	RV	3900003203	633697	41717	5/4/2017	5/12/2017	-62.00	02	5/4/2017	5/4/2017	0.50	5/12/2017	8.50	62.00	527.00
3300005315	RV	3900003266	633697	1012044	5/5/2017	5/17/2017	-65.48	02	5/5/2017	5/5/2017	0.50	5/17/2017	12.50	65.48	818.50
3300005317	RV	3900003389	633697	1012382	5/5/2017	5/22/2017	-60.40	02	5/5/2017	5/5/2017	0.50	5/22/2017	17.50	60.40	1,057.00
3300005318	RV	3900003269	633697	1012044	5/5/2017	5/17/2017	-61.40	02	5/5/2017	5/5/2017	0.50	5/17/2017	12.50	61.40	767.50
3300005319	RV	3900003392	633697	1012382	5/5/2017	5/22/2017	-60.40	02	5/5/2017	5/5/2017	0.50	5/22/2017	17.50	60.40	1,057.00
3300005320	RV	3900003283	633697	1012423	5/5/2017	5/18/2017	-63.80	02	5/5/2017	5/5/2017	0.50	5/18/2017	13.50	63.80	861.30
3300005346	RV	3900003391	633697	41717	5/8/2017	5/22/2017	-61.40	02	5/8/2017	5/8/2017	0.50	5/22/2017	14.50	61.40	890.30
3300005347	RV	3900003393	633697	1012382	5/8/2017	5/22/2017	-63.60	02	5/8/2017	5/8/2017	0.50	5/22/2017	14.50	63.60	922.20
3300005348	RV	3900003546	633697	1012382	5/8/2017	5/31/2017	-60.40	02	5/8/2017	5/8/2017	0.50	5/31/2017	23.50	60.40	1,419.40
3300005349	RV	3900003417	633697	1012382	5/8/2017	5/23/2017	-61.40	02	5/8/2017	5/8/2017	0.50	5/23/2017	15.50	61.40	951.70
3300005350	RV	3900003390	633697	1012382	5/8/2017	5/22/2017	-60.40	02	5/8/2017	5/8/2017	0.50	5/22/2017	14.50	60.40	875.80
3300005351	RV	3900003394	633697	1012382	5/8/2017	5/22/2017	-60.40	02	5/8/2017	5/8/2017	0.50	5/22/2017	14.50	60.40	875.80
3300005352	RV	3900003267	633697	1012044	5/8/2017	5/17/2017	-61.40	02	5/8/2017	5/8/2017	0.50	5/17/2017	9.50	61.40	583.30
3300005353	RV	3900003265	633697	1012044	5/8/2017	5/17/2017	-61.40	02	5/8/2017	5/8/2017	0.50	5/17/2017	9.50	61.40	583.30
3300005354	RV	3900003553	633697	1012382	5/8/2017	5/31/2017	-63.20	02	5/8/2017	5/8/2017	0.50	5/31/2017	23.50	63.20	1,485.20
3300005403	RV	3900004968	633697	1007900	5/10/2017	8/1/2017	-1,550.00	02	5/10/2017	5/10/2017	0.50	8/1/2017	83.50	1,550.00	129,425.00
3300005404	RV	3900003552	633697	1012382	5/10/2017	5/31/2017	-63.60	02	5/10/2017	5/10/2017	0.50	5/31/2017	21.50	63.60	1,367.40
3300005405	RV	3900003554	633697	1012382	5/10/2017	5/31/2017	-62.80	02	5/10/2017	5/10/2017	0.50	5/31/2017	21.50	62.80	1,350.20
3300005406	RV	3900003284	633697	1012423	5/10/2017	5/18/2017	-62.00	02	5/10/2017	5/10/2017	0.50	5/18/2017	8.50	62.00	527.00
3300005407	RV	3900003550	633697	1012382	5/10/2017	5/31/2017	-64.20	02	5/10/2017	5/10/2017	0.50	5/31/2017	21.50	64.20	1,380.30
3300005408	RV	3900003589	633697	1012392	5/10/2017	5/31/2017	-70.25	02	5/10/2017	5/10/2017	0.50	5/31/2017	21.50	70.25	1,510.38
3300005409	RV	3900003547	633697	1012382	5/10/2017	5/31/2017	-61.80	02	5/10/2017	5/10/2017	0.50	5/31/2017	21.50	61.80	1,328.70
3300005410	RV	3900003549	633697	1012382	5/10/2017	5/31/2017	-61.80	02	5/10/2017	5/10/2017	0.50	5/31/2017	21.50	61.80	1,328.70
3300005411	RV	3900003548	633697	1012382	5/10/2017	5/31/2017	-61.80	02	5/10/2017	5/10/2017	0.50	5/31/2017	21.50	61.80	1,328.70
3300005412	RV	3900003551	633697	1012382	5/10/2017	5/31/2017	-65.20	02	5/10/2017	5/10/2017	0.50	5/31/2017	21.50	65.20	1,401.80
3300005413	RV	3300005417	633697	NEM	5/10/2017	5/10/2017	-61.61	02	5/10/2017	5/10/2017	0.50	5/10/2017	0.50	61.61	30.81
3300005414	RV	3900003264	633697	1012044	5/10/2017	5/17/2017	-61.40	02	5/10/2017	5/10/2017	0.50	5/17/2017	7.50	61.40	460.50
3300005415	RV	3900003387	633697	1012434	5/10/2017	5/22/2017	-68.49	02	5/10/2017	5/10/2017	0.50	5/22/2017	12.50	68.49	856.13
3300005416	RV	3900003262	633697	1012044	5/10/2017	5/17/2017	-61.40	02	5/10/2017	5/10/2017	0.50	5/17/2017	7.50	61.40	460.50
3300005417	RV	3300005417	633697	NEM	5/10/2017	5/10/2017	61.61	02	5/10/2017	5/10/2017	0.50	5/10/2017	0.50	(61.61)	(30.81)
3300005418	RV	3900003263	633697	1012044	5/10/2017	5/17/2017	-61.61	02	5/10/2017	5/10/2017	0.50	5/17/2017	7.50	61.61	462.08
3300005504	RV	3900003560	633697	1012382	5/11/2017	5/31/2017	-60.40	02	5/11/2017	5/11/2017	0.50	5/31/2017	20.50	60.40	1,238.20
3300005510	RV	3900003555	633697	1012382	5/11/2017	5/31/2017	-61.80	02	5/11/2017	5/11/2017	0.50	5/31/2017	20.50	61.80	1,266.90
3300005512	RV	3900003568	633697	1012382	5/11/2017	5/31/2017	-66.40	02	5/11/2017	5/11/2017	0.50	5/31/2017	20.50	66.40	1,361.20
3300005513	RV	3900003475	633697	1012358	5/11/2017	5/25/2017	-60.60	02	5/11/2017	5/11/2017	0.50	5/25/2017	14.50	60.60	878.70
3300005514	RV	3900003480	633697	41717	5/11/2017	5/25/2017	-65.20	02	5/11/2017	5/11/2017	0.50	5/25/2017	14.50	65.20	945.40
3300005515	RV	3900003567	633697	1012382	5/11/2017	5/31/2017	-61.80	02	5/11/2017	5/11/2017	0.50	5/31/2017	20.50	61.80	1,266.90
3300005516	RV	3900003571	633697	1012382	5/11/2017	5/31/2017	-65.20	02	5/11/2017	5/11/2017	0.50	5/31/2017	20.50	65.20	1,336.60
3300005517	RV	3300005519	633697	NEM	5/11/2017	5/11/2017	-61.80	02	5/11/2017	5/11/2017	0.50	5/11/2017	0.50	61.80	30.90
3300005518	RV	3900003573	633697	1012382	5/11/2017	5/31/2017	-62.80	02	5/11/2017	5/11/2017	0.50	5/31/2017	20.50	62.80	1,287.40
3300005519	RV	3300005519	633697	NEM	5/11/2017	5/11/2017	61.80	02	5/11/2017	5/11/2017	0.50	5/11/2017	0.50	(61.80)	(30.90)
3300005520	RV	3900003557	633697	NEM	5/11/2017	5/31/2017	-61.80	02	5/11/2017	5/11/2017	0.50	5/31/2017	20.50	61.80	1,266.90
3300005600	RV	3900003588	633697	1012421	5/12/2017	5/31/2017	-61.40	02	5/12/2017	5/12/2017	0.50	5/31/2017	19.50	61.40	1,197.30
3300005601	RV	3900003574	633697	1012382	5/12/2017	5/31/2017	-62.80	02	5/12/2017	5/12/2017	0.50	5/31/2017	19.50	62.80	1,224.60
3300005602	RV	3900003577	633697	1012382	5/12/2017	5/31/2017	-61.80	02	5/12/2017	5/12/2017	0.50	5/31/2017	19.50	61.80	1,205.10
3300005603	RV	3900003576	633697	1012382	5/12/2017	5/31/2017	-61.80	02	5/12/2017	5/12/2017	0.50	5/31/2017	19.50	61.80	1,205.10
3300005604	RV	3900003570	633697	1012382	5/12/2017	5/31/2017	-65.20	02	5/12/2017	5/12/2017	0.50	5/31/2017	19.50	65.20	1,271.40

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3300005605	RV	3900003286	633697	1012044	5/12/2017	5/18/2017	-61.40	02	5/12/2017	5/12/2017	0.50	5/18/2017	6.50	61.40	399.10
3300005607	RV	3300005609	633697	NEM	5/12/2017	5/12/2017	-61.40	02	5/12/2017	5/12/2017	0.50	5/12/2017	0.50	61.40	30.70
3300005608	RV	3900003556	633697	1012382	5/12/2017	5/31/2017	-61.40	02	5/12/2017	5/12/2017	0.50	5/31/2017	19.50	61.40	1,197.30
3300005609	RV	3300005609	633697	NEM	5/12/2017	5/12/2017	61.40	02	5/12/2017	5/12/2017	0.50	5/12/2017	0.50	(61.40)	(30.70)
3300005610	RV	3900003285	633697	1012044	5/12/2017	5/18/2017	-61.40	02	5/12/2017	5/12/2017	0.50	5/18/2017	6.50	61.40	399.10
3300005624	RV	3900003396	633697	1012044	5/15/2017	5/22/2017	-61.40	02	5/15/2017	5/15/2017	0.50	5/22/2017	7.50	61.40	460.50
3300005625	RV	3900003558	633697	1012382	5/15/2017	5/31/2017	-61.40	02	5/15/2017	5/15/2017	0.50	5/31/2017	16.50	61.40	1,013.10
3300005626	RV	3900003395	633697	1012044	5/15/2017	5/22/2017	-61.40	02	5/15/2017	5/15/2017	0.50	5/22/2017	7.50	61.40	460.50
3300005627	RV	3900003464	633697	1012423	5/15/2017	5/25/2017	-61.40	02	5/15/2017	5/15/2017	0.50	5/25/2017	10.50	61.40	644.70
3300005628	RV	3900003465	633697	1012423	5/15/2017	5/25/2017	-61.40	02	5/15/2017	5/15/2017	0.50	5/25/2017	10.50	61.40	644.70
3300005629	RV	3900003467	633697	1012423	5/15/2017	5/25/2017	-63.00	02	5/15/2017	5/15/2017	0.50	5/25/2017	10.50	63.00	661.50
3300005630	RV	3900003559	633697	1012382	5/15/2017	5/31/2017	-61.40	02	5/15/2017	5/15/2017	0.50	5/31/2017	16.50	61.40	1,013.10
3300005631	RV	3900003466	633697	1012423	5/16/2017	5/25/2017	-69.00	02	5/16/2017	5/16/2017	0.50	5/25/2017	9.50	69.00	655.50
3300005632	RV	3900003569	633697	1012382	5/16/2017	5/31/2017	-65.20	02	5/16/2017	5/16/2017	0.50	5/31/2017	15.50	65.20	1,010.60
3300005633	RV	3900003561	633697	1012382	5/16/2017	5/31/2017	-60.40	02	5/16/2017	5/16/2017	0.50	5/31/2017	15.50	60.40	936.20
3300005660	RV	3900003572	633697	1012382	5/16/2017	5/31/2017	-65.20	02	5/16/2017	5/16/2017	0.50	5/31/2017	15.50	65.20	1,010.60
3300005693	RV	3900003613	633697	1012044	5/17/2017	6/2/2017	-61.40	02	5/17/2017	5/17/2017	0.50	6/2/2017	16.50	61.40	1,013.10
3300005701	RV	3900003606	633697	1012044	5/17/2017	6/2/2017	-61.40	02	5/17/2017	5/17/2017	0.50	6/2/2017	16.50	61.40	1,013.10
3300005706	RV	3900003562	633697	1012382	5/17/2017	5/31/2017	-61.40	02	5/17/2017	5/17/2017	0.50	5/31/2017	14.50	61.40	890.30
3300005710	RV	3900003566	633697	1012382	5/17/2017	5/31/2017	-61.40	02	5/17/2017	5/17/2017	0.50	5/31/2017	14.50	61.40	890.30
3300005711	RV	3900003563	633697	1012382	5/17/2017	5/31/2017	-60.40	02	5/17/2017	5/17/2017	0.50	5/31/2017	14.50	60.40	875.80
3300005712	RV	3900003565	633697	1012382	5/17/2017	5/31/2017	-61.40	02	5/17/2017	5/17/2017	0.50	5/31/2017	14.50	61.40	890.30
3300005713	RV	3900003624	633697	1012382	5/17/2017	6/2/2017	-61.40	02	5/17/2017	5/17/2017	0.50	6/2/2017	16.50	61.40	1,013.10
3300005714	RV	3900003564	633697	1012382	5/17/2017	5/31/2017	-60.40	02	5/17/2017	5/17/2017	0.50	5/31/2017	14.50	60.40	875.80
3300005715	RV	3900003625	633697	1012382	5/17/2017	6/2/2017	-60.40	02	5/17/2017	5/17/2017	0.50	6/2/2017	16.50	60.40	996.60
3300005751	RV	3900003605	633697	1012044	5/18/2017	6/2/2017	-60.11	02	5/18/2017	5/18/2017	0.50	6/2/2017	15.50	60.11	931.71
3300005752	RV	3900003622	633697	1012382	5/18/2017	6/2/2017	-72.80	02	5/18/2017	5/18/2017	0.50	6/2/2017	15.50	72.80	1,128.40
3300005753	RV	3900003730	633697	41717	5/18/2017	6/6/2017	-70.00	02	5/18/2017	5/18/2017	0.50	6/6/2017	19.50	70.00	1,365.00
3300005791	RV	3900003621	633697	1012382	5/19/2017	6/2/2017	-63.20	02	5/19/2017	5/19/2017	0.50	6/2/2017	14.50	63.20	916.40
3300005792	RV	3900003604	633697	1012044	5/19/2017	6/2/2017	-61.40	02	5/19/2017	5/19/2017	0.50	6/2/2017	14.50	61.40	890.30
3300005793	RV	3900003619	633697	1012382	5/19/2017	6/2/2017	-68.40	02	5/19/2017	5/19/2017	0.50	6/2/2017	14.50	68.40	991.80
3300005832	RV	3900003691	633697	1012382	5/23/2017	6/5/2017	-60.40	02	5/23/2017	5/23/2017	0.50	6/5/2017	13.50	60.40	815.40
3300005833	RV	3900003646	633697	1012423	5/23/2017	6/5/2017	-65.20	02	5/23/2017	5/23/2017	0.50	6/5/2017	13.50	65.20	880.20
3300005834	RV	3900003694	633697	1012382	5/23/2017	6/5/2017	-61.80	02	5/23/2017	5/23/2017	0.50	6/5/2017	13.50	61.80	834.30
3300005835	RV	3900003685	633697	1012382	5/23/2017	6/5/2017	-60.40	02	5/23/2017	5/23/2017	0.50	6/5/2017	13.50	60.40	815.40
3300005836	RV	3900003696	633697	1012382	5/23/2017	6/5/2017	-65.20	02	5/23/2017	5/23/2017	0.50	6/5/2017	13.50	65.20	880.20
3300005837	RV	3900003681	633697	1012382	5/23/2017	6/5/2017	-60.40	02	5/23/2017	5/23/2017	0.50	6/5/2017	13.50	60.40	815.40
3300005845	RV	3900003618	633697	1012044	5/23/2017	6/2/2017	-61.40	02	5/23/2017	5/23/2017	0.50	6/2/2017	10.50	61.40	644.70
3300005853	RV	3900003687	633697	1012382	5/23/2017	6/5/2017	-65.20	02	5/23/2017	5/23/2017	0.50	6/5/2017	13.50	65.20	880.20
3300005854	RV	3900003683	633697	1012382	5/23/2017	6/5/2017	-60.40	02	5/23/2017	5/23/2017	0.50	6/5/2017	13.50	60.40	815.40
3300005855	RV	3900003699	633697	1012382	5/23/2017	6/5/2017	-61.40	02	5/23/2017	5/23/2017	0.50	6/5/2017	13.50	61.40	828.90
3300005986	RV	3900003647	633697	1012423	5/25/2017	6/5/2017	-71.40	02	5/25/2017	5/25/2017	0.50	6/5/2017	11.50	71.40	821.10
3300005988	RV	3900003765	633697	1012382	5/25/2017	6/7/2017	-63.20	02	5/25/2017	5/25/2017	0.50	6/7/2017	13.50	63.20	853.20
3300005990	RV	3900003617	633697	1012044	5/25/2017	6/2/2017	-61.40	02	5/25/2017	5/25/2017	0.50	6/2/2017	8.50	61.40	521.90
3300005991	RV	3900003616	633697	1012044	5/25/2017	6/2/2017	-61.40	02	5/25/2017	5/25/2017	0.50	6/2/2017	8.50	61.40	521.90
3300005992	RV	3900003773	633697	1012382	5/25/2017	6/7/2017	-80.00	02	5/25/2017	5/25/2017	0.50	6/7/2017	13.50	80.00	1,080.00
3300005993	RV	3300005997	633697	NEM	5/25/2017	5/25/2017	-61.40	02	5/25/2017	5/25/2017	0.50	5/25/2017	0.50	61.40	30.70
3300005994	RV	3900003688	633697	1012382	5/25/2017	6/5/2017	-62.80	02	5/25/2017	5/25/2017	0.50	6/5/2017	11.50	62.80	722.20
3300005995	RV	3900003615	633697	1012382	5/25/2017	6/2/2017	-61.40	02	5/25/2017	5/25/2017	0.50	6/2/2017	8.50	61.40	521.90
3300005996	RV	3900003769	633697	1012382	5/25/2017	6/7/2017	-64.20	02	5/25/2017	5/25/2017	0.50	6/7/2017	13.50	64.20	866.70

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3300005997	RV	3300005997	633697	NEM	5/25/2017	5/25/2017	61.40	02	5/25/2017	5/25/2017	0.50	5/25/2017	0.50	(61.40)	(30.70)
3300005998	RV	3900003690	633697	1012382	5/25/2017	6/5/2017	-61.40	02	5/25/2017	5/25/2017	0.50	6/5/2017	11.50	61.40	706.10
3300006038	RV	3300006039	633697	NEM	5/26/2017	5/26/2017	-65.20	02	5/26/2017	5/26/2017	0.50	5/26/2017	0.50	65.20	32.60
3300006039	RV	3300006039	633697	NEM	5/26/2017	5/26/2017	65.20	02	5/26/2017	5/26/2017	0.50	5/26/2017	0.50	(65.20)	(32.60)
3300006040	RV	3900003614	633697	1012044	5/26/2017	6/2/2017	-65.20	02	5/26/2017	5/26/2017	0.50	6/2/2017	7.50	65.20	489.00
3300006041	RV	3900003682	633697	1012382	5/26/2017	6/5/2017	-65.20	02	5/26/2017	5/26/2017	0.50	6/5/2017	10.50	65.20	684.60
3300006042	RV	3900003734	633697	44262	5/26/2017	6/6/2017	-400.00	02	5/26/2017	5/26/2017	0.50	6/6/2017	11.50	400.00	4,600.00
3300006043	RV	3900003689	633697	1012382	5/26/2017	6/5/2017	-61.40	02	5/26/2017	5/26/2017	0.50	6/5/2017	10.50	61.40	644.70
3300006044	RV	3900003768	633697	1012382	5/26/2017	6/7/2017	-61.40	02	5/26/2017	5/26/2017	0.50	6/7/2017	12.50	61.40	767.50
3300006045	RV	3900003686	633697	1012382	5/26/2017	6/5/2017	-63.20	02	5/26/2017	5/26/2017	0.50	6/5/2017	10.50	63.20	663.60
3300006131	RV	3900003692	633697	1012382	5/30/2017	6/5/2017	-62.80	02	5/30/2017	5/30/2017	0.50	6/5/2017	6.50	62.80	408.20
3300006133	RV	3900005640	633697	1012044	5/30/2017	9/1/2017	-61.40	02	5/30/2017	5/30/2017	0.50	9/1/2017	94.50	61.40	5,802.30
3300006134	RV	3900003698	633697	1012382	5/30/2017	6/5/2017	-62.80	02	5/30/2017	5/30/2017	0.50	6/5/2017	6.50	62.80	408.20
3300006137	RV	3900003908	633697	1012358	5/30/2017	6/15/2017	-61.40	02	5/30/2017	5/30/2017	0.50	6/15/2017	16.50	61.40	1,013.10
3300006138	RV	3300006143	633697	NEM	5/30/2017	5/30/2017	-61.40	02	5/30/2017	5/30/2017	0.50	5/30/2017	0.50	61.40	30.70
3300006139	RV	3300006140	633697	NEM	5/30/2017	5/30/2017	-61.40	02	5/30/2017	5/30/2017	0.50	5/30/2017	0.50	61.40	30.70
3300006140	RV	3300006140	633697	NEM	5/30/2017	5/30/2017	61.40	02	5/30/2017	5/30/2017	0.50	5/30/2017	0.50	(61.40)	(30.70)
3300006141	RV	3900003849	633697	1012044	5/30/2017	6/13/2017	-61.40	02	5/30/2017	5/30/2017	0.50	6/13/2017	14.50	61.40	890.30
3300006142	RV	3900003850	633697	1012044	5/30/2017	6/13/2017	-61.40	02	5/30/2017	5/30/2017	0.50	6/13/2017	14.50	61.40	890.30
3300006143	RV	3300006143	633697	NEM	5/30/2017	5/30/2017	61.40	02	5/30/2017	5/30/2017	0.50	5/30/2017	0.50	(61.40)	(30.70)
3300006144	RV	3900003819	633697	1012423	5/30/2017	6/12/2017	-61.40	02	5/30/2017	5/30/2017	0.50	6/12/2017	13.50	61.40	828.90
3300006167	RV	3900003774	633697	1012382	6/1/2017	6/7/2017	-64.20	02	6/1/2017	6/1/2017	0.50	6/7/2017	6.50	64.20	417.30
3300006168	RV	3900003851	633697	1012044	6/1/2017	6/13/2017	-65.20	02	6/1/2017	6/1/2017	0.50	6/13/2017	12.50	65.20	815.00
3300006169	RV	3300006181	633697	NEM	6/1/2017	6/1/2017	-72.80	02	6/1/2017	6/1/2017	0.50	6/1/2017	0.50	72.80	36.40
3300006171	RV	3900003761	633697	1012382	6/1/2017	6/7/2017	-60.40	02	6/1/2017	6/1/2017	0.50	6/7/2017	6.50	60.40	392.60
3300006172	RV	3900003776	633697	1012382	6/1/2017	6/7/2017	-60.40	02	6/1/2017	6/1/2017	0.50	6/7/2017	6.50	60.40	392.60
3300006175	RV	3900003852	633697	1012044	6/1/2017	6/13/2017	-61.40	02	6/1/2017	6/1/2017	0.50	6/13/2017	12.50	61.40	767.50
3300006176	RV	3900003735	633697	41717	6/1/2017	6/6/2017	-62.60	02	6/1/2017	6/1/2017	0.50	6/6/2017	5.50	62.60	344.30
3300006177	RV	3900004951	633697	1012382	6/1/2017	7/31/2017	-63.20	02	6/1/2017	6/1/2017	0.50	7/31/2017	60.50	63.20	3,823.60
3300006178	RV	3900003770	633697	1012382	6/1/2017	6/7/2017	-61.40	02	6/1/2017	6/1/2017	0.50	6/7/2017	6.50	61.40	399.10
3300006179	RV	3900003757	633697	1012382	6/1/2017	6/7/2017	-63.20	02	6/1/2017	6/1/2017	0.50	6/7/2017	6.50	63.20	410.80
3300006181	RV	3300006181	633697	NEM	6/1/2017	6/1/2017	72.80	02	6/1/2017	6/1/2017	0.50	6/1/2017	0.50	(72.80)	(36.40)
3300006186	RV	3900003762	633697	1012382	6/1/2017	6/7/2017	-72.80	02	6/1/2017	6/1/2017	0.50	6/7/2017	6.50	72.80	473.20
3300006288	RV	3900003984	633697	1012358	6/2/2017	6/20/2017	-60.60	02	6/2/2017	6/2/2017	0.50	6/20/2017	18.50	60.60	1,121.10
3300006291	RV	3900004019	633697	1012382	6/2/2017	6/22/2017	-65.20	02	6/2/2017	6/2/2017	0.50	6/22/2017	20.50	65.20	1,336.60
3300006298	RV	3900003970	633697	1012382	6/2/2017	6/19/2017	-63.20	02	6/2/2017	6/2/2017	0.50	6/19/2017	17.50	63.20	1,106.00
3300006303	RV	3900004018	633697	1012382	6/2/2017	6/22/2017	-60.40	02	6/2/2017	6/2/2017	0.50	6/22/2017	20.50	60.40	1,238.20
3300006305	RV	3900004061	633697	41717	6/2/2017	6/22/2017	-65.20	02	6/2/2017	6/2/2017	0.50	6/22/2017	20.50	65.20	1,336.60
3300006308	RV	3900003983	633697	1012358	6/2/2017	6/20/2017	-62.60	02	6/2/2017	6/2/2017	0.50	6/20/2017	18.50	62.60	1,158.10
3300006344	RV	3900004062	633697	41717	6/5/2017	6/22/2017	-84.20	02	6/5/2017	6/5/2017	0.50	6/22/2017	17.50	84.20	1,473.50
3300006345	RV	3900003969	633697	1012382	6/5/2017	6/19/2017	-60.40	02	6/5/2017	6/5/2017	0.50	6/19/2017	14.50	60.40	875.80
3300006351	RV	3900004115	633697	1012382	6/5/2017	6/27/2017	-60.40	02	6/5/2017	6/5/2017	0.50	6/27/2017	22.50	60.40	1,359.00
3300006352	RV	3900004060	633697	41717	6/5/2017	6/22/2017	-69.00	02	6/5/2017	6/5/2017	0.50	6/22/2017	17.50	69.00	1,207.50
3300006387	RV	3900003968	633697	1012382	6/8/2017	6/19/2017	-64.20	02	6/8/2017	6/8/2017	0.50	6/19/2017	11.50	64.20	738.30
3300006410	RV	3900004024	633697	1012382	6/8/2017	6/22/2017	-60.40	02	6/8/2017	6/8/2017	0.50	6/22/2017	14.50	60.40	875.80
3300006418	RV	3900003950	633697	1012044	6/8/2017	6/19/2017	-60.11	02	6/8/2017	6/8/2017	0.50	6/19/2017	11.50	60.11	691.27
3300006419	RV	3900003946	633697	1012044	6/8/2017	6/19/2017	-61.40	02	6/8/2017	6/8/2017	0.50	6/19/2017	11.50	61.40	706.10
3300006422	RV	3900003971	633697	1012382	6/8/2017	6/19/2017	-60.40	02	6/8/2017	6/8/2017	0.50	6/19/2017	11.50	60.40	694.60
3300006423	RV	3900003949	633697	1012044	6/8/2017	6/19/2017	-61.40	02	6/8/2017	6/8/2017	0.50	6/19/2017	11.50	61.40	706.10
3300006424	RV	3900003972	633697	1012382	6/8/2017	6/19/2017	-65.20	02	6/8/2017	6/8/2017	0.50	6/19/2017	11.50	65.20	749.80

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3300006425	RV	3900004026	633697	1012044	6/8/2017	6/22/2017	-64.40	02	6/8/2017	6/8/2017	0.50	6/22/2017	14.50	64.40	933.80
3300006426	RV	3900003967	633697	1012382	6/8/2017	6/19/2017	-65.20	02	6/8/2017	6/8/2017	0.50	6/19/2017	11.50	65.20	749.80
3300006469	RV	3900004023	633697	1012382	6/9/2017	6/22/2017	-61.40	02	6/9/2017	6/9/2017	0.50	6/22/2017	13.50	61.40	828.90
3300006470	RV	3900004022	633697	1012382	6/9/2017	6/22/2017	-65.20	02	6/9/2017	6/9/2017	0.50	6/22/2017	13.50	65.20	880.20
3300006471	RV	3900003948	633697	1012044	6/9/2017	6/19/2017	-61.40	02	6/9/2017	6/9/2017	0.50	6/19/2017	10.50	61.40	644.70
3300006472	RV	3900003947	633697	1012044	6/9/2017	6/19/2017	-61.40	02	6/9/2017	6/9/2017	0.50	6/19/2017	10.50	61.40	644.70
3300006518	RV	3900004021	633697	1012382	6/12/2017	6/22/2017	-60.40	02	6/12/2017	6/12/2017	0.50	6/22/2017	10.50	60.40	634.20
3300006519	RV	3900003891	633697	1013213	6/12/2017	6/15/2017	-290.00	02	6/12/2017	6/12/2017	0.50	6/15/2017	3.50	290.00	1,015.00
3300006520	RV	3900004017	633697	1012382	6/12/2017	6/22/2017	-60.40	02	6/12/2017	6/12/2017	0.50	6/22/2017	10.50	60.40	634.20
3300006521	RV	3900004016	633697	1012382	6/12/2017	6/22/2017	-61.80	02	6/12/2017	6/12/2017	0.50	6/22/2017	10.50	61.80	648.90
3300006554	RV	3900004027	633697	1012423	6/13/2017	6/22/2017	-63.60	02	6/13/2017	6/13/2017	0.50	6/22/2017	9.50	63.60	604.20
3300006555	RV	3900003966	633697	1012382	6/13/2017	6/19/2017	-60.40	02	6/13/2017	6/13/2017	0.50	6/19/2017	6.50	60.40	392.60
3300006556	RV	3900004020	633697	1012382	6/13/2017	6/22/2017	-60.40	02	6/13/2017	6/13/2017	0.50	6/22/2017	9.50	60.40	573.80
3300006557	RV	3900003892	633697	1013213	6/13/2017	6/15/2017	-170.00	02	6/13/2017	6/13/2017	0.50	6/15/2017	2.50	170.00	425.00
3300006558	RV	3900003973	633697	1012382	6/13/2017	6/19/2017	-62.80	02	6/13/2017	6/13/2017	0.50	6/19/2017	6.50	62.80	408.20
3300006586	RV	3900004364	633697	1012358	6/14/2017	7/5/2017	-63.80	02	6/14/2017	6/14/2017	0.50	7/5/2017	21.50	63.80	1,371.70
3300006596	RV	3900003925	633697	1013213	6/14/2017	6/19/2017	-220.00	02	6/14/2017	6/14/2017	0.50	6/19/2017	5.50	220.00	1,210.00
3300006603	RV	3900003926	633697	1013213	6/14/2017	6/19/2017	-170.00	02	6/14/2017	6/14/2017	0.50	6/19/2017	5.50	170.00	935.00
3300006604	RV	3900004118	633697	41717	6/14/2017	6/27/2017	-62.00	02	6/14/2017	6/14/2017	0.50	6/27/2017	13.50	62.00	837.00
3300006610	RV	3900004025	633697	1012382	6/15/2017	6/22/2017	-72.80	02	6/15/2017	6/15/2017	0.50	6/22/2017	7.50	72.80	546.00
3300006658	RV	3900004366	633697	1012358	6/15/2017	7/5/2017	-61.40	02	6/15/2017	6/15/2017	0.50	7/5/2017	20.50	61.40	1,258.70
3300006731	RV	3900005641	633697	1012044	6/16/2017	9/1/2017	-61.40	02	6/16/2017	6/16/2017	0.50	9/1/2017	77.50	61.40	4,758.50
3300006762	RV	3300006763	633697	NEM	6/19/2017	6/19/2017	-61.40	02	6/19/2017	6/19/2017	0.50	6/19/2017	0.50	61.40	30.70
3300006763	RV	3300006763	633697	NEM	6/19/2017	6/19/2017	61.40	02	6/19/2017	6/19/2017	0.50	6/19/2017	0.50	(61.40)	(30.70)
3300006764	RV	3900005636	633697	1012044	6/19/2017	9/1/2017	-61.40	02	6/19/2017	6/19/2017	0.50	9/1/2017	74.50	61.40	4,574.30
3300006792	RV	3900004076	633697	4005260	6/20/2017	6/26/2017	-63.60	02	6/20/2017	6/20/2017	0.50	6/26/2017	6.50	63.60	413.40
3300006793	RV	3900005637	633697	1012044	6/20/2017	9/1/2017	-61.40	02	6/20/2017	6/20/2017	0.50	9/1/2017	73.50	61.40	4,512.90
3300006794	RV	3900006142	633697	1012382	6/20/2017	9/27/2017	-63.20	02	6/20/2017	6/20/2017	0.50	9/27/2017	99.50	63.20	6,288.40
3300006796	RV	3900006134	633697	1012382	6/20/2017	9/27/2017	-61.20	02	6/20/2017	6/20/2017	0.50	9/27/2017	99.50	61.20	6,089.40
3300006798	RV	3900006136	633697	1012382	6/20/2017	9/27/2017	-60.40	02	6/20/2017	6/20/2017	0.50	9/27/2017	99.50	60.40	6,009.80
3300006800	RV	3900005638	633697	1012044	6/20/2017	9/1/2017	-61.40	02	6/20/2017	6/20/2017	0.50	9/1/2017	73.50	61.40	4,512.90
3300006802	RV	3900005639	633697	1012044	6/20/2017	9/1/2017	-65.20	02	6/20/2017	6/20/2017	0.50	9/1/2017	73.50	65.20	4,792.20
3300006873	RV	3900004592	633697	1012044	6/22/2017	7/13/2017	-61.40	02	6/22/2017	6/22/2017	0.50	7/13/2017	21.50	61.40	1,320.10
3300006880	RV	3900004320	633697	41717	6/22/2017	7/3/2017	-72.80	02	6/22/2017	6/22/2017	0.50	7/3/2017	11.50	72.80	837.20
3300006884	RV	3900004170	633697	1012423	6/22/2017	6/29/2017	-61.40	02	6/22/2017	6/22/2017	0.50	6/29/2017	7.50	61.40	460.50
3300006888	RV	3900004319	633697	41717	6/22/2017	7/3/2017	-63.00	02	6/22/2017	6/22/2017	0.50	7/3/2017	11.50	63.00	724.50
3300006889	RV	3900004326	633697	1012382	6/22/2017	7/3/2017	-65.20	02	6/22/2017	6/22/2017	0.50	7/3/2017	11.50	65.20	749.80
3300006890	RV	3900004328	633697	1012382	6/22/2017	7/3/2017	-64.20	02	6/22/2017	6/22/2017	0.50	7/3/2017	11.50	64.20	738.30
3300006891	RV	3900004169	633697	4005260	6/22/2017	6/29/2017	-61.40	02	6/22/2017	6/22/2017	0.50	6/29/2017	7.50	61.40	460.50
3300006987	RV	3900004168	633697	1012423	6/26/2017	6/29/2017	-65.20	02	6/26/2017	6/26/2017	0.50	6/29/2017	3.50	65.20	228.20
3300007000	RV	3900004595	633697	1012044	6/26/2017	7/13/2017	-61.40	02	6/26/2017	6/26/2017	0.50	7/13/2017	17.50	61.40	1,074.50
3300007003	RV	3900004593	633697	1012044	6/26/2017	7/13/2017	-61.40	02	6/26/2017	6/26/2017	0.50	7/13/2017	17.50	61.40	1,074.50
3300007010	RV	3900004329	633697	1012382	6/26/2017	7/3/2017	-61.40	02	6/26/2017	6/26/2017	0.50	7/3/2017	7.50	61.40	460.50
3300007012	RV	3900004325	633697	1012382	6/26/2017	7/3/2017	-65.60	02	6/26/2017	6/26/2017	0.50	7/3/2017	7.50	65.60	492.00
3300007023	RV	3900004594	633697	1012044	6/26/2017	7/13/2017	-61.40	02	6/26/2017	6/26/2017	0.50	7/13/2017	17.50	61.40	1,074.50
3300007027	RV	3900004327	633697	1012382	6/26/2017	7/3/2017	-61.40	02	6/26/2017	6/26/2017	0.50	7/3/2017	7.50	61.40	460.50
3300007036	RV	3900004597	633697	1012044	6/26/2017	7/13/2017	-61.40	02	6/26/2017	6/26/2017	0.50	7/13/2017	17.50	61.40	1,074.50
3300007037	RV	3900004167	633697	4005260	6/26/2017	6/29/2017	-62.60	02	6/26/2017	6/26/2017	0.50	6/29/2017	3.50	62.60	219.10
3300007038	RV	3900004596	633697	1012044	6/26/2017	7/13/2017	-61.40	02	6/26/2017	6/26/2017	0.50	7/13/2017	17.50	61.40	1,074.50
3300007052	RV	3900004365	633697	1012358	6/27/2017	7/5/2017	-61.00	02	6/27/2017	6/27/2017	0.50	7/5/2017	8.50	61.00	518.50

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3300007061	RV	3900004403	633697	1012382	6/27/2017	7/6/2017	-60.40	02	6/27/2017	6/27/2017	0.50	7/6/2017	9.50	60.40	573.80
3300007064	RV	3900004599	633697	1012044	6/27/2017	7/13/2017	-61.40	02	6/27/2017	6/27/2017	0.50	7/13/2017	16.50	61.40	1,013.10
3300007075	RV	3300007076	633697	1012044	6/27/2017	6/27/2017	-61.40	02	6/27/2017	6/27/2017	0.50	6/27/2017	0.50	61.40	30.70
3300007076	RV	3300007076	633697	1012044	6/27/2017	6/27/2017	61.40	02	6/27/2017	6/27/2017	0.50	6/27/2017	0.50	(61.40)	(30.70)
3300007077	RV	3900004598	633697	1012044	6/27/2017	7/13/2017	-61.40	02	6/27/2017	6/27/2017	0.50	7/13/2017	16.50	61.40	1,013.10
3300007078	RV	3900004600	633697	1012044	6/27/2017	7/13/2017	-61.40	02	6/27/2017	6/27/2017	0.50	7/13/2017	16.50	61.40	1,013.10
3300007079	RV	3900004601	633697	1012044	6/27/2017	7/13/2017	-61.40	02	6/27/2017	6/27/2017	0.50	7/13/2017	16.50	61.40	1,013.10
3300007080	RV	3900004404	633697	1012382	6/27/2017	7/6/2017	-67.60	02	6/27/2017	6/27/2017	0.50	7/6/2017	9.50	67.60	642.20
3300007223	RV	3300007224	633697	NEM	6/28/2017	6/28/2017	-61.40	02	6/28/2017	6/28/2017	0.50	6/28/2017	0.50	61.40	30.70
3300007224	RV	3300007224	633697	NEM	6/28/2017	6/28/2017	61.40	02	6/28/2017	6/28/2017	0.50	6/28/2017	0.50	(61.40)	(30.70)
3300007225	RV	3900004603	633697	1012044	6/28/2017	7/13/2017	-61.40	02	6/28/2017	6/28/2017	0.50	7/13/2017	15.50	61.40	951.70
3300007226	RV	3900004446	633697	1012382	6/28/2017	7/7/2017	-65.20	02	6/28/2017	6/28/2017	0.50	7/7/2017	9.50	65.20	619.40
3300007227	RV	3900004602	633697	1012044	6/28/2017	7/13/2017	-65.20	02	6/28/2017	6/28/2017	0.50	7/13/2017	15.50	65.20	1,010.60
3300007228	RV	3900004447	633697	1012382	6/28/2017	7/7/2017	-61.80	02	6/28/2017	6/28/2017	0.50	7/7/2017	9.50	61.80	587.10
3300007229	RV	3900004517	633697	41717	6/28/2017	7/11/2017	-65.20	02	6/28/2017	6/28/2017	0.50	7/11/2017	13.50	65.20	880.20
3300007230	RV	3900004518	633697	41717	6/28/2017	7/11/2017	-61.40	02	6/28/2017	6/28/2017	0.50	7/11/2017	13.50	61.40	828.90
3300007232	RV	3900004519	633697	41717	6/28/2017	7/11/2017	-61.40	02	6/28/2017	6/28/2017	0.50	7/11/2017	13.50	61.40	828.90
3300007331	RV	3900004604	633697	1012044	6/30/2017	7/13/2017	-61.40	02	6/30/2017	6/30/2017	0.50	7/13/2017	13.50	61.40	828.90
3300007339	RV	3900004509	633697	1012382	6/30/2017	7/11/2017	-61.80	02	6/30/2017	6/30/2017	0.50	7/11/2017	11.50	61.80	710.70
3300007340	RV	3900004847	633697	1012358	6/30/2017	7/25/2017	-61.40	02	6/30/2017	6/30/2017	0.50	7/25/2017	25.50	61.40	1,565.70
3300007347	RV	3900004508	633697	1012382	6/30/2017	7/11/2017	-62.80	02	6/30/2017	6/30/2017	0.50	7/11/2017	11.50	62.80	722.20
3300007373	RV	3900004846	633697	1012358	7/3/2017	7/25/2017	-62.00	02	7/3/2017	7/3/2017	0.50	7/25/2017	22.50	62.00	1,395.00
3300007374	RV	3900004658	633697	1012382	7/3/2017	7/17/2017	-60.40	02	7/3/2017	7/3/2017	0.50	7/17/2017	14.50	60.40	875.80
3300007375	RV	3900004661	633697	1012382	7/3/2017	7/17/2017	-63.20	02	7/3/2017	7/3/2017	0.50	7/17/2017	14.50	63.20	916.40
3300007376	RV	3900004665	633697	1012382	7/3/2017	7/17/2017	-60.40	02	7/3/2017	7/3/2017	0.50	7/17/2017	14.50	60.40	875.80
3300007377	RV	3900006135	633697	1012382	7/3/2017	9/27/2017	-60.40	02	7/3/2017	7/3/2017	0.50	9/27/2017	86.50	60.40	5,224.60
3300007382	RV	3900004583	633697	1012044	7/5/2017	7/13/2017	-65.20	02	7/5/2017	7/5/2017	0.50	7/13/2017	8.50	65.20	554.20
3300007391	RV	3900004657	633697	1012382	7/5/2017	7/17/2017	-60.40	02	7/5/2017	7/5/2017	0.50	7/17/2017	12.50	60.40	755.00
3300007393	RV	3900004659	633697	1012382	7/5/2017	7/17/2017	-61.80	02	7/5/2017	7/5/2017	0.50	7/17/2017	12.50	61.80	772.50
3300007394	RV	3900004663	633697	1012382	7/5/2017	7/17/2017	-62.80	02	7/5/2017	7/5/2017	0.50	7/17/2017	12.50	62.80	785.00
3300007461	RV	3900004660	633697	1012382	7/6/2017	7/17/2017	-60.40	02	7/6/2017	7/6/2017	0.50	7/17/2017	11.50	60.40	694.60
3300007463	RV	3900004584	633697	1012044	7/6/2017	7/13/2017	-61.61	02	7/6/2017	7/6/2017	0.50	7/13/2017	7.50	61.61	462.08
3300007464	RV	3900004647	633697	41717	7/6/2017	7/17/2017	-70.00	02	7/6/2017	7/6/2017	0.50	7/17/2017	11.50	70.00	805.00
3300007482	RV	3900004664	633697	1012382	7/7/2017	7/17/2017	-60.40	02	7/7/2017	7/7/2017	0.50	7/17/2017	10.50	60.40	634.20
3300007485	RV	3900004662	633697	1012382	7/7/2017	7/17/2017	-60.40	02	7/7/2017	7/7/2017	0.50	7/17/2017	10.50	60.40	634.20
3300007486	RV	3900004648	633697	41717	7/7/2017	7/17/2017	-65.20	02	7/7/2017	7/7/2017	0.50	7/17/2017	10.50	65.20	684.60
3300007492	RV	3900004585	633697	1012044	7/10/2017	7/13/2017	-61.40	02	7/10/2017	7/10/2017	0.50	7/13/2017	3.50	61.40	214.90
3300007493	RV	3900004591	633697	1012044	7/10/2017	7/13/2017	-61.40	02	7/10/2017	7/10/2017	0.50	7/13/2017	3.50	61.40	214.90
3300007494	RV	3900004588	633697	1012044	7/10/2017	7/13/2017	-61.40	02	7/10/2017	7/10/2017	0.50	7/13/2017	3.50	61.40	214.90
3300007495	RV	3900004590	633697	1012044	7/10/2017	7/13/2017	-65.20	02	7/10/2017	7/10/2017	0.50	7/13/2017	3.50	65.20	228.20
3300007497	RV	3900004589	633697	1012044	7/10/2017	7/13/2017	-61.40	02	7/10/2017	7/10/2017	0.50	7/13/2017	3.50	61.40	214.90
3300007544	RV	3900004949	633697	4005499	7/11/2017	7/31/2017	-65.20	02	7/11/2017	7/11/2017	0.50	7/31/2017	20.50	65.20	1,336.60
3300007546	RV	3900004937	633697	1012382	7/11/2017	7/31/2017	-61.80	02	7/11/2017	7/11/2017	0.50	7/31/2017	20.50	61.80	1,266.90
3300007547	RV	3900004943	633697	1012382	7/11/2017	7/31/2017	-60.40	02	7/11/2017	7/11/2017	0.50	7/31/2017	20.50	60.40	1,238.20
3300007548	RV	3900004941	633697	1012382	7/11/2017	7/31/2017	-60.40	02	7/11/2017	7/11/2017	0.50	7/31/2017	20.50	60.40	1,238.20
3300007550	RV	3900004931	633697	1012382	7/11/2017	7/31/2017	-63.20	02	7/11/2017	7/11/2017	0.50	7/31/2017	20.50	63.20	1,295.60
3300007551	RV	3900004930	633697	1012382	7/11/2017	7/31/2017	-61.40	02	7/11/2017	7/11/2017	0.50	7/31/2017	20.50	61.40	1,258.70
3300007650	RV	3900005575	633697	4005499	7/12/2017	8/30/2017	-61.60	02	7/12/2017	7/12/2017	0.50	8/30/2017	49.50	61.60	3,049.20
3300007655	RV	3900004838	633697	41717	7/12/2017	7/25/2017	-61.40	02	7/12/2017	7/12/2017	0.50	7/25/2017	13.50	61.40	828.90
3300007664	RV	3300008326	633697	1012044	7/19/2017	7/31/2017	-65.20	02	7/19/2017	7/19/2017	0.50	7/31/2017	12.50	65.20	815.00

POTOMAC ELECTRIC POWER COMPANY
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Other Revenue Lag
Fire & Damage Reconnect, Joint Use Escort and interconnection Application Fee

Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Service period Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300007666	RV	3900004709	633697	1012044	7/12/2017	7/19/2017	-65.20	02	7/12/2017	7/12/2017	0.50	7/19/2017	7.50	65.20	489.00
3300007715	RV	3900004933	633697	1012382	7/13/2017	7/31/2017	-60.40	02	7/13/2017	7/13/2017	0.50	7/31/2017	18.50	60.40	1,117.40
3300007726	RV	3900004932	633697	1012382	7/13/2017	7/31/2017	-63.20	02	7/13/2017	7/13/2017	0.50	7/31/2017	18.50	63.20	1,169.20
3300007732	RV	3900005141	633697	1012044	7/13/2017	8/8/2017	-60.97	02	7/13/2017	7/13/2017	0.50	8/8/2017	26.50	60.97	1,615.71
3300007735	RV	3900004934	633697	1012382	7/13/2017	7/31/2017	-65.20	02	7/13/2017	7/13/2017	0.50	7/31/2017	18.50	65.20	1,206.20
3300007738	RV	3900004857	633697	1012237	7/13/2017	7/26/2017	-183.20	02	7/13/2017	7/13/2017	0.50	7/26/2017	13.50	183.20	2,473.20
3300007744	RV	3900004935	633697	1012382	7/13/2017	7/31/2017	-60.40	02	7/13/2017	7/13/2017	0.50	7/31/2017	18.50	60.40	1,117.40
3300007745	RV	3900004938	633697	1012382	7/13/2017	7/31/2017	-64.20	02	7/13/2017	7/13/2017	0.50	7/31/2017	18.50	64.20	1,187.70
3300007990	RV	3900004936	633697	1012382	7/21/2017	7/31/2017	-60.40	02	7/21/2017	7/21/2017	0.50	7/31/2017	10.50	60.40	634.20
3300007994	RV	3900004940	633697	1012382	7/21/2017	7/31/2017	-60.40	02	7/21/2017	7/21/2017	0.50	7/31/2017	10.50	60.40	634.20
3300007995	RV	3900004942	633697	1012382	7/21/2017	7/31/2017	-64.20	02	7/21/2017	7/21/2017	0.50	7/31/2017	10.50	64.20	674.10
3300007997	RV	3900004939	633697	1012382	7/21/2017	7/31/2017	-64.20	02	7/21/2017	7/21/2017	0.50	7/31/2017	10.50	64.20	674.10
3300008026	RV	3900005010	633697	1012382	7/24/2017	8/3/2017	-65.20	02	7/24/2017	7/24/2017	0.50	8/3/2017	10.50	65.20	684.60
3300008041	RV	3900005020	633697	1012382	7/24/2017	8/3/2017	-60.40	02	7/24/2017	7/24/2017	0.50	8/3/2017	10.50	60.40	634.20
3300008044	RV	3900005009	633697	1012382	7/24/2017	8/3/2017	-60.40	02	7/24/2017	7/24/2017	0.50	8/3/2017	10.50	60.40	634.20
3300008066	RV	3900005136	633697	1012044	7/24/2017	8/8/2017	-61.40	02	7/24/2017	7/24/2017	0.50	8/8/2017	15.50	61.40	951.70
3300008067	RV	3900005228	633697	1012044	7/24/2017	8/10/2017	-61.40	02	7/24/2017	7/24/2017	0.50	8/10/2017	17.50	61.40	1,074.50
3300008070	RV	3900005239	633697	1012044	7/24/2017	8/10/2017	-61.40	02	7/24/2017	7/24/2017	0.50	8/10/2017	17.50	61.40	1,074.50
3300008071	RV	3900005229	633697	1012044	7/24/2017	8/10/2017	-61.40	02	7/24/2017	7/24/2017	0.50	8/10/2017	17.50	61.40	1,074.50
3300008072	RV	3900005013	633697	1012382	7/24/2017	8/3/2017	-60.40	02	7/24/2017	7/24/2017	0.50	8/3/2017	10.50	60.40	634.20
3300008073	RV	3300008074	633697	NEM	7/24/2017	7/24/2017	-67.00	02	7/24/2017	7/24/2017	0.50	7/24/2017	0.50	67.00	33.50
3300008074	RV	3300008074	633697	NEM	7/24/2017	7/24/2017	67.00	02	7/24/2017	7/24/2017	0.50	7/24/2017	0.50	(67.00)	(33.50)
3300008075	RV	3900005019	633697	1012382	7/24/2017	8/3/2017	-67.00	02	7/24/2017	7/24/2017	0.50	8/3/2017	10.50	67.00	703.50
3300008077	RV	3900005015	633697	1012382	7/24/2017	8/3/2017	-63.20	02	7/24/2017	7/24/2017	0.50	8/3/2017	10.50	63.20	663.60
3300008078	RV	3900005014	633697	1012382	7/24/2017	8/3/2017	-60.40	02	7/24/2017	7/24/2017	0.50	8/3/2017	10.50	60.40	634.20
3300008079	RV	3300008251	633697	NEM	7/24/2017	7/27/2017	-61.40	02	7/24/2017	7/24/2017	0.50	7/27/2017	3.50	61.40	214.90
3300008080	RV	3900006279	633697	4005499	7/24/2017	10/6/2017	-64.00	02	7/24/2017	7/24/2017	0.50	10/6/2017	74.50	64.00	4,768.00
3300008081	RV	3900006280	633697	4005499	7/24/2017	10/6/2017	-63.60	02	7/24/2017	7/24/2017	0.50	10/6/2017	74.50	63.60	4,738.20
3300008082	RV	3900006281	633697	4005499	7/24/2017	10/6/2017	-63.00	02	7/24/2017	7/24/2017	0.50	10/6/2017	74.50	63.00	4,693.50
3300008083	RV	3900005018	633697	1012382	7/24/2017	8/3/2017	-61.80	02	7/24/2017	7/24/2017	0.50	8/3/2017	10.50	61.80	648.90
3300008084	RV	3900005016	633697	1012382	7/24/2017	8/3/2017	-67.00	02	7/24/2017	7/24/2017	0.50	8/3/2017	10.50	67.00	703.50
3300008085	RV	3900005240	633697	1012044	7/24/2017	8/10/2017	-61.40	02	7/24/2017	7/24/2017	0.50	8/10/2017	17.50	61.40	1,074.50
3300008086	RV	3900005011	633697	1012382	7/24/2017	8/3/2017	-63.20	02	7/24/2017	7/24/2017	0.50	8/3/2017	10.50	63.20	663.60
3300008087	RV	3300008088	633697	NEM	7/24/2017	7/24/2017	-61.80	02	7/24/2017	7/24/2017	0.50	7/24/2017	0.50	61.80	30.90
3300008088	RV	3300008088	633697	NEM	7/24/2017	7/24/2017	61.80	02	7/24/2017	7/24/2017	0.50	7/24/2017	0.50	(61.80)	(30.90)
3300008089	RV	3900005017	633697	1012382	7/24/2017	8/3/2017	-61.80	02	7/24/2017	7/24/2017	0.50	8/3/2017	10.50	61.80	648.90
3300008090	RV	3900005120	633697	41717	7/24/2017	8/8/2017	-61.40	02	7/24/2017	7/24/2017	0.50	8/8/2017	15.50	61.40	951.70
3300008110	RV	3900004952	633697	1012382	7/25/2017	7/31/2017	-60.40	02	7/25/2017	7/25/2017	0.50	7/31/2017	6.50	60.40	392.60
3300008111	RV	3900006278	633697	4005499	7/25/2017	10/6/2017	-63.00	02	7/25/2017	7/25/2017	0.50	10/6/2017	73.50	63.00	4,630.50
3300008112	RV	3900004955	633697	1012382	7/25/2017	7/31/2017	-64.20	02	7/25/2017	7/25/2017	0.50	7/31/2017	6.50	64.20	417.30
3300008113	RV	3900005140	633697	1012044	7/25/2017	8/8/2017	-61.40	02	7/25/2017	7/25/2017	0.50	8/8/2017	14.50	61.40	890.30
3300008114	RV	3900006030	633697	1012382	7/25/2017	9/21/2017	-60.44	02	7/25/2017	7/25/2017	0.50	9/21/2017	58.50	60.44	3,535.74
3300008115	RV	3900004954	633697	1012382	7/25/2017	7/31/2017	-63.20	02	7/25/2017	7/25/2017	0.50	7/31/2017	6.50	63.20	410.80
3300008116	RV	3900004956	633697	1012382	7/25/2017	7/31/2017	-65.20	02	7/25/2017	7/25/2017	0.50	7/31/2017	6.50	65.20	423.80
3300008117	RV	3300008119	633697	NEM	7/25/2017	7/25/2017	-63.60	02	7/25/2017	7/25/2017	0.50	7/25/2017	0.50	63.60	31.80
3300008118	RV	3900005131	633697	4005499	7/25/2017	8/8/2017	-63.00	02	7/25/2017	7/25/2017	0.50	8/8/2017	14.50	63.00	913.50
3300008119	RV	3300008119	633697	NEM	7/25/2017	7/25/2017	63.60	02	7/25/2017	7/25/2017	0.50	7/25/2017	0.50	(63.60)	(31.80)
3300008120	RV	3900005535	633697	1012759	7/25/2017	8/29/2017	-63.60	02	7/25/2017	7/25/2017	0.50	8/29/2017	35.50	63.60	2,257.80
3300008121	RV	3900005007	633697	1012382	7/25/2017	8/3/2017	-66.60	02	7/25/2017	7/25/2017	0.50	8/3/2017	9.50	66.60	632.70
3300008122	RV	3900005138	633697	1012044	7/25/2017	8/8/2017	-61.40	02	7/25/2017	7/25/2017	0.50	8/8/2017	14.50	61.40	890.30

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3300008123	RV	3900005008	633697	1012382	7/25/2017	8/3/2017	-61.80	02	7/25/2017	7/25/2017	0.50	8/3/2017	9.50	61.80	587.10
3300008124	RV	3900004953	633697	1012382	7/25/2017	7/31/2017	-60.40	02	7/25/2017	7/25/2017	0.50	7/31/2017	6.50	60.40	392.60
3300008126	RV	3900004958	633697	41717	7/25/2017	7/31/2017	-66.00	02	7/25/2017	7/25/2017	0.50	7/31/2017	6.50	66.00	429.00
3300008127	RV	3900005006	633697	1012382	7/25/2017	8/3/2017	-64.20	02	7/25/2017	7/25/2017	0.50	8/3/2017	9.50	64.20	609.90
3300008128	RV	3900005012	633697	1012382	7/25/2017	8/3/2017	-60.40	02	7/25/2017	7/25/2017	0.50	8/3/2017	9.50	60.40	573.80
3300008251	RV	3300008251	633697	NEM	7/24/2017	7/27/2017	61.40	02	7/24/2017	7/24/2017	0.50	7/27/2017	3.50	(61.40)	(214.90)
3300008252	RV	3900005137	633697	1012044	7/27/2017	8/8/2017	-61.40	02	7/27/2017	7/27/2017	0.50	8/8/2017	12.50	61.40	767.50
3300008271	RV	3900005045	633697	4005260	7/27/2017	8/4/2017	-63.80	02	7/27/2017	7/27/2017	0.50	8/4/2017	8.50	63.80	542.30
3300008272	RV	3900005046	633697	4005260	7/27/2017	8/4/2017	-61.40	02	7/27/2017	7/27/2017	0.50	8/4/2017	8.50	61.40	521.90
3300008273	RV	3900005047	633697	4005260	7/27/2017	8/4/2017	-66.40	02	7/27/2017	7/27/2017	0.50	8/4/2017	8.50	66.40	564.40
3300008274	RV	3300008277	633697	NEM	7/27/2017	7/27/2017	-63.00	02	7/27/2017	7/27/2017	0.50	7/27/2017	0.50	63.00	31.50
3300008275	RV	3900005121	633697	41717	7/27/2017	8/8/2017	-67.40	02	7/27/2017	7/27/2017	0.50	8/8/2017	12.50	67.40	842.50
3300008276	RV	3900005135	633697	1012382	7/27/2017	8/8/2017	-69.40	02	7/27/2017	7/27/2017	0.50	8/8/2017	12.50	69.40	867.50
3300008277	RV	3300008277	633697	NEM	7/27/2017	7/27/2017	63.00	02	7/27/2017	7/27/2017	0.50	7/27/2017	0.50	(63.00)	(31.50)
3300008301	RV	3900005119	633697	41717	7/28/2017	8/8/2017	-61.40	02	7/28/2017	7/28/2017	0.50	8/8/2017	11.50	61.40	706.10
3300008303	RV	3900005124	633697	41717	7/28/2017	8/8/2017	-65.20	02	7/28/2017	7/28/2017	0.50	8/8/2017	11.50	65.20	749.80
3300008304	RV	3900005134	633697	1012382	7/28/2017	8/8/2017	-60.40	02	7/28/2017	7/28/2017	0.50	8/8/2017	11.50	60.40	694.60
3300008305	RV	3900005133	633697	1012382	7/28/2017	8/8/2017	-64.20	02	7/28/2017	7/28/2017	0.50	8/8/2017	11.50	64.20	738.30
3300008306	RV	3900005123	633697	41717	7/28/2017	8/8/2017	-61.40	02	7/28/2017	7/28/2017	0.50	8/8/2017	11.50	61.40	706.10
3300008326	RV	3300008326	633697	1012044	7/19/2017	7/31/2017	65.20	02	7/19/2017	7/19/2017	0.50	7/31/2017	12.50	(65.20)	(815.00)
3300008374	RV	3900005237	633697	1012044	8/1/2017	8/10/2017	-61.40	02	8/1/2017	8/1/2017	0.50	8/10/2017	9.50	61.40	583.30
3300008375	RV	3900005230	633697	1012044	8/1/2017	8/10/2017	-61.40	02	8/1/2017	8/1/2017	0.50	8/10/2017	9.50	61.40	583.30
3300008376	RV	3900005126	633697	1012382	8/1/2017	8/8/2017	-61.40	02	8/1/2017	8/1/2017	0.50	8/8/2017	7.50	61.40	460.50
3300008377	RV	3900006282	633697	4005499	8/1/2017	10/6/2017	-61.00	02	8/1/2017	8/1/2017	0.50	10/6/2017	66.50	61.00	4,056.50
3300008379	RV	3900005236	633697	1012044	8/1/2017	8/10/2017	-61.40	02	8/1/2017	8/1/2017	0.50	8/10/2017	9.50	61.40	583.30
3300008381	RV	3900005132	633697	1012605	8/1/2017	8/8/2017	-136.40	02	8/1/2017	8/1/2017	0.50	8/8/2017	7.50	136.40	1,023.00
3300008385	RV	3900005130	633697	1012382	8/1/2017	8/8/2017	-60.40	02	8/1/2017	8/1/2017	0.50	8/8/2017	7.50	60.40	453.00
3300008386	RV	3900006283	633697	4005499	8/1/2017	10/6/2017	-64.00	02	8/1/2017	8/1/2017	0.50	10/6/2017	66.50	64.00	4,256.00
3300008387	RV	3900005127	633697	1012382	8/1/2017	8/8/2017	-61.80	02	8/1/2017	8/1/2017	0.50	8/8/2017	7.50	61.80	463.50
3300008388	RV	3900005254	633697	41717	8/1/2017	8/11/2017	-65.20	02	8/1/2017	8/1/2017	0.50	8/11/2017	10.50	65.20	684.60
3300008389	RV	3900005238	633697	1012044	8/1/2017	8/10/2017	-60.97	02	8/1/2017	8/1/2017	0.50	8/10/2017	9.50	60.97	579.22
3300008390	RV	3900005129	633697	1012382	8/1/2017	8/8/2017	-60.40	02	8/1/2017	8/1/2017	0.50	8/8/2017	7.50	60.40	453.00
3300008391	RV	3900005128	633697	1012382	8/1/2017	8/8/2017	-62.80	02	8/1/2017	8/1/2017	0.50	8/8/2017	7.50	62.80	471.00
3300008392	RV	3900005235	633697	1012044	8/2/2017	8/10/2017	-61.40	02	8/2/2017	8/2/2017	0.50	8/10/2017	8.50	61.40	521.90
3300008393	RV	3900005234	633697	1012044	8/2/2017	8/10/2017	-61.40	02	8/2/2017	8/2/2017	0.50	8/10/2017	8.50	61.40	521.90
3300008397	RV	3900005233	633697	1012044	8/2/2017	8/10/2017	-61.40	02	8/2/2017	8/2/2017	0.50	8/10/2017	8.50	61.40	521.90
3300008398	RV	3300008405	633697	NEM	8/2/2017	8/2/2017	-61.40	02	8/2/2017	8/2/2017	0.50	8/2/2017	0.50	61.40	30.70
3300008399	RV	3900005232	633697	1012044	8/2/2017	8/10/2017	-61.40	02	8/2/2017	8/2/2017	0.50	8/10/2017	8.50	61.40	521.90
3300008405	RV	3300008405	633697	NEM	8/2/2017	8/2/2017	61.40	02	8/2/2017	8/2/2017	0.50	8/2/2017	0.50	(61.40)	(30.70)
3300008410	RV	3900005231	633697	1012044	8/2/2017	8/10/2017	-61.40	02	8/2/2017	8/2/2017	0.50	8/10/2017	8.50	61.40	521.90
3300008448	RV	3900005522	633697	1012382	8/3/2017	8/28/2017	-61.80	02	8/3/2017	8/3/2017	0.50	8/28/2017	25.50	61.80	1,575.90
3300008450	RV	3900005293	633697	41717	8/3/2017	8/14/2017	-65.20	02	8/3/2017	8/3/2017	0.50	8/14/2017	11.50	65.20	749.80
3300008452	RV	3900005309	633697	1012044	8/3/2017	8/15/2017	-61.40	02	8/3/2017	8/3/2017	0.50	8/15/2017	12.50	61.40	767.50
3300008478	RV	3900005521	633697	1012382	8/4/2017	8/28/2017	-70.00	02	8/4/2017	8/4/2017	0.50	8/28/2017	24.50	70.00	1,715.00
3300008479	RV	3900005519	633697	1012382	8/4/2017	8/28/2017	-65.20	02	8/4/2017	8/4/2017	0.50	8/28/2017	24.50	65.20	1,597.40
3300008480	RV	3900005310	633697	1012044	8/4/2017	8/15/2017	-61.40	02	8/4/2017	8/4/2017	0.50	8/15/2017	11.50	61.40	706.10
3300008481	RV	3900005294	633697	41717	8/4/2017	8/14/2017	-65.20	02	8/4/2017	8/4/2017	0.50	8/14/2017	10.50	65.20	684.60
3300008482	RV	3900005518	633697	1012382	8/4/2017	8/28/2017	-61.80	02	8/4/2017	8/4/2017	0.50	8/28/2017	24.50	61.80	1,514.10
3300008484	RV	3900005520	633697	1012382	8/4/2017	8/28/2017	-60.40	02	8/4/2017	8/4/2017	0.50	8/28/2017	24.50	60.40	1,479.80
3300008485	RV	3900005385	633697	1012605	8/7/2017	8/21/2017	-122.00	02	8/7/2017	8/7/2017	0.50	8/21/2017	14.50	122.00	1,769.00

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3300008486	RV	3900005386	633697	1012605	8/7/2017	8/21/2017	-150.80	02	8/7/2017	8/7/2017	0.50	8/21/2017	14.50	150.80	2,186.60
3300008487	RV	3300008488	633697	NEM	8/7/2017	8/7/2017	-122.00	02	8/7/2017	8/7/2017	0.50	8/7/2017	0.50	122.00	61.00
3300008488	RV	3300008488	633697	NEM	8/7/2017	8/7/2017	122.00	02	8/7/2017	8/7/2017	0.50	8/7/2017	0.50	(122.00)	(61.00)
3300008489	RV	3900005387	633697	1012605	8/7/2017	8/21/2017	-122.00	02	8/7/2017	8/7/2017	0.50	8/21/2017	14.50	122.00	1,769.00
3300008490	RV	3900005517	633697	1012382	8/7/2017	8/28/2017	-60.40	02	8/7/2017	8/7/2017	0.50	8/28/2017	21.50	60.40	1,298.60
3300008491	RV	3900005255	633697	4005260	8/7/2017	8/11/2017	-65.20	02	8/7/2017	8/7/2017	0.50	8/11/2017	4.50	65.20	293.40
3300008492	RV	3900005288	633697	1012386	8/7/2017	8/14/2017	-67.60	02	8/7/2017	8/7/2017	0.50	8/14/2017	7.50	67.60	507.00
3300008493	RV	3900005523	633697	1012382	8/7/2017	8/28/2017	-61.80	02	8/7/2017	8/7/2017	0.50	8/28/2017	21.50	61.80	1,328.70
3300008494	RV	3900005313	633697	1012044	8/7/2017	8/15/2017	-61.40	02	8/7/2017	8/7/2017	0.50	8/15/2017	8.50	61.40	521.90
3300008495	RV	3900005524	633697	1012382	8/7/2017	8/28/2017	-60.40	02	8/7/2017	8/7/2017	0.50	8/28/2017	21.50	60.40	1,298.60
3300008520	RV	3900005578	633697	4005499	8/8/2017	8/30/2017	-61.00	02	8/8/2017	8/8/2017	0.50	8/30/2017	22.50	61.00	1,372.50
3300008534	RV	3900007099	633697	1012044	8/8/2017	11/13/2017	-61.40	02	8/8/2017	8/8/2017	0.50	11/13/2017	97.50	61.40	5,986.50
3300008563	RV	3900005283	633697	4005260	8/9/2017	8/14/2017	-61.40	02	8/9/2017	8/9/2017	0.50	8/14/2017	5.50	61.40	337.70
3300008566	RV	3900005513	633697	41717	8/9/2017	8/28/2017	-62.60	02	8/9/2017	8/9/2017	0.50	8/28/2017	19.50	62.60	1,220.70
3300008568	RV	3900005284	633697	1012423	8/9/2017	8/14/2017	-65.20	02	8/9/2017	8/9/2017	0.50	8/14/2017	5.50	65.20	358.60
3300008569	RV	3900005512	633697	41717	8/9/2017	8/28/2017	-66.40	02	8/9/2017	8/9/2017	0.50	8/28/2017	19.50	66.40	1,294.80
3300008583	RV	3900006053	633697	4005499	8/10/2017	9/22/2017	-62.00	02	8/10/2017	8/10/2017	0.50	9/22/2017	43.50	62.00	2,697.00
3300008584	RV	3900005304	633697	1012382	8/10/2017	8/15/2017	-63.20	02	8/10/2017	8/10/2017	0.50	8/15/2017	5.50	63.20	347.60
3300008585	RV	3900005312	633697	1012044	8/10/2017	8/15/2017	-69.00	02	8/10/2017	8/10/2017	0.50	8/15/2017	5.50	69.00	379.50
3300008586	RV	3900005303	633697	1012382	8/10/2017	8/15/2017	-71.80	02	8/10/2017	8/10/2017	0.50	8/15/2017	5.50	71.80	394.90
3300008588	RV	3900005352	633697	4005260	8/10/2017	8/18/2017	-61.40	02	8/10/2017	8/10/2017	0.50	8/18/2017	8.50	61.40	521.90
3300008589	RV	3900005311	633697	1012044	8/10/2017	8/15/2017	-61.40	02	8/10/2017	8/10/2017	0.50	8/15/2017	5.50	61.40	337.70
3300008590	RV	3900005302	633697	1012382	8/10/2017	8/15/2017	-69.00	02	8/10/2017	8/10/2017	0.50	8/15/2017	5.50	69.00	379.50
3300008602	RV	3900005342	633697	1012044	8/11/2017	8/17/2017	-61.40	02	8/11/2017	8/11/2017	0.50	8/17/2017	6.50	61.40	399.10
3300008603	RV	3900005340	633697	1012044	8/11/2017	8/17/2017	-69.00	02	8/11/2017	8/11/2017	0.50	8/17/2017	6.50	69.00	448.50
3300008604	RV	3300008609	633697	NEM	8/11/2017	8/11/2017	-61.40	02	8/11/2017	8/11/2017	0.50	8/11/2017	0.50	61.40	30.70
3300008605	RV	3900005339	633697	1012044	8/11/2017	8/17/2017	-61.40	02	8/11/2017	8/11/2017	0.50	8/17/2017	6.50	61.40	399.10
3300008606	RV	3300008607	633697	NEM	8/11/2017	8/11/2017	-61.80	02	8/11/2017	8/11/2017	0.50	8/11/2017	0.50	61.80	30.90
3300008607	RV	3300008607	633697	NEM	8/11/2017	8/11/2017	61.80	02	8/11/2017	8/11/2017	0.50	8/11/2017	0.50	(61.80)	(30.90)
3300008608	RV	3900005388	633697	1012382	8/11/2017	8/21/2017	-61.80	02	8/11/2017	8/11/2017	0.50	8/21/2017	10.50	61.80	648.90
3300008609	RV	3300008609	633697	NEM	8/11/2017	8/11/2017	61.40	02	8/11/2017	8/11/2017	0.50	8/11/2017	0.50	(61.40)	(30.70)
3300008610	RV	3900005341	633697	1012044	8/11/2017	8/17/2017	-61.40	02	8/11/2017	8/11/2017	0.50	8/17/2017	6.50	61.40	399.10
3300008655	RV	3900005526	633697	1012382	8/14/2017	8/28/2017	-66.40	02	8/14/2017	8/14/2017	0.50	8/28/2017	14.50	66.40	962.80
3300008656	RV	3900005528	633697	1012382	8/14/2017	8/28/2017	-60.40	02	8/14/2017	8/14/2017	0.50	8/28/2017	14.50	60.40	875.80
3300008657	RV	3900005525	633697	1012382	8/14/2017	8/28/2017	-60.40	02	8/14/2017	8/14/2017	0.50	8/28/2017	14.50	60.40	875.80
3300008658	RV	3300008661	633697	NEM	8/14/2017	8/14/2017	-61.40	02	8/14/2017	8/14/2017	0.50	8/14/2017	0.50	61.40	30.70
3300008659	RV	3300008660	633697	4005499	8/14/2017	8/14/2017	-65.00	02	8/14/2017	8/14/2017	0.50	8/14/2017	0.50	65.00	32.50
3300008660	RV	3300008660	633697	4005499	8/14/2017	8/14/2017	65.00	02	8/14/2017	8/14/2017	0.50	8/14/2017	0.50	(65.00)	(32.50)
3300008661	RV	3300008661	633697	NEM	8/14/2017	8/14/2017	61.40	02	8/14/2017	8/14/2017	0.50	8/14/2017	0.50	(61.40)	(30.70)
3300008662	RV	3900005635	633697	1012044	8/14/2017	9/1/2017	-61.40	02	8/14/2017	8/14/2017	0.50	9/1/2017	18.50	61.40	1,135.90
3300008712	RV	3900005527	633697	1012382	8/16/2017	8/28/2017	-60.40	02	8/16/2017	8/16/2017	0.50	8/28/2017	12.50	60.40	755.00
3300008714	RV	3900005471	633697	4005260	8/16/2017	8/24/2017	-72.80	02	8/16/2017	8/16/2017	0.50	8/24/2017	8.50	72.80	618.80
3300008715	RV	3300008831	633697	NEM	8/16/2017	8/21/2017	-61.40	02	8/16/2017	8/16/2017	0.50	8/21/2017	5.50	61.40	337.70
3300008716	RV	3900005529	633697	1012382	8/16/2017	8/28/2017	-62.00	02	8/16/2017	8/16/2017	0.50	8/28/2017	12.50	62.00	775.00
3300008717	RV	3900005599	633697	4005499	8/16/2017	8/30/2017	-61.40	02	8/16/2017	8/16/2017	0.50	8/30/2017	14.50	61.40	890.30
3300008739	RV	3900005503	633697	4005260	8/17/2017	8/28/2017	-61.40	02	8/17/2017	8/17/2017	0.50	8/28/2017	11.50	61.40	706.10
3300008740	RV	3900005620	633697	1012382	8/17/2017	8/31/2017	-60.40	02	8/17/2017	8/17/2017	0.50	8/31/2017	14.50	60.40	875.80
3300008741	RV	3300008745	633697	NEM	8/17/2017	8/17/2017	-61.40	02	8/17/2017	8/17/2017	0.50	8/17/2017	0.50	61.40	30.70
3300008742	RV	3900005622	633697	1012382	8/17/2017	8/31/2017	-60.40	02	8/17/2017	8/17/2017	0.50	8/31/2017	14.50	60.40	875.80
3300008743	RV	3900005504	633697	4005260	8/17/2017	8/28/2017	-65.00	02	8/17/2017	8/17/2017	0.50	8/28/2017	11.50	65.00	747.50

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3300008744	RV	3900005576	633697	4005499	8/17/2017	8/30/2017	-61.00	02	8/17/2017	8/17/2017	0.50	8/30/2017	13.50	61.00	823.50
3300008745	RV	3300008745	633697	NEM	8/17/2017	8/17/2017	61.40	02	8/17/2017	8/17/2017	0.50	8/17/2017	0.50	(61.40)	(30.70)
3300008746	RV	3900005647	633697	1012044	8/17/2017	9/1/2017	-61.40	02	8/17/2017	8/17/2017	0.50	9/1/2017	15.50	61.40	951.70
3300008828	RV	3900005577	633697	4005499	8/21/2017	8/30/2017	-65.00	02	8/21/2017	8/21/2017	0.50	8/30/2017	9.50	65.00	617.50
3300008831	RV	3300008831	633697	NEM	8/16/2017	8/21/2017	61.40	02	8/16/2017	8/16/2017	0.50	8/21/2017	5.50	(61.40)	(337.70)
3300008832	RV	3900005683	633697	1012044	8/21/2017	9/6/2017	-61.40	02	8/21/2017	8/21/2017	0.50	9/6/2017	16.50	61.40	1,013.10
3300008865	RV	3900005579	633697	1012386	8/21/2017	8/30/2017	-62.00	02	8/21/2017	8/21/2017	0.50	8/30/2017	9.50	62.00	589.00
3300008867	RV	3900005645	633697	1012044	8/21/2017	9/1/2017	-61.40	02	8/21/2017	8/21/2017	0.50	9/1/2017	11.50	61.40	706.10
3300008876	RV	3900005646	633697	1012044	8/21/2017	9/1/2017	-65.20	02	8/21/2017	8/21/2017	0.50	9/1/2017	11.50	65.20	749.80
3300008877	RV	3900006149	633697	1012637	8/21/2017	9/28/2017	-60.81	02	8/21/2017	8/21/2017	0.50	9/28/2017	38.50	60.81	2,341.19
3300008878	RV	3300008881	633697	NEM	8/21/2017	8/21/2017	-61.40	02	8/21/2017	8/21/2017	0.50	8/21/2017	0.50	61.40	30.70
3300008881	RV	3300008881	633697	NEM	8/21/2017	8/21/2017	61.40	02	8/21/2017	8/21/2017	0.50	8/21/2017	0.50	(61.40)	(30.70)
3300008882	RV	3900005621	633697	1012382	8/21/2017	8/31/2017	-61.40	02	8/21/2017	8/21/2017	0.50	8/31/2017	10.50	61.40	644.70
3300008924	RV	3900005648	633697	1012044	8/22/2017	9/1/2017	-61.40	02	8/22/2017	8/22/2017	0.50	9/1/2017	10.50	61.40	644.70
3300008925	RV	3900005623	633697	1012382	8/22/2017	8/31/2017	-60.40	02	8/22/2017	8/22/2017	0.50	8/31/2017	9.50	60.40	573.80
3300008946	RV	3900005711	633697	1013217	8/23/2017	9/7/2017	-350.00	02	8/23/2017	8/23/2017	0.50	9/7/2017	15.50	350.00	5,425.00
3300008960	RV	3900005649	633697	1012044	8/23/2017	9/1/2017	-61.40	02	8/23/2017	8/23/2017	0.50	9/1/2017	9.50	61.40	583.30
3300008963	RV	3900005650	633697	1012044	8/23/2017	9/1/2017	-61.40	02	8/23/2017	8/23/2017	0.50	9/1/2017	9.50	61.40	583.30
3300009005	RV	3900005625	633697	1012382	8/23/2017	8/31/2017	-61.80	02	8/23/2017	8/23/2017	0.50	8/31/2017	8.50	61.80	525.30
3300009012	RV	3900005624	633697	1012382	8/23/2017	8/31/2017	-65.20	02	8/23/2017	8/23/2017	0.50	8/31/2017	8.50	65.20	554.20
3300009016	RV	3900005628	633697	1012382	8/23/2017	8/31/2017	-65.20	02	8/23/2017	8/23/2017	0.50	8/31/2017	8.50	65.20	554.20
3300009021	RV	3900005502	633697	4005260	8/23/2017	8/28/2017	-61.40	02	8/23/2017	8/23/2017	0.50	8/28/2017	5.50	61.40	337.70
3300009026	RV	3900005619	633697	1012382	8/23/2017	8/31/2017	-62.80	02	8/23/2017	8/23/2017	0.50	8/31/2017	8.50	62.80	533.80
3300009087	RV	3900006023	633697	1012382	8/24/2017	9/21/2017	-60.40	02	8/24/2017	8/24/2017	0.50	9/21/2017	28.50	60.40	1,721.40
3300009088	RV	3900005610	633697	4005260	8/24/2017	8/31/2017	-69.00	02	8/24/2017	8/24/2017	0.50	8/31/2017	7.50	69.00	517.50
3300009089	RV	3900006029	633697	1012382	8/24/2017	9/21/2017	-61.40	02	8/24/2017	8/24/2017	0.50	9/21/2017	28.50	61.40	1,749.90
3300009090	RV	3900005921	633697	4005499	8/24/2017	9/18/2017	-61.00	02	8/24/2017	8/24/2017	0.50	9/18/2017	25.50	61.00	1,555.50
3300009134	RV	3300009135	633697	NEM	8/25/2017	8/25/2017	-326.00	02	8/25/2017	8/25/2017	0.50	8/25/2017	0.50	326.00	163.00
3300009135	RV	3300009135	633697	NEM	8/25/2017	8/25/2017	326.00	02	8/25/2017	8/25/2017	0.50	8/25/2017	0.50	(326.00)	(163.00)
3300009136	RV	3900005792	633697	1013217	8/25/2017	9/12/2017	-326.00	02	8/25/2017	8/25/2017	0.50	9/12/2017	18.50	326.00	6,031.00
3300009138	RV	3900005862	633697	41717	8/25/2017	9/14/2017	-63.60	02	8/25/2017	8/25/2017	0.50	9/14/2017	20.50	63.60	1,303.80
3300009139	RV	3900005611	633697	1012044	8/25/2017	8/31/2017	-61.40	02	8/25/2017	8/25/2017	0.50	8/31/2017	6.50	61.40	399.10
3300009140	RV	3900006026	633697	1012382	8/25/2017	9/21/2017	-64.20	02	8/25/2017	8/25/2017	0.50	9/21/2017	27.50	64.20	1,765.50
3300009141	RV	3900005612	633697	1012044	8/25/2017	8/31/2017	-61.40	02	8/25/2017	8/25/2017	0.50	8/31/2017	6.50	61.40	399.10
3300009219	RV	3900005813	633697	1013217	8/28/2017	9/12/2017	-326.00	02	8/28/2017	8/28/2017	0.50	9/12/2017	15.50	326.00	5,053.00
3300009221	RV	3900006028	633697	1012382	8/28/2017	9/21/2017	-61.80	02	8/28/2017	8/28/2017	0.50	9/21/2017	24.50	61.80	1,514.10
3300009224	RV	3900006022	633697	1012382	8/28/2017	9/21/2017	-60.40	02	8/28/2017	8/28/2017	0.50	9/21/2017	24.50	60.40	1,479.80
3300009225	RV	3300009234	633697	NEM	8/28/2017	8/29/2017	-61.40	02	8/28/2017	8/28/2017	0.50	8/29/2017	1.50	61.40	92.10
3300009226	RV	3900005615	633697	1012044	8/28/2017	8/31/2017	-61.40	02	8/28/2017	8/28/2017	0.50	8/31/2017	3.50	61.40	214.90
3300009227	RV	3900005614	633697	1012044	8/28/2017	8/31/2017	-65.20	02	8/28/2017	8/28/2017	0.50	8/31/2017	3.50	65.20	228.20
3300009228	RV	3900006027	633697	1012382	8/28/2017	9/21/2017	-60.40	02	8/28/2017	8/28/2017	0.50	9/21/2017	24.50	60.40	1,479.80
3300009229	RV	3300009233	633697	NEM	8/28/2017	8/29/2017	-70.60	02	8/28/2017	8/28/2017	0.50	8/29/2017	1.50	70.60	105.90
3300009233	RV	3300009233	633697	NEM	8/28/2017	8/29/2017	70.60	02	8/28/2017	8/28/2017	0.50	8/29/2017	1.50	(70.60)	(105.90)
3300009234	RV	3300009234	633697	NEM	8/28/2017	8/29/2017	61.40	02	8/28/2017	8/28/2017	0.50	8/29/2017	1.50	(61.40)	(92.10)
3300009235	RV	3900005613	633697	1012044	8/29/2017	8/31/2017	-61.40	02	8/29/2017	8/29/2017	0.50	8/31/2017	2.50	61.40	153.50
3300009236	RV	3900006052	633697	1012382	8/29/2017	9/22/2017	-70.60	02	8/29/2017	8/29/2017	0.50	9/22/2017	24.50	70.60	1,729.70
3300009300	RV	3900006025	633697	1012382	8/29/2017	9/21/2017	-61.40	02	8/29/2017	8/29/2017	0.50	9/21/2017	23.50	61.40	1,442.90
3300009302	RV	3900005673	633697	4005260	8/29/2017	9/5/2017	-63.00	02	8/29/2017	8/29/2017	0.50	9/5/2017	7.50	63.00	472.50
3300009305	RV	3900006024	633697	1012382	8/29/2017	9/21/2017	-63.60	02	8/29/2017	8/29/2017	0.50	9/21/2017	23.50	63.60	1,494.60
3300009399	RV	3900006004	633697	1012382	8/30/2017	9/21/2017	-64.20	02	8/30/2017	8/30/2017	0.50	9/21/2017	22.50	64.20	1,444.50

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Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Service period Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300009400	RV	3900005775	633697	1012044	8/30/2017	9/11/2017	-65.20	02	8/30/2017	8/30/2017	0.50	9/11/2017	12.50	65.20	815.00
3300009401	RV	3900005774	633697	1012044	8/30/2017	9/11/2017	-61.40	02	8/30/2017	8/30/2017	0.50	9/11/2017	12.50	61.40	767.50
3300009402	RV	3900006021	633697	1012382	8/30/2017	9/21/2017	-61.40	02	8/30/2017	8/30/2017	0.50	9/21/2017	22.50	61.40	1,381.50
3300009408	RV	3900005923	633697	4005499	8/31/2017	9/18/2017	-61.40	02	8/31/2017	8/31/2017	0.50	9/18/2017	18.50	61.40	1,135.90
3300009409	RV	3900005791	633697	1012382	8/31/2017	9/12/2017	-61.60	02	8/31/2017	8/31/2017	0.50	9/12/2017	12.50	61.60	770.00
3300009451	RV	3900005953	633697	41717	9/1/2017	9/20/2017	-65.20	02	9/1/2017	9/1/2017	0.50	9/20/2017	19.50	65.20	1,271.40
3300009452	RV	3900006754	633697	1013276	9/1/2017	10/27/2017	-266.00	02	9/1/2017	9/1/2017	0.50	10/27/2017	56.50	266.00	15,029.00
3300009473	RV	3900005925	633697	4005499	9/6/2017	9/18/2017	-61.40	02	9/6/2017	9/6/2017	0.50	9/18/2017	12.50	61.40	767.50
3300009476	RV	3900005772	633697	1012044	9/6/2017	9/11/2017	-61.40	02	9/6/2017	9/6/2017	0.50	9/11/2017	5.50	61.40	337.70
3300009477	RV	3900005851	633697	1012382	9/6/2017	9/13/2017	-60.40	02	9/6/2017	9/6/2017	0.50	9/13/2017	7.50	60.40	453.00
3300009478	RV	3900005954	633697	41717	9/6/2017	9/20/2017	-70.00	02	9/6/2017	9/6/2017	0.50	9/20/2017	14.50	70.00	1,015.00
3300009479	RV	3900005773	633697	1012044	9/6/2017	9/11/2017	-63.12	02	9/6/2017	9/6/2017	0.50	9/11/2017	5.50	63.12	347.16
3300009480	RV	3900005776	633697	4005260	9/6/2017	9/11/2017	-61.40	02	9/6/2017	9/6/2017	0.50	9/11/2017	5.50	61.40	337.70
3300009516	RV	3900007155	633697	1012435	9/7/2017	11/15/2017	-64.00	02	9/7/2017	9/7/2017	0.50	11/15/2017	69.50	64.00	4,448.00
3300009518	RV	3900005853	633697	1012382	9/7/2017	9/13/2017	-61.80	02	9/7/2017	9/7/2017	0.50	9/13/2017	6.50	61.80	401.70
3300009519	RV	3900005850	633697	1012382	9/7/2017	9/13/2017	-63.20	02	9/7/2017	9/7/2017	0.50	9/13/2017	6.50	63.20	410.80
3300009520	RV	3900005852	633697	1012382	9/7/2017	9/13/2017	-65.20	02	9/7/2017	9/7/2017	0.50	9/13/2017	6.50	65.20	423.80
3300009521	RV	3900005785	633697	1012044	9/7/2017	9/11/2017	-61.40	02	9/7/2017	9/7/2017	0.50	9/11/2017	4.50	61.40	276.30
3300009530	RV	3900006054	633697	4005499	9/8/2017	9/22/2017	-62.20	02	9/8/2017	9/8/2017	0.50	9/22/2017	14.50	62.20	901.90
3300009531	RV	3900005919	633697	1012382	9/8/2017	9/18/2017	-60.40	02	9/8/2017	9/8/2017	0.50	9/18/2017	10.50	60.40	634.20
3300009532	RV	3900005957	633697	41717	9/8/2017	9/20/2017	-65.20	02	9/8/2017	9/8/2017	0.50	9/20/2017	12.50	65.20	815.00
3300009533	RV	3300009538	633697	NEM	9/8/2017	9/8/2017	-62.80	02	9/8/2017	9/8/2017	0.50	9/8/2017	0.50	62.80	31.40
3300009534	RV	3900005860	633697	1013277	9/8/2017	9/14/2017	-925.00	02	9/8/2017	9/8/2017	0.50	9/14/2017	6.50	925.00	6,012.50
3300009535	RV	3900005955	633697	41717	9/8/2017	9/20/2017	-70.00	02	9/8/2017	9/8/2017	0.50	9/20/2017	12.50	70.00	875.00
3300009536	RV	3900005911	633697	1012382	9/8/2017	9/18/2017	-60.40	02	9/8/2017	9/8/2017	0.50	9/18/2017	10.50	60.40	634.20
3300009537	RV	3900005912	633697	1012382	9/8/2017	9/18/2017	-64.20	02	9/8/2017	9/8/2017	0.50	9/18/2017	10.50	64.20	674.10
3300009538	RV	3300009538	633697	NEM	9/8/2017	9/8/2017	62.80	02	9/8/2017	9/8/2017	0.50	9/8/2017	0.50	(62.80)	(31.40)
3300009539	RV	3900005917	633697	1012382	9/8/2017	9/18/2017	-62.80	02	9/8/2017	9/8/2017	0.50	9/18/2017	10.50	62.80	659.40
3300009540	RV	3900005956	633697	41717	9/8/2017	9/20/2017	-62.60	02	9/8/2017	9/8/2017	0.50	9/20/2017	12.50	62.60	782.50
3300009611	RV	3300011530	633697	1012044	9/11/2017	10/30/2017	-61.40	02	9/11/2017	9/11/2017	0.50	10/30/2017	49.50	61.40	3,039.30
3300009612	RV	3300009615	633697	NEM	9/11/2017	9/11/2017	-61.40	02	9/11/2017	9/11/2017	0.50	9/11/2017	0.50	61.40	30.70
3300009613	RV	3900005964	633697	1012044	9/11/2017	9/20/2017	-65.20	02	9/11/2017	9/11/2017	0.50	9/20/2017	9.50	65.20	619.40
3300009614	RV	3900005913	633697	1012382	9/11/2017	9/18/2017	-60.40	02	9/11/2017	9/11/2017	0.50	9/18/2017	7.50	60.40	453.00
3300009615	RV	3300009615	633697	NEM	9/11/2017	9/11/2017	61.40	02	9/11/2017	9/11/2017	0.50	9/11/2017	0.50	(61.40)	(30.70)
3300009616	RV	3900005965	633697	1012044	9/11/2017	9/20/2017	-61.40	02	9/11/2017	9/11/2017	0.50	9/20/2017	9.50	61.40	583.30
3300009617	RV	3900005966	633697	1012044	9/11/2017	9/20/2017	-65.20	02	9/11/2017	9/11/2017	0.50	9/20/2017	9.50	65.20	619.40
3300009653	RV	3900005958	633697	41717	9/12/2017	9/20/2017	-70.00	02	9/12/2017	9/12/2017	0.50	9/20/2017	8.50	70.00	595.00
3300009654	RV	3300009686	633697	NEM	9/12/2017	9/14/2017	-61.40	02	9/12/2017	9/12/2017	0.50	9/14/2017	2.50	61.40	153.50
3300009677	RV	3800000566	633697	4005260	9/13/2017	9/20/2017	-65.20	02	9/13/2017	9/13/2017	0.50	9/20/2017	7.50	65.20	489.00
3300009681	RV	3900005963	633697	1012044	9/13/2017	9/20/2017	-61.40	02	9/13/2017	9/13/2017	0.50	9/20/2017	7.50	61.40	460.50
3300009682	RV	3900005959	633697	1012044	9/13/2017	9/20/2017	-61.40	02	9/13/2017	9/13/2017	0.50	9/20/2017	7.50	61.40	460.50
3300009683	RV	3900005961	633697	1012044	9/13/2017	9/20/2017	-61.40	02	9/13/2017	9/13/2017	0.50	9/20/2017	7.50	61.40	460.50
3300009684	RV	3900005962	633697	1012044	9/13/2017	9/20/2017	-61.40	02	9/13/2017	9/13/2017	0.50	9/20/2017	7.50	61.40	460.50
3300009685	RV	3900005960	633697	1012044	9/13/2017	9/20/2017	-65.20	02	9/13/2017	9/13/2017	0.50	9/20/2017	7.50	65.20	489.00
3300009686	RV	3300009686	633697	NEM	9/12/2017	9/14/2017	61.40	02	9/12/2017	9/12/2017	0.50	9/14/2017	2.50	(61.40)	(153.50)
3300009687	RV	3900007594	633697	1012044	9/14/2017	12/8/2017	-61.40	02	9/14/2017	9/14/2017	0.50	12/8/2017	85.50	61.40	5,249.70
3300009758	RV	3900006083	633697	1012044	9/15/2017	9/25/2017	-61.40	02	9/15/2017	9/15/2017	0.50	9/25/2017	10.50	61.40	644.70
3300009760	RV	3900006208	633697	1012382	9/15/2017	10/3/2017	-68.40	02	9/15/2017	9/15/2017	0.50	10/3/2017	18.50	68.40	1,265.40
3300009763	RV	3900006207	633697	1012382	9/15/2017	10/3/2017	-61.80	02	9/15/2017	9/15/2017	0.50	10/3/2017	18.50	61.80	1,143.30
3300009764	RV	3900006210	633697	1012382	9/15/2017	10/3/2017	-63.20	02	9/15/2017	9/15/2017	0.50	10/3/2017	18.50	63.20	1,169.20

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3300009765	RV	3900006206	633697	1012382	9/15/2017	10/3/2017	-61.80	02	9/15/2017	9/15/2017	0.50	10/3/2017	18.50	61.80	1,143.30
3300009766	RV	3300009767	633697	NEM	9/15/2017	9/15/2017	-61.40	02	9/15/2017	9/15/2017	0.50	9/15/2017	0.50	61.40	30.70
3300009767	RV	3300009767	633697	NEM	9/15/2017	9/15/2017	61.40	02	9/15/2017	9/15/2017	0.50	9/15/2017	0.50	(61.40)	(30.70)
3300009768	RV	3900006082	633697	1012044	9/15/2017	9/25/2017	-61.40	02	9/15/2017	9/15/2017	0.50	9/25/2017	10.50	61.40	644.70
3300009829	RV	3900006124	633697	4005499	9/18/2017	9/27/2017	-60.60	02	9/18/2017	9/18/2017	0.50	9/27/2017	9.50	60.60	575.70
3300009830	RV	3900006123	633697	4005499	9/18/2017	9/27/2017	-66.60	02	9/18/2017	9/18/2017	0.50	9/27/2017	9.50	66.60	632.70
3300009845	RV	3900006084	633697	1012044	9/18/2017	9/25/2017	-61.40	02	9/18/2017	9/18/2017	0.50	9/25/2017	7.50	61.40	460.50
3300009861	RV	3800000566	633697	4005260	9/19/2017	9/20/2017	65.20	02	9/19/2017	9/19/2017	0.50	9/20/2017	1.50	(65.20)	(97.80)
3300009940	RV	3900006153	633697	1012382	9/19/2017	9/28/2017	-60.40	02	9/19/2017	9/19/2017	0.50	9/28/2017	9.50	60.40	573.80
3300009946	RV	3900006205	633697	1012382	9/19/2017	10/3/2017	-67.00	02	9/19/2017	9/19/2017	0.50	10/3/2017	14.50	67.00	971.50
3300009947	RV	3900006081	633697	1012044	9/19/2017	9/25/2017	-65.20	02	9/19/2017	9/19/2017	0.50	9/25/2017	6.50	65.20	423.80
3300009949	RV	3300013423	633697	4005260	9/19/2017	12/15/2017	-63.00	02	9/19/2017	9/19/2017	0.50	12/15/2017	87.50	63.00	5,512.50
3300009950	RV	3900006152	633697	1012382	9/19/2017	9/28/2017	-60.40	02	9/19/2017	9/19/2017	0.50	9/28/2017	9.50	60.40	573.80
3300009957	RV	3900006102	633697	1012055	9/20/2017	9/25/2017	-61.40	02	9/20/2017	9/20/2017	0.50	9/25/2017	5.50	61.40	337.70
3300009963	RV	3900006209	633697	1012382	9/20/2017	10/3/2017	-60.40	02	9/20/2017	9/20/2017	0.50	10/3/2017	13.50	60.40	815.40
3300009972	RV	3300009978	633697	NEM	9/20/2017	9/20/2017	-61.40	02	9/20/2017	9/20/2017	0.50	9/20/2017	0.50	61.40	30.70
3300009973	RV	3300009980	633697	NEM	9/20/2017	9/20/2017	-63.20	02	9/20/2017	9/20/2017	0.50	9/20/2017	0.50	63.20	31.60
3300009974	RV	3900007593	633697	1012044	9/20/2017	12/8/2017	-65.20	02	9/20/2017	9/20/2017	0.50	12/8/2017	79.50	65.20	5,183.40
3300009975	RV	3900007592	633697	1012044	9/20/2017	12/8/2017	-61.40	02	9/20/2017	9/20/2017	0.50	12/8/2017	79.50	61.40	4,881.30
3300009977	RV	3900007591	633697	1012044	9/20/2017	12/8/2017	-61.40	02	9/20/2017	9/20/2017	0.50	12/8/2017	79.50	61.40	4,881.30
3300009978	RV	3300009978	633697	NEM	9/20/2017	9/20/2017	61.40	02	9/20/2017	9/20/2017	0.50	9/20/2017	0.50	(61.40)	(30.70)
3300009979	RV	3300009993	633697	NEM	9/20/2017	9/20/2017	-61.40	02	9/20/2017	9/20/2017	0.50	9/20/2017	0.50	61.40	30.70
3300009980	RV	3300009980	633697	NEM	9/20/2017	9/20/2017	63.20	02	9/20/2017	9/20/2017	0.50	9/20/2017	0.50	(63.20)	(31.60)
3300009993	RV	3300009993	633697	NEM	9/20/2017	9/20/2017	61.40	02	9/20/2017	9/20/2017	0.50	9/20/2017	0.50	(61.40)	(30.70)
3300009994	RV	3900006313	633697	1012044	9/20/2017	10/9/2017	-61.40	02	9/20/2017	9/20/2017	0.50	10/9/2017	19.50	61.40	1,197.30
3300010168	RV	3900006415	633697	1012382	9/27/2017	10/12/2017	-62.80	02	9/27/2017	9/27/2017	0.50	10/12/2017	15.50	62.80	973.40
3300010170	RV	3900006351	633697	1012382	9/27/2017	10/10/2017	-62.80	02	9/27/2017	9/27/2017	0.50	10/10/2017	13.50	62.80	847.80
3300010171	RV	3900006315	633697	1012044	9/27/2017	10/9/2017	-61.40	02	9/27/2017	9/27/2017	0.50	10/9/2017	12.50	61.40	767.50
3300010172	RV	3900006193	633697	1012044	9/27/2017	10/3/2017	-65.20	02	9/27/2017	9/27/2017	0.50	10/3/2017	6.50	65.20	423.80
3300010173	RV	3300010174	633697	NEM	9/27/2017	9/27/2017	-63.20	02	9/27/2017	9/27/2017	0.50	9/27/2017	0.50	63.20	31.60
3300010174	RV	3300010174	633697	NEM	9/27/2017	9/27/2017	63.20	02	9/27/2017	9/27/2017	0.50	9/27/2017	0.50	(63.20)	(31.60)
3300010175	RV	3900006353	633697	1012382	9/27/2017	10/10/2017	-63.20	02	9/27/2017	9/27/2017	0.50	10/10/2017	13.50	63.20	853.20
3300010176	RV	3900006192	633697	1012044	9/27/2017	10/3/2017	-61.40	02	9/27/2017	9/27/2017	0.50	10/3/2017	6.50	61.40	399.10
3300010177	RV	3900007114	633697	1012673	9/27/2017	11/14/2017	-65.20	02	9/27/2017	9/27/2017	0.50	11/14/2017	48.50	65.20	3,162.20
3300010194	RV	3900006194	633697	1012044	9/27/2017	10/3/2017	-61.40	02	9/27/2017	9/27/2017	0.50	10/3/2017	6.50	61.40	399.10
3300010195	RV	3900006292	633697	1012382	9/27/2017	10/6/2017	-68.00	02	9/27/2017	9/27/2017	0.50	10/6/2017	9.50	68.00	646.00
3300010196	RV	3900007590	633697	1012044	9/27/2017	12/8/2017	-61.40	02	9/27/2017	9/27/2017	0.50	12/8/2017	72.50	61.40	4,451.50
3300010197	RV	3900006414	633697	1012382	9/27/2017	10/12/2017	-61.80	02	9/27/2017	9/27/2017	0.50	10/12/2017	15.50	61.80	957.90
3300010198	RV	3900006352	633697	1012382	9/27/2017	10/10/2017	-60.60	02	9/27/2017	9/27/2017	0.50	10/10/2017	13.50	60.60	818.10
3300010199	RV	3900006482	633697	41717	9/27/2017	10/17/2017	-65.20	02	9/27/2017	9/27/2017	0.50	10/17/2017	20.50	65.20	1,336.60
3300010200	RV	3900006350	633697	1012382	9/27/2017	10/10/2017	-62.60	02	9/27/2017	9/27/2017	0.50	10/10/2017	13.50	62.60	845.10
3300010201	RV	3900006195	633697	1012044	9/27/2017	10/3/2017	-61.40	02	9/27/2017	9/27/2017	0.50	10/3/2017	6.50	61.40	399.10
3300010202	RV	3900006349	633697	1012382	9/27/2017	10/10/2017	-60.40	02	9/27/2017	9/27/2017	0.50	10/10/2017	13.50	60.40	815.40
3300010203	RV	3900006197	633697	1012044	9/27/2017	10/3/2017	-65.20	02	9/27/2017	9/27/2017	0.50	10/3/2017	6.50	65.20	423.80
3300010204	RV	3900006196	633697	1012044	9/27/2017	10/3/2017	-61.40	02	9/27/2017	9/27/2017	0.50	10/3/2017	6.50	61.40	399.10
3300010205	RV	3900006413	633697	1012382	9/27/2017	10/12/2017	-62.80	02	9/27/2017	9/27/2017	0.50	10/12/2017	15.50	62.80	973.40
3300010206	RV	3900006481	633697	41717	9/27/2017	10/17/2017	-62.60	02	9/27/2017	9/27/2017	0.50	10/17/2017	20.50	62.60	1,283.30
3300010207	RV	3900006503	633697	4005499	9/27/2017	10/17/2017	-64.00	02	9/27/2017	9/27/2017	0.50	10/17/2017	20.50	64.00	1,312.00
3300010208	RV	3900006287	633697	1012382	9/27/2017	10/6/2017	-64.20	02	9/27/2017	9/27/2017	0.50	10/6/2017	9.50	64.20	609.90
3300010209	RV	3900006314	633697	1012044	9/27/2017	10/9/2017	-61.40	02	9/27/2017	9/27/2017	0.50	10/9/2017	12.50	61.40	767.50

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3300010210	RV	3900006198	633697	1012044	9/27/2017	10/3/2017	-65.20	02	9/27/2017	9/27/2017	0.50	10/3/2017	6.50	65.20	423.80
3300010211	RV	3900006312	633697	1012044	9/27/2017	10/9/2017	-61.40	02	9/27/2017	9/27/2017	0.50	10/9/2017	12.50	61.40	767.50
3300010232	RV	3900006306	633697	1012044	9/28/2017	10/9/2017	-65.20	02	9/28/2017	9/28/2017	0.50	10/9/2017	11.50	65.20	749.80
3300010233	RV	3900006285	633697	1012382	9/28/2017	10/6/2017	-63.20	02	9/28/2017	9/28/2017	0.50	10/6/2017	8.50	63.20	537.20
3300010234	RV	3900006286	633697	1012382	9/28/2017	10/6/2017	-63.20	02	9/28/2017	9/28/2017	0.50	10/6/2017	8.50	63.20	537.20
3300010237	RV	3900006284	633697	1012382	9/28/2017	10/6/2017	-69.80	02	9/28/2017	9/28/2017	0.50	10/6/2017	8.50	69.80	593.30
3300010238	RV	3900006290	633697	1012382	9/28/2017	10/6/2017	-60.40	02	9/28/2017	9/28/2017	0.50	10/6/2017	8.50	60.40	513.40
3300010239	RV	3900006289	633697	1012382	9/28/2017	10/6/2017	-61.40	02	9/28/2017	9/28/2017	0.50	10/6/2017	8.50	61.40	521.90
3300010241	RV	3900006480	633697	41717	9/28/2017	10/17/2017	-61.40	02	9/28/2017	9/28/2017	0.50	10/17/2017	19.50	61.40	1,197.30
3300010286	RV	3900006288	633697	1012382	9/28/2017	10/6/2017	-61.80	02	9/28/2017	9/28/2017	0.50	10/6/2017	8.50	61.80	525.30
3300010368	RV	3900006316	633697	1012044	9/29/2017	10/9/2017	-61.40	02	9/29/2017	9/29/2017	0.50	10/9/2017	10.50	61.40	644.70
3300010370	RV	3900006307	633697	1012044	9/29/2017	10/9/2017	-61.40	02	9/29/2017	9/29/2017	0.50	10/9/2017	10.50	61.40	644.70
3300010372	RV	3900006311	633697	1012044	9/29/2017	10/9/2017	-61.40	02	9/29/2017	9/29/2017	0.50	10/9/2017	10.50	61.40	644.70
3300010373	RV	3900006355	633697	1012382	9/29/2017	10/10/2017	-64.20	02	9/29/2017	9/29/2017	0.50	10/10/2017	11.50	64.20	738.30
3300010378	RV	3900006310	633697	1012044	9/29/2017	10/9/2017	-61.40	02	9/29/2017	9/29/2017	0.50	10/9/2017	10.50	61.40	644.70
3300010379	RV	3900006309	633697	1012044	9/29/2017	10/9/2017	-61.40	02	9/29/2017	9/29/2017	0.50	10/9/2017	10.50	61.40	644.70
3300010380	RV	3900006291	633697	1012382	9/29/2017	10/6/2017	-62.60	02	9/29/2017	9/29/2017	0.50	10/6/2017	7.50	62.60	469.50
3300010383	RV	3300010384	633697	NEM	9/29/2017	9/29/2017	-96.00	02	9/29/2017	9/29/2017	0.50	9/29/2017	0.50	96.00	48.00
3300010384	RV	3300010384	633697	NEM	9/29/2017	9/29/2017	96.00	02	9/29/2017	9/29/2017	0.50	9/29/2017	0.50	(96.00)	(48.00)
3300010385	RV	3900006269	633697	1012240	9/29/2017	10/6/2017	-96.00	02	9/29/2017	9/29/2017	0.50	10/6/2017	7.50	96.00	720.00
3300010388	RV	3300010395	633697	NEM	9/29/2017	9/29/2017	-124.75	02	9/29/2017	9/29/2017	0.50	9/29/2017	0.50	124.75	62.38
3300010395	RV	3300010395	633697	NEM	9/29/2017	9/29/2017	124.75	02	9/29/2017	9/29/2017	0.50	9/29/2017	0.50	(124.75)	(62.38)
3300010400	RV	3900006270	633697	1012240	9/29/2017	10/6/2017	-124.75	02	9/29/2017	9/29/2017	0.50	10/6/2017	7.50	124.75	935.63
3300010405	RV	3900006308	633697	1012044	9/29/2017	10/9/2017	-61.40	02	9/29/2017	9/29/2017	0.50	10/9/2017	10.50	61.40	644.70
3300010428	RV	3900006546	633697	1012382	10/2/2017	10/19/2017	-66.00	02	10/2/2017	10/2/2017	0.50	10/19/2017	17.50	66.00	1,155.00
3300010429	RV	3900006564	633697	41717	10/2/2017	10/20/2017	-65.20	02	10/2/2017	10/2/2017	0.50	10/20/2017	18.50	65.20	1,206.20
3300010430	RV	3900006657	633697	1012382	10/2/2017	10/25/2017	-65.60	02	10/2/2017	10/2/2017	0.50	10/25/2017	23.50	65.60	1,541.60
3300010431	RV	3900006545	633697	1012382	10/2/2017	10/19/2017	-60.40	02	10/2/2017	10/2/2017	0.50	10/19/2017	17.50	60.40	1,057.00
3300010453	RV	3900007161	633697	1013303	10/3/2017	11/15/2017	-60.10	02	10/3/2017	10/3/2017	0.50	11/15/2017	43.50	60.10	2,614.35
3300010454	RV	3900006305	633697	1012044	10/3/2017	10/9/2017	-65.20	02	10/3/2017	10/3/2017	0.50	10/9/2017	6.50	65.20	423.80
3300010455	RV	3900006301	633697	1012044	10/3/2017	10/9/2017	-61.40	02	10/3/2017	10/3/2017	0.50	10/9/2017	6.50	61.40	399.10
3300010456	RV	3900006304	633697	1012044	10/3/2017	10/9/2017	-65.20	02	10/3/2017	10/3/2017	0.50	10/9/2017	6.50	65.20	423.80
3300010457	RV	3900006302	633697	1012044	10/3/2017	10/9/2017	-61.40	02	10/3/2017	10/3/2017	0.50	10/9/2017	6.50	61.40	399.10
3300010458	RV	3900007678	633697	1012044	10/3/2017	12/13/2017	-65.20	02	10/3/2017	10/3/2017	0.50	12/13/2017	71.50	65.20	4,661.80
3300010471	RV	3900006817	633697	1012421	10/4/2017	10/30/2017	-146.00	02	10/4/2017	10/4/2017	0.50	10/30/2017	26.50	146.00	3,869.00
3300010473	RV	3900006303	633697	1012044	10/4/2017	10/9/2017	-61.40	02	10/4/2017	10/4/2017	0.50	10/9/2017	5.50	61.40	337.70
3300010474	RV	3900006300	633697	1012044	10/4/2017	10/9/2017	-61.40	02	10/4/2017	10/4/2017	0.50	10/9/2017	5.50	61.40	337.70
3300010475	RV	3900006271	633697	1012240	10/4/2017	10/6/2017	-124.75	02	10/4/2017	10/4/2017	0.50	10/6/2017	2.50	124.75	311.88
3300010477	RV	3900006449	633697	1012382	10/4/2017	10/13/2017	-60.40	02	10/4/2017	10/4/2017	0.50	10/13/2017	9.50	60.40	573.80
3300010478	RV	3900006541	633697	1012382	10/4/2017	10/19/2017	-61.80	02	10/4/2017	10/4/2017	0.50	10/19/2017	15.50	61.80	957.90
3300010479	RV	3300010480	633697	NEM	10/4/2017	10/4/2017	-62.00	02	10/4/2017	10/4/2017	0.50	10/4/2017	0.50	62.00	31.00
3300010480	RV	3300010480	633697	NEM	10/4/2017	10/4/2017	62.00	02	10/4/2017	10/4/2017	0.50	10/4/2017	0.50	(62.00)	(31.00)
3300010481	RV	3900006638	633697	41717	10/4/2017	10/23/2017	-62.00	02	10/4/2017	10/4/2017	0.50	10/23/2017	19.50	62.00	1,209.00
3300010483	RV	3900006447	633697	1012382	10/4/2017	10/13/2017	-60.40	02	10/4/2017	10/4/2017	0.50	10/13/2017	9.50	60.40	573.80
3300010484	RV	3300010485	633697	NEM	10/4/2017	10/4/2017	-60.40	02	10/4/2017	10/4/2017	0.50	10/4/2017	0.50	60.40	30.20
3300010485	RV	3300010485	633697	NEM	10/4/2017	10/4/2017	60.40	02	10/4/2017	10/4/2017	0.50	10/4/2017	0.50	(60.40)	(30.20)
3300010486	RV	3900006448	633697	1012382	10/4/2017	10/13/2017	-60.40	02	10/4/2017	10/4/2017	0.50	10/13/2017	9.50	60.40	573.80
3300010487	RV	3900006299	633697	1012044	10/4/2017	10/9/2017	-61.40	02	10/4/2017	10/4/2017	0.50	10/9/2017	5.50	61.40	337.70
3300010493	RV	3900007434	633697	1012673	10/5/2017	12/4/2017	-61.40	02	10/5/2017	10/5/2017	0.50	12/4/2017	60.50	61.40	3,714.70
3300010496	RV	3900006634	633697	1012382	10/5/2017	10/23/2017	-60.40	02	10/5/2017	10/5/2017	0.50	10/23/2017	18.50	60.40	1,117.40

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3300010497	RV	3900006515	633697	1012382	10/5/2017	10/18/2017	-61.80	02	10/5/2017	10/5/2017	0.50	10/18/2017	13.50	61.80	834.30
3300010502	RV	3900006542	633697	1012382	10/5/2017	10/19/2017	-65.60	02	10/5/2017	10/5/2017	0.50	10/19/2017	14.50	65.60	951.20
3300010506	RV	3900006563	633697	41717	10/5/2017	10/20/2017	-65.20	02	10/5/2017	10/5/2017	0.50	10/20/2017	15.50	65.20	1,010.60
3300010509	RV	3900006484	633697	1012044	10/5/2017	10/17/2017	-61.40	02	10/5/2017	10/5/2017	0.50	10/17/2017	12.50	61.40	767.50
3300010510	RV	3300010514	633697	NEM	10/5/2017	10/5/2017	-65.20	02	10/5/2017	10/5/2017	0.50	10/5/2017	0.50	65.20	32.60
3300010514	RV	3300010514	633697	NEM	10/5/2017	10/5/2017	65.20	02	10/5/2017	10/5/2017	0.50	10/5/2017	0.50	(65.20)	(32.60)
3300010516	RV	3900006514	633697	1012382	10/5/2017	10/18/2017	-65.20	02	10/5/2017	10/5/2017	0.50	10/18/2017	13.50	65.20	880.20
3300010540	RV	3900006504	633697	4005499	10/6/2017	10/17/2017	-64.00	02	10/6/2017	10/6/2017	0.50	10/17/2017	11.50	64.00	736.00
3300010541	RV	3900006544	633697	1012382	10/6/2017	10/19/2017	-60.40	02	10/6/2017	10/6/2017	0.50	10/19/2017	13.50	60.40	815.40
3300010542	RV	3900006518	633697	1012382	10/6/2017	10/18/2017	-65.20	02	10/6/2017	10/6/2017	0.50	10/18/2017	12.50	65.20	815.00
3300010571	RV	3900006516	633697	1012382	10/6/2017	10/18/2017	-60.40	02	10/6/2017	10/6/2017	0.50	10/18/2017	12.50	60.40	755.00
3300010602	RV	3900006658	633697	1012382	10/9/2017	10/25/2017	-61.00	02	10/9/2017	10/9/2017	0.50	10/25/2017	16.50	61.00	1,006.50
3300010603	RV	3900006391	633697	1012240	10/9/2017	10/12/2017	-96.00	02	10/9/2017	10/9/2017	0.50	10/12/2017	3.50	96.00	336.00
3300010604	RV	3900006543	633697	1012382	10/9/2017	10/19/2017	-60.40	02	10/9/2017	10/9/2017	0.50	10/19/2017	10.50	60.40	634.20
3300010605	RV	3900006517	633697	1012382	10/9/2017	10/18/2017	-61.40	02	10/9/2017	10/9/2017	0.50	10/18/2017	9.50	61.40	583.30
3300010621	RV	3900006505	633697	4005499	10/10/2017	10/17/2017	-66.00	02	10/10/2017	10/10/2017	0.50	10/17/2017	7.50	66.00	495.00
3300010632	RV	3300010635	633697	NEM	10/11/2017	10/11/2017	-61.60	02	10/11/2017	10/11/2017	0.50	10/11/2017	0.50	61.60	30.80
3300010635	RV	3300010635	633697	NEM	10/11/2017	10/11/2017	61.60	02	10/11/2017	10/11/2017	0.50	10/11/2017	0.50	(61.60)	(30.80)
3300010637	RV	3900006676	633697	1012044	10/11/2017	10/25/2017	-61.40	02	10/11/2017	10/11/2017	0.50	10/25/2017	14.50	61.40	890.30
3300010640	RV	3900006662	633697	1012382	10/11/2017	10/25/2017	-63.20	02	10/11/2017	10/11/2017	0.50	10/25/2017	14.50	63.20	916.40
3300010641	RV	3300011576	633697	NEM	10/11/2017	10/31/2017	-63.00	02	10/11/2017	10/11/2017	0.50	10/31/2017	20.50	63.00	1,291.50
3300010642	RV	3900006787	633697	1012044	10/11/2017	10/30/2017	-61.40	02	10/11/2017	10/11/2017	0.50	10/30/2017	19.50	61.40	1,197.30
3300010701	RV	3900006786	633697	1012044	10/12/2017	10/30/2017	-61.40	02	10/12/2017	10/12/2017	0.50	10/30/2017	18.50	61.40	1,135.90
3300010702	RV	3900006659	633697	1012382	10/12/2017	10/25/2017	-61.80	02	10/12/2017	10/12/2017	0.50	10/25/2017	13.50	61.80	834.30
3300010709	RV	3300010713	633697	NEM	10/12/2017	10/12/2017	-61.40	02	10/12/2017	10/12/2017	0.50	10/12/2017	0.50	61.40	30.70
3300010713	RV	3300010713	633697	NEM	10/12/2017	10/12/2017	61.40	02	10/12/2017	10/12/2017	0.50	10/12/2017	0.50	(61.40)	(30.70)
3300010715	RV	3900006785	633697	1012044	10/12/2017	10/30/2017	-61.40	02	10/12/2017	10/12/2017	0.50	10/30/2017	18.50	61.40	1,135.90
3300010717	RV	3900006784	633697	1012044	10/12/2017	10/30/2017	-65.20	02	10/12/2017	10/12/2017	0.50	10/30/2017	18.50	65.20	1,206.20
3300010718	RV	3900006661	633697	1012382	10/12/2017	10/25/2017	-62.60	02	10/12/2017	10/12/2017	0.50	10/25/2017	13.50	62.60	845.10
3300010729	RV	3900006783	633697	1012044	10/12/2017	10/30/2017	-61.40	02	10/12/2017	10/12/2017	0.50	10/30/2017	18.50	61.40	1,135.90
3300010734	RV	3900006664	633697	1012382	10/12/2017	10/25/2017	-60.40	02	10/12/2017	10/12/2017	0.50	10/25/2017	13.50	60.40	815.40
3300010736	RV	3900006635	633697	1012382	10/12/2017	10/23/2017	-61.00	02	10/12/2017	10/12/2017	0.50	10/23/2017	11.50	61.00	701.50
3300010765	RV	3300010811	633697	NEM	10/13/2017	10/13/2017	-63.20	02	10/13/2017	10/13/2017	0.50	10/13/2017	0.50	63.20	31.60
3300010769	RV	3900006595	633697	1012237	10/13/2017	10/20/2017	-183.20	02	10/13/2017	10/13/2017	0.50	10/20/2017	7.50	183.20	1,374.00
3300010771	RV	3900006633	633697	1012382	10/13/2017	10/23/2017	-61.80	02	10/13/2017	10/13/2017	0.50	10/23/2017	10.50	61.80	648.90
3300010772	RV	3900006660	633697	1012382	10/13/2017	10/25/2017	-60.40	02	10/13/2017	10/13/2017	0.50	10/25/2017	12.50	60.40	755.00
3300010811	RV	3300010811	633697	NEM	10/13/2017	10/13/2017	63.20	02	10/13/2017	10/13/2017	0.50	10/13/2017	0.50	(63.20)	(31.60)
3300010812	RV	3300010813	633697	NEM	10/13/2017	10/13/2017	-63.20	02	10/13/2017	10/13/2017	0.50	10/13/2017	0.50	63.20	31.60
3300010813	RV	3300010813	633697	NEM	10/13/2017	10/13/2017	63.20	02	10/13/2017	10/13/2017	0.50	10/13/2017	0.50	(63.20)	(31.60)
3300010814	RV	3900006663	633697	1012382	10/13/2017	10/25/2017	-63.20	02	10/13/2017	10/13/2017	0.50	10/25/2017	12.50	63.20	790.00
3300010925	RV	3900006824	633697	1012382	10/17/2017	10/30/2017	-63.20	02	10/17/2017	10/17/2017	0.50	10/30/2017	13.50	63.20	853.20
3300010944	RV	3900006864	633697	4005260	10/17/2017	11/1/2017	-61.40	02	10/17/2017	10/17/2017	0.50	11/1/2017	15.50	61.40	951.70
3300010945	RV	3900007442	633697	41717	10/17/2017	12/5/2017	-80.00	02	10/17/2017	10/17/2017	0.50	12/5/2017	49.50	80.00	3,960.00
3300010946	RV	3900006756	633697	1012382	10/17/2017	10/27/2017	-67.40	02	10/17/2017	10/17/2017	0.50	10/27/2017	10.50	67.40	707.70
3300010947	RV	3900006882	633697	1012382	10/17/2017	11/1/2017	-60.40	02	10/17/2017	10/17/2017	0.50	11/1/2017	15.50	60.40	936.20
3300010989	RV	3900006821	633697	1012382	10/18/2017	10/30/2017	-60.40	02	10/18/2017	10/18/2017	0.50	10/30/2017	12.50	60.40	755.00
3300010990	RV	3900006820	633697	1012382	10/18/2017	10/30/2017	-64.20	02	10/18/2017	10/18/2017	0.50	10/30/2017	12.50	64.20	802.50
3300011024	RV	3900006736	633697	1012386	10/19/2017	10/27/2017	-67.60	02	10/19/2017	10/19/2017	0.50	10/27/2017	8.50	67.60	574.60
3300011025	RV	3900006782	633697	1012044	10/19/2017	10/30/2017	-61.40	02	10/19/2017	10/19/2017	0.50	10/30/2017	11.50	61.40	706.10
3300011027	RV	3900006822	633697	1012382	10/19/2017	10/30/2017	-62.80	02	10/19/2017	10/19/2017	0.50	10/30/2017	11.50	62.80	722.20

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3300011030	RV	3900006880	633697	1012382	10/19/2017	11/1/2017	-64.20	02	10/19/2017	10/19/2017	0.50	11/1/2017	13.50	64.20	866.70
3300011034	RV	3900006781	633697	1012044	10/19/2017	10/30/2017	-61.40	02	10/19/2017	10/19/2017	0.50	10/30/2017	11.50	61.40	706.10
3300011069	RV	3900006755	633697	1012382	10/19/2017	10/27/2017	-62.80	02	10/19/2017	10/19/2017	0.50	10/27/2017	8.50	62.80	533.80
3300011087	RV	3900006884	633697	1012382	10/19/2017	11/1/2017	-62.80	02	10/19/2017	10/19/2017	0.50	11/1/2017	13.50	62.80	847.80
3300011088	RV	3900006776	633697	1012044	10/19/2017	10/30/2017	-60.32	02	10/19/2017	10/19/2017	0.50	10/30/2017	11.50	60.32	693.68
3300011109	RV	3900006642	633697	1012435	10/20/2017	10/24/2017	-64.56	02	10/20/2017	10/20/2017	0.50	10/24/2017	4.50	64.56	290.52
3300011110	RV	3900006823	633697	1012382	10/20/2017	10/30/2017	-62.80	02	10/20/2017	10/20/2017	0.50	10/30/2017	10.50	62.80	659.40
3300011111	RV	3900006780	633697	1012044	10/20/2017	10/30/2017	-61.40	02	10/20/2017	10/20/2017	0.50	10/30/2017	10.50	61.40	644.70
3300011112	RV	3900006779	633697	1012044	10/20/2017	10/30/2017	-61.40	02	10/20/2017	10/20/2017	0.50	10/30/2017	10.50	61.40	644.70
3300011113	RV	3900006778	633697	1012044	10/20/2017	10/30/2017	-61.40	02	10/20/2017	10/20/2017	0.50	10/30/2017	10.50	61.40	644.70
3300011119	RV	3900006881	633697	1012382	10/20/2017	11/1/2017	-62.00	02	10/20/2017	10/20/2017	0.50	11/1/2017	12.50	62.00	775.00
3300011127	RV	3900006775	633697	1012044	10/20/2017	10/30/2017	-61.40	02	10/20/2017	10/20/2017	0.50	10/30/2017	10.50	61.40	644.70
3300011128	RV	3900006777	633697	1012044	10/20/2017	10/30/2017	-65.20	02	10/20/2017	10/20/2017	0.50	10/30/2017	10.50	65.20	684.60
3300011129	RV	3900007096	633697	41717	10/20/2017	11/13/2017	-65.00	02	10/20/2017	10/20/2017	0.50	11/13/2017	24.50	65.00	1,592.50
3300011130	RV	3900006885	633697	1012382	10/20/2017	11/1/2017	-61.00	02	10/20/2017	10/20/2017	0.50	11/1/2017	12.50	61.00	762.50
3300011152	RV	3900007121	633697	1013217	10/23/2017	11/14/2017	-290.00	02	10/23/2017	10/23/2017	0.50	11/14/2017	22.50	290.00	6,525.00
3300011169	RV	3900007684	633697	1012044	10/23/2017	12/13/2017	-65.20	02	10/23/2017	10/23/2017	0.50	12/13/2017	51.50	65.20	3,357.80
3300011170	RV	3900006774	633697	1012044	10/23/2017	10/30/2017	-65.20	02	10/23/2017	10/23/2017	0.50	10/30/2017	7.50	65.20	489.00
3300011178	RV	3900006909	633697	4005499	10/24/2017	11/2/2017	-61.40	02	10/24/2017	10/24/2017	0.50	11/2/2017	9.50	61.40	583.30
3300011179	RV	3900006875	633697	1012044	10/24/2017	11/1/2017	-61.40	02	10/24/2017	10/24/2017	0.50	11/1/2017	8.50	61.40	521.90
3300011180	RV	3900006877	633697	1012382	10/24/2017	11/1/2017	-60.40	02	10/24/2017	10/24/2017	0.50	11/1/2017	8.50	60.40	513.40
3300011181	RV	3900006874	633697	1012044	10/24/2017	11/1/2017	-61.40	02	10/24/2017	10/24/2017	0.50	11/1/2017	8.50	61.40	521.90
3300011182	RV	3900006873	633697	1012044	10/24/2017	11/1/2017	-61.40	02	10/24/2017	10/24/2017	0.50	11/1/2017	8.50	61.40	521.90
3300011183	RV	3900006872	633697	1012044	10/24/2017	11/1/2017	-65.20	02	10/24/2017	10/24/2017	0.50	11/1/2017	8.50	65.20	554.20
3300011184	RV	3900006886	633697	1012382	10/24/2017	11/1/2017	-60.40	02	10/24/2017	10/24/2017	0.50	11/1/2017	8.50	60.40	513.40
3300011225	RV	3900007095	633697	41717	10/25/2017	11/13/2017	-66.00	02	10/25/2017	10/25/2017	0.50	11/13/2017	19.50	66.00	1,287.00
3300011226	RV	3900006908	633697	4005499	10/25/2017	11/2/2017	-62.60	02	10/25/2017	10/25/2017	0.50	11/2/2017	8.50	62.60	532.10
3300011227	RV	3900006871	633697	1012044	10/25/2017	11/1/2017	-65.20	02	10/25/2017	10/25/2017	0.50	11/1/2017	7.50	65.20	489.00
3300011228	RV	3900007518	633697	1012180	10/25/2017	12/7/2017	-61.52	02	10/25/2017	10/25/2017	0.50	12/7/2017	43.50	61.52	2,676.12
3300011230	RV	3900006883	633697	1012382	10/25/2017	11/1/2017	-61.40	02	10/25/2017	10/25/2017	0.50	11/1/2017	7.50	61.40	460.50
3300011231	RV	3900006870	633697	1012044	10/25/2017	11/1/2017	-61.40	02	10/25/2017	10/25/2017	0.50	11/1/2017	7.50	61.40	460.50
3300011357	RV	3900006879	633697	1012382	10/26/2017	11/1/2017	-61.80	02	10/26/2017	10/26/2017	0.50	11/1/2017	6.50	61.80	401.70
3300011366	RV	3300011377	633697	NEM	10/26/2017	10/26/2017	-60.40	02	10/26/2017	10/26/2017	0.50	10/26/2017	0.50	60.40	30.20
3300011370	RV	3900006878	633697	1012382	10/26/2017	11/1/2017	-60.40	02	10/26/2017	10/26/2017	0.50	11/1/2017	6.50	60.40	392.60
3300011371	RV	3900006907	633697	4005499	10/26/2017	11/2/2017	-63.00	02	10/26/2017	10/26/2017	0.50	11/2/2017	7.50	63.00	472.50
3300011372	RV	3900007094	633697	41717	10/26/2017	11/13/2017	-70.00	02	10/26/2017	10/26/2017	0.50	11/13/2017	18.50	70.00	1,295.00
3300011377	RV	3300011377	633697	NEM	10/26/2017	10/26/2017	60.40	02	10/26/2017	10/26/2017	0.50	10/26/2017	0.50	(60.40)	(30.20)
3300011378	RV	3900007145	633697	1012382	10/26/2017	11/14/2017	-60.40	02	10/26/2017	10/26/2017	0.50	11/14/2017	19.50	60.40	1,177.80
3300011420	RV	3900007097	633697	1012382	10/27/2017	11/13/2017	-61.40	02	10/27/2017	10/27/2017	0.50	11/13/2017	17.50	61.40	1,074.50
3300011424	RV	3900006857	633697	1013317	10/27/2017	11/1/2017	-64.00	02	10/27/2017	10/27/2017	0.50	11/1/2017	5.50	64.00	352.00
3300011425	RV	3900006952	633697	1012382	10/27/2017	11/6/2017	-65.40	02	10/27/2017	10/27/2017	0.50	11/6/2017	10.50	65.40	686.70
3300011426	RV	3900006953	633697	1012382	10/27/2017	11/6/2017	-62.60	02	10/27/2017	10/27/2017	0.50	11/6/2017	10.50	62.60	657.30
3300011427	RV	3900007098	633697	1012044	10/27/2017	11/13/2017	-61.40	02	10/27/2017	10/27/2017	0.50	11/13/2017	17.50	61.40	1,074.50
3300011530	RV	3300011530	633697	1012044	9/11/2017	10/30/2017	61.40	02	9/11/2017	9/11/2017	0.50	10/30/2017	49.50	(61.40)	(3,039.30)
3300011535	RV	3900006951	633697	4005499	10/30/2017	11/6/2017	-62.00	02	10/30/2017	10/30/2017	0.50	11/6/2017	7.50	62.00	465.00
3300011538	RV	3900006963	633697	26961	10/30/2017	11/6/2017	-65.36	02	10/30/2017	10/30/2017	0.50	11/6/2017	7.50	65.36	490.20
3300011540	RV	3900007120	633697	1012382	10/30/2017	11/14/2017	-62.60	02	10/30/2017	10/30/2017	0.50	11/14/2017	15.50	62.60	970.30
3300011541	RV	3900007332	633697	41717	10/30/2017	11/29/2017	-67.60	02	10/30/2017	10/30/2017	0.50	11/29/2017	30.50	67.60	2,061.80
3300011542	RV	3300011546	633697	NEM	10/30/2017	10/30/2017	-65.20	02	10/30/2017	10/30/2017	0.50	10/30/2017	0.50	65.20	32.60
3300011543	RV	3300011544	633697	NEM	10/30/2017	10/30/2017	-64.20	02	10/30/2017	10/30/2017	0.50	10/30/2017	0.50	64.20	32.10

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3300011544	RV	3300011544	633697	NEM	10/30/2017	10/30/2017	64.20	02	10/30/2017	10/30/2017	0.50	10/30/2017	0.50	(64.20)	(32.10)
3300011545	RV	3900007143	633697	1012382	10/30/2017	11/14/2017	-64.20	02	10/30/2017	10/30/2017	0.50	11/14/2017	15.50	64.20	995.10
3300011546	RV	3300011546	633697	NEM	10/30/2017	10/30/2017	65.20	02	10/30/2017	10/30/2017	0.50	10/30/2017	0.50	(65.20)	(32.60)
3300011547	RV	3900006924	633697	4005260	10/30/2017	11/3/2017	-65.20	02	10/30/2017	10/30/2017	0.50	11/3/2017	4.50	65.20	293.40
3300011555	RV	3900006950	633697	4005499	10/31/2017	11/6/2017	-61.40	02	10/31/2017	10/31/2017	0.50	11/6/2017	6.50	61.40	399.10
3300011558	RV	3900007100	633697	1012044	10/31/2017	11/13/2017	-61.40	02	10/31/2017	10/31/2017	0.50	11/13/2017	13.50	61.40	828.90
3300011559	RV	3900007144	633697	1012382	10/31/2017	11/14/2017	-61.00	02	10/31/2017	10/31/2017	0.50	11/14/2017	14.50	61.00	884.50
3300011560	RV	3900007101	633697	1012044	10/31/2017	11/13/2017	-61.40	02	10/31/2017	10/31/2017	0.50	11/13/2017	13.50	61.40	828.90
3300011561	RV	3900007110	633697	1012044	10/31/2017	11/14/2017	-61.40	02	10/31/2017	10/31/2017	0.50	11/14/2017	14.50	61.40	890.30
3300011562	RV	3900007022	633697	1012382	10/31/2017	11/8/2017	-68.40	02	10/31/2017	10/31/2017	0.50	11/8/2017	8.50	68.40	581.40
3300011571	RV	3300011574	633697	NEM	10/31/2017	10/31/2017	-65.40	02	10/31/2017	10/31/2017	0.50	10/31/2017	0.50	65.40	32.70
3300011572	RV	3900007157	633697	1012382	10/31/2017	11/15/2017	-65.20	02	10/31/2017	10/31/2017	0.50	11/15/2017	15.50	65.20	1,010.60
3300011573	RV	3900007146	633697	1012382	10/31/2017	11/14/2017	-60.40	02	10/31/2017	10/31/2017	0.50	11/14/2017	14.50	60.40	875.80
3300011574	RV	3300011574	633697	NEM	10/31/2017	10/31/2017	65.40	02	10/31/2017	10/31/2017	0.50	10/31/2017	0.50	(65.40)	(32.70)
3300011575	RV	3900007021	633697	1012382	10/31/2017	11/8/2017	-65.40	02	10/31/2017	10/31/2017	0.50	11/8/2017	8.50	65.40	555.90
3300011576	RV	3300011576	633697	NEM	10/11/2017	10/31/2017	63.00	02	10/11/2017	10/11/2017	0.50	10/31/2017	20.50	(63.00)	(1,291.50)
3300011599	RV	3900007106	633697	1012044	11/1/2017	11/14/2017	-61.40	02	11/1/2017	11/1/2017	0.50	11/14/2017	13.50	61.40	828.90
3300011600	RV	3900007082	633697	4005499	11/1/2017	11/13/2017	-63.60	02	11/1/2017	11/1/2017	0.50	11/13/2017	12.50	63.60	795.00
3300011603	RV	3900007242	633697	1012044	11/2/2017	11/20/2017	-65.20	02	11/2/2017	11/2/2017	0.50	11/20/2017	18.50	65.20	1,206.20
3300011605	RV	3900007241	633697	4005260	11/2/2017	11/20/2017	-64.40	02	11/2/2017	11/2/2017	0.50	11/20/2017	18.50	64.40	1,191.40
3300011606	RV	3900007330	633697	41717	11/2/2017	11/29/2017	-65.00	02	11/2/2017	11/2/2017	0.50	11/29/2017	27.50	65.00	1,787.50
3300011646	RV	3900007246	633697	1012044	11/2/2017	11/20/2017	-65.20	02	11/2/2017	11/2/2017	0.50	11/20/2017	18.50	65.20	1,206.20
3300011647	RV	3900007331	633697	41717	11/2/2017	11/29/2017	-63.00	02	11/2/2017	11/2/2017	0.50	11/29/2017	27.50	63.00	1,732.50
3300011687	RV	3900007325	633697	1012382	11/3/2017	11/28/2017	-66.80	02	11/3/2017	11/3/2017	0.50	11/28/2017	25.50	66.80	1,703.40
3300011688	RV	3900007243	633697	1012044	11/3/2017	11/20/2017	-61.40	02	11/3/2017	11/3/2017	0.50	11/20/2017	17.50	61.40	1,074.50
3300011689	RV	3900007244	633697	1012044	11/3/2017	11/20/2017	-65.20	02	11/3/2017	11/3/2017	0.50	11/20/2017	17.50	65.20	1,141.00
3300011704	RV	3900007363	633697	4005499	11/6/2017	11/30/2017	-66.00	02	11/6/2017	11/6/2017	0.50	11/30/2017	24.50	66.00	1,617.00
3300011708	RV	3900007319	633697	1012382	11/6/2017	11/28/2017	-60.40	02	11/6/2017	11/6/2017	0.50	11/28/2017	22.50	60.40	1,359.00
3300011709	RV	3900007316	633697	1012382	11/6/2017	11/28/2017	-63.20	02	11/6/2017	11/6/2017	0.50	11/28/2017	22.50	63.20	1,422.00
3300011710	RV	3900007323	633697	1012382	11/6/2017	11/28/2017	-61.00	02	11/6/2017	11/6/2017	0.50	11/28/2017	22.50	61.00	1,372.50
3300011749	RV	3900007322	633697	1012382	11/7/2017	11/28/2017	-70.80	02	11/7/2017	11/7/2017	0.50	11/28/2017	21.50	70.80	1,522.20
3300011752	RV	3900007320	633697	1012382	11/7/2017	11/28/2017	-62.20	02	11/7/2017	11/7/2017	0.50	11/28/2017	21.50	62.20	1,337.30
3300011753	RV	3900007321	633697	1012382	11/7/2017	11/28/2017	-65.20	02	11/7/2017	11/7/2017	0.50	11/28/2017	21.50	65.20	1,401.80
3300011754	RV	3900007318	633697	1012382	11/7/2017	11/28/2017	-64.00	02	11/7/2017	11/7/2017	0.50	11/28/2017	21.50	64.00	1,376.00
3300011755	RV	3900007324	633697	1012382	11/7/2017	11/28/2017	-62.60	02	11/7/2017	11/7/2017	0.50	11/28/2017	21.50	62.60	1,345.90
3300011780	RV	3900007439	633697	41717	11/8/2017	12/5/2017	-75.00	02	11/8/2017	11/8/2017	0.50	12/5/2017	27.50	75.00	2,062.50
3300011781	RV	3900007682	633697	1012044	11/8/2017	12/13/2017	-65.20	02	11/8/2017	11/8/2017	0.50	12/13/2017	35.50	65.20	2,314.60
3300011782	RV	3900007769	633697	1013325	11/8/2017	12/15/2017	-112.50	02	11/8/2017	11/8/2017	0.50	12/15/2017	37.50	112.50	4,218.75
3300011783	RV	3900007422	633697	4005260	11/8/2017	12/4/2017	-64.40	02	11/8/2017	11/8/2017	0.50	12/4/2017	26.50	64.40	1,706.60
3300011784	RV	3900007395	633697	1012382	11/8/2017	12/1/2017	-60.40	02	11/8/2017	11/8/2017	0.50	12/1/2017	23.50	60.40	1,419.40
3300011798	RV	3900007401	633697	1012382	11/9/2017	12/1/2017	-62.60	02	11/9/2017	11/9/2017	0.50	12/1/2017	22.50	62.60	1,408.50
3300011808	RV	3900007394	633697	1012382	11/10/2017	12/1/2017	-61.80	02	11/10/2017	11/10/2017	0.50	12/1/2017	21.50	61.80	1,328.70
3300011809	RV	3900007245	633697	1012044	11/10/2017	11/20/2017	-61.40	02	11/10/2017	11/10/2017	0.50	11/20/2017	10.50	61.40	644.70
3300011810	RV	3300011825	633697	4005499	11/10/2017	11/10/2017	-62.60	02	11/10/2017	11/10/2017	0.50	11/10/2017	0.50	62.60	31.30
3300011811	RV	3900007440	633697	41717	11/10/2017	12/5/2017	-61.40	02	11/10/2017	11/10/2017	0.50	12/5/2017	25.50	61.40	1,565.70
3300011813	RV	3900007399	633697	1012382	11/10/2017	12/1/2017	-61.80	02	11/10/2017	11/10/2017	0.50	12/1/2017	21.50	61.80	1,328.70
3300011825	RV	3300011825	633697	4005499	11/10/2017	11/10/2017	62.60	02	11/10/2017	11/10/2017	0.50	11/10/2017	0.50	(62.60)	(31.30)
3300011826	RV	3900007362	633697	4005499	11/10/2017	11/30/2017	-62.60	02	11/10/2017	11/10/2017	0.50	11/30/2017	20.50	62.60	1,283.30
3300011884	RV	3900007239	633697	1012435	11/13/2017	11/20/2017	-65.12	02	11/13/2017	11/13/2017	0.50	11/20/2017	7.50	65.12	488.40
3300011885	RV	3900007398	633697	1012382	11/13/2017	12/1/2017	-65.40	02	11/13/2017	11/13/2017	0.50	12/1/2017	18.50	65.40	1,209.90

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3300011886	RV	3900007397	633697	1012382	11/13/2017	12/1/2017	-65.20	02	11/13/2017	11/13/2017	0.50	12/1/2017	18.50	65.20	1,206.20
3300011940	RV	3900007317	633697	1012382	11/14/2017	11/28/2017	-65.20	02	11/14/2017	11/14/2017	0.50	11/28/2017	14.50	65.20	945.40
3300011941	RV	3900007595	633697	1012044	11/14/2017	12/8/2017	-61.40	02	11/14/2017	11/14/2017	0.50	12/8/2017	24.50	61.40	1,504.30
3300011983	RV	3300011989	633697	NEM	11/15/2017	11/15/2017	-61.40	02	11/15/2017	11/15/2017	0.50	11/15/2017	0.50	61.40	30.70
3300011984	RV	3900007247	633697	1012044	11/15/2017	11/20/2017	-61.40	02	11/15/2017	11/15/2017	0.50	11/20/2017	5.50	61.40	337.70
3300011985	RV	3900007396	633697	1012382	11/15/2017	12/1/2017	-68.00	02	11/15/2017	11/15/2017	0.50	12/1/2017	16.50	68.00	1,122.00
3300011986	RV	3900007361	633697	1012382	11/15/2017	11/30/2017	-60.40	02	11/15/2017	11/15/2017	0.50	11/30/2017	15.50	60.40	936.20
3300011987	RV	3900007400	633697	1012382	11/15/2017	12/1/2017	-61.80	02	11/15/2017	11/15/2017	0.50	12/1/2017	16.50	61.80	1,019.70
3300011988	RV	3900007360	633697	1012382	11/15/2017	11/30/2017	-61.80	02	11/15/2017	11/15/2017	0.50	11/30/2017	15.50	61.80	957.90
3300011989	RV	3300011989	633697	NEM	11/15/2017	11/15/2017	61.40	02	11/15/2017	11/15/2017	0.50	11/15/2017	0.50	(61.40)	(30.70)
3300011990	RV	3900007248	633697	1012044	11/15/2017	11/20/2017	-61.40	02	11/15/2017	11/15/2017	0.50	11/20/2017	5.50	61.40	337.70
3300012129	RV	3900007441	633697	41717	11/20/2017	12/5/2017	-61.40	02	11/20/2017	11/20/2017	0.50	12/5/2017	15.50	61.40	951.70
3300012130	RV	3900007437	633697	41717	11/20/2017	12/5/2017	-61.40	02	11/20/2017	11/20/2017	0.50	12/5/2017	15.50	61.40	951.70
3300012131	RV	3900007512	633697	1012382	11/20/2017	12/6/2017	-65.60	02	11/20/2017	11/20/2017	0.50	12/6/2017	16.50	65.60	1,082.40
3300012132	RV	3900007438	633697	41717	11/20/2017	12/5/2017	-62.00	02	11/20/2017	11/20/2017	0.50	12/5/2017	15.50	62.00	961.00
3300012135	RV	3900007511	633697	1012382	11/20/2017	12/6/2017	-60.40	02	11/20/2017	11/20/2017	0.50	12/6/2017	16.50	60.40	996.60
3300012136	RV	3900007596	633697	1012044	11/20/2017	12/8/2017	-61.40	02	11/20/2017	11/20/2017	0.50	12/8/2017	18.50	61.40	1,135.90
3300012156	RV	3900007627	633697	1012382	11/21/2017	12/12/2017	-60.40	02	11/21/2017	11/21/2017	0.50	12/12/2017	21.50	60.40	1,298.60
3300012157	RV	3900007498	633697	4005499	11/21/2017	12/6/2017	-61.00	02	11/21/2017	11/21/2017	0.50	12/6/2017	15.50	61.00	945.50
3300012175	RV	3900007623	633697	1012382	11/22/2017	12/12/2017	-71.80	02	11/22/2017	11/22/2017	0.50	12/12/2017	20.50	71.80	1,471.90
3300012176	RV	3900007820	633697	1012382	11/22/2017	12/18/2017	-62.60	02	11/22/2017	11/22/2017	0.50	12/18/2017	26.50	62.60	1,658.90
3300012177	RV	3900007814	633697	1012382	11/22/2017	12/18/2017	-60.40	02	11/22/2017	11/22/2017	0.50	12/18/2017	26.50	60.40	1,600.60
3300012178	RV	3900007622	633697	1012382	11/22/2017	12/12/2017	-61.60	02	11/22/2017	11/22/2017	0.50	12/12/2017	20.50	61.60	1,262.80
3300012179	RV	3900007624	633697	1012382	11/22/2017	12/12/2017	-70.80	02	11/22/2017	11/22/2017	0.50	12/12/2017	20.50	70.80	1,451.40
3300012180	RV	3900007629	633697	1012382	11/22/2017	12/12/2017	-69.00	02	11/22/2017	11/22/2017	0.50	12/12/2017	20.50	69.00	1,414.50
3300012181	RV	3900007827	633697	1012382	11/22/2017	12/18/2017	-65.20	02	11/22/2017	11/22/2017	0.50	12/18/2017	26.50	65.20	1,727.80
3300012184	RV	3900007817	633697	1012382	11/22/2017	12/18/2017	-67.60	02	11/22/2017	11/22/2017	0.50	12/18/2017	26.50	67.60	1,791.40
3300012187	RV	3900007826	633697	1012382	11/22/2017	12/18/2017	-70.40	02	11/22/2017	11/22/2017	0.50	12/18/2017	26.50	70.40	1,865.60
3300012192	RV	3900007683	633697	41717	11/22/2017	12/13/2017	-62.00	02	11/22/2017	11/22/2017	0.50	12/13/2017	21.50	62.00	1,333.00
3300012245	RV	3900007828	633697	1012382	11/27/2017	12/18/2017	-63.20	02	11/27/2017	11/27/2017	0.50	12/18/2017	21.50	63.20	1,358.80
3300012272	RV	3300012293	633697	1012382	11/27/2017	11/27/2017	-62.80	02	11/27/2017	11/27/2017	0.50	11/27/2017	0.50	62.80	31.40
3300012274	RV	3900007816	633697	1012382	11/27/2017	12/18/2017	-70.00	02	11/27/2017	11/27/2017	0.50	12/18/2017	21.50	70.00	1,505.00
3300012275	RV	3900007701	633697	41717	11/27/2017	12/14/2017	-62.00	02	11/27/2017	11/27/2017	0.50	12/14/2017	17.50	62.00	1,085.00
3300012279	RV	3900007821	633697	1012382	11/27/2017	12/18/2017	-61.80	02	11/27/2017	11/27/2017	0.50	12/18/2017	21.50	61.80	1,328.70
3300012284	RV	3900007597	633697	1012044	11/27/2017	12/8/2017	-65.20	02	11/27/2017	11/27/2017	0.50	12/8/2017	11.50	65.20	749.80
3300012286	RV	3900007824	633697	1012382	11/27/2017	12/18/2017	-60.40	02	11/27/2017	11/27/2017	0.50	12/18/2017	21.50	60.40	1,298.60
3300012287	RV	3900007825	633697	1012382	11/27/2017	12/18/2017	-63.20	02	11/27/2017	11/27/2017	0.50	12/18/2017	21.50	63.20	1,358.80
3300012288	RV	3300012291	633697	41717	11/27/2017	11/27/2017	-62.00	02	11/27/2017	11/27/2017	0.50	11/27/2017	0.50	62.00	31.00
3300012290	RV	3900007812	633697	1012382	11/27/2017	12/18/2017	-61.80	02	11/27/2017	11/27/2017	0.50	12/18/2017	21.50	61.80	1,328.70
3300012291	RV	3300012291	633697	41717	11/27/2017	11/27/2017	62.00	02	11/27/2017	11/27/2017	0.50	11/27/2017	0.50	(62.00)	(31.00)
3300012292	RV	3900007699	633697	41717	11/27/2017	12/14/2017	-62.00	02	11/27/2017	11/27/2017	0.50	12/14/2017	17.50	62.00	1,085.00
3300012293	RV	3300012293	633697	1012382	11/27/2017	11/27/2017	62.80	02	11/27/2017	11/27/2017	0.50	11/27/2017	0.50	(62.80)	(31.40)
3300012294	RV	3900007819	633697	1012382	11/27/2017	12/18/2017	-62.80	02	11/27/2017	11/27/2017	0.50	12/18/2017	21.50	62.80	1,350.20
3300012605	RV	3900007823	633697	1012382	11/29/2017	12/18/2017	-61.80	02	11/29/2017	11/29/2017	0.50	12/18/2017	19.50	61.80	1,205.10
3300012606	RV	3300012607	633697	NEM	11/29/2017	11/29/2017	-65.20	02	11/29/2017	11/29/2017	0.50	11/29/2017	0.50	65.20	32.60
3300012607	RV	3300012607	633697	NEM	11/29/2017	11/29/2017	65.20	02	11/29/2017	11/29/2017	0.50	11/29/2017	0.50	(65.20)	(32.60)
3300012608	RV	3900007600	633697	1012044	11/29/2017	12/8/2017	-65.20	02	11/29/2017	11/29/2017	0.50	12/8/2017	9.50	65.20	619.40
3300012609	RV	3900007674	633697	1013341	11/29/2017	12/12/2017	-64.84	02	11/29/2017	11/29/2017	0.50	12/12/2017	13.50	64.84	875.34
3300012610	RV	3900007499	633697	1012423	11/29/2017	12/6/2017	-69.00	02	11/29/2017	11/29/2017	0.50	12/6/2017	7.50	69.00	517.50
3300012611	RV	3900007601	633697	1012044	11/29/2017	12/8/2017	-65.20	02	11/29/2017	11/29/2017	0.50	12/8/2017	9.50	65.20	619.40

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital Study
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Other Revenue Lag
Fire & Damage Reconnect, Joint Use Escort and interconnection Application Fee

Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Service period Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300012613	RV	3900000909	633697	1012044	11/29/2017	2/22/2018	-61.40	02	11/29/2017	11/29/2017	0.50	2/22/2018	85.50	61.40	5,249.70
3300012622	RV	3900007598	633697	1012044	11/30/2017	12/8/2017	-61.40	02	11/30/2017	11/30/2017	0.50	12/8/2017	8.50	61.40	521.90
3300012623	RV	3900007813	633697	1012382	11/30/2017	12/18/2017	-61.80	02	11/30/2017	11/30/2017	0.50	12/18/2017	18.50	61.80	1,143.30
3300012624	RV	3900007599	633697	1012044	11/30/2017	12/8/2017	-61.40	02	11/30/2017	11/30/2017	0.50	12/8/2017	8.50	61.40	521.90
3300012625	RV	3900007818	633697	1012382	11/30/2017	12/18/2017	-74.40	02	11/30/2017	11/30/2017	0.50	12/18/2017	18.50	74.40	1,376.40
3300012626	RV	3900007815	633697	1012382	11/30/2017	12/18/2017	-60.20	02	11/30/2017	11/30/2017	0.50	12/18/2017	18.50	60.20	1,113.70
3300012628	RV	3900007822	633697	1012382	11/30/2017	12/18/2017	-61.60	02	11/30/2017	11/30/2017	0.50	12/18/2017	18.50	61.60	1,139.60
3300012730	RV	3900007705	633697	4005499	12/1/2017	12/14/2017	-65.20	02	12/1/2017	12/1/2017	0.50	12/14/2017	13.50	65.20	880.20
3300012732	RV	3900007680	633697	1012044	12/1/2017	12/13/2017	-61.40	02	12/1/2017	12/1/2017	0.50	12/13/2017	12.50	61.40	767.50
3300012733	RV	3900007681	633697	1012044	12/1/2017	12/13/2017	-65.20	02	12/1/2017	12/1/2017	0.50	12/13/2017	12.50	65.20	815.00
3300012735	RV	3900007704	633697	4005499	12/1/2017	12/14/2017	-67.60	02	12/1/2017	12/1/2017	0.50	12/14/2017	13.50	67.60	912.60
3300012737	RV	3900007679	633697	1012044	12/1/2017	12/13/2017	-61.40	02	12/1/2017	12/1/2017	0.50	12/13/2017	12.50	61.40	767.50
3300012738	RV	3900007703	633697	4005499	12/1/2017	12/14/2017	-63.00	02	12/1/2017	12/1/2017	0.50	12/14/2017	13.50	63.00	850.50
3300012762	RV	3900007589	633697	1012044	12/4/2017	12/8/2017	-65.20	02	12/4/2017	12/4/2017	0.50	12/8/2017	4.50	65.20	293.40
3300012767	RV	3900007588	633697	1012044	12/4/2017	12/8/2017	-65.20	02	12/4/2017	12/4/2017	0.50	12/8/2017	4.50	65.20	293.40
3300012772	RV	3900007700	633697	41717	12/4/2017	12/14/2017	-137.00	02	12/4/2017	12/4/2017	0.50	12/14/2017	10.50	137.00	1,438.50
3300012791	RV	3900007517	633697	21320	12/1/2017	12/7/2017	-982.40	02	12/1/2017	12/1/2017	0.50	12/7/2017	6.50	982.40	6,385.60
3300012792	RV	3900000530	633697	4005499	12/5/2017	2/1/2018	-63.60	02	12/5/2017	12/5/2017	0.50	2/1/2018	58.50	63.60	3,720.60
3300012794	RV	3900007945	633697	41717	12/5/2017	12/21/2017	-63.60	02	12/5/2017	12/5/2017	0.50	12/21/2017	16.50	63.60	1,049.40
3300012799	RV	3900007913	633697	1012382	12/5/2017	12/19/2017	-60.40	02	12/5/2017	12/5/2017	0.50	12/19/2017	14.50	60.40	875.80
3300012804	RV	3900007909	633697	1012382	12/5/2017	12/19/2017	-61.80	02	12/5/2017	12/5/2017	0.50	12/19/2017	14.50	61.80	896.10
3300012805	RV	3300012806	633697	NEM	12/5/2017	12/5/2017	-61.40	02	12/5/2017	12/5/2017	0.50	12/5/2017	0.50	61.40	30.70
3300012806	RV	3300012806	633697	NEM	12/5/2017	12/5/2017	61.40	02	12/5/2017	12/5/2017	0.50	12/5/2017	0.50	(61.40)	(30.70)
3300012814	RV	3900007706	633697	4005499	12/5/2017	12/14/2017	-61.40	02	12/5/2017	12/5/2017	0.50	12/14/2017	9.50	61.40	583.30
3300012865	RV	3900007829	633697	1012044	12/6/2017	12/18/2017	-65.20	02	12/6/2017	12/6/2017	0.50	12/18/2017	12.50	65.20	815.00
3300012866	RV	3900007707	633697	4005499	12/6/2017	12/14/2017	-61.40	02	12/6/2017	12/6/2017	0.50	12/14/2017	8.50	61.40	521.90
3300012879	RV	3900007911	633697	1012382	12/7/2017	12/19/2017	-61.00	02	12/7/2017	12/7/2017	0.50	12/19/2017	12.50	61.00	762.50
3300012880	RV	3900007907	633697	1012382	12/7/2017	12/19/2017	-67.80	02	12/7/2017	12/7/2017	0.50	12/19/2017	12.50	67.80	847.50
3300012881	RV	3900007686	633697	4005260	12/7/2017	12/13/2017	-64.40	02	12/7/2017	12/7/2017	0.50	12/13/2017	6.50	64.40	418.60
3300012885	RV	3900007830	633697	1012044	12/7/2017	12/18/2017	-65.20	02	12/7/2017	12/7/2017	0.50	12/18/2017	11.50	65.20	749.80
3300012891	RV	3900007833	633697	1012044	12/7/2017	12/18/2017	-61.40	02	12/7/2017	12/7/2017	0.50	12/18/2017	11.50	61.40	706.10
3300012894	RV	3900007910	633697	1012382	12/7/2017	12/19/2017	-62.80	02	12/7/2017	12/7/2017	0.50	12/19/2017	12.50	62.80	785.00
3300012895	RV	3900007916	633697	1012382	12/7/2017	12/19/2017	-62.60	02	12/7/2017	12/7/2017	0.50	12/19/2017	12.50	62.60	782.50
3300012896	RV	3900007912	633697	1012382	12/7/2017	12/19/2017	-60.40	02	12/7/2017	12/7/2017	0.50	12/19/2017	12.50	60.40	755.00
3300012897	RV	3900007908	633697	1012382	12/7/2017	12/19/2017	-64.20	02	12/7/2017	12/7/2017	0.50	12/19/2017	12.50	64.20	802.50
3300012899	RV	3900007834	633697	1012044	12/7/2017	12/18/2017	-61.40	02	12/7/2017	12/7/2017	0.50	12/18/2017	11.50	61.40	706.10
3300012966	RV	3900007832	633697	1012044	12/8/2017	12/18/2017	-61.40	02	12/8/2017	12/8/2017	0.50	12/18/2017	10.50	61.40	644.70
3300012972	RV	3900008019	633697	1012382	12/8/2017	12/28/2017	-72.80	02	12/8/2017	12/8/2017	0.50	12/28/2017	20.50	72.80	1,492.40
3300012975	RV	3900000919	633697	1012044	12/8/2017	2/22/2018	-65.20	02	12/8/2017	12/8/2017	0.50	2/22/2018	76.50	65.20	4,987.80
3300012977	RV	3900007831	633697	1012044	12/8/2017	12/18/2017	-61.40	02	12/8/2017	12/8/2017	0.50	12/18/2017	10.50	61.40	644.70
3300013193	RV	3900008080	633697	1012044	12/11/2017	12/28/2017	-65.20	02	12/11/2017	12/11/2017	0.50	12/28/2017	17.50	65.20	1,141.00
3300013194	RV	3900000011	633697	41717	12/11/2017	1/2/2018	-70.00	02	12/11/2017	12/11/2017	0.50	1/2/2018	22.50	70.00	1,575.00
3300013195	RV	3300013198	633697	NEM	12/11/2017	12/11/2017	-60.40	02	12/11/2017	12/11/2017	0.50	12/11/2017	0.50	60.40	30.20
3300013198	RV	3300013198	633697	NEM	12/11/2017	12/11/2017	60.40	02	12/11/2017	12/11/2017	0.50	12/11/2017	0.50	(60.40)	(30.20)
3300013199	RV	3900008026	633697	1012382	12/11/2017	12/28/2017	-60.40	02	12/11/2017	12/11/2017	0.50	12/28/2017	17.50	60.40	1,057.00
3300013407	RV	3900008023	633697	1012382	12/14/2017	12/28/2017	-75.40	02	12/14/2017	12/14/2017	0.50	12/28/2017	14.50	75.40	1,093.30
3300013408	RV	3900008081	633697	1012044	12/14/2017	12/28/2017	-61.40	02	12/14/2017	12/14/2017	0.50	12/28/2017	14.50	61.40	890.30
3300013410	RV	3900008082	633697	1012382	12/14/2017	12/28/2017	-61.40	02	12/14/2017	12/14/2017	0.50	12/28/2017	14.50	61.40	890.30
3300013411	RV	3900008027	633697	1012382	12/14/2017	12/28/2017	-62.60	02	12/14/2017	12/14/2017	0.50	12/28/2017	14.50	62.60	907.70
3300013414	RV	3900008083	633697	1012044	12/14/2017	12/28/2017	-65.20	02	12/14/2017	12/14/2017	0.50	12/28/2017	14.50	65.20	945.40

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3300013416	RV	3900008025	633697	1012382	12/14/2017	12/28/2017	-62.00	02	12/14/2017	12/14/2017	0.50	12/28/2017	14.50	62.00	899.00
3300013417	RV	3900008021	633697	1012382	12/14/2017	12/28/2017	-60.40	02	12/14/2017	12/14/2017	0.50	12/28/2017	14.50	60.40	875.80
3300013418	RV	3900008020	633697	1012382	12/14/2017	12/28/2017	-61.39	02	12/14/2017	12/14/2017	0.50	12/28/2017	14.50	61.39	890.16
3300013419	RV	3900008024	633697	1012382	12/14/2017	12/28/2017	-60.40	02	12/14/2017	12/14/2017	0.50	12/28/2017	14.50	60.40	875.80
3300013421	RV	3900000920	633697	1012044	12/14/2017	2/22/2018	-65.23	02	12/14/2017	12/14/2017	0.50	2/22/2018	70.50	65.23	4,598.72
3300013422	RV	3900008022	633697	1012382	12/14/2017	12/28/2017	-66.00	02	12/14/2017	12/14/2017	0.50	12/28/2017	14.50	66.00	957.00
3300013423	RV	3300013423	633697	4005260	9/19/2017	12/15/2017	63.00	02	9/19/2017	9/19/2017	0.50	12/15/2017	87.50	(63.00)	(5,512.50)
3300013595	RV	3900007989	633697	1012385	12/19/2017	12/22/2017	-110.00	02	12/19/2017	12/19/2017	0.50	12/22/2017	3.50	110.00	385.00
3300013596	RV	3300013597	633697	NEM	12/19/2017	12/19/2017	-61.40	02	12/19/2017	12/19/2017	0.50	12/19/2017	0.50	61.40	30.70
3300013597	RV	3300013597	633697	NEM	12/19/2017	12/19/2017	61.40	02	12/19/2017	12/19/2017	0.50	12/19/2017	0.50	(61.40)	(30.70)
3300013598	RV	3900008084	633697	1012044	12/19/2017	12/28/2017	-61.40	02	12/19/2017	12/19/2017	0.50	12/28/2017	9.50	61.40	583.30
3300013599	RV	3900000207	633697	1012382	12/19/2017	1/11/2018	-60.20	02	12/19/2017	12/19/2017	0.50	1/11/2018	23.50	60.20	1,414.70
3300013601	RV	3900000206	633697	1012382	12/19/2017	1/11/2018	-60.40	02	12/19/2017	12/19/2017	0.50	1/11/2018	23.50	60.40	1,419.40
3300013737	RV	3900000208	633697	1012382	12/20/2017	1/11/2018	-60.41	02	12/20/2017	12/20/2017	0.50	1/11/2018	22.50	60.41	1,359.23
3300013738	RV	3900008028	633697	4005260	12/20/2017	12/28/2017	-61.39	02	12/20/2017	12/20/2017	0.50	12/28/2017	8.50	61.39	521.82
3300013740	RV	3900008098	633697	1012044	12/20/2017	12/28/2017	-61.40	02	12/20/2017	12/20/2017	0.50	12/28/2017	8.50	61.40	521.90
3300013741	RV	3900000197	633697	1012382	12/20/2017	1/11/2018	-61.80	02	12/20/2017	12/20/2017	0.50	1/11/2018	22.50	61.80	1,390.50
3300013742	RV	3800000717	633697	4005260	12/20/2017	12/28/2017	-61.40	02	12/20/2017	12/20/2017	0.50	12/28/2017	8.50	61.40	521.90
3300013743	RV	3900000205	633697	1012382	12/20/2017	1/11/2018	-61.40	02	12/20/2017	12/20/2017	0.50	1/11/2018	22.50	61.40	1,381.50
3300013744	RV	3900000198	633697	1012382	12/20/2017	1/11/2018	-61.80	02	12/20/2017	12/20/2017	0.50	1/11/2018	22.50	61.80	1,390.50
3300013745	RV	3900008099	633697	1012044	12/20/2017	12/28/2017	-61.40	02	12/20/2017	12/20/2017	0.50	12/28/2017	8.50	61.40	521.90
3300013775	RV	3900000202	633697	1012382	12/21/2017	1/11/2018	-60.20	02	12/21/2017	12/21/2017	0.50	1/11/2018	21.50	60.20	1,294.30
3300013808	RV	3900000138	633697	4005499	12/22/2017	1/9/2018	-66.00	02	12/22/2017	12/22/2017	0.50	1/9/2018	18.50	66.00	1,221.00
3300013810	RV	3900000203	633697	1012382	12/22/2017	1/11/2018	-60.40	02	12/22/2017	12/22/2017	0.50	1/11/2018	20.50	60.40	1,238.20
3300013813	RV	3900000118	633697	1012044	12/22/2017	1/9/2018	-61.40	02	12/22/2017	12/22/2017	0.50	1/9/2018	18.50	61.40	1,135.90
3300013829	RV	3900000204	633697	1012382	12/22/2017	1/11/2018	-62.80	02	12/22/2017	12/22/2017	0.50	1/11/2018	20.50	62.80	1,287.40
3300013830	RV	3900000119	633697	1012044	12/22/2017	1/9/2018	-61.40	02	12/22/2017	12/22/2017	0.50	1/9/2018	18.50	61.40	1,135.90
3300013832	RV	3900000199	633697	1012382	12/22/2017	1/11/2018	-62.60	02	12/22/2017	12/22/2017	0.50	1/11/2018	20.50	62.60	1,283.30
3300013856	RV	3900000201	633697	1012382	12/27/2017	1/11/2018	-60.40	02	12/27/2017	12/27/2017	0.50	1/11/2018	15.50	60.40	936.20
3300013857	RV	3900000200	633697	1012382	12/27/2017	1/11/2018	-60.40	02	12/27/2017	12/27/2017	0.50	1/11/2018	15.50	60.40	936.20
3300013858	RV	3900000120	633697	1012044	12/27/2017	1/9/2018	-61.40	02	12/27/2017	12/27/2017	0.50	1/9/2018	13.50	61.40	828.90
3300013859	RV	3900000121	633697	1012044	12/27/2017	1/9/2018	-65.20	02	12/27/2017	12/27/2017	0.50	1/9/2018	13.50	65.20	880.20
3300013865	RV	3900000122	633697	1012044	12/27/2017	1/9/2018	-61.40	02	12/27/2017	12/27/2017	0.50	1/9/2018	13.50	61.40	828.90
3300013873	RV	3900000123	633697	1012044	12/27/2017	1/9/2018	-61.40	02	12/27/2017	12/27/2017	0.50	1/9/2018	13.50	61.40	828.90
3300013936	RV	3900000242	633697	1012237	12/28/2017	1/15/2018	-249.80	02	12/28/2017	12/28/2017	0.50	1/15/2018	18.50	249.80	4,621.30
3300013937	RV	3800000717	633697	4005260	12/28/2017	12/28/2017	61.40	02	12/28/2017	12/28/2017	0.50	12/28/2017	0.50	(61.40)	(30.70)
3300000278	RV	3300000278	633699	1012811	10/5/2016	1/11/2017	500.00	09	10/5/2016	10/5/2016	0.50	1/11/2017	98.50	(500.00)	(49,250.00)
3300000429	RV	3900001128	633699	1012240	1/18/2017	2/21/2017	-500.00	09	1/18/2017	1/18/2017	0.50	2/21/2017	34.50	500.00	17,250.00
3300000803	RV	3900000958	633699	1012382	1/27/2017	2/15/2017	-500.00	09	1/27/2017	1/27/2017	0.50	2/15/2017	19.50	500.00	9,750.00
3300001147	RV	3900000742	633699	36926	1/31/2017	2/8/2017	-500.00	09	1/31/2017	1/31/2017	0.50	2/8/2017	8.50	500.00	4,250.00
3300001925	RV	3900001577	633699	1013078	2/22/2017	3/7/2017	-500.00	09	2/22/2017	2/22/2017	0.50	3/7/2017	13.50	500.00	6,750.00
3300002743	RV	3900002065	633699	1012386	3/16/2017	3/28/2017	-500.00	09	3/16/2017	3/16/2017	0.50	3/28/2017	12.50	500.00	6,250.00
3300002746	RV	3900001878	633699	36926	3/16/2017	3/21/2017	-500.00	09	3/16/2017	3/16/2017	0.50	3/21/2017	5.50	500.00	2,750.00
3300002807	RV	3900001863	633699	36926	3/16/2017	3/20/2017	-500.00	09	3/16/2017	3/16/2017	0.50	3/20/2017	4.50	500.00	2,250.00
3300003136	RV	3900002277	633699	1012386	3/23/2017	4/6/2017	-500.00	09	3/23/2017	3/23/2017	0.50	4/6/2017	14.50	500.00	7,250.00
3300003844	RV	3300003845	633699	NEM	4/4/2017	4/4/2017	-500.00	09	4/4/2017	4/4/2017	0.50	4/4/2017	0.50	500.00	250.00
3300003845	RV	3300003845	633699	NEM	4/4/2017	4/4/2017	500.00	09	4/4/2017	4/4/2017	0.50	4/4/2017	0.50	(500.00)	(250.00)
3300003846	RV	3900002275	633699	1013119	4/4/2017	4/6/2017	-500.00	09	4/4/2017	4/4/2017	0.50	4/6/2017	2.50	500.00	1,250.00
3300004001	RV	3900002484	633699	36926	4/7/2017	4/14/2017	-500.00	09	4/7/2017	4/7/2017	0.50	4/14/2017	7.50	500.00	3,750.00
3300004005	RV	3900002761	633699	1012386	4/7/2017	4/24/2017	-500.00	09	4/7/2017	4/7/2017	0.50	4/24/2017	17.50	500.00	8,750.00

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Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Service period Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300004062	RV	3900002527	633699	36926	4/10/2017	4/17/2017	-500.00	09	4/10/2017	4/10/2017	0.50	4/17/2017	7.50	500.00	3,750.00
3300004063	RV	3900002574	633699	36926	4/10/2017	4/19/2017	-500.00	09	4/10/2017	4/10/2017	0.50	4/19/2017	9.50	500.00	4,750.00
3300004072	RV	3300004078	633699	NEM	4/10/2017	4/10/2017	-500.00	09	4/10/2017	4/10/2017	0.50	4/10/2017	0.50	500.00	250.00
3300004078	RV	3300004078	633699	NEM	4/10/2017	4/10/2017	500.00	09	4/10/2017	4/10/2017	0.50	4/10/2017	0.50	(500.00)	(250.00)
3300004079	RV	3900003279	633699	36926	4/10/2017	5/18/2017	-500.00	09	4/10/2017	4/10/2017	0.50	5/18/2017	38.50	500.00	19,250.00
3300004268	RV	3300004276	633699	NEM	4/13/2017	4/13/2017	-500.00	09	4/13/2017	4/13/2017	0.50	4/13/2017	0.50	500.00	250.00
3300004276	RV	3300004276	633699	NEM	4/13/2017	4/13/2017	500.00	09	4/13/2017	4/13/2017	0.50	4/13/2017	0.50	(500.00)	(250.00)
3300004674	RV	3900003071	633699	1012357	4/21/2017	5/8/2017	-500.00	09	4/21/2017	4/21/2017	0.50	5/8/2017	17.50	500.00	8,750.00
3300004675	RV	3900003073	633699	1012357	4/21/2017	5/8/2017	-500.00	09	4/21/2017	4/21/2017	0.50	5/8/2017	17.50	500.00	8,750.00
3300005316	RV	3900004005	633699	1013171	5/5/2017	6/21/2017	-500.00	09	5/5/2017	5/5/2017	0.50	6/21/2017	47.50	500.00	23,750.00
3300005659	RV	3900003620	633699	1012382	5/16/2017	6/2/2017	-500.00	09	5/16/2017	5/16/2017	0.50	6/2/2017	17.50	500.00	8,750.00
3300005691	RV	3900003441	633699	1013119	5/17/2017	5/24/2017	-500.00	09	5/17/2017	5/17/2017	0.50	5/24/2017	7.50	500.00	3,750.00
3300005698	RV	3900003542	633699	1013171	5/17/2017	5/31/2017	-500.00	09	5/17/2017	5/17/2017	0.50	5/31/2017	14.50	500.00	7,250.00
3300005789	RV	3900003400	633699	1013119	5/19/2017	5/23/2017	-500.00	09	5/19/2017	5/19/2017	0.50	5/23/2017	4.50	500.00	2,250.00
3300005790	RV	3900003401	633699	1013198	5/19/2017	5/23/2017	-500.00	09	5/19/2017	5/19/2017	0.50	5/23/2017	4.50	500.00	2,250.00
3300006135	RV	3900003733	633699	1012386	5/30/2017	6/6/2017	-500.00	09	5/30/2017	5/30/2017	0.50	6/6/2017	7.50	500.00	3,750.00
3300006136	RV	3900003595	633699	36926	5/30/2017	6/2/2017	-500.00	09	5/30/2017	5/30/2017	0.50	6/2/2017	3.50	500.00	1,750.00
3300006170	RV	3900003641	633699	1013119	6/1/2017	6/5/2017	-500.00	09	6/1/2017	6/1/2017	0.50	6/5/2017	4.50	500.00	2,250.00
3300006173	RV	3900003911	633699	36926	6/1/2017	6/16/2017	-500.00	09	6/1/2017	6/1/2017	0.50	6/16/2017	15.50	500.00	7,750.00
3300006174	RV	3300009404	633699	1012386	6/1/2017	8/30/2017	-500.00	09	6/1/2017	6/1/2017	0.50	8/30/2017	90.50	500.00	45,250.00
3300006180	RV	3900003888	633699	36926	6/1/2017	6/15/2017	-500.00	09	6/1/2017	6/1/2017	0.50	6/15/2017	14.50	500.00	7,250.00
3300006420	RV	3900003889	633699	1012723	6/8/2017	6/15/2017	-500.00	09	6/8/2017	6/8/2017	0.50	6/15/2017	7.50	500.00	3,750.00
3300006421	RV	3900003924	633699	1013119	6/8/2017	6/19/2017	-500.00	09	6/8/2017	6/8/2017	0.50	6/19/2017	11.50	500.00	5,750.00
3300006427	RV	3900003921	633699	36926	6/8/2017	6/19/2017	-500.00	09	6/8/2017	6/8/2017	0.50	6/19/2017	11.50	500.00	5,750.00
3300006473	RV	3900003890	633699	1013119	6/9/2017	6/15/2017	-500.00	09	6/9/2017	6/9/2017	0.50	6/15/2017	6.50	500.00	3,250.00
3300006559	RV	3900003974	633699	36926	6/13/2017	6/20/2017	-500.00	09	6/13/2017	6/13/2017	0.50	6/20/2017	7.50	500.00	3,750.00
3300006872	RV	3900004134	633699	1005466	6/22/2017	6/28/2017	-500.00	09	6/22/2017	6/22/2017	0.50	6/28/2017	6.50	500.00	3,250.00
3300006881	RV	3900004918	633699	36926	6/22/2017	7/31/2017	-500.00	09	6/22/2017	6/22/2017	0.50	7/31/2017	39.50	500.00	19,750.00
3300007011	RV	3300007039	633699	NEM	6/26/2017	6/26/2017	-500.00	09	6/26/2017	6/26/2017	0.50	6/26/2017	0.50	500.00	250.00
3300007039	RV	3300007039	633699	NEM	6/26/2017	6/26/2017	500.00	09	6/26/2017	6/26/2017	0.50	6/26/2017	0.50	(500.00)	(250.00)
3300007040	RV	3900005332	633699	1012499	6/26/2017	8/17/2017	-500.00	09	6/26/2017	6/26/2017	0.50	8/17/2017	52.50	500.00	26,250.00
3300007346	RV	3900004334	633699	1012237	6/30/2017	7/5/2017	-500.00	09	6/30/2017	6/30/2017	0.50	7/5/2017	5.50	500.00	2,750.00
3300007381	RV	3900004828	633699	1012386	7/5/2017	7/25/2017	-500.00	09	7/5/2017	7/5/2017	0.50	7/25/2017	20.50	500.00	10,250.00
3300007496	RV	3900004966	633699	36926	7/10/2017	8/1/2017	-500.00	09	7/10/2017	7/10/2017	0.50	8/1/2017	22.50	500.00	11,250.00
3300007722	RV	3300008309	633699	35528	7/13/2017	7/28/2017	-500.00	09	7/13/2017	7/13/2017	0.50	7/28/2017	15.50	500.00	7,750.00
3300008060	RV	3900005573	633699	1012637	7/24/2017	8/30/2017	-500.00	09	7/24/2017	7/24/2017	0.50	8/30/2017	37.50	500.00	18,750.00
3300008076	RV	3900005501	633699	36926	7/24/2017	8/28/2017	-500.00	09	7/24/2017	7/24/2017	0.50	8/28/2017	35.50	500.00	17,750.00
3300008309	RV	3300008309	633699	35528	7/13/2017	7/28/2017	500.00	09	7/13/2017	7/13/2017	0.50	7/28/2017	15.50	(500.00)	(7,750.00)
3300008394	RV	3300008395	633699	NEM	8/2/2017	8/2/2017	-500.00	09	8/2/2017	8/2/2017	0.50	8/2/2017	0.50	500.00	250.00
3300008395	RV	3300008395	633699	NEM	8/2/2017	8/2/2017	500.00	09	8/2/2017	8/2/2017	0.50	8/2/2017	0.50	(500.00)	(250.00)
3300008396	RV	3900005876	633699	1013119	8/2/2017	9/15/2017	-500.00	09	8/2/2017	8/2/2017	0.50	9/15/2017	44.50	500.00	22,250.00
3300008449	RV	3900005596	633699	1012382	8/3/2017	8/30/2017	-500.00	09	8/3/2017	8/3/2017	0.50	8/30/2017	27.50	500.00	13,750.00
3300008451	RV	3900005144	633699	1013119	8/3/2017	8/9/2017	-500.00	09	8/3/2017	8/3/2017	0.50	8/9/2017	6.50	500.00	3,250.00
3300008453	RV	3900005410	633699	1012357	8/3/2017	8/22/2017	-500.00	09	8/3/2017	8/3/2017	0.50	8/22/2017	19.50	500.00	9,750.00
3300008483	RV	3900006039	633699	1012237	8/4/2017	9/21/2017	-500.00	09	8/4/2017	8/4/2017	0.50	9/21/2017	48.50	500.00	24,250.00
3300008713	RV	3900005511	633699	41717	8/16/2017	8/28/2017	-500.00	09	8/16/2017	8/16/2017	0.50	8/28/2017	12.50	500.00	6,250.00
3300008866	RV	3300008880	633699	NEM	8/21/2017	8/21/2017	-500.00	09	8/21/2017	8/21/2017	0.50	8/21/2017	0.50	500.00	250.00
3300008875	RV	3900005654	633699	1012357	8/21/2017	9/1/2017	-500.00	09	8/21/2017	8/21/2017	0.50	9/1/2017	11.50	500.00	5,750.00
3300008879	RV	3900005629	633699	1012382	8/21/2017	8/31/2017	-500.00	09	8/21/2017	8/21/2017	0.50	8/31/2017	10.50	500.00	5,250.00
3300008880	RV	3300008880	633699	NEM	8/21/2017	8/21/2017	500.00	09	8/21/2017	8/21/2017	0.50	8/21/2017	0.50	(500.00)	(250.00)

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3300008926	RV	3900007180	633699	1012382	8/22/2017	11/16/2017	-500.00	09	8/22/2017	8/22/2017	0.50	11/16/2017	86.50	500.00	43,250.00
3300008945	RV	3900005712	633699	1013217	8/23/2017	9/7/2017	-500.00	09	8/23/2017	8/23/2017	0.50	9/7/2017	15.50	500.00	7,750.00
3300009086	RV	3900005531	633699	1012385	8/24/2017	8/29/2017	-500.00	09	8/24/2017	8/24/2017	0.50	8/29/2017	5.50	500.00	2,750.00
3300009220	RV	3900005534	633699	1012386	8/28/2017	8/29/2017	-500.00	09	8/28/2017	8/28/2017	0.50	8/29/2017	1.50	500.00	750.00
3300009222	RV	3300009223	633699	NEM	8/28/2017	8/28/2017	-500.00	09	8/28/2017	8/28/2017	0.50	8/28/2017	0.50	500.00	250.00
3300009223	RV	3300009223	633699	NEM	8/28/2017	8/28/2017	500.00	09	8/28/2017	8/28/2017	0.50	8/28/2017	0.50	(500.00)	(250.00)
3300009237	RV	3900005563	633699	1013130	8/29/2017	8/30/2017	-500.00	09	8/29/2017	8/29/2017	0.50	8/30/2017	1.50	500.00	750.00
3300009404	RV	3300009404	633699	1012386	6/1/2017	8/30/2017	500.00	09	6/1/2017	6/1/2017	0.50	8/30/2017	90.50	(500.00)	(45,250.00)
3300009474	RV	3900006036	633699	1012386	9/6/2017	9/21/2017	-500.00	09	9/6/2017	9/6/2017	0.50	9/21/2017	15.50	500.00	7,750.00
3300009475	RV	3900005946	633699	1013119	9/6/2017	9/19/2017	-500.00	09	9/6/2017	9/6/2017	0.50	9/19/2017	13.50	500.00	6,750.00
3300009517	RV	3900006186	633699	36926	9/7/2017	10/3/2017	-500.00	09	9/7/2017	9/7/2017	0.50	10/3/2017	26.50	500.00	13,250.00
3300009652	RV	3900006386	633699	36926	9/12/2017	10/12/2017	-500.00	09	9/12/2017	9/12/2017	0.50	10/12/2017	30.50	500.00	15,250.00
3300009680	RV	3900006158	633699	1012357	9/13/2017	9/28/2017	-500.00	09	9/13/2017	9/13/2017	0.50	9/28/2017	15.50	500.00	7,750.00
3300009756	RV	3900005995	633699	1012523	9/15/2017	9/21/2017	-500.00	09	9/15/2017	9/15/2017	0.50	9/21/2017	6.50	500.00	3,250.00
3300009956	RV	3900006048	633699	1013119	9/20/2017	9/22/2017	-500.00	09	9/20/2017	9/20/2017	0.50	9/22/2017	2.50	500.00	1,250.00
3300010169	RV	3900006173	633699	1013119	9/27/2017	10/2/2017	-500.00	09	9/27/2017	9/27/2017	0.50	10/2/2017	5.50	500.00	2,750.00
3300010178	RV	3900006162	633699	1012385	9/27/2017	9/29/2017	-500.00	09	9/27/2017	9/27/2017	0.50	9/29/2017	2.50	500.00	1,250.00
3300010369	RV	3900006376	633699	1012382	9/29/2017	10/11/2017	-500.00	09	9/29/2017	9/29/2017	0.50	10/11/2017	12.50	500.00	6,250.00
3300010495	RV	3900007038	633699	36926	10/5/2017	11/9/2017	-500.00	09	10/5/2017	10/5/2017	0.50	11/9/2017	35.50	500.00	17,750.00
3300010508	RV	3900006845	633699	36926	10/5/2017	10/31/2017	-500.00	09	10/5/2017	10/5/2017	0.50	10/31/2017	26.50	500.00	13,250.00
3300010573	RV	3900007800	633699	36926	10/6/2017	12/16/2017	-500.00	09	10/6/2017	10/6/2017	0.50	12/16/2017	71.50	500.00	35,750.00
3300010606	RV	3900000116	633699	1013306	10/10/2017	1/9/2018	-500.00	09	10/10/2017	10/10/2017	0.50	1/9/2018	91.50	500.00	45,750.00
3300010627	RV	3900000095	633699	1013306	10/11/2017	1/8/2018	-500.00	09	10/11/2017	10/11/2017	0.50	1/8/2018	89.50	500.00	44,750.00
3300010628	RV	3900000093	633699	1013306	10/11/2017	1/8/2018	-500.00	09	10/11/2017	10/11/2017	0.50	1/8/2018	89.50	500.00	44,750.00
3300010630	RV	3900000108	633699	1013306	10/11/2017	1/9/2018	-500.00	09	10/11/2017	10/11/2017	0.50	1/9/2018	90.50	500.00	45,250.00
3300010631	RV	3900000097	633699	1013306	10/11/2017	1/8/2018	-500.00	09	10/11/2017	10/11/2017	0.50	1/8/2018	89.50	500.00	44,750.00
3300010633	RV	3300010643	633699	NEM	10/11/2017	10/11/2017	-500.00	09	10/11/2017	10/11/2017	0.50	10/11/2017	0.50	500.00	250.00
3300010634	RV	3900000106	633699	1013306	10/11/2017	1/9/2018	-500.00	09	10/11/2017	10/11/2017	0.50	1/9/2018	90.50	500.00	45,250.00
3300010638	RV	3900000100	633699	1013306	10/11/2017	1/8/2018	-500.00	09	10/11/2017	10/11/2017	0.50	1/8/2018	89.50	500.00	44,750.00
3300010643	RV	3300010643	633699	NEM	10/11/2017	10/11/2017	500.00	09	10/11/2017	10/11/2017	0.50	10/11/2017	0.50	(500.00)	(250.00)
3300010930	RV	3900006724	633699	1013119	10/17/2017	10/27/2017	-500.00	09	10/17/2017	10/17/2017	0.50	10/27/2017	10.50	500.00	5,250.00
3300011185	RV	3900006971	633699	1012357	10/24/2017	11/6/2017	-500.00	09	10/24/2017	10/24/2017	0.50	11/6/2017	13.50	500.00	6,750.00
3300011229	RV	3900007602	633699	1013119	10/25/2017	12/11/2017	-500.00	09	10/25/2017	10/25/2017	0.50	12/11/2017	47.50	500.00	23,750.00
3300011548	RV	3300011552	633699	NEM	10/31/2017	10/31/2017	-500.00	09	10/31/2017	10/31/2017	0.50	10/31/2017	0.50	500.00	250.00
3300011552	RV	3300011552	633699	NEM	10/31/2017	10/31/2017	500.00	09	10/31/2017	10/31/2017	0.50	10/31/2017	0.50	(500.00)	(250.00)
3300011554	RV	3900006904	633699	1013119	10/31/2017	11/2/2017	-500.00	09	10/31/2017	10/31/2017	0.50	11/2/2017	2.50	500.00	1,250.00
3300011686	RV	3900007410	633699	1013318	11/3/2017	12/1/2017	-500.00	09	11/3/2017	11/3/2017	0.50	12/1/2017	28.50	500.00	14,250.00
3300011706	RV	3300011711	633699	NEM	11/6/2017	11/6/2017	-500.00	09	11/6/2017	11/6/2017	0.50	11/6/2017	0.50	500.00	250.00
3300011711	RV	3300011711	633699	NEM	11/6/2017	11/6/2017	500.00	09	11/6/2017	11/6/2017	0.50	11/6/2017	0.50	(500.00)	(250.00)
3300011756	RV	3900007315	633699	1012382	11/7/2017	11/28/2017	-500.00	09	11/7/2017	11/7/2017	0.50	11/28/2017	21.50	500.00	10,750.00
3300011887	RV	3900000018	633699	36926	11/13/2017	1/3/2018	-500.00	09	11/13/2017	11/13/2017	0.50	1/3/2018	51.50	500.00	25,750.00
3300011939	RV	3900007408	633699	1012386	11/14/2017	12/1/2017	-500.00	09	11/14/2017	11/14/2017	0.50	12/1/2017	17.50	500.00	8,750.00
3300011942	RV	3900007260	633699	1013130	11/14/2017	11/20/2017	-500.00	09	11/14/2017	11/14/2017	0.50	11/20/2017	6.50	500.00	3,250.00
3300012133	RV	3900007280	633699	1013119	11/20/2017	11/22/2017	-500.00	09	11/20/2017	11/20/2017	0.50	11/22/2017	2.50	500.00	1,250.00
3300012244	RV	3900007808	633699	1012605	11/27/2017	12/18/2017	-500.00	09	11/27/2017	11/27/2017	0.50	12/18/2017	21.50	500.00	10,750.00
3300012259	RV	3900007637	633699	1012386	11/27/2017	12/12/2017	-500.00	09	11/27/2017	11/27/2017	0.50	12/12/2017	15.50	500.00	7,750.00
3300012604	RV	3900000266	633699	1012386	11/29/2017	1/17/2018	-500.00	09	11/29/2017	11/29/2017	0.50	1/17/2018	49.50	500.00	24,750.00
3300012612	RV	3900000347	633699	1012045	11/29/2017	1/22/2018	-500.00	09	11/29/2017	11/29/2017	0.50	1/22/2018	54.50	500.00	27,250.00
3300012731	RV	3900000153	633699	36926	12/1/2017	1/10/2018	-500.00	09	12/1/2017	12/1/2017	0.50	1/10/2018	40.50	500.00	20,250.00
3300012739	RV	3900007519	633699	1013119	12/1/2017	12/7/2017	-500.00	09	12/1/2017	12/1/2017	0.50	12/7/2017	6.50	500.00	3,250.00

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital Study
For the Period January 2017 through December 2017
Other Revenue Lag
Fire & Damage Reconnect, Joint Use Escort and interconnection Application Fee

Document Number	Document Type	Clearing Document	Account	Offsetting acct no.	Document Date	Clearing date	Amount in local currency	Assignment	Service period Beginning	Ending	Midpoint	Payment Received	Lag Days	Revenue	Dollar Days
3300012795	RV	3900007603	633699	1013119	12/5/2017	12/11/2017	-500.00	09	12/5/2017	12/5/2017	0.50	12/11/2017	6.50	500.00	3,250.00
3300012867	RV	3900000495	633699	36926	12/6/2017	1/30/2018	-500.00	09	12/6/2017	12/6/2017	0.50	1/30/2018	55.50	500.00	27,750.00
3300012886	RV	3300012888	633699	NEM	12/7/2017	12/7/2017	-500.00	09	12/7/2017	12/7/2017	0.50	12/7/2017	0.50	500.00	250.00
3300012888	RV	3300012888	633699	NEM	12/7/2017	12/7/2017	500.00	09	12/7/2017	12/7/2017	0.50	12/7/2017	0.50	(500.00)	(250.00)
3300012889	RV	3900007915	633699	1012382	12/7/2017	12/19/2017	-500.00	09	12/7/2017	12/7/2017	0.50	12/19/2017	12.50	500.00	6,250.00
3300012971	RV	3900000798	633699	1013342	12/8/2017	2/14/2018	-500.00	09	12/8/2017	12/8/2017	0.50	2/14/2018	68.50	500.00	34,250.00
3300012973	RV	3900000877	633699	36926	12/8/2017	2/21/2018	-500.00	09	12/8/2017	12/8/2017	0.50	2/21/2018	75.50	500.00	37,750.00
3300013603	RV	3900000933	633699	36926	12/19/2017	2/24/2018	-500.00	09	12/19/2017	12/19/2017	0.50	2/24/2018	67.50	500.00	33,750.00
3300013604	RV	3900008107	633699	41717	12/19/2017	12/29/2017	-500.00	09	12/19/2017	12/19/2017	0.50	12/29/2017	10.50	500.00	5,250.00
3300013606	RV	3900000984	633699	36926	12/19/2017	2/27/2018	-500.00	09	12/19/2017	12/19/2017	0.50	2/27/2018	70.50	500.00	35,250.00
3300013773	RV	3900000330	633699	1012382	12/21/2017	1/18/2018	-500.00	09	12/21/2017	12/21/2017	0.50	1/18/2018	28.50	500.00	14,250.00
3300013774	RV	3900001143	633699	36926	12/21/2017	3/7/2018	-500.00	09	12/21/2017	12/21/2017	0.50	3/7/2018	76.50	500.00	38,250.00
3300013809	RV	3900000040	633699	1013198	12/22/2017	1/4/2018	-500.00	09	12/22/2017	12/22/2017	0.50	1/4/2018	13.50	500.00	6,750.00
3300013812	RV	3900000043	633699	26961	12/22/2017	1/4/2018	-500.00	09	12/22/2017	12/22/2017	0.50	1/4/2018	13.50	500.00	6,750.00
3300013827	RV	3900001083	633699	36926	12/22/2017	3/1/2018	-500.00	09	12/22/2017	12/22/2017	0.50	3/1/2018	69.50	500.00	34,750.00
3300013860	RV	3900008106	633699	1012240	12/27/2017	12/29/2017	-500.00	09	12/27/2017	12/27/2017	0.50	12/29/2017	2.50	500.00	1,250.00
3300013934	RV	3900000324	633699	1012386	12/28/2017	1/18/2018	-500.00	09	12/28/2017	12/28/2017	0.50	1/18/2018	21.50	500.00	10,750.00
														158,791.79	3,417,686.21
													Lag Days		**21.52**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
Summary of Gross Payroll Lag Days
January 2017 - December 2017

		Amount	Dollar Days	Weighted Lag Days
1	**Weekly Payroll**			
2	Net Payroll	$ 65,396,000	$ 416,269,177	6.37
3	Federal Income Tax Withholding	16,544,200	121,893,209	7.37
4	FICA Withholding (Employee Portion)	7,827,655	57,793,553	7.38
5	State & Local Income Tax Withholding	6,979,897	51,422,346	7.37
6	Contribution to Savings & Thrift Plan	8,905,340	74,592,460	8.38
7	Loan Repayment to Savings & Thrift Plan	2,699,093	22,576,579	8.36
8	Credit Union Withholdings	250	2,075	8.30
9	Weekly Gross Payroll Lag	$ 108,352,435	$ 744,549,398	6.87
10	**Semi-Monthly Payroll**			
11	Net Payroll	$ 28,809,896	$ 350,265,388	12.16
12	Federal Income Tax Withholding	7,312,913	95,489,827	13.06
13	FICA Withholding (Employee Portion)	3,459,817	45,513,396	13.15
14	State & Local Income Tax Withholding	3,054,642	40,074,999	13.12
15	Contribution to Savings & Thrift Plan	5,700,758	81,894,570	14.37
16	Loan Repayment to Savings & Thrift Plan	1,088,414	15,629,917	14.36
17	Credit Union Withholdings	-	-	-
18	Semi-Monthly Gross Payroll Lag	$ 49,426,440	$ 628,868,097	12.72
19	**Total Average Payroll Lag** (line 9 + line 18)	**$ 157,778,875**	**$ 1,373,417,496**	**8.70**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
Summary of Employer Payroll Tax Lag Days
January 2017 - December 2017

		Amount	Dollar Days	Weighted Lag Days
1	**Social Security / Medicare (FICA)**			
2	Weekly Payroll	$ 7,827,655	$ 57,793,553	7.38
3	Semi-Monthly Payroll	3,459,817	45,513,396	13.15
4	**FICA Tax Lag**	**$ 11,287,472**	**$ 103,306,949**	**9.15**
5	**Federal Unemployment Tax (FUTA)**			
6	Weekly Payroll	$ (49,126)	$ (355,999)	7.25
7	Semi-Monthly Payroll	(20,139)	(260,675)	12.94
8	FUTA Tax Lag	$ (69,265)	$ (616,674)	8.90
9	**State Unemployment Tax (SUTA)**			
10	Weekly Payroll	$ (145,856)	$ (1,059,298)	7.26
11	Semi-Monthly Payroll	(64,323)	(847,783)	13.18
12	SUTA Tax Lag	$ (210,179)	$ (1,907,081)	9.07
13	**FUTA/SUTA Tax Lag** (line 4 + line 8 + line 12)	**$ (279,445)**	**$ (2,523,755)**	**9.03**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
WEEKLY Net Pay Analysis
January 2017 - December 2017

	PAY CYCLE FROM	PAY CYCLE TO	MIDPOINT	PAYROLL DATE	REMIT TO ADP	LAG DAYS	TOTAL PAID	TOTAL LAG $
1	12/26/16	01/01/17	3.50	01/06/17	01/04/17	6.50	$ 1,106,183	$ 7,190,189.76
2	01/02/17	01/08/17	3.50	01/13/17	01/11/17	6.50	$ 1,217,090	7,911,087.47
3	01/09/17	01/15/17	3.50	01/19/17	01/17/17	5.50	$ 1,179,777	6,488,775.10
4	01/16/17	01/22/17	3.50	01/27/17	01/25/17	6.50	$ 1,293,711	8,409,120.92
5	01/23/17	01/29/17	3.50	02/03/17	02/01/17	6.50	$ 1,283,834	8,344,919.83
6	01/30/17	02/05/17	3.50	02/10/17	02/08/17	6.50	$ 1,290,617	8,389,007.77
7	02/06/17	02/12/17	3.50	02/17/17	02/15/17	6.50	$ 1,220,388	7,932,520.38
8	02/13/17	02/19/17	3.50	02/24/17	02/22/17	6.50	$ 1,202,628	7,817,079.40
9	02/20/17	02/26/17	3.50	03/03/17	03/01/17	6.50	$ 1,278,409	8,309,659.22
10	02/27/17	03/05/17	3.50	03/10/17	03/08/17	6.50	$ 1,281,890	8,332,283.31
11	03/06/17	03/12/17	3.50	03/17/17	03/15/17	6.50	$ 1,217,324	7,912,604.25
12	03/13/17	03/19/17	3.50	03/24/17	03/22/17	6.50	$ 1,361,313	8,848,534.31
13	03/20/17	03/26/17	3.50	03/31/17	03/29/17	6.50	$ 1,245,916	8,098,456.15
14	03/27/17	04/02/17	3.50	04/07/17	04/05/17	6.50	$ 1,246,028	8,099,181.81
15	04/03/17	04/09/17	3.50	04/13/17	04/11/17	5.50	$ 1,256,412	6,910,265.62
16	04/10/17	04/16/17	3.50	04/21/17	04/19/17	6.50	$ 1,151,929	7,487,540.00
17	04/17/17	04/23/17	3.50	04/28/17	04/26/17	6.50	$ 1,236,985	8,040,402.76
18	04/24/17	04/30/17	3.50	05/05/17	05/03/17	6.50	$ 1,266,601	8,232,907.48
19	05/01/17	05/07/17	3.50	05/12/17	05/10/17	6.50	$ 1,242,983	8,079,389.96
20	05/08/17	05/14/17	3.50	05/19/17	05/17/17	6.50	$ 1,158,507	7,530,294.59
21	05/15/17	05/21/17	3.50	05/26/17	05/24/17	6.50	$ 1,259,071	8,183,961.44
22	05/22/17	05/28/17	3.50	06/02/17	05/31/17	6.50	$ 1,155,422	7,510,241.51
23	05/29/17	06/04/17	3.50	06/09/17	06/07/17	6.50	$ 1,277,634	8,304,621.52
24	06/05/17	06/11/17	3.50	06/16/17	06/14/17	6.50	$ 1,216,014	7,904,089.05
25	06/12/17	06/18/17	3.50	06/23/17	06/21/17	6.50	$ 1,223,455	7,952,456.59
26	06/19/17	06/25/17	3.50	06/30/17	06/28/17	6.50	$ 1,263,742	8,214,322.35
27	06/26/17	07/02/17	3.50	07/07/17	07/05/17	6.50	$ 1,419,402	9,226,115.28
28	07/03/17	07/09/17	3.50	07/14/17	07/12/17	6.50	$ 1,419,402	9,226,115.28
29	07/10/17	07/16/17	3.50	07/21/17	07/19/17	6.50	$ 1,056,453	6,866,942.29
30	07/17/17	07/23/17	3.50	07/28/17	07/26/17	6.50	$ 1,367,936	8,891,581.08
31	07/24/17	07/30/17	3.50	08/04/17	08/02/17	6.50	$ 1,267,279	8,237,310.84
32	07/31/17	08/06/17	3.50	08/11/17	08/09/17	6.50	$ 1,263,413	8,212,181.71
33	08/07/17	08/13/17	3.50	08/18/17	08/16/17	6.50	$ 1,286,380	8,361,471.95
34	08/14/17	08/20/17	3.50	08/25/17	08/23/17	6.50	$ 1,302,757	8,467,917.77
35	08/21/17	08/27/17	3.50	09/01/17	08/30/17	6.50	$ 1,240,383	8,062,491.00
36	08/28/17	09/03/17	3.50	09/08/17	09/06/17	6.50	$ 1,245,915	8,098,447.57
37	09/04/17	09/10/17	3.50	09/15/17	09/13/17	6.50	$ 1,294,493	8,414,207.49
38	09/11/17	09/17/17	3.50	09/22/17	09/20/17	6.50	$ 1,348,983	8,768,389.96
39	09/18/17	09/24/17	3.50	09/29/17	09/27/17	6.50	$ 1,373,196	8,925,771.60
40	09/25/17	10/01/17	3.50	10/06/17	10/04/17	6.50	$ 1,276,987	8,300,413.36
41	10/02/17	10/08/17	3.50	10/13/17	10/11/17	6.50	$ 1,265,941	8,228,613.84
42	10/09/17	10/15/17	3.50	10/20/17	10/18/17	6.50	$ 1,241,118	8,067,267.65
43	10/16/17	10/22/17	3.50	10/27/17	10/25/17	6.50	$ 1,224,672	7,960,366.83
44	10/23/17	10/29/17	3.50	11/03/17	11/01/17	6.50	$ 1,245,569	8,096,197.98
45	10/30/17	11/05/17	3.50	11/09/17	11/07/17	5.50	$ 1,232,234	6,777,285.74
46	11/06/17	11/12/17	3.50	11/17/17	11/15/17	6.50	$ 1,324,217	8,607,410.70
47	11/13/17	11/19/17	3.50	11/22/17	11/20/17	4.50	$ 1,321,128	5,945,077.26
48	11/20/17	11/26/17	3.50	12/01/17	11/29/17	6.50	$ 1,160,504	7,543,277.24
49	11/27/17	12/03/17	3.50	12/08/17	12/06/17	6.50	$ 1,339,824	8,708,856.98
50	12/04/17	12/10/17	3.50	12/15/17	12/13/17	6.50	$ 1,249,811	8,123,770.85
51	12/11/17	12/17/17	3.50	12/21/17	12/19/17	5.50	$ 1,314,922	7,232,070.73
52	12/18/17	12/24/17	3.50	12/28/17	12/26/17	5.50	$ 1,179,220	6,485,711.43
							$ 65,395,999.78	**$ 416,269,176.96**

WEIGHTED LAG DAYS **6.37**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
WEEKLY Federal Income Tax (FIT) Withholding Analysis
January 2017 - December 2017

	PAY CYCLE FROM	PAY CYCLE TO	MIDPOINT	PAYROLL DATE	REMIT TO ADP	LAG DAYS	FIT WITHHOLDING	TOTAL LAG $
1	12/26/16	01/01/17	3.50	01/06/17	01/05/17	7.50	$ 266,444	$ 1,998,330.15
2	01/02/17	01/08/17	3.50	01/13/17	01/12/17	7.50	$ 304,669	2,285,019.98
3	01/09/17	01/15/17	3.50	01/19/17	01/18/17	6.50	$ 287,013	1,865,581.58
4	01/16/17	01/22/17	3.50	01/27/17	01/26/17	7.50	$ 317,304	2,379,782.63
5	01/23/17	01/29/17	3.50	02/03/17	02/02/17	7.50	$ 324,766	2,435,746.43
6	01/30/17	02/05/17	3.50	02/10/17	02/09/17	7.50	$ 321,410	2,410,576.95
7	02/06/17	02/12/17	3.50	02/17/17	02/16/17	7.50	$ 303,091	2,273,184.90
8	02/13/17	02/19/17	3.50	02/24/17	02/23/17	7.50	$ 299,445	2,245,838.55
9	02/20/17	02/26/17	3.50	03/03/17	03/02/17	7.50	$ 328,675	2,465,062.43
10	02/27/17	03/05/17	3.50	03/10/17	03/09/17	7.50	$ 330,497	2,478,725.63
11	03/06/17	03/12/17	3.50	03/17/17	03/16/17	7.50	$ 310,594	2,329,454.03
12	03/13/17	03/19/17	3.50	03/24/17	03/23/17	7.50	$ 371,826	2,788,696.58
13	03/20/17	03/26/17	3.50	03/31/17	03/30/17	7.50	$ 311,192	2,333,940.98
14	03/27/17	04/02/17	3.50	04/07/17	04/06/17	7.50	$ 319,910	2,399,322.60
15	04/03/17	04/09/17	3.50	04/13/17	04/12/17	6.50	$ 326,105	2,119,682.63
16	04/10/17	04/16/17	3.50	04/21/17	04/20/17	7.50	$ 279,105	2,093,286.83
17	04/17/17	04/23/17	3.50	04/28/17	04/27/17	7.50	$ 317,690	2,382,676.28
18	04/24/17	04/30/17	3.50	05/05/17	05/04/17	7.50	$ 328,245	2,461,838.78
19	05/01/17	05/07/17	3.50	05/12/17	05/11/17	7.50	$ 318,348	2,387,607.98
20	05/08/17	05/14/17	3.50	05/19/17	05/18/17	7.50	$ 283,014	2,122,604.10
21	05/15/17	05/21/17	3.50	05/26/17	05/25/17	7.50	$ 321,386	2,410,394.78
22	05/22/17	05/28/17	3.50	06/02/17	06/01/17	7.50	$ 278,668	2,090,013.45
23	05/29/17	06/04/17	3.50	06/09/17	06/08/17	7.50	$ 330,501	2,478,758.55
24	06/05/17	06/11/17	3.50	06/16/17	06/15/17	7.50	$ 302,981	2,272,359.08
25	06/12/17	06/18/17	3.50	06/23/17	06/22/17	7.50	$ 304,379	2,282,840.25
26	06/19/17	06/25/17	3.50	06/30/17	06/29/17	7.50	$ 314,392	2,357,937.45
27	06/26/17	07/02/17	3.50	07/07/17	07/06/17	7.50	$ 395,714	2,967,853.88
28	07/03/17	07/09/17	3.50	07/14/17	07/13/17	7.50	$ 296,655	2,224,915.80
29	07/10/17	07/16/17	3.50	07/21/17	07/20/17	7.50	$ 334,581	2,509,354.50
30	07/17/17	07/23/17	3.50	07/28/17	07/27/17	7.50	$ 368,849	2,766,367.88
31	07/24/17	07/30/17	3.50	08/04/17	08/03/17	7.50	$ 323,889	2,429,164.35
32	07/31/17	08/06/17	3.50	08/11/17	08/10/17	7.50	$ 327,978	2,459,831.25
33	08/07/17	08/13/17	3.50	08/18/17	08/17/17	7.50	$ 329,871	2,474,034.38
34	08/14/17	08/20/17	3.50	08/25/17	08/24/17	7.50	$ 341,028	2,557,713.23
35	08/21/17	08/27/17	3.50	09/01/17	08/31/17	7.50	$ 310,017	2,325,126.90
36	08/28/17	09/03/17	3.50	09/08/17	09/07/17	7.50	$ 311,420	2,335,648.65
37	09/04/17	09/10/17	3.50	09/15/17	09/14/17	7.50	$ 328,941	2,467,056.23
38	09/11/17	09/17/17	3.50	09/22/17	09/21/17	7.50	$ 364,790	2,735,924.48
39	09/18/17	09/24/17	3.50	09/29/17	09/28/17	7.50	$ 360,861	2,706,460.20
40	09/25/17	10/01/17	3.50	10/06/17	10/05/17	7.50	$ 324,081	2,430,608.85
41	10/02/17	10/08/17	3.50	10/13/17	10/12/17	7.50	$ 316,072	2,370,539.70
42	10/09/17	10/15/17	3.50	10/20/17	10/19/17	7.50	$ 306,955	2,302,164.08
43	10/16/17	10/22/17	3.50	10/27/17	10/26/17	7.50	$ 300,022	2,250,162.60
44	10/23/17	10/29/17	3.50	11/03/17	11/02/17	7.50	$ 305,285	2,289,637.88
45	10/30/17	11/05/17	3.50	11/09/17	11/08/17	6.50	$ 306,571	1,992,708.77
46	11/06/17	11/12/17	3.50	11/17/17	11/16/17	7.50	$ 339,559	2,546,689.35
47	11/13/17	11/19/17	3.50	11/22/17	11/21/17	5.50	$ 336,089	1,848,488.84
48	11/20/17	11/26/17	3.50	12/01/17	11/30/17	7.50	$ 271,645	2,037,337.20
49	11/27/17	12/03/17	3.50	12/08/17	12/07/17	7.50	$ 338,873	2,541,547.05
50	12/04/17	12/10/17	3.50	12/15/17	12/14/17	7.50	$ 306,377	2,297,826.60
51	12/11/17	12/17/17	3.50	12/21/17	12/20/17	6.50	$ 333,181	2,165,674.23
52	12/18/17	12/24/17	3.50	12/28/17	12/27/17	6.50	$ 263,247	1,711,108.36
							$ 16,544,200.36	**$ 121,893,208.70**

WEIGHTED LAG DAYS

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
WEEKLY FICA/Medicare Tax Withholding Analysis
January 2017 - December 2017

	PAY CYCLE FROM	PAY CYCLE TO	MIDPOINT	PAYROLL DATE	REMIT TO ADP	LAG DAYS	FICA/MEDICARE WITHHOLDING	TOTAL LAG $
1	12/26/16	01/01/17	3.50	01/06/17	01/05/17	7.50	$ 143,345	$ 1,075,088.55
2	01/02/17	01/08/17	3.50	01/13/17	01/12/17	7.50	$ 156,784	1,175,881.28
3	01/09/17	01/15/17	3.50	01/19/17	01/18/17	6.50	$ 151,321	983,584.42
4	01/16/17	01/22/17	3.50	01/27/17	01/26/17	7.50	$ 164,723	1,235,419.65
5	01/23/17	01/29/17	3.50	02/03/17	02/02/17	7.50	$ 164,623	1,234,675.35
6	01/30/17	02/05/17	3.50	02/10/17	02/09/17	7.50	$ 163,978	1,229,833.43
7	02/06/17	02/12/17	3.50	02/17/17	02/16/17	7.50	$ 157,130	1,178,477.10
8	02/13/17	02/19/17	3.50	02/24/17	02/23/17	7.50	$ 155,188	1,163,907.08
9	02/20/17	02/26/17	3.50	03/03/17	03/02/17	7.50	$ 164,868	1,236,507.45
10	02/27/17	03/05/17	3.50	03/10/17	03/09/17	7.50	$ 165,081	1,238,105.63
11	03/06/17	03/12/17	3.50	03/17/17	03/16/17	7.50	$ 157,418	1,180,637.70
12	03/13/17	03/19/17	3.50	03/24/17	03/23/17	7.50	$ 176,332	1,322,486.48
13	03/20/17	03/26/17	3.50	03/31/17	03/30/17	7.50	$ 158,811	1,191,080.48
14	03/27/17	04/02/17	3.50	04/07/17	04/06/17	7.50	$ 161,213	1,209,095.25
15	04/03/17	04/09/17	3.50	04/13/17	04/12/17	6.50	$ 162,320	1,055,082.73
16	04/10/17	04/16/17	3.50	04/21/17	04/20/17	7.50	$ 148,540	1,114,052.55
17	04/17/17	04/23/17	3.50	04/28/17	04/27/17	7.50	$ 159,858	1,198,935.60
18	04/24/17	04/30/17	3.50	05/05/17	05/04/17	7.50	$ 163,366	1,225,242.83
19	05/01/17	05/07/17	3.50	05/12/17	05/11/17	7.50	$ 160,548	1,204,112.63
20	05/08/17	05/14/17	3.50	05/19/17	05/18/17	7.50	$ 149,624	1,122,182.70
21	05/15/17	05/21/17	3.50	05/26/17	05/25/17	7.50	$ 162,007	1,215,054.45
22	05/22/17	05/28/17	3.50	06/02/17	06/01/17	7.50	$ 149,115	1,118,363.25
23	05/29/17	06/04/17	3.50	06/09/17	06/08/17	7.50	$ 165,222	1,239,165.08
24	06/05/17	06/11/17	3.50	06/16/17	06/15/17	7.50	$ 157,335	1,180,011.00
25	06/12/17	06/18/17	3.50	06/23/17	06/22/17	7.50	$ 157,561	1,181,709.75
26	06/19/17	06/25/17	3.50	06/30/17	06/29/17	7.50	$ 160,754	1,205,652.53
27	06/26/17	07/02/17	3.50	07/07/17	07/06/17	7.50	$ 180,495	1,353,712.35
28	07/03/17	07/09/17	3.50	07/14/17	07/13/17	7.50	$ 152,691	1,145,182.28
29	07/10/17	07/16/17	3.50	07/21/17	07/20/17	7.50	$ 163,987	1,229,904.98
30	07/17/17	07/23/17	3.50	07/28/17	07/27/17	7.50	$ 173,494	1,301,204.63
31	07/24/17	07/30/17	3.50	08/04/17	08/03/17	7.50	$ 159,498	1,196,237.33
32	07/31/17	08/06/17	3.50	08/11/17	08/10/17	7.50	$ 159,010	1,192,572.75
33	08/07/17	08/13/17	3.50	08/18/17	08/17/17	7.50	$ 158,999	1,192,489.65
34	08/14/17	08/20/17	3.50	08/25/17	08/24/17	7.50	$ 160,353	1,202,645.10
35	08/21/17	08/27/17	3.50	09/01/17	08/31/17	7.50	$ 150,813	1,131,095.85
36	08/28/17	09/03/17	3.50	09/08/17	09/07/17	7.50	$ 148,912	1,116,842.93
37	09/04/17	09/10/17	3.50	09/15/17	09/14/17	7.50	$ 151,468	1,136,008.13
38	09/11/17	09/17/17	3.50	09/22/17	09/21/17	7.50	$ 156,526	1,173,942.98
39	09/18/17	09/24/17	3.50	09/29/17	09/28/17	7.50	$ 154,229	1,156,716.23
40	09/25/17	10/01/17	3.50	10/06/17	10/05/17	7.50	$ 141,376	1,060,318.80
41	10/02/17	10/08/17	3.50	10/13/17	10/12/17	7.50	$ 135,676	1,017,573.08
42	10/09/17	10/15/17	3.50	10/20/17	10/19/17	7.50	$ 130,270	977,027.25
43	10/16/17	10/22/17	3.50	10/27/17	10/26/17	7.50	$ 128,487	963,651.38
44	10/23/17	10/29/17	3.50	11/03/17	11/02/17	7.50	$ 129,483	971,125.20
45	10/30/17	11/05/17	3.50	11/09/17	11/08/17	6.50	$ 124,291	807,888.25
46	11/06/17	11/12/17	3.50	11/17/17	11/16/17	7.50	$ 131,588	986,906.93
47	11/13/17	11/19/17	3.50	11/22/17	11/21/17	5.50	$ 127,294	700,117.94
48	11/20/17	11/26/17	3.50	12/01/17	11/30/17	7.50	$ 113,211	849,084.53
49	11/27/17	12/03/17	3.50	12/08/17	12/07/17	7.50	$ 122,507	918,803.10
50	12/04/17	12/10/17	3.50	12/15/17	12/14/17	7.50	$ 114,595	859,461.23
51	12/11/17	12/17/17	3.50	12/21/17	12/20/17	6.50	$ 117,216	761,901.47
52	12/18/17	12/24/17	3.50	12/28/17	12/27/17	6.50	$ 104,122	676,793.78
							$ 7,827,654.75	**$ 57,793,552.96**

WEIGHTED LAG DAYS

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
WEEKLY Unemployment Tax Analysis
January 2017 - December 2017

	FROM	TO	MIDPOINT	PAYROLL DATE	REMIT TO ADP	LAG DAYS	FUTA AMOUNT	SUTA AMOUNT	FUTA LAG $	SUTA LAG $
1	12/26/16	01/01/17	3.50	01/06/17	01/05/17	7.50	$ (11,323)	$ (26,728)	$ (84,920.78)	$ (200,458.88)
2	01/02/17	01/08/17	3.50	01/13/17	01/12/17	7.50	$ (12,373)	$ (30,259)	(92,794.58)	(226,939.95)
3	01/09/17	01/15/17	3.50	01/19/17	01/18/17	6.50	$ (9,593)	$ (26,625)	(62,353.98)	(173,060.94)
4	01/16/17	01/22/17	3.50	01/27/17	01/26/17	7.50	$ (6,094)	$ (20,786)	(45,701.93)	(155,896.95)
5	01/23/17	01/29/17	3.50	02/03/17	02/02/17	7.50	$ (3,085)	$ (13,596)	(23,140.65)	(101,973.00)
6	01/30/17	02/05/17	3.50	02/10/17	02/09/17	7.50	$ (1,121)	$ (7,566)	(8,407.43)	(56,746.20)
7	02/06/17	02/12/17	3.50	02/17/17	02/16/17	7.50	$ (490)	$ (3,574)	(3,673.35)	(26,804.40)
8	02/13/17	02/19/17	3.50	02/24/17	02/23/17	7.50	$ (208)	$ (1,608)	(1,561.65)	(12,061.35)
9	02/20/17	02/26/17	3.50	03/03/17	03/02/17	7.50	$ (255)	$ (959)	(1,915.50)	(7,193.18)
10	02/27/17	03/05/17	3.50	03/10/17	03/09/17	7.50	$ (144)	$ (564)	(1,077.08)	(4,228.73)
11	03/06/17	03/12/17	3.50	03/17/17	03/16/17	7.50	$ (98)	$ (484)	(736.20)	(3,629.40)
12	03/13/17	03/19/17	3.50	03/24/17	03/23/17	7.50	$ (126)	$ (438)	(945.30)	(3,281.93)
13	03/20/17	03/26/17	3.50	03/31/17	03/30/17	7.50	$ (138)	$ (319)	(1,036.58)	(2,388.83)
14	03/27/17	04/02/17	3.50	04/07/17	04/06/17	7.50	$ (130)	$ (266)	(978.45)	(1,991.25)
15	04/03/17	04/09/17	3.50	04/13/17	04/12/17	6.50	$ (175)	$ (322)	(1,138.54)	(2,090.34)
16	04/10/17	04/16/17	3.50	04/21/17	04/20/17	7.50	$ (166)	$ (295)	(1,245.75)	(2,214.15)
17	04/17/17	04/23/17	3.50	04/28/17	04/27/17	7.50	$ (146)	$ (399)	(1,091.25)	(2,993.03)
18	04/24/17	04/30/17	3.50	05/05/17	05/04/17	7.50	$ (121)	$ (332)	(908.03)	(2,491.73)
19	05/01/17	05/07/17	3.50	05/12/17	05/11/17	7.50	$ (120)	$ (284)	(899.25)	(2,132.55)
20	05/08/17	05/14/17	3.50	05/19/17	05/18/17	7.50	$ (87)	$ (247)	(651.83)	(1,849.58)
21	05/15/17	05/21/17	3.50	05/26/17	05/25/17	7.50	$ (72)	$ (246)	(538.95)	(1,847.33)
22	05/22/17	05/28/17	3.50	06/02/17	06/01/17	7.50	$ (79)	$ (211)	(596.18)	(1,579.05)
23	05/29/17	06/04/17	3.50	06/09/17	06/08/17	7.50	$ (98)	$ (266)	(734.78)	(1,993.50)
24	06/05/17	06/11/17	3.50	06/16/17	06/15/17	7.50	$ (128)	$ (422)	(956.85)	(3,161.63)
25	06/12/17	06/18/17	3.50	06/23/17	06/22/17	7.50	$ (83)	$ (412)	(621.60)	(3,088.20)
26	06/19/17	06/25/17	3.50	06/30/17	06/29/17	7.50	$ (115)	$ (484)	(864.30)	(3,632.03)
27	06/26/17	07/02/17	3.50	07/07/17	07/06/17	7.50	$ (99)	$ (323)	(739.88)	(2,423.33)
28	07/03/17	07/09/17	3.50	07/14/17	07/13/17	7.50	$ (133)	$ (411)	(995.03)	(3,083.78)
29	07/10/17	07/16/17	3.50	07/21/17	07/20/17	7.50	$ (158)	$ (477)	(1,186.65)	(3,580.43)
30	07/17/17	07/23/17	3.50	07/28/17	07/27/17	7.50	$ (121)	$ (530)	(905.85)	(3,971.48)
31	07/24/17	07/30/17	3.50	08/04/17	08/03/17	7.50	$ (94)	$ (382)	(701.70)	(2,862.38)
32	07/31/17	08/06/17	3.50	08/11/17	08/10/17	7.50	$ (104)	$ (308)	(778.05)	(2,308.80)
33	08/07/17	08/13/17	3.50	08/18/17	08/17/17	7.50	$ (101)	$ (306)	(756.60)	(2,291.85)
34	08/14/17	08/20/17	3.50	08/25/17	08/24/17	7.50	$ (112)	$ (442)	(839.55)	(3,311.48)
35	08/21/17	08/27/17	3.50	09/01/17	08/31/17	7.50	$ (56)	$ (251)	(419.48)	(1,884.08)
36	08/28/17	09/03/17	3.50	09/08/17	09/07/17	7.50	$ (48)	$ (163)	(356.78)	(1,221.30)
37	09/04/17	09/10/17	3.50	09/15/17	09/14/17	7.50	$ (26)	$ (135)	(194.70)	(1,013.48)
38	09/11/17	09/17/17	3.50	09/22/17	09/21/17	7.50	$ (9)	$ (161)	(69.08)	(1,209.68)
39	09/18/17	09/24/17	3.50	09/29/17	09/28/17	7.50	$ (42)	$ (129)	(311.25)	(964.88)
40	09/25/17	10/01/17	3.50	10/06/17	10/05/17	7.50	$ (42)	$ (87)	(312.08)	(652.13)
41	10/02/17	10/08/17	3.50	10/13/17	10/12/17	7.50	$ (40)	$ (90)	(302.10)	(678.15)
42	10/09/17	10/15/17	3.50	10/20/17	10/19/17	7.50	$ (40)	$ (68)	(301.88)	(509.25)
43	10/16/17	10/22/17	3.50	10/27/17	10/26/17	7.50	$ (51)	$ (101)	(383.85)	(755.10)
44	10/23/17	10/29/17	3.50	11/03/17	11/02/17	7.50	$ (71)	$ (142)	(535.80)	(1,062.98)
45	10/30/17	11/05/17	3.50	11/09/17	11/08/17	6.50	$ (67)	$ (145)	(434.92)	(941.66)
46	11/06/17	11/12/17	3.50	11/17/17	11/16/17	7.50	$ (104)	$ (282)	(779.70)	(2,112.15)
47	11/13/17	11/19/17	3.50	11/22/17	11/21/17	5.50	$ (79)	$ (284)	(431.92)	(1,564.31)
48	11/20/17	11/26/17	3.50	12/01/17	11/30/17	7.50	$ (153)	$ (493)	(1,148.18)	(3,700.50)
49	11/27/17	12/03/17	3.50	12/08/17	12/07/17	7.50	$ (141)	$ (478)	(1,059.45)	(3,582.60)
50	12/04/17	12/10/17	3.50	12/15/17	12/14/17	7.50	$ (189)	$ (572)	(1,419.60)	(4,291.88)
51	12/11/17	12/17/17	3.50	12/21/17	12/20/17	6.50	$ (176)	$ (553)	(1,143.81)	(3,592.29)
52	12/18/17	12/24/17	3.50	12/28/17	12/27/17	6.50	$ (304)	$ (855)		
							$ (49,126.48)	**$ (145,856.28)**	**$ (355,998.66)**	**$ (1,059,298.06)**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
WEEKLY State & Local Income Tax Withholding Analysis
January 2017 - December 2017

	PAY CYCLE FROM	PAY CYCLE TO	MIDPOINT	PAYROLL DATE	REMIT TO ADP	LAG DAYS	STATE WITHHOLDING	LOCAL WITHHOLDING	TOTAL WITHHOLDING	TOTAL LAG $
1	12/26/16	01/01/17	3.50	01/06/17	01/05/17	7.50	77,784	40,870	$ 118,653.42	$ 889,900.65
2	01/02/17	01/08/17	3.50	01/13/17	01/12/17	7.50	85,759	45,001	$ 130,760.47	980,703.53
3	01/09/17	01/15/17	3.50	01/19/17	01/18/17	6.50	82,120	42,954	$ 125,074.21	812,982.37
4	01/16/17	01/22/17	3.50	01/27/17	01/26/17	7.50	89,047	47,270	$ 136,316.86	1,022,376.45
5	01/23/17	01/29/17	3.50	02/03/17	02/02/17	7.50	90,048	46,624	$ 136,672.30	1,025,042.25
6	01/30/17	02/05/17	3.50	02/10/17	02/09/17	7.50	90,473	46,722	$ 137,194.73	1,028,960.48
7	02/06/17	02/12/17	3.50	02/17/17	02/16/17	7.50	85,810	44,413	$ 130,223.31	976,674.83
8	02/13/17	02/19/17	3.50	02/24/17	02/23/17	7.50	84,209	43,759	$ 127,967.34	959,755.05
9	02/20/17	02/26/17	3.50	03/03/17	03/02/17	7.50	90,458	46,948	$ 137,406.23	1,030,546.73
10	02/27/17	03/05/17	3.50	03/10/17	03/09/17	7.50	91,786	46,540	$ 138,326.40	1,037,448.00
11	03/06/17	03/12/17	3.50	03/17/17	03/16/17	7.50	86,109	44,715	$ 130,824.65	981,184.88
12	03/13/17	03/19/17	3.50	03/24/17	03/23/17	7.50	98,795	51,899	$ 150,693.96	1,130,204.70
13	03/20/17	03/26/17	3.50	03/31/17	03/30/17	7.50	85,996	45,474	$ 131,470.11	986,025.83
14	03/27/17	04/02/17	3.50	04/07/17	04/06/17	7.50	88,758	46,660	$ 135,417.70	1,015,632.75
15	04/03/17	04/09/17	3.50	04/13/17	04/12/17	6.50	89,135	46,451	$ 135,586.00	881,309.00
16	04/10/17	04/16/17	3.50	04/21/17	04/20/17	7.50	80,037	41,555	$ 121,591.96	911,939.70
17	04/17/17	04/23/17	3.50	04/28/17	04/27/17	7.50	87,806	45,592	$ 133,397.91	1,000,484.33
18	04/24/17	04/30/17	3.50	05/05/17	05/04/17	7.50	90,491	46,626	$ 137,116.90	1,028,376.75
19	05/01/17	05/07/17	3.50	05/12/17	05/11/17	7.50	88,004	45,692	$ 133,695.38	1,002,715.35
20	05/08/17	05/14/17	3.50	05/19/17	05/18/17	7.50	80,634	42,034	$ 122,668.19	920,011.43
21	05/15/17	05/21/17	3.50	05/26/17	05/25/17	7.50	88,736	46,454	$ 135,189.43	1,013,920.73
22	05/22/17	05/28/17	3.50	06/02/17	06/01/17	7.50	80,481	41,672	$ 122,152.82	916,146.15
23	05/29/17	06/04/17	3.50	06/09/17	06/08/17	7.50	90,964	47,426	$ 138,390.22	1,037,926.65
24	06/05/17	06/11/17	3.50	06/16/17	06/15/17	7.50	85,220	44,553	$ 129,773.43	973,300.73
25	06/12/17	06/18/17	3.50	06/23/17	06/22/17	7.50	85,606	44,680	$ 130,285.88	977,144.10
26	06/19/17	06/25/17	3.50	06/30/17	06/29/17	7.50	87,613	45,983	$ 133,595.96	1,001,969.70
27	06/26/17	07/02/17	3.50	07/07/17	07/06/17	7.50	104,830	55,240	$ 160,070.69	1,200,530.18
28	07/03/17	07/09/17	3.50	07/14/17	07/13/17	7.50	83,896	43,432	$ 127,327.54	954,956.55
29	07/10/17	07/16/17	3.50	07/21/17	07/20/17	7.50	91,444	47,472	$ 138,915.98	1,041,869.85
30	07/17/17	07/23/17	3.50	07/28/17	07/27/17	7.50	98,007	50,842	$ 148,849.59	1,116,371.93
31	07/24/17	07/30/17	3.50	08/04/17	08/03/17	7.50	89,408	46,608	$ 136,015.44	1,020,115.80
32	07/31/17	08/06/17	3.50	08/11/17	08/10/17	7.50	89,775	47,083	$ 136,857.62	1,026,432.15
33	08/07/17	08/13/17	3.50	08/18/17	08/17/17	7.50	90,737	47,183	$ 137,920.21	1,034,401.58
34	08/14/17	08/20/17	3.50	08/25/17	08/24/17	7.50	93,505	47,134	$ 140,639.61	1,054,797.08
35	08/21/17	08/27/17	3.50	09/01/17	08/31/17	7.50	86,558	45,203	$ 131,760.71	988,205.33
36	08/28/17	09/03/17	3.50	09/08/17	09/07/17	7.50	87,040	45,248	$ 132,288.26	992,161.95
37	09/04/17	09/10/17	3.50	09/15/17	09/14/17	7.50	90,668	46,996	$ 137,664.27	1,032,482.03
38	09/11/17	09/17/17	3.50	09/22/17	09/21/17	7.50	96,745	50,298	$ 147,043.36	1,102,825.20
39	09/18/17	09/24/17	3.50	09/29/17	09/28/17	7.50	96,782	49,622	$ 146,403.13	1,098,023.48
40	09/25/17	10/01/17	3.50	10/06/17	10/05/17	7.50	89,628	47,141	$ 136,769.04	1,025,767.80
41	10/02/17	10/08/17	3.50	10/13/17	10/12/17	7.50	87,564	45,493	$ 133,056.74	997,925.55
42	10/09/17	10/15/17	3.50	10/20/17	10/19/17	7.50	85,439	44,867	$ 130,305.47	977,291.03
43	10/16/17	10/22/17	3.50	10/27/17	10/26/17	7.50	84,186	43,888	$ 128,074.08	960,555.60
44	10/23/17	10/29/17	3.50	11/03/17	11/02/17	7.50	85,308	44,545	$ 129,852.54	973,894.05
45	10/30/17	11/05/17	3.50	11/09/17	11/08/17	6.50	85,164	45,122	$ 130,286.59	846,862.84
46	11/06/17	11/12/17	3.50	11/17/17	11/16/17	7.50	91,841	48,088	$ 139,928.88	1,049,466.60
47	11/13/17	11/19/17	3.50	11/22/17	11/21/17	5.50	91,546	47,784	$ 139,330.64	766,318.52
48	11/20/17	11/26/17	3.50	12/01/17	11/30/17	7.50	78,661	41,018	$ 119,678.28	897,587.10
49	11/27/17	12/03/17	3.50	12/08/17	12/07/17	7.50	93,506	48,844	$ 142,350.21	1,067,626.58
50	12/04/17	12/10/17	3.50	12/15/17	12/14/17	7.50	86,020	44,767	$ 130,787.34	980,905.05
51	12/11/17	12/17/17	3.50	12/21/17	12/20/17	6.50	91,738	47,120	$ 138,858.17	902,578.11
52	12/18/17	12/24/17	3.50	12/28/17	12/27/17	6.50	77,995	40,423	$ 118,417.16	769,711.54
							4,589,870.31	2,390,027.01	**$ 6,979,897.32**	**$ 51,422,346.49**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
WEEKLY Retirement Savings Contribution Analysis
January 2017 - December 2017

	PAY CYCLE FROM	PAY CYCLE TO	MIDPOINT	PAYROLL DATE	LAG DAYS	EMPLOYEE CONTRIBUTION	EMPLOYER CONTRIBUTION	TOTAL CONTRIBUTION	TOTAL LAG $
1	12/26/16	01/01/17	3.50	01/06/17	8.50	137,373	34,205	$ 171,577.03	$ 1,458,404.76
2	01/02/17	01/08/17	3.50	01/13/17	8.50	140,441	34,959	175,399.82	1,490,898.47
3	01/09/17	01/15/17	3.50	01/19/17	7.50	140,124	34,914	175,037.49	1,312,781.18
4	01/16/17	01/22/17	3.50	01/27/17	8.50	128,517	35,201	163,718.55	1,391,607.68
5	01/23/17	01/29/17	3.50	02/03/17	8.50	141,714	35,160	176,874.04	1,503,429.34
6	01/30/17	02/05/17	3.50	02/10/17	8.50	141,812	35,146	176,957.46	1,504,138.41
7	02/06/17	02/12/17	3.50	02/17/17	8.50	142,297	35,017	177,313.24	1,507,162.54
8	02/13/17	02/19/17	3.50	02/24/17	8.50	141,664	34,936	176,600.35	1,501,102.98
9	02/20/17	02/26/17	3.50	03/03/17	8.50	142,606	34,973	177,578.50	1,509,417.25
10	02/27/17	03/05/17	3.50	03/10/17	8.50	141,762	34,745	176,507.15	1,500,310.78
11	03/06/17	03/12/17	3.50	03/17/17	8.50	144,390	35,102	179,492.12	1,525,683.02
12	03/13/17	03/19/17	3.50	03/24/17	8.50	143,807	34,881	178,688.88	1,518,855.48
13	03/20/17	03/26/17	3.50	03/31/17	8.50	143,857	34,909	178,765.92	1,519,510.32
14	03/27/17	04/02/17	3.50	04/07/17	8.50	146,426	35,175	181,601.14	1,543,609.69
15	04/03/17	04/09/17	3.50	04/13/17	7.50	145,955	35,081	181,035.73	1,357,767.98
16	04/10/17	04/16/17	3.50	04/21/17	8.50	144,317	34,963	179,279.65	1,523,877.03
17	04/17/17	04/23/17	3.50	04/28/17	8.50	144,567	34,821	179,388.63	1,524,803.36
18	04/24/17	04/30/17	3.50	05/05/17	8.50	144,889	34,837	179,725.97	1,527,670.75
19	05/01/17	05/07/17	3.50	05/12/17	8.50	144,745	34,891	179,635.27	1,526,899.80
20	05/08/17	05/14/17	3.50	05/19/17	8.50	145,450	34,958	180,407.79	1,533,466.22
21	05/15/17	05/21/17	3.50	05/26/17	8.50	144,007	34,987	178,993.54	1,521,445.09
22	05/22/17	05/28/17	3.50	06/02/17	8.50	142,095	34,642	176,736.43	1,502,259.66
23	05/29/17	06/04/17	3.50	06/09/17	8.50	142,721	35,207	177,927.83	1,512,386.56
24	06/05/17	06/11/17	3.50	06/16/17	8.50	146,652	36,032	182,683.69	1,552,811.37
25	06/12/17	06/18/17	3.50	06/23/17	8.50	145,109	35,659	180,767.90	1,536,527.15
26	06/19/17	06/25/17	3.50	06/30/17	8.50	146,070	35,796	181,866.39	1,545,864.32
27	06/26/17	07/02/17	3.50	07/07/17	8.50	146,299	35,896	182,195.14	1,548,658.69
28	07/03/17	07/09/17	3.50	07/14/17	8.50	144,935	35,772	180,707.06	1,536,010.01
29	07/10/17	07/16/17	3.50	07/21/17	8.50	143,126	35,460	178,586.26	1,517,983.21
30	07/17/17	07/23/17	3.50	07/28/17	8.50	142,968	35,617	178,585.32	1,517,975.22
31	07/24/17	07/30/17	3.50	08/04/17	8.50	142,254	35,599	177,853.22	1,511,752.37
32	07/31/17	08/06/17	3.50	08/11/17	8.50	141,902	35,727	177,629.52	1,509,850.92
33	08/07/17	08/13/17	3.50	08/18/17	8.50	141,712	35,761	177,473.31	1,508,523.14
34	08/14/17	08/20/17	3.50	08/25/17	8.50	141,068	35,678	176,746.45	1,502,344.83
35	08/21/17	08/27/17	3.50	09/01/17	8.50	139,568	35,678	175,246.06	1,489,591.51
36	08/28/17	09/03/17	3.50	09/08/17	8.50	138,125	35,729	173,853.91	1,477,758.24
37	09/04/17	09/10/17	3.50	09/15/17	8.50	135,870	35,372	171,242.07	1,455,557.60
38	09/11/17	09/17/17	3.50	09/22/17	8.50	134,915	35,372	170,286.94	1,447,438.99
39	09/18/17	09/24/17	3.50	09/29/17	8.50	132,165	35,374	167,539.27	1,424,083.80
40	09/25/17	10/01/17	3.50	10/06/17	8.50	129,080	35,170	164,250.09	1,396,125.77
41	10/02/17	10/08/17	3.50	10/13/17	8.50	126,351	35,399	161,750.46	1,374,878.91
42	10/09/17	10/15/17	3.50	10/20/17	8.50	125,243	35,068	160,310.73	1,362,641.21
43	10/16/17	10/22/17	3.50	10/27/17	8.50	124,130	35,036	159,165.51	1,352,906.84
44	10/23/17	10/29/17	3.50	11/03/17	8.50	122,215	35,007	157,222.20	1,336,388.70
45	10/30/17	11/05/17	3.50	11/09/17	7.50	119,786	34,347	154,133.01	1,155,997.58
46	11/06/17	11/12/17	3.50	11/17/17	8.50	118,786	34,529	153,314.37	1,303,172.15
47	11/13/17	11/19/17	3.50	11/22/17	6.50	117,068	34,426	151,493.48	984,707.62
48	11/20/17	11/26/17	3.50	12/01/17	8.50	115,524	34,296	149,819.88	1,273,468.98
49	11/27/17	12/03/17	3.50	12/08/17	8.50	112,123	33,963	146,086.21	1,241,732.79
50	12/04/17	12/10/17	3.50	12/15/17	8.50	111,756	33,793	145,548.87	1,237,165.40
51	12/11/17	12/17/17	3.50	12/21/17	7.50	112,420	33,843	146,263.47	1,096,976.03
52	12/18/17	12/24/17	3.50	12/28/17	7.50	109,653	33,824	143,477.08	1,076,078.10
								$ 8,905,340.40	**$ 74,592,459.66**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
WEEKLY Loan Repayment Analysis
January 2017 - December 2017

	PAY CYCLE FROM	PAY CYCLE TO	MIDPOINT	PAYROLL DATE	LAG DAYS	LOAN REPAYMENTS	TOTAL LAG $
1	12/26/16	01/01/17	3.50	01/06/17	8.50	51,936	$ 441,456.60
2	01/02/17	01/08/17	3.50	01/13/17	8.50	52,133	443,133.99
3	01/09/17	01/15/17	3.50	01/19/17	7.50	51,993	389,948.33
4	01/16/17	01/22/17	3.50	01/27/17	8.50	52,197	443,671.44
5	01/23/17	01/29/17	3.50	02/03/17	8.50	52,494	446,198.07
6	01/30/17	02/05/17	3.50	02/10/17	8.50	52,453	445,849.40
7	02/06/17	02/12/17	3.50	02/17/17	8.50	51,911	441,243.42
8	02/13/17	02/19/17	3.50	02/24/17	8.50	51,750	439,871.60
9	02/20/17	02/26/17	3.50	03/03/17	8.50	52,245	444,084.37
10	02/27/17	03/05/17	3.50	03/10/17	8.50	52,227	443,931.03
11	03/06/17	03/12/17	3.50	03/17/17	8.50	51,268	435,779.28
12	03/13/17	03/19/17	3.50	03/24/17	8.50	50,989	433,409.22
13	03/20/17	03/26/17	3.50	03/31/17	8.50	51,346	436,436.75
14	03/27/17	04/02/17	3.50	04/07/17	8.50	51,611	438,690.10
15	04/03/17	04/09/17	3.50	04/13/17	7.50	50,451	378,380.03
16	04/10/17	04/16/17	3.50	04/21/17	8.50	49,728	422,691.40
17	04/17/17	04/23/17	3.50	04/28/17	8.50	49,637	421,916.12
18	04/24/17	04/30/17	3.50	05/05/17	8.50	50,032	425,275.06
19	05/01/17	05/07/17	3.50	05/12/17	8.50	50,214	426,817.98
20	05/08/17	05/14/17	3.50	05/19/17	8.50	49,952	424,593.02
21	05/15/17	05/21/17	3.50	05/26/17	8.50	49,749	422,867.52
22	05/22/17	05/28/17	3.50	06/02/17	8.50	50,150	426,273.39
23	05/29/17	06/04/17	3.50	06/09/17	8.50	50,743	431,317.37
24	06/05/17	06/11/17	3.50	06/16/17	8.50	51,305	436,096.24
25	06/12/17	06/18/17	3.50	06/23/17	8.50	50,240	427,039.58
26	06/19/17	06/25/17	3.50	06/30/17	8.50	50,934	432,936.03
27	06/26/17	07/02/17	3.50	07/07/17	8.50	51,232	435,468.69
28	07/03/17	07/09/17	3.50	07/14/17	8.50	51,115	434,475.12
29	07/10/17	07/16/17	3.50	07/21/17	8.50	51,648	439,004.86
30	07/17/17	07/23/17	3.50	07/28/17	8.50	51,530	438,006.87
31	07/24/17	07/30/17	3.50	08/04/17	8.50	52,730	448,204.32
32	07/31/17	08/06/17	3.50	08/11/17	8.50	52,819	448,960.23
33	08/07/17	08/13/17	3.50	08/18/17	8.50	53,398	453,881.56
34	08/14/17	08/20/17	3.50	08/25/17	8.50	53,276	452,849.66
35	08/21/17	08/27/17	3.50	09/01/17	8.50	53,997	458,977.90
36	08/28/17	09/03/17	3.50	09/08/17	8.50	53,654	456,058.24
37	09/04/17	09/10/17	3.50	09/15/17	8.50	53,394	453,847.56
38	09/11/17	09/17/17	3.50	09/22/17	8.50	53,737	456,762.55
39	09/18/17	09/24/17	3.50	09/29/17	8.50	53,510	454,833.73
40	09/25/17	10/01/17	3.50	10/06/17	8.50	52,677	447,753.23
41	10/02/17	10/08/17	3.50	10/13/17	8.50	52,148	443,261.74
42	10/09/17	10/15/17	3.50	10/20/17	8.50	52,175	443,488.35
43	10/16/17	10/22/17	3.50	10/27/17	8.50	52,763	448,484.91
44	10/23/17	10/29/17	3.50	11/03/17	8.50	52,735	448,250.56
45	10/30/17	11/05/17	3.50	11/09/17	7.50	52,421	393,154.28
46	11/06/17	11/12/17	3.50	11/17/17	8.50	52,501	446,256.63
47	11/13/17	11/19/17	3.50	11/22/17	6.50	52,868	343,639.73
48	11/20/17	11/26/17	3.50	12/01/17	8.50	53,251	452,631.04
49	11/27/17	12/03/17	3.50	12/08/17	8.50	52,616	447,236.94
50	12/04/17	12/10/17	3.50	12/15/17	8.50	52,102	442,864.20
51	12/11/17	12/17/17	3.50	12/21/17	7.50	52,511	393,835.28
52	12/18/17	12/24/17	3.50	12/28/17	7.50	52,598	394,483.35
						$ 2,699,092.65	**$ 22,576,578.73**

WEIGHTED LAG DAYS

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
WEEKLY Credit Union Withholdings Analysis
January 2017 - December 2017

	PAY CYCLE FROM	PAY CYCLE TO	MIDPOINT	PAYROLL DATE	LAG DAYS	TOTAL CREDIT UNION	TOTAL LAG $
1	12/26/16	01/01/17	3.50	01/06/17	8.50	$ 50.00	$ 425.00
2	01/02/17	01/08/17	3.50	01/13/17	8.50	$ 50.00	425.00
3	01/09/17	01/15/17	3.50	01/19/17	7.50	$ 50.00	375.00
4	01/16/17	01/22/17	3.50	01/27/17	8.50	$ 50.00	425.00
5	01/23/17	01/29/17	3.50	02/03/17	8.50	$ 50.00	425.00
6	01/30/17	02/05/17	3.50	02/10/17	8.50	0.00	-
7	02/06/17	02/12/17	3.50	02/17/17	8.50	0.00	-
8	02/13/17	02/19/17	3.50	02/24/17	8.50	0.00	-
9	02/20/17	02/26/17	3.50	03/03/17	8.50	0.00	-
10	02/27/17	03/05/17	3.50	03/10/17	8.50	0.00	-
11	03/06/17	03/12/17	3.50	03/17/17	8.50	0.00	-
12	03/13/17	03/19/17	3.50	03/24/17	8.50	0.00	-
13	03/20/17	03/26/17	3.50	03/31/17	8.50	0.00	-
14	03/27/17	04/02/17	3.50	04/07/17	8.50	0.00	-
15	04/03/17	04/09/17	3.50	04/13/17	7.50	0.00	-
16	04/10/17	04/16/17	3.50	04/21/17	8.50	0.00	-
17	04/17/17	04/23/17	3.50	04/28/17	8.50	0.00	-
18	04/24/17	04/30/17	3.50	05/05/17	8.50	0.00	-
19	05/01/17	05/07/17	3.50	05/12/17	8.50	0.00	-
20	05/08/17	05/14/17	3.50	05/19/17	8.50	0.00	-
21	05/15/17	05/21/17	3.50	05/26/17	8.50	0.00	-
22	05/22/17	05/28/17	3.50	06/02/17	8.50	0.00	-
23	05/29/17	06/04/17	3.50	06/09/17	8.50	0.00	-
24	06/05/17	06/11/17	3.50	06/16/17	8.50	0.00	-
25	06/12/17	06/18/17	3.50	06/23/17	8.50	0.00	-
26	06/19/17	06/25/17	3.50	06/30/17	8.50	0.00	-
27	06/26/17	07/02/17	3.50	07/07/17	8.50	0.00	-
28	07/03/17	07/09/17	3.50	07/14/17	8.50	0.00	-
29	07/10/17	07/16/17	3.50	07/21/17	8.50	0.00	-
30	07/17/17	07/23/17	3.50	07/28/17	8.50	0.00	-
31	07/24/17	07/30/17	3.50	08/04/17	8.50	0.00	-
32	07/31/17	08/06/17	3.50	08/11/17	8.50	0.00	-
33	08/07/17	08/13/17	3.50	08/18/17	8.50	0.00	-
34	08/14/17	08/20/17	3.50	08/25/17	8.50	0.00	-
35	08/21/17	08/27/17	3.50	09/01/17	8.50	0.00	-
36	08/28/17	09/03/17	3.50	09/08/17	8.50	0.00	-
37	09/04/17	09/10/17	3.50	09/15/17	8.50	0.00	-
38	09/11/17	09/17/17	3.50	09/22/17	8.50	0.00	-
39	09/18/17	09/24/17	3.50	09/29/17	8.50	0.00	-
40	09/25/17	10/01/17	3.50	10/06/17	8.50	0.00	-
41	10/02/17	10/08/17	3.50	10/13/17	8.50	0.00	-
42	10/09/17	10/15/17	3.50	10/20/17	8.50	0.00	-
43	10/16/17	10/22/17	3.50	10/27/17	8.50	0.00	-
44	10/23/17	10/29/17	3.50	11/03/17	8.50	0.00	-
45	10/30/17	11/05/17	3.50	11/09/17	7.50	0.00	-
46	11/06/17	11/12/17	3.50	11/17/17	8.50	0.00	-
47	11/13/17	11/19/17	3.50	11/22/17	6.50	0.00	-
48	11/20/17	11/26/17	3.50	12/01/17	8.50	0.00	-
49	11/27/17	12/03/17	3.50	12/08/17	8.50	0.00	-
50	12/04/17	12/10/17	3.50	12/15/17	8.50	0.00	-
51	12/11/17	12/17/17	3.50	12/21/17	7.50	0.00	-
52	12/18/17	12/24/17	3.50	12/28/17	7.50	0.00	-
						$ 250.00	**$ 2,075.00**

WEIGHTED LAG DAYS

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
SEMI-MONTHLY Net Pay Analysis
January 2017 - December 2017

	PAY CYCLE FROM	PAY CYCLE TO	MIDPOINT	PAYROLL DATE	REMIT TO ADP	LAG DAYS	TOTAL PAID	TOTAL LAG $
1	12/24/16	01/08/17	8.00	1/13/2017	01/11/17	11.00	$ 1,001,954	$ 11,021,495.10
2	01/09/17	01/23/17	7.50	1/31/2017	01/29/17	13.50	$ 1,039,639	14,035,126.91
3	01/24/17	02/08/17	8.00	2/15/2017	02/13/17	13.00	$ 1,166,450	15,163,848.70
4	02/09/17	02/23/17	7.50	2/28/2017	02/26/17	10.50	$ 4,167,919	43,763,151.71
5	02/24/17	03/08/17	6.50	3/15/2017	03/13/17	11.50	$ 1,112,027	12,788,307.97
6	03/09/17	03/23/17	7.50	3/31/2017	03/29/17	13.50	$ 1,015,211	13,705,352.01
7	03/24/17	04/08/17	8.00	4/14/2017	04/12/17	12.00	$ 1,028,451	12,341,411.64
8	04/09/17	04/23/17	7.50	4/28/2017	04/26/17	10.50	$ 999,003	10,489,534.44
9	04/24/17	05/08/17	7.50	5/15/2017	05/13/17	12.50	$ 1,028,063	12,850,790.88
10	05/09/17	05/23/17	7.50	5/31/2017	05/29/17	13.50	$ 1,007,891	13,606,533.50
11	05/24/17	06/08/17	8.00	6/15/2017	06/13/17	13.00	$ 1,023,614	13,306,985.51
12	06/09/17	06/23/17	7.50	6/30/2017	06/28/17	12.50	$ 1,057,900	13,223,746.50
13	06/24/17	07/08/17	7.50	7/14/2017	07/12/17	11.50	$ 1,078,026	12,397,299.35
14	07/09/17	07/23/17	7.50	7/31/2017	07/29/17	13.50	$ 1,074,999	14,512,488.26
15	07/24/17	08/08/17	8.00	8/15/2017	08/13/17	13.00	$ 1,071,421	13,928,478.46
16	08/09/17	08/23/17	7.50	8/31/2017	08/29/17	13.50	$ 1,084,882	14,645,903.22
17	08/24/17	09/08/17	8.00	9/15/2017	09/13/17	13.00	$ 1,087,784	14,141,186.93
18	09/09/17	09/23/17	7.50	9/29/2017	09/27/17	11.50	$ 1,080,612	12,427,042.95
19	09/24/17	10/08/17	7.50	10/13/2017	10/11/17	10.50	$ 1,051,474	11,040,479.94
20	10/09/17	10/23/17	7.50	10/31/2017	10/29/17	13.50	$ 1,078,742	14,563,012.55
21	10/24/17	11/08/17	8.00	11/15/2017	11/13/17	13.00	$ 1,092,338	14,200,390.75
22	11/09/17	11/23/17	7.50	11/30/2017	11/28/17	12.50	$ 1,145,848	14,323,099.50
23	11/24/17	12/08/17	7.50	12/15/2017	12/13/17	12.50	$ 1,159,787	14,497,340.13
24	12/09/17	12/23/17	7.50	12/29/2017	12/27/17	11.50	$ 1,155,859	13,292,380.92
							$ 28,809,895.58	**$ 350,265,387.83**

WEIGHTED LAG DAYS **12.16**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
SEMI-MONTHLY Federal Income Tax (FIT) Withholding Analysis
January 2017 - December 2017

	PAY CYCLE FROM	PAY CYCLE TO	MIDPOINT	PAYROLL DATE	REMIT TO ADP	LAG DAYS	FIT WITHHOLDING	TOTAL LAG $
1	12/24/16	01/08/17	8.00	01/13/17	01/12/17	12.00	$ 239,174	$ 2,870,092.68
2	01/09/17	01/23/17	7.50	01/31/17	01/30/17	14.50	$ 250,256	3,628,707.36
3	01/24/17	02/08/17	8.00	02/15/17	02/14/17	14.00	$ 294,419	4,121,861.80
4	02/09/17	02/23/17	7.50	02/28/17	02/27/17	11.50	$ 1,446,072	16,629,833.29
5	02/24/17	03/08/17	6.50	03/15/17	03/14/17	12.50	$ 271,641	3,395,512.88
6	03/09/17	03/23/17	7.50	03/31/17	03/30/17	14.50	$ 239,786	3,476,897.44
7	03/24/17	04/08/17	8.00	04/14/17	04/13/17	13.00	$ 246,813	3,208,569.65
8	04/09/17	04/23/17	7.50	04/28/17	04/27/17	11.50	$ 236,292	2,717,356.62
9	04/24/17	05/08/17	7.50	05/15/17	05/14/17	13.50	$ 246,762	3,331,289.03
10	05/09/17	05/23/17	7.50	05/31/17	05/30/17	14.50	$ 238,218	3,454,158.25
11	05/24/17	06/08/17	8.00	06/15/17	06/14/17	14.00	$ 248,756	3,482,577.56
12	06/09/17	06/23/17	7.50	06/30/17	06/29/17	13.50	$ 249,033	3,361,943.75
13	06/24/17	07/08/17	7.50	07/14/17	07/13/17	12.50	$ 257,351	3,216,882.63
14	07/09/17	07/23/17	7.50	07/31/17	07/30/17	14.50	$ 257,288	3,730,679.92
15	07/24/17	08/08/17	8.00	08/15/17	08/14/17	14.00	$ 253,032	3,542,449.82
16	08/09/17	08/23/17	7.50	08/31/17	08/30/17	14.50	$ 256,167	3,714,427.16
17	08/24/17	09/08/17	8.00	09/15/17	09/14/17	14.00	$ 261,095	3,655,323.98
18	09/09/17	09/23/17	7.50	09/29/17	09/28/17	12.50	$ 257,305	3,216,309.13
19	09/24/17	10/08/17	7.50	10/13/17	10/12/17	11.50	$ 240,459	2,765,281.61
20	10/09/17	10/23/17	7.50	10/31/17	10/30/17	14.50	$ 250,501	3,632,265.66
21	10/24/17	11/08/17	8.00	11/15/17	11/14/17	14.00	$ 257,475	3,604,655.60
22	11/09/17	11/23/17	7.50	11/30/17	11/29/17	13.50	$ 276,497	3,732,710.99
23	11/24/17	12/08/17	7.50	12/15/17	12/14/17	13.50	$ 268,526	3,625,098.71
24	12/09/17	12/23/17	7.50	12/29/17	12/28/17	12.50	$ 269,995	3,374,941.63
							$ 7,312,913.31	**$ 95,489,827.09**

WEIGHTED LAG DAYS **13.06**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
SEMI-MONTHLY FICA/Medicare Tax Withholding Analysis
January 2017 - December 2017

	PAY CYCLE FROM	PAY CYCLE TO	MIDPOINT	PAYROLL DATE	REMIT TO ADP	LAG DAYS	FICA/MEDICARE WITHHOLDING	TOTAL LAG $
1	12/24/16	01/08/17	8.00	01/13/17	01/12/17	12.00	$ 134,579	$ 1,614,953.40
2	01/09/17	01/23/17	7.50	01/31/17	01/30/17	14.50	$ 138,554	2,009,037.93
3	01/24/17	02/08/17	8.00	02/15/17	02/14/17	14.00	$ 152,297	2,132,154.78
4	02/09/17	02/23/17	7.50	02/28/17	02/27/17	11.50	$ 522,782	6,011,993.69
5	02/24/17	03/08/17	6.50	03/15/17	03/14/17	12.50	$ 145,813	1,822,659.13
6	03/09/17	03/23/17	7.50	03/31/17	03/30/17	14.50	$ 134,962	1,956,944.80
7	03/24/17	04/08/17	8.00	04/14/17	04/13/17	13.00	$ 135,914	1,766,885.90
8	04/09/17	04/23/17	7.50	04/28/17	04/27/17	11.50	$ 132,079	1,518,911.15
9	04/24/17	05/08/17	7.50	05/15/17	05/14/17	13.50	$ 135,757	1,832,718.69
10	05/09/17	05/23/17	7.50	05/31/17	05/30/17	14.50	$ 133,227	1,931,790.20
11	05/24/17	06/08/17	8.00	06/15/17	06/14/17	14.00	$ 135,500	1,896,999.30
12	06/09/17	06/23/17	7.50	06/30/17	06/29/17	13.50	$ 135,492	1,829,140.79
13	06/24/17	07/08/17	7.50	07/14/17	07/13/17	12.50	$ 137,916	1,723,955.63
14	07/09/17	07/23/17	7.50	07/31/17	07/30/17	14.50	$ 136,058	1,972,840.86
15	07/24/17	08/08/17	8.00	08/15/17	08/14/17	14.00	$ 134,024	1,876,332.92
16	08/09/17	08/23/17	7.50	08/31/17	08/30/17	14.50	$ 131,980	1,913,716.38
17	08/24/17	09/08/17	8.00	09/15/17	09/14/17	14.00	$ 127,263	1,781,678.92
18	09/09/17	09/23/17	7.50	09/29/17	09/28/17	12.50	$ 122,401	1,530,016.75
19	09/24/17	10/08/17	7.50	10/13/17	10/12/17	11.50	$ 115,894	1,332,781.69
20	10/09/17	10/23/17	7.50	10/31/17	10/30/17	14.50	$ 112,926	1,637,422.36
21	10/24/17	11/08/17	8.00	11/15/17	11/14/17	14.00	$ 107,827	1,509,575.76
22	11/09/17	11/23/17	7.50	11/30/17	11/29/17	13.50	$ 105,568	1,425,164.49
23	11/24/17	12/08/17	7.50	12/15/17	12/14/17	13.50	$ 98,171	1,325,306.61
24	12/09/17	12/23/17	7.50	12/29/17	12/28/17	12.50	$ 92,833	1,160,414.38
							$ 3,459,817.41	**$ 45,513,396.47**

WEIGHTED LAG DAYS **13.15**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
SEMI-MONTHLY Unemployment Tax Analysis
January 2017 - December 2017

	FROM	TO	MIDPOINT	PAYROLL DATE	REMIT TO ADP	LAG DAYS	FUTA AMOUNT	SUTA AMOUNT	FUTA LAG $	SUTA LAG $
1	12/24/16	01/08/17	8.00	01/13/17	01/12/17	12.00	$ (10,784.12)	$ (27,139.82)	$ (129,409.44)	$ (325,677.84)
2	01/09/17	01/23/17	7.50	01/31/17	01/30/17	14.50	(5,774.45)	(21,461.14)	(83,729.53)	(311,186.53)
3	01/24/17	02/08/17	8.00	02/15/17	02/14/17	14.00	(582.36)	(5,545.73)	(8,153.04)	(77,640.22)
4	02/09/17	02/23/17	7.50	02/28/17	02/27/17	11.50	(540.41)	(1,951.61)	(6,214.72)	(22,443.52)
5	02/24/17	03/08/17	6.50	03/15/17	03/14/17	12.50	(27.27)	(143.94)	(340.88)	(1,799.25)
6	03/09/17	03/23/17	7.50	03/31/17	03/30/17	14.50	(52.68)	(200.09)	(763.86)	(2,901.31)
7	03/24/17	04/08/17	8.00	04/14/17	04/13/17	13.00	(121.96)	(354.83)	(1,585.48)	(4,612.79)
8	04/09/17	04/23/17	7.50	04/28/17	04/27/17	11.50	(147.38)	(414.31)	(1,694.87)	(4,764.57)
9	04/24/17	05/08/17	7.50	05/15/17	05/14/17	13.50	(65.97)	(267.60)	(890.60)	(3,612.60)
10	05/09/17	05/23/17	7.50	05/31/17	05/30/17	14.50	(60.95)	(159.50)	(883.78)	(2,312.75)
11	05/24/17	06/08/17	8.00	06/15/17	06/14/17	14.00	(72.77)	(240.98)	(1,018.78)	(3,373.72)
12	06/09/17	06/23/17	7.50	06/30/17	06/29/17	13.50	(199.11)	(586.23)	(2,687.99)	(7,914.11)
13	06/24/17	07/08/17	7.50	07/14/17	07/13/17	12.50	(290.85)	(901.03)	(3,635.63)	(11,262.88)
14	07/09/17	07/23/17	7.50	07/31/17	07/30/17	14.50	(259.88)	(803.68)	(3,768.26)	(11,653.36)
15	07/24/17	08/08/17	8.00	08/15/17	08/14/17	14.00	(306.97)	(1,091.60)	(4,297.58)	(15,282.40)
16	08/09/17	08/23/17	7.50	08/31/17	08/30/17	14.50	(173.16)	(559.98)	(2,510.82)	(8,119.71)
17	08/24/17	09/08/17	8.00	09/15/17	09/14/17	14.00	(63.84)	(241.63)	(893.76)	(3,382.82)
18	09/09/17	09/23/17	7.50	09/29/17	09/28/17	12.50	(40.89)	(148.30)	(511.13)	(1,853.75)
19	09/24/17	10/08/17	7.50	10/13/17	10/12/17	11.50	(45.21)	(202.43)	(519.92)	(2,327.95)
20	10/09/17	10/23/17	7.50	10/31/17	10/30/17	14.50	(104.39)	(261.06)	(1,513.66)	(3,785.37)
21	10/24/17	11/08/17	8.00	11/15/17	11/14/17	14.00	(88.83)	(318.99)	(1,243.62)	(4,465.86)
22	11/09/17	11/23/17	7.50	11/30/17	11/29/17	13.50	(107.17)	(427.26)	(1,446.80)	(5,768.01)
23	11/24/17	12/08/17	7.50	12/15/17	12/14/17	13.50	(106.49)	(373.34)	(1,437.62)	(5,040.09)
24	12/09/17	12/23/17	7.50	12/29/17	12/28/17	12.50	(121.89)	(528.12)	(1,523.63)	(6,601.50)
							$ (20,139.00)	**$ (64,323.20)**	**$ (260,675.40)**	**$ (847,782.91)**
						WEIGHTED LAG DAYS			**12.94**	**13.18**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
SEMI-MONTHLY Local Income Tax Withholding Analysis
January 2017 - December 2017

	PAY CYCLE FROM	PAY CYCLE TO	MIDPOINT	PAYROLL DATE	REMIT TO ADP	LAG DAYS	STATE WITHHOLDING	LOCAL WITHHOLDING	TOTAL WITHHOLDING	TOTAL LAG $
1	12/24/16	01/08/17	8.00	01/13/17	01/12/17	12.00	$ 73,470	$ 32,001	$ 105,471.27	$ 1,265,655.24
2	01/09/17	01/23/17	7.50	01/31/17	01/30/17	14.50	$ 76,554	$ 32,335	108,888.98	1,578,890.21
3	01/24/17	02/08/17	8.00	02/15/17	02/14/17	14.00	$ 90,051	$ 33,710	123,760.76	1,732,650.64
4	02/09/17	02/23/17	7.50	02/28/17	02/27/17	11.50	$ 368,517	$ 137,521	506,038.28	5,819,440.22
5	02/24/17	03/08/17	6.50	03/15/17	03/14/17	12.50	$ 81,261	$ 34,842	116,103.14	1,451,289.25
6	03/09/17	03/23/17	7.50	03/31/17	03/30/17	14.50	$ 73,691	$ 31,646	105,337.60	1,527,395.20
7	03/24/17	04/08/17	8.00	04/14/17	04/13/17	13.00	$ 74,964	$ 32,161	107,125.35	1,392,629.55
8	04/09/17	04/23/17	7.50	04/28/17	04/27/17	11.50	$ 73,000	$ 31,027	104,026.47	1,196,304.41
9	04/24/17	05/08/17	7.50	05/15/17	05/14/17	13.50	$ 75,090	$ 32,280	107,369.41	1,449,487.04
10	05/09/17	05/23/17	7.50	05/31/17	05/30/17	14.50	$ 73,563	$ 31,527	105,089.57	1,523,798.77
11	05/24/17	06/08/17	8.00	06/15/17	06/14/17	14.00	$ 75,778	$ 32,221	107,998.86	1,511,984.04
12	06/09/17	06/23/17	7.50	06/30/17	06/29/17	13.50	$ 76,382	$ 32,999	109,380.70	1,476,639.45
13	06/24/17	07/08/17	7.50	07/14/17	07/13/17	12.50	$ 78,479	$ 33,822	112,301.67	1,403,770.88
14	07/09/17	07/23/17	7.50	07/31/17	07/30/17	14.50	$ 78,373	$ 33,539	111,911.59	1,622,718.06
15	07/24/17	08/08/17	8.00	08/15/17	08/14/17	14.00	$ 78,212	$ 33,315	111,527.38	1,561,383.32
16	08/09/17	08/23/17	7.50	08/31/17	08/30/17	14.50	$ 78,542	$ 33,476	112,017.97	1,624,260.57
17	08/24/17	09/08/17	8.00	09/15/17	09/14/17	14.00	$ 79,501	$ 33,610	113,111.39	1,583,559.46
18	09/09/17	09/23/17	7.50	09/29/17	09/28/17	12.50	$ 77,608	$ 33,019	110,627.57	1,382,844.63
19	09/24/17	10/08/17	7.50	10/13/17	10/12/17	11.50	$ 74,492	$ 31,666	106,157.68	1,220,813.32
20	10/09/17	10/23/17	7.50	10/31/17	10/30/17	14.50	$ 77,085	$ 32,294	109,379.91	1,586,008.70
21	10/24/17	11/08/17	8.00	11/15/17	11/14/17	14.00	$ 78,424	$ 33,362	111,785.36	1,564,995.04
22	11/09/17	11/23/17	7.50	11/30/17	11/29/17	13.50	$ 82,331	$ 34,920	117,251.56	1,582,896.06
23	11/24/17	12/08/17	7.50	12/15/17	12/14/17	13.50	$ 81,520	$ 34,322	115,842.47	1,563,873.35
24	12/09/17	12/23/17	7.50	12/29/17	12/28/17	12.50	$ 81,338	$ 34,799	116,136.92	1,451,711.50
							2,158,227.11	896,414.75	**$ 3,054,641.86**	**$ 40,074,998.87**

WEIGHTED LAG DAYS **13.12**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
SEMI-MONTHLY Retirement Savings Contribution Analysis
January 2017 - December 2017

	PAY CYCLE FROM	PAY CYCLE TO	MIDPOINT	PAYROLL DATE	LAG DAYS	EMPLOYEE CONTRIBUTION	EMPLOYER CONTRIBUTION	LOAN REPAYMENTS	TOTAL LAG $
1	12/24/16	01/08/17	8.00	01/13/17	13.00	177,218	67,858	$ 245,075.53	$ 3,185,981.89
2	01/09/17	01/23/17	7.50	01/31/17	15.50	178,458	68,478	246,935.85	3,827,505.68
3	01/24/17	02/08/17	8.00	02/15/17	15.00	178,215	68,453	246,668.27	3,700,024.05
4	02/09/17	02/23/17	7.50	02/28/17	12.50	179,600	68,196	247,796.63	3,097,457.88
5	02/24/17	03/08/17	6.50	03/15/17	13.50	184,368	69,429	253,796.39	3,426,251.27
6	03/09/17	03/23/17	7.50	03/31/17	15.50	194,157	74,406	268,562.51	4,162,718.91
7	03/24/17	04/08/17	8.00	04/14/17	14.00	182,445	70,205	252,649.92	3,537,098.88
8	04/09/17	04/23/17	7.50	04/28/17	12.50	180,397	70,119	250,516.69	3,131,458.63
9	04/24/17	05/08/17	7.50	05/15/17	14.50	181,640	70,055	251,694.97	3,649,577.07
10	05/09/17	05/23/17	7.50	05/31/17	15.50	183,177	69,388	252,564.67	3,914,752.39
11	05/24/17	06/08/17	8.00	06/15/17	15.00	185,716	70,413	256,128.90	3,841,933.50
12	06/09/17	06/23/17	7.50	06/30/17	14.50	182,645	70,302	252,946.63	3,667,726.14
13	06/24/17	07/08/17	7.50	07/14/17	13.50	180,754	70,351	251,104.98	3,389,917.23
14	07/09/17	07/23/17	7.50	07/31/17	15.50	179,631	70,525	250,156.13	3,877,420.02
15	07/24/17	08/08/17	8.00	08/15/17	15.00	177,685	70,851	248,535.76	3,728,036.40
16	08/09/17	08/23/17	7.50	08/31/17	15.50	173,263	70,601	243,863.40	3,779,882.70
17	08/24/17	09/08/17	8.00	09/15/17	15.00	166,742	70,594	237,336.40	3,560,046.00
18	09/09/17	09/23/17	7.50	09/29/17	13.50	156,838	69,931	226,768.60	3,061,376.10
19	09/24/17	10/08/17	7.50	10/13/17	12.50	148,412	69,704	218,116.50	2,726,456.25
20	10/09/17	10/23/17	7.50	10/31/17	15.50	144,409	70,216	214,624.58	3,326,680.99
21	10/24/17	11/08/17	8.00	11/15/17	15.00	141,516	68,938	210,453.72	3,156,805.80
22	11/09/17	11/23/17	7.50	11/30/17	14.50	130,592	67,909	198,500.23	2,878,253.34
23	11/24/17	12/08/17	7.50	12/15/17	14.50	125,036	66,706	191,741.39	2,780,250.16
24	12/09/17	12/23/17	7.50	12/29/17	13.50	120,405	63,814	184,219.17	2,486,958.80
								$ 5,700,757.82	**$ 81,894,570.02**

WEIGHTED LAG DAYS **14.37**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
SEMI-MONTHLY Loan Repayment Analysis
January 2017 - December 2017

	PAY CYCLE FROM	PAY CYCLE TO	MIDPOINT	PAYROLL DATE	LAG DAYS	TOTAL REPAYMENTS	TOTAL LAG $
1	12/24/16	01/08/17	8.00	01/13/17	13.00	44,006	$ 572,072.28
2	01/09/17	01/23/17	7.50	01/31/17	15.50	43,956	681,317.85
3	01/24/17	02/08/17	8.00	02/15/17	15.00	44,543	668,151.00
4	02/09/17	02/23/17	7.50	02/28/17	12.50	44,657	558,213.13
5	02/24/17	03/08/17	6.50	03/15/17	13.50	43,718	590,186.52
6	03/09/17	03/23/17	7.50	03/31/17	15.50	43,456	673,575.60
7	03/24/17	04/08/17	8.00	04/14/17	14.00	44,130	617,820.70
8	04/09/17	04/23/17	7.50	04/28/17	12.50	43,878	548,472.25
9	04/24/17	05/08/17	7.50	05/15/17	14.50	44,419	644,068.69
10	05/09/17	05/23/17	7.50	05/31/17	15.50	44,897	695,899.16
11	05/24/17	06/08/17	8.00	06/15/17	15.00	44,524	667,853.70
12	06/09/17	06/23/17	7.50	06/30/17	14.50	44,821	649,904.94
13	06/24/17	07/08/17	7.50	07/14/17	13.50	45,049	608,161.91
14	07/09/17	07/23/17	7.50	07/31/17	15.50	46,242	716,744.96
15	07/24/17	08/08/17	8.00	08/15/17	15.00	46,221	693,312.15
16	08/09/17	08/23/17	7.50	08/31/17	15.50	47,002	728,531.31
17	08/24/17	09/08/17	8.00	09/15/17	15.00	46,486	697,294.35
18	09/09/17	09/23/17	7.50	09/29/17	13.50	46,201	623,708.78
19	09/24/17	10/08/17	7.50	10/13/17	12.50	45,889	573,606.38
20	10/09/17	10/23/17	7.50	10/31/17	15.50	47,066	729,518.66
21	10/24/17	11/08/17	8.00	11/15/17	15.00	46,379	695,683.80
22	11/09/17	11/23/17	7.50	11/30/17	14.50	46,387	672,605.56
23	11/24/17	12/08/17	7.50	12/15/17	14.50	47,601	690,220.45
24	12/09/17	12/23/17	7.50	12/29/17	13.50	46,888	632,992.73
						$ 1,088,413.61	**$ 15,629,916.80**

WEIGHTED LAG DAYS **14.36**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
SEMI-MONTHLY Credit Union Withholdings Analysis
January 2017 - December 2017

	PAY CYCLE			PAYROLL	LAG	TOTAL	TOTAL
	FROM	TO	MIDPOINT	DATE	DAYS	CREDIT UNION	LAG $
1	12/24/16	01/08/17	8.00	01/13/17	13.00	$ -	$ -
2	01/09/17	01/23/17	7.50	01/31/17	15.50	$ -	-
3	01/24/17	02/08/17	8.00	02/15/17	15.00	$ -	-
4	02/09/17	02/23/17	7.50	02/28/17	12.50	$ -	-
5	02/24/17	03/08/17	6.50	03/15/17	13.50	$ -	-
6	03/09/17	03/23/17	7.50	03/31/17	15.50	$ -	-
7	03/24/17	04/08/17	8.00	04/14/17	14.00	$ -	-
8	04/09/17	04/23/17	7.50	04/28/17	12.50	$ -	-
9	04/24/17	05/08/17	7.50	05/15/17	14.50	$ -	-
10	05/09/17	05/23/17	7.50	05/31/17	15.50	$ -	-
11	05/24/17	06/08/17	8.00	06/15/17	15.00	$ -	-
12	06/09/17	06/23/17	7.50	06/30/17	14.50	$ -	-
13	06/24/17	07/08/17	7.50	07/14/17	13.50	$ -	-
14	07/09/17	07/23/17	7.50	07/31/17	15.50	$ -	-
15	07/24/17	08/08/17	8.00	08/15/17	15.00	$ -	-
16	08/09/17	08/23/17	7.50	08/31/17	15.50	$ -	-
17	08/24/17	09/08/17	8.00	09/15/17	15.00	$ -	-
18	09/09/17	09/23/17	7.50	09/29/17	13.50	$ -	-
19	09/24/17	10/08/17	7.50	10/13/17	12.50	$ -	-
20	10/09/17	10/23/17	7.50	10/31/17	15.50	$ -	-
21	10/24/17	11/08/17	8.00	11/15/17	15.00	$ -	-
22	11/09/17	11/23/17	7.50	11/30/17	14.50	$ -	-
23	11/24/17	12/08/17	7.50	12/15/17	14.50	$ -	-
24	12/09/17	12/23/17	7.50	12/29/17	13.50	$ -	-
						$ -	**$ -**

WEIGHTED LAG DAYS **#DIV/0!**

POTOMAC ELECTRIC POWER COMPANY
Cash Working Capital
Annual Incentive Pay Analysis
January 2017 - December 2017

	PAY CYCLE FROM	PAY CYCLE TO	MIDPOINT		Payroll Date	LAG DAYS	INCENTIVE PAY	TOTAL LAG $
1	01/01/17	12/31/17	182.50		02/28/18	241.50	$ 5,174,667.40	$ 1,249,682,177.10
2	01/01/17	12/31/17	182.50		02/28/18	241.50	139,450.00	33,677,175.00
							$ 5,314,117	**$ 1,283,359,352.10**
						WEIGHTED LAG DAYS		**241.00**

Notes:
Line 1 MVP/AIP, Safety
Line 2 Bonus, Awards, Recognitions

POTOMAC ELECTRIC POWER COMPANY

Cash Working Capital Analysis
Control Center Lease Lag Days
January - December 2017

Service Period			Payment		Lag	Dollar
Begin	End	Midpoint	Date	Amount	Days	Days
12/22/2016	6/21/2017	91.00	6/21/2017	3,808,298	91.00	$ 346,555,129
6/22/2017	12/21/2017	91.50	12/15/2017	3,808,298	85.50	325,609,489
				$ 7,616,596	**88.25**	$ 672,164,618

POTOMAC ELECTRIC POWER COMPANY
Weighted Other O&M Expense Lag
Twelve Months Ended December 31, 2017

	Amount	Lag Days	Dollar Days
Service Company Bill - Utility Operations	$ 172,526,080	30.92	$ 5,334,506,405
Exelon Business Service Company - Utility Operations	50,266,559	30.95	$ 1,555,750,001
Other O&M Expense	151,110,406	42.95	6,490,238,236
Total	$ 373,903,045	35.79	$ 13,380,494,643

POTOMAC ELECTRIC POWER COMPANY
Derivation of Other O&M Expense
Twelve Months Ended December 31, 2017

Power Production Expense	$ 663,528,006	1
Transmission	31,874,937	2
Regional Transmission Organization (RTO)	(30,347)	3
Distribution	155,656,644	4
Customer Accounts	89,391,968	5
Customer Service & Information	9,315,533	6
Sales	-	7
Administrative & General	156,729,695	8
Total Electric O&M Expense	$ 1,106,466,436	9
Less:		
Purchased Power	$ (634,996,987)	10
Pepco Salaries & Wages	(81,232,578)	11
Storm Expense (Non-Deferred)	(1,100,633)	12
Control Center Lease	(15,233,192)	13
Service Company Bill - Utility Operations	(172,526,080)	14
Exelon Business Service Company - Utility Operations	(50,266,559)	14
Total Other O&M Expense	**$ 151,110,406**	

Reference:

1 Pepco 2017 FERC Form 1, pages 320-323, line 80

2 Pepco 2017 FERC Form 1, pages 320-323, line 112

3 Pepco 2017 FERC Form 1, pages 320-323, line 131

4 Pepco 2017 FERC Form 1, pages 320-323, line 156

5 Pepco 2017 FERC Form 1, pages 320-323, line 164

6 Pepco 2017 FERC Form 1, pages 320-323, line 171

7 Pepco 2017 FERC Form 1, pages 320-323, line 178

8 Pepco 2017 FERC Form 1, pages 320-323, line 197

9 Pepco 2017 FERC Form 1, pages 320-323, line 198

10 Pepco 2017 FERC Form 1, pages 320-323, line 76

11 Pepco 2017 FERC Form 1, page 354, line 28, column (b)

12 Z:\Services\Finance\0992_pepcoreg\MD Case No. XXXX (Fall 2017)\Test Year - December 2017 (12+0)\O&M Expenses\Storms\Storm Costs - Cumulative & 12 mons Dec 31 2017

13 Reflected in accounts 575.8 and 589

14 Pepco 2017 FERC Form 1, page 429, line 4, column d, footnote data, accounts 556-935

PHISCO Indirect Charges to PEPCO by FERC Account
Company Code
7000

FERC Account		Direct	Indirect	Total
107	Constr Work In Progress	23,186,042	13,359,159	36,545,201
182.3	Other Regulatory Assets	495,159	6,602,070	7,097,229
184	Clearing Accounts - Other	652,156	91,286	743,443
408.1	Taxes other than inc taxes, utility operating inc	-	1,742	1,742
416	Exp from Merchandising, Jobbing & Contract Work	535,836	387,725	923,560
417.1	Exp of Nonutility Operations	49,573	22,128	71,700
419	Interest and Dividend Income	-	(42,153)	(42,153)
426.1	Donations	0	153,958	153,958
426.2	Life Insurance	-	(431,740)	(431,740)
426.3	Penalties	-	1,894	1,894
426.4	Exp for certain civic, political & related active	132	86,852	86,985
426.5	Other Deductions	-	1,316,510	1,316,510
430	Interest-Debt to Associated Companies	-	45,561	45,561
431	Interest-Short Term Debt	-	(21,440)	(21,440)
556	System cont & load dispatch	77	1,967,326	1,967,404
557	Other expenses	886,344	322,994	1,209,338
560	Operation Supervision & Engineering	2,032,524	2,597,660	4,630,184
561.2	Load Dispatch - Monitor & Operate Transmission Sys	679,925	47,685	727,609
561.3	Load Dispatch - Transmission Service & Scheduling	16,870	12,531	29,401
561.5	Reliability, Planning and Standards	-	131,562	131,562
563	Overhead line expenses	163	62	225
562	Station expenses	4,678	1,910	6,587
564	Underground Line Expenses - Transmission	375	150	525
566	Miscellaneous transmission expenses	382,413	533,996	916,409
568	Maintenance Supervision & Engineering	465,128	75	465,203
569	Maint of structures	6,921	248	7,169
569.2	Maintenance of Computer Software	457,266	-	457,266
569.4	Maintenance of Transmission Plant	3	1	4
570	Maintenance of station equipment	290,216	77,037	367,252
571	Maintenance of overhead lines	590,246	660	590,906
572	Maintenance of underground lines	835	302	1,137
573	Maintenance of miscellaneous transmission plant	110,988	34,489	145,477
575.5	Ancillary services market administration	8,913	32	8,945
580	Operation Supervision & Engineering	1,289,833	52,967	1,342,800
581	Load dispatching	1,431,374	190,658	1,622,032
582	Station expenses	60,690	67,263	127,953
583	Overhead line expenses	28,574	9,397	37,971
584	Underground line expenses	144,106	37,392	181,498
585	Street lighting	20	7	27
586	Meter expenses	630,062	484,018	1,114,080
587	Customer installations expenses	889,909	113,436	1,003,345
588	Miscellaneous distribution expenses	703,531	6,105,664	6,809,195
589	Rents	77,296	-	77,296
590	Maintenance Supervision & Engineering	485,152	14,258	499,410
591	Maintain structures	6,638	336	6,974
592	Maintain equipment	736,719	179,953	916,673
593	Maintain overhead lines	1,684,025	165,990	1,850,015
594	Maintain underground line	536,949	191,538	728,487
595	Maintain line transformers	115,608	34,978	150,585
596	Maintain street lighting & signal systems	4,180	2,126	6,306
597	Maintain meters	102,091	30,493	132,584
598	Maintain distribution plant	562,971	11,234	574,205
902	Meter reading expenses	124,234	5,417	129,651
903	Customer records and collection expenses	6,767,132	41,564,113	48,331,246
907	Supervision - Customer Svc & Information	42,120	3	42,124
908	Customer assistance expenses	435,547	109,797	545,344
909	Informational & instructional advertising	23,400	811,490	834,890
920	Administrative & General salaries	689,110	-	689,110
921	Office supplies & expenses	-	361	361
923	Outside services employed	3,188,346	72,796,736	75,985,083
924	Property insurance	-	154	154
926	Employee pensions & benefits	-	12,245,344	12,245,344
928	Regulatory commission expenses	2,602,243	84,279	2,686,522
929	Duplicate charges-Credit	397,531	719,533	1,117,064
930.1	General ad expenses	-	356	356
930.2	Miscellaneous general expenses	42,649	956,775	999,424
935	Maintenance of general plant	4,052	71,319	75,371
		54,658,874	164,359,657	219,018,530
	Capital			(43,642,430)

POTOMAC ELECTRIC POWER COMPANY
Service Company Bill - Utility Operations
Cash Working Capital Analysis
2017 Service Company Lag

Service Period			Payment	Total Service Co.	Lag	Dollar
Begin	End	Midpoint	Date	Bill to Pepco	Days	Days
1/1/2017	1/31/2017	15.50	2/15/2017	$ 17,681,279	30.50	$ 539,279,001
2/1/2017	2/28/2017	14.00	3/15/2017	17,202,943	29.00	498,885,351
3/1/2017	3/31/2017	15.50	4/17/2017	19,201,776	32.50	624,057,733
4/1/2017	4/30/2017	15.00	5/15/2017	16,780,255	30.00	503,407,644
5/1/2017	5/31/2017	15.50	6/15/2017	19,628,904	30.50	598,681,578
6/1/2017	6/30/2017	15.00	7/19/2017	18,756,120	34.00	637,708,092
7/1/2017	7/31/2017	15.50	8/15/2017	17,320,933	30.50	528,288,457
8/1/2017	8/31/2017	15.50	9/15/2017	17,174,606	30.50	523,825,491
9/1/2017	9/30/2017	15.00	10/16/2017	17,469,191	31.00	541,544,930
10/1/2017	10/31/2017	15.50	11/15/2017	18,346,140	30.50	559,557,279
11/1/2017	11/30/2017	15.00	12/15/2017	16,981,264	30.00	509,437,925
12/1/2017	12/31/2017	15.50	1/16/2018	22,475,118	31.50	707,966,209
				$ 219,018,530	**30.92**	$ 6,772,639,690

EBSC Indirect Charges to PEPCO by FERC Account
Company Code

	7000	
FERC Accounts		
Clearing Accounts - Other	184	19,980,801
Donations	426.1	1,721,287
Penalties	426.3	3
Exp for certain civic, political & related active	426.4	191,313
Other Deductions	426.5	1,211
Operation Supervision & Engineering	560	849,628
Informational & instructional advertising	909	17,005
Administrative & General salaries	920	545
Outside services employed	923	48,173,245
Property insurance	924	1,008,650
General ad expenses	930.1	217,486
		72,161,174
Clearing Accounts - Other		(19,980,801)
Below the line		(1,913,814)
		50,266,559

POTOMAC ELECTRIC POWER COMPANY
Exelon Business Service Company - Utility Operations
Cash Working Capital Analysis
2017 Service Company Lag

Service Period			Payment	Total EBSC	Lag	Dollar
Begin	End	Midpoint	Date	Bill to Pepco	Days	Days
1/1/2017	1/31/2017	15.50	2/15/2017	$ 3,532,139	30.50	$ 107,730,236
2/1/2017	2/28/2017	14.00	3/15/2017	3,704,055	29.00	107,417,590
3/1/2017	3/31/2017	15.50	4/17/2017	4,509,072	32.50	146,544,826
4/1/2017	4/30/2017	15.00	5/15/2017	3,931,446	30.00	117,943,380
5/1/2017	5/31/2017	15.50	6/15/2017	4,564,541	30.50	139,218,499
6/1/2017	6/30/2017	15.00	7/19/2017	6,262,506	34.00	212,925,213
7/1/2017	7/31/2017	15.50	8/15/2017	5,283,975	30.50	161,161,246
8/1/2017	8/31/2017	15.50	9/15/2017	6,174,567	30.50	188,324,294
9/1/2017	9/30/2017	15.00	10/16/2017	6,409,003	31.00	198,679,108
10/1/2017	10/31/2017	15.50	11/15/2017	8,129,454	30.50	247,948,360
11/1/2017	11/30/2017	15.00	12/15/2017	9,348,363	30.00	280,450,895
12/1/2017	12/31/2017	15.50	1/16/2018	10,312,051	31.50	324,829,607
				$ 72,161,173	**30.95**	$ 2,233,173,253

POTOMAC ELECTRIC POWER COMPANY
Other O&M Expense Lag
Cash Working Capital Analysis
January 1, 2017 through December 31, 2017
Pepco Invoice Sample

Line No.	Random No.	Acct Doc No	Vendor Name	G/L Account	Category	Doc. date	Clearing date	Amount	Service Period Begin	Service Period End	Midpoint	Dollars	Lag Days	Dollar Days
1	0.999613	1414492	TRC SOLUTIONS	760005	Contractors	11/17/2017	12/1/2017	20,421.27	10/21/2017	11/3/2017	7.00	20,421.27	35.00	714,744
2	0.999587	1408971	ORCHARD FARMS INC	760020	Contractors	6/29/2017	7/28/2017	10,203.38	6/29/2017	6/29/2017	0.50	10,203.38	29.50	301,000
3	0.999526	1401502	COMVERGE INC	760010	Contractors	1/26/2017	2/24/2017	24,696.00	2/8/2017	2/7/2018	182.50	24,696.00	(165.50)	(4,087,188)
4	0.998246	1831915	THE KERRY S PEARSON LLC	760005	Contractors	11/1/2017	11/1/2017	40,000.00	2/1/2017	2/28/2017	14.00	40,000.00	260.00	10,400,000
5	0.997986	1413815	DAVEY TREE EXPERT CO	760041	Contractors	10/24/2017	12/8/2017	11,105.45	9/2/2017	9/30/2017	14.50	11,105.45	83.50	927,305
6	0.997901	1406972	DAVEY TREE EXPERT CO	760041	Contractors	6/7/2017	7/21/2017	11,053.26	5/6/2017	5/27/2017	11.00	11,053.26	66.00	729,515
7	0.997560	1400638	B FRANK JOY LLC	760040	Contractors	12/20/2016	1/19/2017	15,512.00	11/27/2016	12/3/2016	3.50	15,512.00	50.50	783,356
8	0.995782	1401807	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	1/19/2017	2/17/2017	71,765.51	11/26/2016	12/31/2016	18.00	71,765.51	66.00	4,736,524
9	0.993769	1407745	GENESIS SECURITY SYSTEMS LLC	760010	Contractors	1/1/2017	6/30/2017	19,643.52	4/1/2017	6/30/2017	45.50	19,643.52	45.50	893,780
10	0.993144	1400494	BATES WHITE LLC	760005	Contractors	12/14/2016	1/13/2017	36,401.25	11/1/2016	11/30/2016	15.00	36,401.25	59.00	2,147,674
11	0.992564	1411715	COX INDUSTRIES INC	760010	Contractors	9/22/2017	10/2/2017	10,762.75	8/22/2017	8/23/2017	1.00	10,762.75	41.00	441,273
12	0.992384	1401818	RIGGS DISTLER & COMPANY, INC	760041	Contractors	2/2/2017	3/3/2017	32,316.89	1/23/2017	1/29/2017	3.50	32,316.89	36.50	1,179,566
13	0.991996	1414568	BURNS & MCDONNELL	760005	Contractors	11/14/2017	12/11/2017	38,570.18	10/31/2017	10/31/2017	0.50	38,570.18	41.50	1,600,662
14	0.990620	1401807	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	1/19/2017	2/17/2017	56,631.83	11/26/2016	12/31/2016	18.00	56,631.83	66.00	3,737,701
15	0.990562	1408614	AUI INC	760040	Contractors	7/21/2017	7/31/2017	40,324.99	7/13/2017	7/19/2017	3.50	40,324.99	15.50	625,037
16	0.990064	1410788	COMVERGE INC	760010	Contractors	8/23/2017	9/22/2017	70,195.25	7/11/2017	8/10/2017	15.50	70,195.25	58.50	4,106,422
17	0.990055	1824090	REGULATED CAPITAL CONSULTANTS LLC	760005	Contractors	6/23/2017	7/28/2017	17,525.62	6/17/2017	7/21/2017	17.50	17,525.62	24.50	429,378
18	0.989973	1416128	TRC SOLUTIONS	760005	Contractors	12/15/2017	12/28/2017	30,626.05	11/25/2017	12/8/2017	7.00	30,626.05	27.00	826,903
19	0.989820	1405310	DYNAMIC CONCEPTS INC	760040	Contractors	4/4/2017	7/10/2017	19,901.25	3/1/2017	3/31/2017	15.50	19,901.25	116.50	2,318,496
20	0.989637	1413307	KCW ENGINEERING TECHNOLOGIES	760005	Contractors	10/1/2017	11/15/2017	40,462.04	10/1/2017	10/31/2017	15.50	40,462.04	30.50	1,234,092
21	0.989472	1416185	CSI INTERNATIONAL	760020	Contractors	11/1/2017	12/26/2017	12,672.68	11/1/2017	11/30/2017	15.00	12,672.68	41.00	519,580
22	0.989210	1405796	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	4/10/2017	5/16/2017	27,500.00	1/1/2017	3/31/2017	45.00	27,500.00	91.00	2,502,500
23	0.989154	1415472	CMGRP INC	760010	Contractors	11/21/2017	12/19/2017	85,502.50	8/1/2017	8/31/2017	15.50	85,502.50	125.50	10,730,564
24	0.988982	1412999	TRC SOLUTIONS	760005	Contractors	9/15/2017	10/30/2017	29,004.38	5/23/2017	9/8/2017	54.50	29,004.38	106.50	3,088,966
25	0.988954	1407123	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	5/27/2017	6/26/2017	10,707.71	5/27/2017	5/27/2017	0.50	10,707.71	30.50	326,585
26	0.987612	1405253	HENKELS & MCCOY INC	760010	Contractors	4/17/2017	6/1/2017	20,136.96	2/13/2017	2/13/2017	0.50	20,136.96	108.50	2,184,860
27	0.987533	1411234	WEST NOTIFICATIONS DBA	760010	Contractors	7/12/2017	9/22/2017	11,856.15	6/30/2017	6/30/2017	0.50	11,856.15	84.50	1,001,845
28	0.985340	1830094	NESCO LLC	770015	Rents	9/18/2017	11/2/2017	23,850.00	8/21/2017	9/17/2017	14.00	23,850.00	60.00	1,431,000
29	0.984814	1410757	UTILIQUEST LLC	760040	Contractors	9/5/2017	10/20/2017	20,595.50	8/27/2017	9/2/2017	3.50	20,595.50	51.50	1,060,668
30	0.984198	1408182	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	6/26/2017	7/26/2017	58,547.21	5/6/2017	5/27/2017	11.00	58,547.21	71.00	4,156,852
31	0.982714	1409754	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	8/14/2017	9/13/2017	61,172.88	6/3/2017	7/1/2017	14.50	61,172.88	88.50	5,413,800
32	0.982554	1413887	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	11/10/2017	12/8/2017	47,772.56	10/7/2017	11/10/2017	17.50	47,772.56	45.50	2,173,651
33	0.982433	1408089	TYNDALE COMPANY INC	794100	General	4/10/2017	7/12/2017	11,885.39	1/1/2017	3/31/2017	45.00	11,885.39	148.00	1,759,038
34	0.982041	1406901	RESOURCE ASSET MANAGEMENT	760010	Contractors	6/1/2017	6/13/2017	13,435.85	5/1/2017	5/31/2017	15.50	13,435.85	28.50	382,922
35	0.981357	1410410	GENESIS SECURITY SYSTEMS LLC	760010	Contractors	7/1/2017	8/31/2017	19,643.52	7/1/2019	9/30/2017	(319.00)	19,643.52	(349.00)	(6,855,588)
36	0.981356	1411661	SARGENT & LUNDY LLC	760005	Contractors	8/23/2017	10/6/2017	12,142.48	6/1/2017	7/31/2017	30.50	12,142.48	97.50	1,183,892
37	0.981065	1413308	KCW ENGINEERING TECHNOLOGIES	760005	Contractors	10/1/2017	11/15/2017	144,980.54	10/1/2017	10/31/2017	15.50	144,980.54	30.50	4,421,906
38	0.980907	1411075	BELTWAY INTERNATIONAL LLC	760020	Contractors	9/12/2017	10/12/2017	14,617.91	8/25/2017	8/25/2017	0.50	14,617.91	48.50	708,969
39	0.980492	1413879	SEBESTA INC	760005	Contractors	11/5/2017	12/11/2017	16,633.00	10/1/2017	10/28/2017	14.00	16,633.00	58.00	964,714
40	0.980255	1409846	COMVERGE INC	760010	Contractors	8/9/2017	9/8/2017	24,631.64	8/1/2017	8/31/2017	15.50	24,631.64	23.50	578,844
41	0.979272	1404910	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	4/20/2017	5/19/2017	35,540.78	3/4/2017	4/1/2017	14.50	35,540.78	62.50	2,221,299
42	0.978787	1413726	CMGRP INC	760010	Contractors	10/6/2017	11/20/2017	168,418.85	7/1/2017	12/31/2017	92.00	168,418.85	51.00	8,589,361
43	0.976940	1404775	RR DONNELLEY RECEIVABLES INC.	760010	Contractors	3/31/2017	5/15/2017	27,825.72	3/31/2017	3/31/2017	0.50	27,825.72	45.50	1,266,070
44	0.976789	1410253	ARCADIS U.S. INC	760005	Contractors	8/10/2017	9/22/2017	46,347.60	6/26/2017	7/23/2017	14.00	46,347.60	75.00	3,476,070
45	0.976671	1400108	UTILIQUEST LLC	760040	Contractors	1/3/2017	2/17/2017	16,320.00	12/25/2016	12/31/2016	3.50	16,320.00	51.50	840,480
46	0.976303	1409115	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	7/1/2017	8/2/2017	10,154.54	7/1/2017	7/1/2017	0.50	10,154.54	32.50	330,023
47	0.975250	1408244	ADMIRAL SECURITY SERVICES	760010	Contractors	6/28/2017	7/28/2017	11,014.72	6/4/2017	6/17/2017	7.00	11,014.72	48.00	528,707
48	0.972903	1822290	D C TREASURER	794035	General	7/7/2017	7/12/2017	45,000.00	7/11/2017	7/11/2017	0.50	45,000.00	1.50	67,500
49	0.972591	1404984	CONDUENT STATE & LOCAL SOLUTIONS IN	760010	Contractors	4/21/2017	5/22/2017	66,096.78	3/14/2017	3/16/2017	1.50	66,096.78	68.50	4,527,629
50	0.972551	1414631	KCW ENGINEERING TECHNOLOGIES	760005	Contractors	11/1/2017	12/11/2017	115,217.79	11/1/2017	11/30/2017	15.00	115,217.79	26.00	2,995,663
51	0.971700	1408295	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	6/24/2017	7/24/2017	23,784.09	6/24/2017	6/24/2017	0.50	23,784.09	30.50	725,415
52	0.971283	1412149	DYNAMIC CONCEPTS INC	760041	Contractors	10/4/2017	10/24/2017	64,324.50	9/1/2017	9/30/2017	15.00	64,324.50	39.00	2,508,656
53	0.971191	1401621	UTILIQUEST LLC	760040	Contractors	2/7/2017	3/24/2017	18,955.00	1/29/2017	2/4/2017	3.50	18,955.00	51.50	976,183
54	0.970540	1407209	CSI INTERNATIONAL	760020	Contractors	6/1/2017	7/14/2017	12,672.68	6/1/2017	6/30/2017	15.00	12,672.68	29.00	367,508
55	0.970466	1805768	RM THORNTON MECHANICAL	760020	Contractors	2/3/2017	3/9/2017	10,288.08	1/16/2017	1/25/2017	5.00	10,288.08	48.00	493,828
56	0.968260	1402159	KUBRA DATA TRANSFER LTD	760010	Contractors	11/1/2016	2/27/2017	43,101.51	11/1/2016	11/1/2016	0.50	43,101.51	118.50	5,107,529
57	0.968231	1405527	KCI TECHNOLOGIES	760010	Contractors	5/2/2017	6/16/2017	24,042.65	4/1/2017	4/30/2017	15.00	24,042.65	62.00	1,490,644
58	0.967878	1414147	NATURAL ENVIRONMENT LLC	760020	Contractors	11/8/2017	12/11/2017	13,975.00	11/8/2017	11/8/2017	0.50	13,975.00	33.50	468,163
59	0.967546	1414772	OSMOSE UTILITIES SERVICE INC	760010	Contractors	10/26/2017	12/6/2017	11,401.81	9/22/2017	10/19/2017	14.00	11,401.81	62.00	706,912
60	0.967225	1411395	ART ENGINEERING LLC	760005	Contractors	9/19/2017	10/24/2017	94,854.26	8/16/2017	8/31/2017	8.00	94,854.26	62.00	5,880,964
61	0.967070	1816823	JACKSON LEWIS LLP	760005	Contractors	5/11/2017	5/25/2017	19,373.00	4/1/2017	4/30/2017	15.00	19,373.00	40.00	774,920
62	0.966937	1409757	PRIMERA ENGINEERS LTD	790010	Travel	8/16/2017	9/29/2017	31,232.75	7/1/2017	7/28/2017	14.00	31,232.75	77.00	2,404,922

POTOMAC ELECTRIC POWER COMPANY
Other O&M Expense Lag
Cash Working Capital Analysis
January 1, 2017 through December 31, 2017
Pepco Invoice Sample

Line No.	Random No.	Acct Doc No	Vendor Name	G/L Account	Category	Doc. date	Clearing date	Amount	Service Period Begin	Service Period End	Midpoint	Dollars	Lag Days	Dollar Days
63	0.966696	1416114	TRC SOLUTIONS	760005	Contractors	12/15/2017	12/28/2017	30,486.98	11/25/2017	12/8/2017	7.00	30,486.98	27.00	823,148
64	0.966675	1413006	TRC SOLUTIONS	760005	Contractors	9/15/2017	10/30/2017	11,220.90	7/20/2017	9/8/2017	25.50	11,220.90	77.50	869,620
65	0.966526	1403148	DAVEY TREE EXPERT CO	760041	Contractors	3/8/2017	4/21/2017	10,362.07	2/4/2017	2/25/2017	11.00	10,362.07	66.00	683,897
66	0.964886	1408221	COMVERGE INC	760010	Contractors	7/6/2017	8/4/2017	13,462.05	7/1/2017	7/31/2017	15.50	13,462.05	19.50	262,510
67	0.964721	1411396	ART ENGINEERING LLC	760005	Contractors	9/8/2017	10/23/2017	52,288.20	8/9/2017	8/15/2017	3.50	52,288.20	72.50	3,790,895
68	0.964217	1406729	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	5/22/2017	6/21/2017	91,677.48	4/8/2017	4/29/2017	11.00	91,677.48	64.00	5,867,359
69	0.964121	1802709	RM THORNTON MECHANICAL	760020	Contractors	1/20/2017	2/17/2017	17,537.19	12/21/2016	1/14/2017	12.50	17,537.19	46.50	815,479
70	0.963841	1409549	ADMIRAL SECURITY SERVICES	760010	Contractors	8/8/2017	9/7/2017	22,031.06	7/6/2017	7/29/2017	12.00	22,031.06	52.00	1,145,615
71	0.963800	1805218	UNITED STATES POSTAL SERVICE	794041	General	3/1/2017	3/2/2017	280,000.00	3/1/2017	3/31/2017	15.50	280,000.00	(13.50)	(3,780,000)
72	0.962802	1827036	TNT EQUIPMENT SALES & RENTALS INC	770015	Rents	8/15/2017	8/29/2017	10,146.71	7/28/2017	8/25/2017	14.50	10,146.71	18.50	187,714
73	0.962756	1403237	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	3/13/2017	4/12/2017	124,488.69	2/4/2017	2/25/2017	11.00	124,488.69	57.00	7,095,855
74	0.962497	1403187	RESOURCE ASSET MANAGEMENT	760010	Contractors	3/13/2017	3/17/2017	21,785.40	2/28/2017	3/11/2017	6.00	21,785.40	12.00	261,425
75	0.961552	1402827	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	2/21/2017	3/23/2017	135,473.66	1/7/2017	1/28/2017	11.00	135,473.66	65.00	8,805,788
76	0.961242	1403871	OSMOSE UTILITIES SERVICE INC	760010	Contractors	2/22/2017	3/30/2017	31,242.35	1/28/2017	2/3/2017	3.50	31,242.35	58.50	1,827,677
77	0.960292	1413227	SYNTHETIC OILS & LUBRICANTS	760010	Contractors	10/19/2017	11/3/2017	54,541.17	10/19/2017	10/19/2017	0.50	54,541.17	15.50	845,388
78	0.960093	1400811	M.J. ELECTRIC LLC	760010	Contractors	1/5/2017	2/3/2017	12,290.08	1/5/2017	1/5/2017	0.50	12,290.08	29.50	362,557
79	0.959781	1413884	DAVEY TREE EXPERT CO	760041	Contractors	11/8/2017	12/11/2017	11,075.10	10/7/2017	10/28/2017	11.00	11,075.10	55.00	609,131
80	0.959725	1414979	CREDIT BUREAU COLLECTION SVC INC	794006	Collection	11/30/2017	12/12/2017	57,437.09	11/30/2017	11/30/2017	0.50	57,437.09	12.50	717,964
81	0.959214	1415532	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	12/15/2017	12/19/2017	56,127.98	11/4/2017	11/25/2017	11.00	56,127.98	35.00	1,964,479
82	0.958834	1412759	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	10/19/2017	11/17/2017	17,729.85	9/2/2017	9/30/2017	14.50	17,729.85	62.50	1,108,116
83	0.958525	1403952	RESOURCE ASSET MANAGEMENT	760010	Contractors	3/27/2017	3/31/2017	22,213.61	3/1/2017	3/24/2017	12.00	22,213.61	19.00	422,059
84	0.956895	1409288	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	7/27/2017	8/25/2017	28,986.60	7/15/2017	7/15/2017	0.50	28,986.60	41.50	1,202,944
85	0.955797	1404464	MCCLAFFERTY PRINTING CO	760010	Contractors	3/24/2017	6/27/2017	12,476.00	3/24/2017	3/24/2017	0.50	12,476.00	95.50	1,191,458
86	0.954652	1414918	SCOPE SERVICES INC	760010	Contractors	12/4/2017	12/11/2017	54,884.60	11/30/2017	11/30/2017	0.50	54,884.60	11.50	631,173
87	0.954321	1413887	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	11/10/2017	12/8/2017	157,054.93	10/7/2017	10/28/2017	11.00	157,054.93	52.00	8,166,856
88	0.953742	1415948	ACCELA, INC	760005	Contractors	11/30/2017	12/28/2017	84,211.23	1/1/2018	12/31/2018	182.50	84,211.23	(185.50)	(15,621,183)
89	0.952756	1407816	WEST NOTIFICATIONS DBA	760010	Contractors	6/12/2017	7/12/2017	10,697.38	5/31/2017	5/31/2017	0.50	10,697.38	42.50	454,639
90	0.951068	1406578	RIGGS DISTLER & COMPANY, INC	760040	Contractors	5/7/2017	6/6/2017	10,207.52	5/1/2017	5/2/2017	1.00	10,207.52	36.00	367,471
91	0.950621	1828677	WASHINGTON GAS LIGHT COMPANY	794035	General	9/13/2017	9/13/2017	50,000.00	9/13/2017	9/13/2017	0.50	50,000.00	0.50	25,000
92	0.950582	1412899	TRC SOLUTIONS	760005	Contractors	10/13/2017	11/27/2017	20,226.54	9/11/2017	10/6/2017	13.00	20,226.54	65.00	1,314,725
93	0.949791	1415100	SCOPE SERVICES INC	760040	Contractors	11/15/2017	12/13/2017	34,185.17	10/17/2017	10/31/2017	7.50	34,185.17	50.50	1,726,351
94	0.949614	1828535	UNITED STATES POSTAL SERVICE	794041	General	9/12/2017	9/26/2017	280,000.00	9/15/2017	10/15/2017	15.50	280,000.00	(3.50)	(980,000)
95	0.949035	1810719	THE KERRY S PEARSON LLC	760005	Contractors	4/11/2017	4/18/2017	40,000.00	5/1/2017	5/31/2017	15.50	40,000.00	(27.50)	(1,100,000)
96	0.948577	1410820	JUDD FIRE PROTECTION LLC	760020	Contractors	2/28/2017	9/14/2017	27,049.00	2/1/2017	2/28/2017	14.00	27,049.00	212.00	5,734,388
97	0.948069	1411520	KCW ENGINEERING TECHNOLOGIES	760005	Contractors	9/1/2017	10/16/2017	29,084.13	8/1/2017	8/19/2017	9.50	29,084.13	67.50	1,963,179
98	0.947698	1408523	RIGGS DISTLER & COMPANY, INC	760040	Contractors	7/5/2017	8/4/2017	62,083.44	6/1/2017	6/30/2017	15.00	62,083.44	50.00	3,104,172
99	0.946683	1413005	TRC SOLUTIONS	760005	Contractors	9/15/2017	10/30/2017	64,956.53	7/24/2017	9/8/2017	23.50	64,956.53	75.50	4,904,218
100	0.946357	1401807	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	1/19/2017	2/17/2017	73,355.99	11/20/2016	12/24/2016	17.50	73,355.99	72.50	5,318,309
101	0.946302	1401842	BENTLEY SYSTEMS INC	730010	Materials	12/22/2016	2/21/2017	14,835.27	11/21/2016	12/9/2016	9.50	14,835.27	83.50	1,238,745
102	0.946138	1404932	RR DONNELLEY RECEIVABLES INC.	760010	Contractors	3/31/2017	5/15/2017	59,194.07	3/31/2017	3/31/2017	0.50	59,194.07	45.50	2,693,330
103	0.946010	1411245	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	9/13/2017	10/13/2017	21,547.91	7/31/2016	8/26/2017	196.00	21,547.91	244.00	5,257,690
104	0.944771	1401807	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	1/19/2017	2/17/2017	49,101.50	11/20/2016	12/24/2016	17.50	49,101.50	72.50	3,559,859
105	0.944721	1404704	SCOPE SERVICES INC	760040	Contractors	3/15/2017	4/20/2017	39,921.91	2/1/2017	2/28/2017	14.00	39,921.91	65.00	2,594,924
106	0.944358	1400286	OSMOSE UTILITIES SERVICE INC	760041	Contractors	12/29/2016	2/1/2017	15,960.86	11/15/2016	12/13/2016	14.50	15,960.86	64.50	1,029,475
107	0.944205	1403759	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	3/13/2017	4/12/2017	144,127.78	1/29/2017	2/25/2017	14.00	144,127.78	60.00	8,647,667
108	0.944192	1411087	COX INDUSTRIES INC	760010	Contractors	8/24/2017	9/22/2017	10,767.82	7/25/2017	7/28/2017	2.00	10,767.82	58.00	624,534
109	0.944053	1412425	SCOPE SERVICES INC	760010	Contractors	10/4/2017	11/3/2017	42,989.40	9/1/2017	9/30/2017	15.00	42,989.40	49.00	2,106,481
110	0.943487	1830451	GENESIS SECURITY SYSTEMS LLC	760020	Contractors	6/8/2017	9/29/2017	14,502.85	6/8/2017	6/8/2017	0.50	14,502.85	113.50	1,646,073
111	0.943231	1408960	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	7/24/2017	8/23/2017	67,966.06	6/3/2017	7/1/2017	14.50	67,966.06	67.50	4,587,709
112	0.942918	1408301	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	6/24/2017	7/24/2017	12,200.52	6/18/2017	6/24/2017	3.50	12,200.52	33.50	408,717
113	0.940478	1406817	RICKART COLLECTION SYSTEMS INC	794006	Collection	1/31/2017	6/12/2017	11,619.04	1/1/2017	1/31/2017	15.50	11,619.04	147.50	1,713,808
114	0.939266	1831916	TNT EQUIPMENT SALES & RENTALS INC	770015	Rents	10/10/2017	11/22/2017	10,146.71	9/22/2017	10/20/2017	14.50	10,146.71	47.50	481,969
115	0.938557	1409034	GENESIS SECURITY SYSTEMS LLC	760010	Contractors	7/24/2017	9/26/2017	12,000.00	7/24/2017	7/24/2017	0.50	12,000.00	64.50	774,000
116	0.938387	1406479	RESOURCE ASSET MANAGEMENT	760010	Contractors	5/30/2017	6/1/2017	23,300.68	5/22/2017	5/29/2017	4.00	23,300.68	7.00	163,105
117	0.938377	1402746	RESOURCE ASSET MANAGEMENT	760010	Contractors	2/14/2017	3/9/2017	40,483.80	1/16/2017	2/14/2017	15.00	40,483.80	38.00	1,538,384
118	0.937796	1403420	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	3/14/2017	4/13/2017	39,832.32	2/26/2017	3/4/2017	3.50	39,832.32	43.50	1,732,706
119	0.936248	1407854	REGULATED CAPITAL CONSULTANTS LLC	760005	Contractors	5/26/2017	7/3/2017	16,603.61	5/26/2017	5/26/2017	0.50	16,603.61	38.50	639,239
120	0.935526	1403692	SCOTTMADDEN INC	760005	Contractors	3/2/2017	4/13/2017	38,208.75	1/1/2017	1/31/2017	15.50	38,208.75	87.50	3,343,266
121	0.935450	1402827	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	2/21/2017	3/23/2017	130,920.66	1/7/2017	1/28/2017	11.00	130,920.66	65.00	8,509,843
122	0.931165	1400811	M.J. ELECTRIC LLC	760010	Contractors	1/5/2017	2/3/2017	21,022.50	12/10/2017	12/22/2017	6.50	21,022.50	(315.50)	(6,632,599)
123	0.929903	1414696	TRC SOLUTIONS	760005	Contractors	11/7/2017	12/11/2017	15,845.96	10/9/2017	10/20/2017	6.00	15,845.96	58.00	919,066
124	0.929553	1406730	DAVEY TREE EXPERT CO	760041	Contractors	5/24/2017	7/7/2017	36,855.60	4/8/2017	4/29/2017	11.00	36,855.60	80.00	2,948,448
125	0.928547	1415930	HMI TECHNICAL SOLUTIONS LLC	760005	Contractors	12/12/2017	12/28/2017	10,543.00	11/1/2017	11/30/2017	15.00	10,543.00	43.00	453,349

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126	0.928534	1415935	HMI TECHNICAL SOLUTIONS LLC	760005	Contractors	12/12/2017	12/28/2017	13,725.00	10/1/2017	10/31/2017	15.50	13,725.00	73.50	1,008,788
127	0.928519	1407493	SCOPE SERVICES INC	760040	Contractors	6/15/2017	7/14/2017	28,942.23	5/1/2017	5/31/2017	15.50	28,942.23	59.50	1,722,063
128	0.928045	1413331	ADMIRAL SECURITY SERVICES	760010	Contractors	10/31/2017	11/30/2017	22,031.06	10/1/2017	10/21/2017	10.50	22,031.06	50.50	1,112,569
129	0.926891	1400614	RESOURCE ASSET MANAGEMENT	760010	Contractors	1/9/2017	1/17/2017	22,900.84	1/1/2017	1/9/2017	4.50	22,900.84	12.50	286,261
130	0.925688	1416060	POWER COMM CONSTRUCTION INC	760040	Contractors	11/22/2017	12/22/2017	13,424.16	11/5/2017	11/11/2017	3.50	13,424.16	44.50	597,375
131	0.925049	1411245	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	9/13/2017	10/13/2017	79,907.54	8/5/2017	8/26/2017	11.00	79,907.54	59.00	4,714,545
132	0.924213	1401912	UTILIQUEST LLC	760040	Contractors	2/13/2017	3/30/2017	19,116.50	2/5/2017	2/11/2017	3.50	19,116.50	50.50	965,383
133	0.923937	1410756	ACCU-READ SVCS	760040	Contractors	9/8/2017	10/6/2017	64,610.15	8/1/2017	8/31/2017	15.50	64,610.15	51.50	3,327,423
134	0.923906	1405011	CONVERGENT OUTSOURCING INC	760010	Contractors	4/1/2017	5/16/2017	256,931.80	3/1/2017	3/31/2017	15.50	256,931.80	61.50	15,801,306
135	0.923160	1415513	HMI TECHNICAL SOLUTIONS LLC	760005	Contractors	12/12/2017	12/19/2017	14,313.00	9/1/2017	9/30/2017	15.00	14,313.00	95.00	1,359,735
136	0.923094	1403262	R B HINKLE CONSTRUCTION INC	760040	Contractors	3/1/2017	3/31/2017	15,239.52	1/10/2017	1/14/2017	2.50	15,239.52	78.50	1,196,302
137	0.921705	1412897	TRC SOLUTIONS	760005	Contractors	10/13/2017	11/27/2017	11,125.89	9/12/2017	10/6/2017	12.50	11,125.89	64.50	717,620
138	0.921314	1409703	WEST NOTIFICATIONS DBA	760010	Contractors	4/11/2017	9/13/2017	26,466.05	4/1/2017	4/30/2017	15.00	26,466.05	151.00	3,996,374
139	0.921047	1500010	1919 PENNSYLVANIA ASSOCIATES LLC	770015	Rents	12/1/2017	12/4/2017	220,833.33	7/1/2017	12/31/2017	92.00	220,833.33	65.00	14,354,166
140	0.919611	1403458	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	3/13/2017	4/12/2017	54,026.68	2/4/2017	3/13/2017	19.00	54,026.68	49.00	2,647,307
141	0.918502	1829187	TNT EQUIPMENT SALES & RENTALS INC	770015	Rents	9/12/2017	9/20/2017	10,146.71	9/12/2017	9/22/2017	5.50	10,146.71	3.50	35,513
142	0.916081	1400078	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	12/21/2016	1/20/2017	11,341.51	10/29/2016	11/19/2016	11.00	11,341.51	73.00	827,930
143	0.916020	1413349	COMVERGE INC	760010	Contractors	10/31/2017	11/30/2017	13,462.04	10/1/2017	10/31/2017	15.50	13,462.04	45.50	612,523
144	0.915876	1416316	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	12/12/2017	12/28/2017	245,664.61	11/4/2017	11/25/2017	11.00	245,664.61	44.00	10,809,243
145	0.915786	1808147	REGULATED CAPITAL CONSULTANTS LLC	760005	Contractors	3/30/2017	4/5/2017	12,445.77	2/24/2017	3/3/2017	4.00	12,445.77	37.00	460,493
146	0.915696	1402827	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	2/21/2017	3/23/2017	13,310.34	1/7/2017	1/28/2017	11.00	13,310.34	65.00	865,172
147	0.915629	1408977	SCOPE SERVICES INC	760040	Contractors	7/15/2017	8/14/2017	48,811.82	5/1/2017	5/31/2017	15.50	48,811.82	90.50	4,417,470
148	0.915410	1416220	COMVERGE INC	760010	Contractors	12/18/2017	12/28/2017	31,818.73	12/1/2017	12/31/2017	15.50	31,818.73	12.50	397,734
149	0.914738	1825976	NESCO LLC	770015	Rents	7/24/2017	9/7/2017	23,850.00	6/19/2017	6/19/2017	0.50	23,850.00	80.50	1,919,925
150	0.914583	1401445	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	1/17/2017	2/16/2017	14,642.86	11/26/2016	12/31/2016	18.00	14,642.86	65.00	951,786
151	0.914577	1405859	SCOTTMADDEN INC	760005	Contractors	4/28/2017	6/12/2017	11,431.85	3/1/2017	3/30/2017	15.00	11,431.85	89.00	1,017,435
152	0.913073	1415951	THE BRATTLE GROUP INC	760005	Contractors	10/31/2017	12/26/2017	110,283.75	10/1/2017	10/31/2017	15.50	110,283.75	71.50	7,885,288
153	0.913070	1406616	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	5/22/2017	6/21/2017	117,805.08	4/8/2017	4/29/2017	11.00	117,805.08	64.00	7,539,525
154	0.912530	1401739	DAVEY TREE EXPERT CO	760041	Contractors	2/6/2017	3/23/2017	15,817.50	10/29/2016	11/19/2016	11.00	15,817.50	135.00	2,135,363
155	0.912455	1403556	RESOURCE ASSET MANAGEMENT	760010	Contractors	3/13/2017	3/27/2017	21,043.05	2/28/2017	3/11/2017	6.00	21,043.05	22.00	462,947
156	0.911953	1407402	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	6/15/2017	7/14/2017	51,738.47	5/6/2017	5/27/2017	11.00	51,738.47	59.00	3,052,570
157	0.911110	1400078	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	12/21/2016	1/20/2017	14,650.05	10/29/2016	11/19/2016	11.00	14,650.05	73.00	1,069,454
158	0.910082	1402745	RESOURCE ASSET MANAGEMENT	760010	Contractors	2/28/2017	3/9/2017	25,386.90	2/20/2017	2/28/2017	4.50	25,386.90	13.50	342,723
159	0.909329	1409148	RIGGS DISTLER & COMPANY, INC	760040	Contractors	6/29/2017	8/2/2017	11,109.36	6/19/2017	6/25/2017	3.50	11,109.36	41.50	461,038
160	0.907750	1404555	COMVERGE INC	760010	Contractors	3/31/2017	4/28/2017	57,470.80	3/11/2017	3/31/2017	10.50	57,470.80	38.50	2,212,626
161	0.907095	1413133	DEWBERRY CONSULTANTS, LLC	760005	Contractors	10/19/2017	11/22/2017	50,500.00	9/29/2017	9/29/2017	0.50	50,500.00	54.50	2,752,250
162	0.906858	1400782	RESOURCE ASSET MANAGEMENT	760010	Contractors	1/9/2017	1/23/2017	34,409.76	12/1/2017	12/31/2017	15.50	34,409.76	(326.50)	(11,234,787)
163	0.906850	1416115	TRC SOLUTIONS	760005	Contractors	12/15/2017	12/28/2017	21,181.00	11/27/2017	12/8/2017	6.00	21,181.00	26.00	550,706
164	0.906383	1407540	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	6/19/2017	7/19/2017	20,584.48	5/6/2017	5/27/2017	11.00	20,584.48	64.00	1,317,407
165	0.905600	1407512	ONE CALL CONCEPT INC	760040	Contractors	5/31/2017	6/30/2017	13,257.10	5/1/2017	5/31/2017	15.50	13,257.10	45.50	603,198
166	0.903636	1834762	THE KERRY S PEARSON LLC	760005	Contractors	11/14/2017	11/17/2017	40,000.00	12/1/2017	12/31/2017	15.50	40,000.00	(28.50)	(1,140,000)
167	0.903085	1402951	ADMIRAL SECURITY SERVICES	760010	Contractors	1/25/2017	3/14/2017	23,059.42	1/1/2017	1/14/2017	7.00	23,059.42	66.00	1,521,922
168	0.900972	1407540	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	6/19/2017	7/19/2017	12,586.99	5/6/2017	5/27/2017	11.00	12,586.99	64.00	805,567
169	0.900863	1409408	VEOLIA	760010	Contractors	8/4/2017	9/1/2017	10,588.49	6/20/2017	7/18/2017	14.50	10,588.49	59.50	630,015
170	0.900177	1409046	AECOM TECHNICAL SERVICES INC	760010	Contractors	7/28/2017	8/25/2017	31,404.38	6/24/2017	7/21/2017	14.00	31,404.38	49.00	1,538,815
171	0.899469	1411648	HEFFRON COMPANY INC	760020	Contractors	8/25/2017	9/28/2017	19,047.00	8/1/2017	8/15/2017	7.50	19,047.00	51.50	980,921
172	0.899049	1415682	COMVERGE INC	760010	Contractors	12/18/2017	12/19/2017	19,779.95	11/1/2017	11/30/2017	15.00	19,779.95	34.00	672,518
173	0.898128	1400119	UTILIQUEST LLC	760040	Contractors	12/27/2016	2/10/2017	20,094.00	12/18/2016	12/24/2016	3.50	20,094.00	51.50	1,034,841
174	0.896654	1415961	TRC SOLUTIONS	760005	Contractors	12/5/2017	12/28/2017	11,766.98	11/6/2018	11/22/2018	8.50	11,766.98	(320.50)	(3,771,317)
175	0.896402	1407402	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	6/15/2017	7/14/2017	26,639.02	5/6/2017	5/27/2017	11.00	26,639.02	59.00	1,571,702
176	0.894851	1410577	UTILIQUEST LLC	760040	Contractors	8/28/2017	10/12/2017	23,069.00	8/20/2017	8/26/2017	3.50	23,069.00	50.50	1,164,985
177	0.894258	1410426	OSMOSE UTILITIES SERVICE INC	760010	Contractors	7/26/2017	9/1/2017	18,391.47	5/24/2017	7/20/2017	29.00	18,391.47	72.00	1,324,186
178	0.893740	1416036	UTILIQUEST LLC	760040	Contractors	12/18/2017	12/28/2017	18,326.00	12/10/2017	12/16/2017	3.50	18,326.00	15.50	284,053
179	0.893671	1402765	RIGGS DISTLER & COMPANY, INC	760040	Contractors	11/14/2016	3/9/2017	38,477.24	7/18/2016	7/24/2016	3.50	38,477.24	231.50	8,907,481
180	0.893642	1407249	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	6/15/2017	7/14/2017	11,250.16	5/30/2017	6/3/2017	2.50	11,250.16	43.50	489,382
181	0.892850	1836974	SCOTTMADDEN INC	760005	Contractors	6/21/2017	12/11/2017	24,978.96	4/1/2017	5/31/2017	30.50	24,978.96	224.50	5,607,777
182	0.892232	1402744	RESOURCE ASSET MANAGEMENT	760010	Contractors	2/21/2017	3/9/2017	34,199.55	2/13/2017	2/20/2017	4.00	34,199.55	21.00	718,191
183	0.892022	1415611	HMI TECHNICAL SOLUTIONS LLC	760005	Contractors	12/12/2017	12/19/2017	14,605.50	11/1/2018	11/30/2018	15.00	14,605.50	(331.00)	(4,834,421)
184	0.890803	1412836	ALTRAN US CORP	760005	Contractors	9/22/2017	11/6/2017	137,668.56	8/1/2018	8/31/2018	15.50	137,668.56	(282.50)	(38,891,368)
185	0.888614	1406436	CONDUENT STATE & LOCAL SOLUTIONS IN	760010	Contractors	5/10/2017	6/9/2017	37,153.65	4/1/2017	4/30/2017	15.00	37,153.65	55.00	2,043,451
186	0.888522	1411245	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	9/13/2017	10/13/2017	20,519.42	8/5/2017	8/26/2017	11.00	20,519.42	59.00	1,210,646
187	0.886842	1408182	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	6/26/2017	7/26/2017	91,138.01	5/6/2017	5/27/2017	11.00	91,138.01	71.00	6,470,799
188	0.884396	1408589	UTILIQUEST LLC	760040	Contractors	7/17/2017	8/31/2017	21,870.50	7/9/2017	7/15/2017	3.50	21,870.50	50.50	1,104,460

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189	0.882883	1411620	SCOPE SERVICES INC	760040	Contractors	9/15/2017	10/13/2017	23,444.51	8/1/2017	8/30/2017	15.00	23,444.51	59.00	1,383,226
190	0.882836	1406985	UTILIQUEST LLC	760040	Contractors	6/12/2017	7/27/2017	21,981.00	6/4/2017	6/10/2017	3.50	21,981.00	50.50	1,110,041
191	0.882691	1404584	ADMIRAL SECURITY SERVICES	760010	Contractors	4/5/2017	5/5/2017	21,993.63	3/12/2017	3/25/2017	7.00	21,993.63	48.00	1,055,694
192	0.882549	1411678	ADMIRAL SECURITY SERVICES	760010	Contractors	9/20/2017	10/20/2017	11,185.28	8/27/2017	9/9/2017	7.00	11,185.28	48.00	536,893
193	0.880491	1408294	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	6/24/2017	7/24/2017	50,798.48	6/19/2017	6/24/2017	3.00	50,798.48	33.00	1,676,350
194	0.879842	1409754	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	8/14/2017	9/13/2017	40,277.87	6/3/2017	7/1/2017	14.50	40,277.87	88.50	3,564,591
195	0.879835	1409102	PRIMERA ENGINEERS LTD	790010	Travel	7/26/2017	9/8/2017	59,816.88	5/27/2017	6/30/2017	17.50	59,816.88	87.50	5,233,977
196	0.879754	1411412	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	9/20/2017	10/20/2017	105,267.17	7/1/2017	7/29/2017	14.50	105,267.17	97.50	10,263,549
197	0.879630	1410554	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	8/23/2017	9/22/2017	113,117.02	7/8/2017	7/29/2017	11.00	113,117.02	66.00	7,465,723
198	0.878623	1414945	RR DONNELLEY RECEIVABLES INC.	760010	Contractors	11/30/2017	12/11/2017	57,272.61	11/30/2017	11/30/2017	0.50	57,272.61	11.50	658,635
199	0.878279	1411393	POWER DELIVERY SOLUTIONS LLC	760010	Contractors	9/21/2017	10/20/2017	10,252.76	8/1/2017	8/31/2017	15.50	10,252.76	65.50	671,556
200	0.877179	1404245	ADMIRAL SECURITY SERVICES	760010	Contractors	3/21/2017	4/20/2017	22,230.66	3/11/2017	3/11/2017	0.50	22,230.66	40.50	900,342
201	0.876038	1411622	WEST NOTIFICATIONS DBA	760005	Contractors	7/31/2017	9/28/2017	14,254.30	7/12/2017	7/20/2017	4.50	14,254.30	74.50	1,061,945
202	0.875509	1410836	CHA CONSULTING INC	760005	Contractors	9/1/2017	9/15/2017	319,326.82	7/31/2017	8/11/2017	6.00	319,326.82	41.00	13,092,400
203	0.875047	1410414	SCOPE SERVICES INC	760040	Contractors	8/11/2017	9/8/2017	23,416.20	7/1/2017	7/31/2017	15.50	23,416.20	54.50	1,276,183
204	0.874365	1402827	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	2/21/2017	3/23/2017	14,281.78	1/1/2017	1/28/2017	14.00	14,281.78	68.00	971,161
205	0.872863	1405633	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	5/4/2017	6/2/2017	62,901.99	2/25/2017	4/1/2017	18.00	62,901.99	80.00	5,032,159
206	0.872600	1404700	TELOGIS INC	795017	General	4/1/2017	5/1/2017	20,718.03	4/1/2017	4/30/2017	15.00	20,718.03	16.00	331,488
207	0.871468	1824092	VERIZON BUSINESS	795016	General	7/10/2017	7/28/2017	24,012.93	6/10/2017	7/10/2017	15.50	24,012.93	33.50	804,433
208	0.869737	1824089	REGULATED CAPITAL CONSULTANTS LLC	760005	Contractors	7/21/2017	7/28/2017	22,839.22	6/17/2017	7/21/2017	17.50	22,839.22	24.50	559,561
209	0.869216	1412475	TRC SOLUTIONS	760005	Contractors	10/13/2017	11/27/2017	15,310.14	9/11/2017	10/6/2017	13.00	15,310.14	65.00	995,159
210	0.868867	1402294	STAR MEDIA INC	760005	Contractors	2/6/2017	3/8/2017	11,994.43	10/31/2017	12/25/2017	28.00	11,994.43	(264.00)	(3,166,530)
211	0.868830	1414144	POWER DELIVERY SOLUTIONS LLC	760010	Contractors	11/17/2017	12/11/2017	14,817.08	9/1/2017	9/30/2017	15.00	14,817.08	87.00	1,289,086
212	0.867384	1405499	ASHTON MANOR ENVIRONMENTAL	760041	Contractors	4/10/2017	5/10/2017	47,456.50	3/1/2017	3/30/2017	15.00	47,456.50	56.00	2,657,564
213	0.867242	1414096	GENERAL ELECTRIC COMPANY	760010	Contractors	6/7/2017	12/1/2017	12,520.00	6/7/2017	6/7/2017	0.50	12,520.00	177.50	2,222,300
214	0.866749	1408611	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	7/1/2017	7/31/2017	39,250.18	7/1/2017	7/13/2017	6.50	39,250.18	24.50	961,629
215	0.866617	1405034	RIGGS DISTLER & COMPANY, INC	760040	Contractors	3/31/2017	4/28/2017	19,939.54	3/27/2017	4/2/2017	3.50	19,939.54	29.50	588,216
216	0.865897	1400811	M.J. ELECTRIC LLC	760010	Contractors	1/5/2017	2/3/2017	22,316.18	12/9/2017	12/22/2017	7.00	22,316.18	(315.00)	(7,029,597)
217	0.865446	1404307	UTILIQUEST LLC	760040	Contractors	3/27/2017	5/11/2017	18,555.50	3/19/2017	3/25/2017	3.50	18,555.50	50.50	937,053
218	0.865080	1403759	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	3/13/2017	4/12/2017	68,954.98	2/4/2017	2/25/2017	11.00	68,954.98	57.00	3,930,434
219	0.865041	1415924	TURNING POINT COLLECTION LLC	760020	Contractors	11/27/2017	12/26/2017	23,259.56	11/27/2017	11/27/2017	0.50	23,259.56	29.50	686,157
220	0.863684	1407418	CONDUENT STATE & LOCAL SOLUTIONS IN	760010	Contractors	6/14/2017	7/14/2017	40,950.61	5/1/2017	5/31/2017	15.50	40,950.61	59.50	2,436,561
221	0.863656	1415496	HMI TECHNICAL SOLUTIONS LLC	760005	Contractors	12/12/2017	12/19/2017	11,470.50	8/1/2017	8/31/2017	15.50	11,470.50	125.50	1,439,548
222	0.862864	1838010	BALTIC CONSTRUCTION INC	760020	Contractors	11/24/2017	12/21/2017	26,070.00	11/24/2017	11/24/2017	0.50	26,070.00	27.50	716,925
223	0.862667	1409538	COMVERGE INC	760010	Contractors	8/9/2017	9/8/2017	163,554.09	8/1/2017	8/31/2017	15.50	163,554.09	23.50	3,843,521
224	0.862486	1814340	PENN SCHOEN & BERLAND ASSOC LLC	760010	Contractors	1/10/2017	5/8/2017	35,000.00	12/1/2016	2/28/2017	45.00	35,000.00	114.00	3,990,000
225	0.861635	1407252	ASHTON MANOR ENVIRONMENTAL	760041	Contractors	5/31/2017	6/30/2017	163,233.70	5/1/2017	5/24/2017	12.00	163,233.70	49.00	7,998,451
226	0.861281	1404696	MIRARCHI BROTHERS INC	760040	Contractors	4/10/2017	4/20/2017	12,208.10	3/13/2017	3/19/2017	3.50	12,208.10	35.50	433,388
227	0.860926	1838134	BALTIC CONSTRUCTION INC	760020	Contractors	11/6/2017	12/22/2017	19,726.00	11/6/2017	11/6/2017	0.50	19,726.00	46.50	917,259
228	0.860385	1406671	MARSHALL MOYA DESIGN LLC	760010	Contractors	4/10/2017	6/7/2017	14,060.00	12/8/2016	3/31/2017	57.00	14,060.00	125.00	1,757,500
229	0.859918	1409795	CREDIT BUREAU COLLECTION SVC INC	794006	Collection	7/31/2017	8/30/2017	22,732.98	10/7/2017	10/28/2017	11.00	22,732.98	(48.00)	(1,091,183)
230	0.859611	1400404	DYNAMIC CONCEPTS INC	760040	Contractors	1/4/2017	2/17/2017	22,463.25	12/1/2017	12/31/2017	15.50	22,463.25	(301.50)	(6,772,670)
231	0.859525	1411585	CONDUENT STATE & LOCAL SOLUTIONS IN	760010	Contractors	8/16/2017	9/27/2017	24,774.26	7/1/2017	7/31/2017	15.50	24,774.26	73.50	1,820,908
232	0.858263	1413797	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	11/9/2017	12/8/2017	29,633.43	10/1/2017	10/31/2017	15.50	29,633.43	53.50	1,585,389
233	0.857894	1412515	UTILIQUEST LLC	760040	Contractors	10/16/2017	11/30/2017	21,522.00	10/8/2017	10/14/2017	3.50	21,522.00	50.50	1,086,861
234	0.857800	1410866	W.A. CHESTER LLC	760040	Contractors	9/6/2017	10/20/2017	10,473.65	8/21/2017	8/27/2017	3.50	10,473.65	57.50	602,235
235	0.855572	1838011	TNT EQUIPMENT SALES & RENTALS INC	770015	Rents	12/4/2017	12/28/2017	10,146.71	11/16/2017	12/14/2017	14.50	10,146.71	28.50	289,181
236	0.855390	1412405	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	10/12/2017	11/10/2017	13,402.98	8/26/2017	9/30/2017	18.00	13,402.98	59.00	790,776
237	0.855290	1413637	SCOPE SERVICES INC	760010	Contractors	11/3/2017	12/1/2017	33,293.70	10/1/2017	10/31/2017	15.50	33,293.70	46.50	1,548,157
238	0.854714	1412493	TRC SOLUTIONS	760005	Contractors	9/15/2017	10/30/2017	130,540.55	3/1/2017	9/8/2017	96.00	130,540.55	148.00	19,320,001
239	0.854512	1411725	GENESIS SECURITY SYSTEMS LLC	760010	Contractors	9/25/2017	11/9/2017	18,855.00	9/25/2017	9/25/2017	0.50	18,855.00	45.50	857,903
240	0.854250	1413688	CHEMSOLV INC	760010	Contractors	10/12/2017	11/14/2017	26,691.83	10/4/2017	10/4/2017	0.50	26,691.83	41.50	1,107,711
241	0.854162	1401807	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	1/19/2017	2/17/2017	41,403.37	11/26/2016	12/31/2016	18.00	41,403.37	66.00	2,732,622
242	0.853857	1407777	CREATIVE CO-OP LLC	760010	Contractors	6/20/2017	7/20/2017	34,019.76	5/1/2017	5/31/2017	15.50	34,019.76	65.50	2,228,294
243	0.852764	1406729	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	5/22/2017	6/21/2017	30,704.52	4/8/2017	4/29/2017	11.00	30,704.52	64.00	1,965,089
244	0.852366	1405969	SCOTTMADDEN INC	760005	Contractors	4/28/2017	6/12/2017	16,990.00	4/1/2017	4/30/2017	15.00	16,990.00	58.00	985,420
245	0.852342	1400520	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	12/22/2016	1/20/2017	58,827.22	10/29/2016	11/19/2016	11.00	58,827.22	73.00	4,294,387
246	0.852320	1404777	DAVEY TREE EXPERT CO	760041	Contractors	4/18/2017	6/2/2017	42,077.92	2/26/2017	4/1/2017	17.50	42,077.92	79.50	3,345,195
247	0.851571	1406455	BGP COMMUNICATIONS JV, LLC	760010	Contractors	5/16/2017	6/15/2017	72,100.00	4/1/2017	4/30/2017	15.00	72,100.00	61.00	4,398,100
248	0.851110	1410685	DENISON LANDSCAPING INC	760020	Contractors	8/29/2017	9/28/2017	11,316.24	8/24/2017	8/24/2017	0.50	11,316.24	35.50	401,727
249	0.850981	1410834	ART ENGINEERING LLC	760005	Contractors	8/16/2017	9/15/2017	59,537.68	8/1/2017	8/8/2017	4.00	59,537.68	42.00	2,500,583
250	0.850343	1818947	UNITED STATES POSTAL SERVICE	794041	General	6/9/2017	6/12/2017	280,000.00	6/20/2017	7/31/2017	21.00	280,000.00	(28.00)	(7,840,000)
251	0.850189	1405633	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	5/4/2017	6/2/2017	108,368.56	2/26/2017	4/1/2017	17.50	108,368.56	79.50	8,615,301

POTOMAC ELECTRIC POWER COMPANY
Other O&M Expense Lag
Cash Working Capital Analysis
January 1, 2017 through December 31, 2017
Pepco Invoice Sample

Line No.	Random No.	Acct Doc No	Vendor Name	G/L Account	Category	Doc. date	Clearing date	Amount	Service Period Begin	Service Period End	Midpoint	Dollars	Lag Days	Dollar Days
252	0.849804	1414730	REGULATED CAPITAL CONSULTANTS LLC	760005	Contractors	11/3/2017	12/11/2017	15,766.47	10/30/2017	11/3/2017	2.50	15,766.47	40.50	638,542
253	0.849199	1413569	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	10/30/2017	11/29/2017	27,500.00	10/1/2017	12/31/2017	46.00	27,500.00	14.00	385,000
254	0.849009	1405101	UTILIQUEST LLC	760040	Contractors	4/24/2017	6/8/2017	21,930.00	4/17/2017	4/22/2017	3.00	21,930.00	50.00	1,096,500
255	0.847212	1407120	DAVEY TREE EXPERT CO	760041	Contractors	6/7/2017	7/21/2017	11,136.79	5/1/2017	5/27/2017	13.50	11,136.79	68.50	762,870
256	0.846759	1415538	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	11/30/2017	12/19/2017	12,083.30	11/11/2017	11/18/2017	4.00	12,083.30	35.00	422,916
257	0.846535	1411833	UTILIQUEST LLC	760040	Contractors	9/25/2017	11/9/2017	23,774.50	9/17/2017	9/23/2017	3.50	23,774.50	50.50	1,200,612
258	0.845132	1400733	UTILIQUEST LLC	760040	Contractors	1/16/2017	3/2/2017	22,329.50	1/8/2017	1/14/2017	3.50	22,329.50	50.50	1,127,640
259	0.844817	1403237	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	3/13/2017	4/12/2017	114,505.73	1/28/2017	2/25/2017	14.50	114,505.73	60.50	6,927,597
260	0.844076	1406616	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	5/22/2017	6/21/2017	22,763.79	4/1/2017	4/29/2017	14.50	22,763.79	67.50	1,536,556
261	0.843153	1412549	ADMIRAL SECURITY SERVICES	760010	Contractors	10/17/2017	11/16/2017	22,031.06	10/6/2017	10/6/2017	0.50	22,031.06	41.50	914,289
262	0.842909	1411676	ADMIRAL SECURITY SERVICES	760010	Contractors	9/20/2017	10/20/2017	19,493.09	8/27/2017	9/9/2017	7.00	19,493.09	48.00	935,668
263	0.842074	1403149	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	3/9/2017	4/7/2017	37,951.59	2/4/2017	2/25/2017	11.00	37,951.59	52.00	1,973,483
264	0.841506	1401807	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	1/19/2017	2/17/2017	65,661.76	11/19/2016	12/31/2016	21.50	65,661.76	69.50	4,563,492
265	0.841048	1406076	DAVEY TREE EXPERT CO	760041	Contractors	5/8/2017	6/22/2017	11,778.56	2/1/2017	2/25/2017	12.50	11,778.56	129.50	1,525,324
266	0.840438	1415640	DYNAMIC CONCEPTS INC	760040	Contractors	12/8/2017	12/28/2017	72,047.10	11/1/2017	11/30/2017	15.00	72,047.10	43.00	3,098,025
267	0.839923	1407795	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	4/17/2017	6/30/2017	29,504.24	2/26/2017	4/1/2017	17.50	29,504.24	107.50	3,171,706
268	0.839112	1400941	W.A. CHESTER LLC	760040	Contractors	12/19/2016	1/25/2017	24,102.00	12/5/2016	12/11/2017	186.00	24,102.00	(134.00)	(3,229,668)
269	0.838878	1413797	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	11/9/2017	12/8/2017	47,988.22	10/1/2017	10/28/2017	14.00	47,988.22	55.00	2,639,352
270	0.838825	1403443	PPC LUBRICANTS	760020	Contractors	3/20/2017	4/19/2017	10,019.00	3/20/2017	3/20/2017	0.50	10,019.00	30.50	305,580
271	0.838640	1407810	R B HINKLE CONSTRUCTION INC	760040	Contractors	6/21/2017	7/21/2017	12,936.80	5/14/2017	5/20/2017	3.50	12,936.80	65.50	847,360
272	0.838577	1411612	CONVERGENT OUTSOURCING INC	760010	Contractors	9/1/2017	10/16/2017	290,226.72	8/1/2017	8/31/2017	15.50	290,226.72	61.50	17,848,943
273	0.836656	1410522	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	8/23/2017	9/15/2017	27,002.05	7/1/2017	7/29/2017	14.50	27,002.05	62.50	1,687,628
274	0.836537	1406849	COMVERGE INC	760010	Contractors	6/5/2017	7/3/2017	163,554.09	6/1/2017	6/30/2017	15.00	163,554.09	18.00	2,943,974
275	0.835693	1401816	RIGGS DISTLER & COMPANY, INC	760041	Contractors	1/31/2017	3/2/2017	17,988.72	1/23/2017	1/29/2017	3.50	17,988.72	35.50	638,600
276	0.835517	1402735	RESOURCE ASSET MANAGEMENT	760010	Contractors	3/6/2017	3/8/2017	26,048.40	2/13/2017	2/20/2017	4.00	26,048.40	20.00	520,968
277	0.835365	1412017	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	9/29/2017	10/27/2017	67,217.74	8/5/2017	8/26/2017	11.00	67,217.74	73.00	4,906,895
278	0.834732	1411523	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	9/22/2017	10/20/2017	63,639.10	7/29/2017	8/26/2017	14.50	63,639.10	69.50	4,422,917
279	0.834352	1407799	TYNDALE COMPANY INC	794100	General	4/10/2017	6/30/2017	11,543.69	3/1/2017	3/31/2017	15.50	11,543.69	106.50	1,229,403
280	0.834110	1403714	UTILIQUEST LLC	760040	Contractors	3/13/2017	4/27/2017	18,759.50	3/5/2017	3/11/2017	3.50	18,759.50	50.50	947,355
281	0.833298	1402517	DAVEY TREE EXPERT CO	760041	Contractors	2/14/2017	3/31/2017	12,039.39	1/7/2017	1/28/2017	11.00	12,039.39	73.00	878,875
282	0.831806	1410535	RIGGS DISTLER & COMPANY, INC	760040	Contractors	7/31/2017	9/6/2017	37,108.22	7/24/2017	7/30/2017	3.50	37,108.22	41.50	1,539,991
283	0.830712	1405056	ONE CALL CONCEPT INC	760040	Contractors	4/10/2017	5/10/2017	10,395.00	3/1/2017	3/31/2017	15.50	10,395.00	55.50	576,923
284	0.829255	1400617	RESOURCE ASSET MANAGEMENT	760010	Contractors	1/4/2017	2/3/2017	27,594.40	12/15/2016	12/31/2016	8.50	27,594.40	42.50	1,172,762
285	0.827366	1413229	CREDIT BUREAU COLLECTION SVC INC	794006	Collection	5/31/2017	11/3/2017	13,136.56	5/31/2017	5/31/2017	0.50	13,136.56	156.50	2,055,872
286	0.827158	1406573	RIGGS DISTLER & COMPANY, INC	760040	Contractors	5/1/2017	6/5/2017	13,344.20	4/24/2017	4/30/2017	3.50	13,344.20	39.50	527,096
287	0.826816	1409128	UTILIQUEST LLC	760040	Contractors	7/24/2017	9/7/2017	22,890.50	7/16/2017	7/22/2017	3.50	22,890.50	50.50	1,155,970
288	0.826494	1830605	THE SALVATION ARMY	770005	Rents	9/30/2017	10/2/2017	10,166.57	6/30/2017	9/30/2017	46.50	10,166.57	48.50	493,079
289	0.825820	1406367	RR DONNELLEY & SONS COMPANY	760010	Contractors	5/8/2017	6/22/2017	54,579.97	5/5/2017	5/8/2017	2.00	54,579.97	47.00	2,565,259
290	0.825748	1835416	NATURAL ENVIRONMENT LLC	760020	Contractors	11/15/2017	11/24/2017	18,500.00	11/15/2017	11/15/2017	0.50	18,500.00	9.50	175,750
291	0.824762	1414528	TRC SOLUTIONS	760005	Contractors	11/7/2017	12/1/2017	11,865.72	10/10/2017	10/20/2017	5.50	11,865.72	47.50	563,622
292	0.823862	1410384	WASHINGTON SUBURBAN	794020	General	6/19/2017	8/31/2017	23,301.65	6/19/2017	7/14/2017	13.00	23,301.65	61.00	1,421,401
293	0.823668	1415181	TRC SOLUTIONS	760005	Contractors	12/1/2017	12/18/2017	23,944.83	9/9/2017	10/6/2017	14.00	23,944.83	87.00	2,083,200
294	0.822925	1410723	KCW ENGINEERING TECHNOLOGIES	760041	Contractors	9/7/2017	9/15/2017	10,663.38	8/1/2017	8/19/2017	9.50	10,663.38	36.50	389,213
295	0.822132	1402533	SCOPE SERVICES INC	760040	Contractors	2/16/2017	3/17/2017	27,829.50	1/1/2017	1/31/2017	15.50	27,829.50	60.50	1,683,685
296	0.821905	1405824	DAVEY TREE EXPERT CO	760041	Contractors	5/9/2017	6/23/2017	13,204.69	4/8/2017	4/29/2017	11.00	13,204.69	66.00	871,510
297	0.821755	1414716	L G MOORE	760010	Contractors	12/1/2017	12/11/2017	11,927.86	10/24/2017	10/30/2017	3.50	11,927.86	45.50	542,718
298	0.821324	1414710	TRC SOLUTIONS	760005	Contractors	11/7/2017	12/11/2017	51,964.25	10/8/2017	10/20/2017	6.50	51,964.25	58.50	3,039,909
299	0.820966	1403993	CSI INTERNATIONAL	760020	Contractors	4/1/2017	5/16/2017	12,672.68	4/1/2017	4/30/2017	15.00	12,672.68	31.00	392,853
300	0.820803	1409772	KCI TECHNOLOGIES	760010	Contractors	8/3/2017	9/15/2017	24,000.00	7/1/2017	7/31/2017	15.50	24,000.00	61.50	1,476,000
301	0.820000	1411745	CSI INTERNATIONAL	760020	Contractors	9/1/2017	10/16/2017	12,672.68	9/1/2017	9/30/2017	15.00	12,672.68	31.00	392,853
302	0.819763	1403018	DAVEY TREE EXPERT CO	760041	Contractors	3/8/2017	4/21/2017	11,206.77	2/4/2017	2/25/2017	11.00	11,206.77	66.00	739,647
303	0.817993	1408228	FLIPPO CONSTRUCTION CO INC	760040	Contractors	7/3/2017	8/2/2017	22,167.00	6/18/2017	6/24/2017	3.50	22,167.00	42.50	942,098
304	0.815360	1405842	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	4/29/2017	5/26/2017	12,392.77	4/23/2017	4/29/2017	3.50	12,392.77	30.50	377,979
305	0.815162	1409627	COMVERGE INC	760010	Contractors	8/9/2017	9/8/2017	20,798.59	7/1/2017	7/31/2017	15.50	20,798.59	54.50	1,133,523
306	0.815102	1404791	DC WATER & SEWER AUTHORITY	794020	General	3/21/2017	4/24/2017	53,449.17	2/8/2017	3/17/2017	19.00	53,449.17	57.00	3,046,603
307	0.814564	1803078	PRICEWATERHOUSECOOPERS LLP	760005	Contractors	2/3/2017	2/8/2017	18,467.00	7/1/2017	10/31/2017	61.50	18,467.00	(203.50)	(3,758,035)
308	0.814276	1413793	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	11/10/2017	12/8/2017	144,737.62	10/1/2017	11/10/2017	20.50	144,737.62	48.50	7,019,775
309	0.813495	1410522	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	8/23/2017	9/15/2017	171,817.17	7/8/2017	8/23/2017	23.50	171,817.17	46.50	7,989,498
310	0.813072	1404703	DAVEY TREE EXPERT CO	760041	Contractors	3/28/2017	5/12/2017	14,312.91	12/10/2016	12/31/2016	11.00	14,312.91	143.00	2,046,746
311	0.812977	1411614	TURNING POINT COLLECTION LLC	760020	Contractors	9/7/2017	9/28/2017	40,404.00	9/7/2017	9/7/2017	0.50	40,404.00	21.50	868,686
312	0.811243	1414380	BGP COMMUNICATIONS JV, LLC	760010	Contractors	11/14/2017	12/11/2017	65,162.64	9/1/2017	12/31/2017	61.00	65,162.64	41.00	2,671,668
313	0.810798	1406818	RICKART COLLECTION SYSTEMS INC	794006	Collection	3/31/2017	6/12/2017	14,495.80	3/1/2017	3/31/2017	15.50	14,495.80	88.50	1,282,878
314	0.809953	1414476	TRC SOLUTIONS	760005	Contractors	11/17/2017	12/1/2017	30,505.24	10/21/2017	11/3/2017	7.00	30,505.24	35.00	1,067,683

POTOMAC ELECTRIC POWER COMPANY
Other O&M Expense Lag
Cash Working Capital Analysis
January 1, 2017 through December 31, 2017
Pepco Invoice Sample

Line No.	Random No.	Acct Doc No	Vendor Name	G/L Account	Category	Doc. date	Clearing date	Amount	Service Period Begin	Service Period End	Midpoint	Dollars	Lag Days	Dollar Days
315	0.809883	1400520	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	12/22/2016	1/20/2017	15,408.20	10/29/2016	12/22/2016	27.50	15,408.20	56.50	870,563
316	0.809006	1409711	WEST NOTIFICATIONS DBA	760010	Contractors	7/12/2017	9/13/2017	26,014.66	7/1/2017	7/31/2017	15.50	26,014.66	59.50	1,547,872
317	0.808740	1407027	RR DONNELLEY RECEIVABLES INC.	760010	Contractors	5/31/2017	7/14/2017	29,026.64	5/31/2017	5/31/2017	0.50	29,026.64	44.50	1,291,685
318	0.807456	1414381	M.J. ELECTRIC LLC	760010	Contractors	11/28/2017	12/11/2017	169,203.35	10/16/2017	10/29/2017	7.00	169,203.35	50.00	8,460,168
319	0.806175	1410554	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	8/23/2017	9/22/2017	71,185.88	7/8/2017	8/23/2017	23.50	71,185.88	53.50	3,808,445
320	0.803833	1407894	AUI INC	760040	Contractors	6/16/2017	7/14/2017	13,015.38	4/6/2017	4/7/2017	1.00	13,015.38	99.00	1,288,523
321	0.803823	1405451	DYNAMIC CONCEPTS INC	760041	Contractors	5/2/2017	5/31/2017	66,291.75	3/15/2017	4/30/2017	23.50	66,291.75	54.50	3,612,900
322	0.803674	1409552	ADMIRAL SECURITY SERVICES	760010	Contractors	8/8/2017	9/7/2017	11,028.48	7/16/2017	7/29/2017	7.00	11,028.48	47.00	518,339
323	0.802774	1406410	CSI INTERNATIONAL	760020	Contractors	5/1/2017	6/15/2017	12,672.68	5/1/2017	5/31/2017	15.50	12,672.68	30.50	386,517
324	0.802507	1401807	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	1/19/2017	2/17/2017	53,833.15	11/26/2016	12/31/2016	18.00	53,833.15	66.00	3,552,988
325	0.802358	1407043	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	5/25/2017	6/23/2017	18,549.14	4/8/2017	5/25/2017	24.00	18,549.14	53.00	983,104
326	0.801932	1415532	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	12/15/2017	12/19/2017	21,759.97	11/4/2017	12/15/2017	21.00	21,759.97	25.00	543,999
327	0.801638	1807700	ERNST & YOUNG US LLP	760015	Contractors	2/28/2017	3/31/2017	34,400.00	1/3/2017	2/3/2017	16.00	34,400.00	72.00	2,476,800
328	0.801030	1401122	ORCHARD FARMS INC	760020	Contractors	1/8/2017	2/7/2017	10,152.55	1/7/2017	1/8/2017	1.00	10,152.55	31.00	314,729
329	0.799042	1407719	RESOURCE ASSET MANAGEMENT	760010	Contractors	6/26/2017	6/29/2017	32,781.88	6/13/2017	6/25/2017	6.50	32,781.88	10.50	344,210
330	0.798008	1412451	TRC SOLUTIONS	760005	Contractors	9/15/2017	10/30/2017	12,044.17	8/7/2017	9/8/2017	16.50	12,044.17	68.50	825,026
331	0.797290	1408215	UTILIQUEST LLC	760040	Contractors	7/10/2017	8/24/2017	17,884.00	7/2/2017	7/8/2017	3.50	17,884.00	50.50	903,142
332	0.797081	1413718	CMGRP INC	760010	Contractors	10/6/2017	11/20/2017	102,761.50	10/1/2017	12/31/2017	46.00	102,761.50	5.00	513,808
333	0.796570	1831467	THE KERRY S PEARSON LLC	760005	Contractors	10/3/2017	10/11/2017	40,000.00	9/1/2017	9/30/2017	15.00	40,000.00	26.00	1,040,000
334	0.796481	1406849	COMVERGE INC	760010	Contractors	6/5/2017	7/3/2017	13,462.05	6/1/2017	6/30/2017	15.00	13,462.05	18.00	242,317
335	0.794939	1400289	OSMOSE UTILITIES SERVICE INC	760041	Contractors	12/29/2016	2/1/2017	13,469.60	12/8/2016	12/16/2016	4.50	13,469.60	51.50	693,684
336	0.793429	1500002	1919 PENNSYLVANIA ASSOCIATES LLC	770005	Rents	3/1/2017	3/2/2017	26,919.58	3/1/2017	3/31/2017	15.50	26,919.58	(13.50)	(363,414)
337	0.791440	1407402	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	6/15/2017	7/14/2017	13,226.60	5/6/2017	6/15/2017	20.50	13,226.60	49.50	654,717
338	0.790711	1411913	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	9/28/2017	10/27/2017	10,195.30	9/9/2018	9/22/2017	(175.50)	10,195.30	(140.50)	(1,432,440)
339	0.790710	1400078	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	12/21/2016	1/20/2017	10,927.83	10/29/2016	11/19/2016	11.00	10,927.83	73.00	797,732
340	0.789761	1408308	ASPLUNDH TREE EXPERT COMPANY	760041	Contractors	6/17/2017	7/18/2017	15,018.69	6/10/2017	6/23/2018	189.50	15,018.69	(150.50)	(2,260,313)
	0.929464	207679	FREEMAN & FREEMAN PC	760035	Contractors	4/7/2017	5/1/2017	15,485.80	3/1/2017	3/31/2017	15.50	15,485.80	46.50	720,090
	0.904405	220661	LEFTWICH & LUDAWAY LLC	760035	Contractors	9/19/2017	11/1/2017	25,227.00	8/1/2017	8/31/2017	15.50	25,227.00	77.50	1,955,093
	0.899434	224290	HUNTON & WILLIAMS LLP	760035	Contractors	12/11/2017	12/26/2017	98,390.50	11/1/2017	11/30/2017	15.00	98,390.50	41.00	4,034,011
	0.897605	216036	MORGAN LEWIS & BOCKIUS LLP	760035	Contractors	5/30/2017	8/29/2017	88,068.40	4/1/2017	4/30/2017	15.00	88,068.40	136.00	11,977,302
	0.883536	216040	THE NORTHBRIDGE GROUP INC	760035	Contractors	6/20/2017	8/29/2017	36,424.44	1/1/2017	1/31/2017	15.50	36,424.44	225.50	8,213,711
	0.881851	224293	LEFTWICH & LUDAWAY LLC	760035	Contractors	12/8/2017	12/26/2017	19,954.50	11/1/2017	11/30/2017	15.00	19,954.50	41.00	818,135
	0.817993	1408228	FLIPPO CONSTRUCTION CO INC	760040	Contractors	7/3/2017	8/2/2017	22,167.00	6/18/2017	6/24/2017	3.50	22,167.00	42.50	942,098
								14,273,161.01				14,273,161.01	42.95	613,036,638.05

PEPCO
Cash Working Capital Analysis
DC Other Taxes - Lag Days
Year 2017

Type	VI
Jurisdiction	DC

Category	Account	Account Name	DocumentNo	Doc. Date	Pstng Date	Encash Dt	Clearing	Sum of Amount in local cur.		Service Period Beginning	Service Period Ending	Service Period Midpoint	Clearing Date	Lag Days	Dollar Days
Ballpark Fee	**236250**	Taxes Accrued - Taxes other than income taxes	**1818966**	6/15/2017	**06/09/17**	6/15/2017	6/15/2017	16,500.00		6/1/2016	5/31/2017	182.5	6/15/2017	197.50	3,258,750
Ballpark Fee Total								**16,500.00**	x					**197.50**	**3,258,750**
										10/1/2017	9/30/2018				
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1806776**	3/20/2017	**03/20/17**	3/29/2017	3/21/2017	970.37		4/1/2017	9/30/2017	91.5	3/21/2017	(101.50)	(98,493)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1806777**	3/20/2017	**03/20/17**	3/29/2017	3/21/2017	889.28		4/1/2017	9/30/2017	91.5	3/21/2017	(101.50)	(90,262)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1806778**	3/20/2017	**03/20/17**	3/29/2017	3/21/2017	5,418.70		4/1/2017	9/30/2017	91.5	3/21/2017	(101.50)	(549,998)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1806779**	3/20/2017	**03/20/17**	3/29/2017	3/21/2017	2,960.32		4/1/2017	9/30/2017	91.5	3/21/2017	(101.50)	(300,472)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1806780**	3/20/2017	**03/20/17**	3/29/2017	3/21/2017	3,099.36		4/1/2017	9/30/2017	91.5	3/21/2017	(101.50)	(314,585)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1806781**	3/20/2017	**03/20/17**	3/29/2017	3/21/2017	31,812.33		4/1/2017	9/30/2017	91.5	3/21/2017	(101.50)	(3,228,951)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1806782**	3/20/2017	**03/20/17**	3/29/2017	3/21/2017	283.36		4/1/2017	9/30/2017	91.5	3/21/2017	(101.50)	(28,761)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1806783**	3/20/2017	**03/20/17**	3/29/2017	3/21/2017	2,718.08		4/1/2017	9/30/2017	91.5	3/21/2017	(101.50)	(275,885)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1806784**	3/20/2017	**03/20/17**	3/29/2017	3/21/2017	2,911.36		4/1/2017	9/30/2017	91.5	3/21/2017	(101.50)	(295,503)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1806785**	3/20/2017	**03/20/17**	3/29/2017	3/21/2017	1,506.57		4/1/2017	9/30/2017	91.5	3/21/2017	(101.50)	(152,917)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1806786**	3/20/2017	**03/20/17**	3/29/2017	3/21/2017	456.04		4/1/2017	9/30/2017	91.5	3/21/2017	(101.50)	(46,288)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1806787**	3/20/2017	**03/20/17**	3/29/2017	3/21/2017	546.93		4/1/2017	9/30/2017	91.5	3/21/2017	(101.50)	(55,513)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1806788**	3/20/2017	**03/20/17**	3/29/2017	3/21/2017	1,785.00		4/1/2017	9/30/2017	91.5	3/21/2017	(101.50)	(181,178)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1828038**	9/6/2017	**09/06/17**	9/19/2017	9/7/2017	206.46		10/1/2017	3/31/2018	91	9/7/2017	(114.00)	(23,536)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1828039**	9/6/2017	**09/06/17**	9/19/2017	9/7/2017	7,572.90		10/1/2017	3/31/2018	91	9/7/2017	(114.00)	(863,311)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1828040**	9/6/2017	**09/06/17**	9/19/2017	9/7/2017	2,887.96		10/1/2017	3/31/2018	91	9/7/2017	(114.00)	(329,227)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1828041**	9/6/2017	**09/06/17**	9/20/2017	9/7/2017	1,521.04		10/1/2017	3/31/2018	91	9/7/2017	(114.00)	(173,399)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1828042**	9/6/2017	**09/06/17**	9/19/2017	9/7/2017	33,800.59		10/1/2017	3/31/2018	91	9/7/2017	(114.00)	(3,853,267)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1828043**	9/6/2017	**09/06/17**	9/20/2017	9/7/2017	459.55		10/1/2017	3/31/2018	91	9/7/2017	(114.00)	(52,389)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1828044**	9/6/2017	**09/06/17**	9/20/2017	9/7/2017	3,192.34		10/1/2017	3/31/2018	91	9/7/2017	(114.00)	(363,927)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1828045**	9/6/2017	**09/06/17**	9/20/2017	9/7/2017	551.44		10/1/2017	3/31/2018	91	9/7/2017	(114.00)	(62,864)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1828046**	9/6/2017	**09/06/17**	9/20/2017	9/7/2017	1,785.00		10/1/2017	3/31/2018	91	9/7/2017	(114.00)	(203,490)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1828047**	9/6/2017	**09/06/17**	9/20/2017	9/7/2017	3,049.13		10/1/2017	3/31/2018	91	9/7/2017	(114.00)	(347,601)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1828048**	9/6/2017	**09/06/17**	9/20/2017	9/7/2017	5,418.70		10/1/2017	3/31/2018	91	9/7/2017	(114.00)	(617,732)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1828049**	9/6/2017	**09/06/17**	9/20/2017	9/7/2017	889.28		10/1/2017	3/31/2018	91	9/7/2017	(114.00)	(101,378)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1828050**	9/6/2017	**09/06/17**	9/20/2017	9/7/2017	6,214.56		10/1/2017	3/31/2018	91	9/7/2017	(114.00)	(708,460)
Business Improvement	**236250**	Taxes Accrued - Taxes other than income taxes	**1836769**	12/6/2017	**12/06/17**	12/13/2017	12/7/2017	13,472.01		10/1/2017	3/31/2018	91	12/7/2017	(23.00)	(309,856)
Business Improvement Total								**136,378.66**	x					**(99.94)**	**(13,629,243)**
DC Delivery Tax	**241340**	G/R Tax Payable-Washington DC	**1801315**	1/20/2017	**01/18/17**	1/20/2017	1/20/2017	6,715,476.03		12/1/2016	12/31/2016	15.5	1/20/2017	35.50	238,399,399
DC Delivery Tax	**241340**	G/R Tax Payable-Washington DC	**1803560**	2/21/2017	**02/13/17**	2/21/2017	2/21/2017	6,982,598.47		1/1/2017	1/31/2017	15.5	2/21/2017	36.50	254,864,844
DC Delivery Tax	**241340**	G/R Tax Payable-Washington DC	**1806423**	3/20/2017	**03/15/17**	3/20/2017	3/20/2017	6,048,497.38		2/1/2017	2/28/2017	14	3/20/2017	34.00	205,648,911
DC Delivery Tax	**241340**	G/R Tax Payable-Washington DC	**1810729**	4/20/2017	**04/17/17**	4/20/2017	4/20/2017	6,568,173.52		3/1/2017	3/31/2017	15.5	4/20/2017	35.50	233,170,160
DC Delivery Tax	**241340**	G/R Tax Payable-Washington DC	**1814986**	5/22/2017	**05/10/17**	5/22/2017	5/22/2017	6,068,176.86		4/1/2017	4/30/2017	15	5/22/2017	37.00	224,522,544
DC Delivery Tax	**241340**	G/R Tax Payable-Washington DC	**1818963**	6/20/2017	**06/09/17**	6/20/2017	6/20/2017	6,439,515.63		5/1/2017	5/31/2017	15.5	6/20/2017	35.50	228,602,805
DC Delivery Tax	**241340**	G/R Tax Payable-Washington DC	**1822896**	7/20/2017	**07/17/17**	7/20/2017	7/20/2017	7,494,181.23		6/1/2017	6/30/2017	15	7/20/2017	35.00	262,296,343
DC Delivery Tax	**241340**	G/R Tax Payable-Washington DC	**1825501**	8/21/2017	**08/10/17**	8/21/2017	8/21/2017	8,371,603.02		7/1/2017	7/31/2017	15.5	8/21/2017	36.50	305,563,510
DC Delivery Tax	**241340**	G/R Tax Payable-Washington DC	**1828962**	9/20/2017	**09/15/17**	9/20/2017	9/20/2017	7,798,391.87		8/1/2017	8/31/2017	15.5	9/20/2017	35.50	276,842,911
DC Delivery Tax	**241340**	G/R Tax Payable-Washington DC	**1831816**	10/20/2017	**10/12/17**	10/20/2017	10/20/2017	6,937,584.90		9/1/2017	9/30/2017	15	10/20/2017	35.00	242,815,472
DC Delivery Tax	**241340**	G/R Tax Payable-Washington DC	**1834755**	11/20/2017	**11/15/17**	11/20/2017	11/20/2017	6,661,392.96		10/1/2017	10/31/2017	15.5	11/20/2017	35.50	236,479,450
DC Delivery Tax	**241340**	G/R Tax Payable-Washington DC	**1837665**	12/20/2017	**12/15/17**	12/18/2017	12/18/2017	6,224,256.98		11/1/2017	11/30/2017	15	12/18/2017	33.00	205,400,480
DC Delivery Tax Total								**82,309,848.85**	x					**35.41**	**2,914,606,829**
DC Sales & Use Tax	**241365**	Washington DC Sales Tax Payable	**1801049**	1/20/2017	**01/16/17**	1/20/2017	1/20/2017	1,132,963.35		12/1/2016	12/31/2016	15.5	1/20/2017	35.50	40,220,199
DC Sales & Use Tax	**241365**	Washington DC Sales Tax Payable	**1803551**	2/21/2017	**02/13/17**	2/21/2017	2/21/2017	1,209,467.87		1/1/2017	1/31/2017	15.5	2/21/2017	36.50	44,145,577
DC Sales & Use Tax	**241365**	Washington DC Sales Tax Payable	**1806429**	3/20/2017	**03/15/17**	3/20/2017	3/20/2017	1,244,677.86		2/1/2017	2/28/2017	14	3/20/2017	34.00	42,319,047
DC Sales & Use Tax	**241365**	Washington DC Sales Tax Payable	**1809831**	4/20/2017	**04/13/17**	4/20/2017	4/20/2017	1,174,495.60		3/1/2017	3/31/2017	15.5	4/20/2017	35.50	41,694,594
DC Sales & Use Tax	**241365**	Washington DC Sales Tax Payable	**1815222**	5/22/2017	**05/11/17**	5/22/2017	5/22/2017	1,114,861.54		4/1/2017	4/30/2017	15	5/22/2017	37.00	41,249,877
DC Sales & Use Tax	**241365**	Washington DC Sales Tax Payable	**1819076**	6/20/2017	**06/12/17**	6/20/2017	6/20/2017	1,247,972.07		5/1/2017	5/31/2017	15.5	6/20/2017	35.50	44,303,008
DC Sales & Use Tax	**241365**	Washington DC Sales Tax Payable	**1822895**	7/20/2017	**07/17/17**	7/20/2017	7/20/2017	1,334,198.39		6/1/2017	6/30/2017	15	7/20/2017	35.00	46,696,944
DC Sales & Use Tax	**241365**	Washington DC Sales Tax Payable	**1825504**	8/21/2017	**08/10/17**	8/23/2017	8/23/2017	1,323,428.60		7/1/2017	7/31/2017	15.5	8/23/2017	38.50	50,952,001
DC Sales & Use Tax	**241365**	Washington DC Sales Tax Payable	**1828537**	9/20/2017	**09/12/17**	9/20/2017	9/20/2017	1,499,021.96		8/1/2017	8/31/2017	15.5	9/20/2017	35.50	53,215,280
DC Sales & Use Tax	**241365**	Washington DC Sales Tax Payable	**1831817**	10/20/2017	**10/12/17**	10/20/2017	10/20/2017	1,368,354.65		9/1/2017	9/30/2017	15	10/20/2017	35.00	47,892,413

DC Sales & Use Tax	**241365**	Washington DC Sales Tax Payable	**1834757**	11/20/2017	**11/15/17**	11/20/2017	11/20/2017	1,484,166.45	10/1/2017	10/31/2017	15.5	11/20/2017	35.50	52,687,909
DC Sales & Use Tax	**241365**	Washington DC Sales Tax Payable	**1837667**	12/20/2017	**12/15/17**	12/28/2017	12/20/2017	1,203,605.08	11/1/2017	11/30/2017	15	12/20/2017	35.00	42,126,178
DC Sales & Use Tax	**241375**	Sales Taxes Payable	**1801049**	1/20/2017	**01/16/17**	1/20/2017	1/20/2017	20,977.65	12/1/2016	12/31/2016	15.5	1/20/2017	35.50	744,707
DC Sales & Use Tax	**241375**	Sales Taxes Payable	**1803551**	2/21/2017	**02/13/17**	2/21/2017	2/21/2017	6,416.85	1/1/2017	1/31/2017	15.5	2/21/2017	36.50	234,215
DC Sales & Use Tax	**241375**	Sales Taxes Payable	**1806429**	3/20/2017	**03/15/17**	3/20/2017	3/20/2017	35,914.85	2/1/2017	2/28/2017	14	3/20/2017	34.00	1,221,105
DC Sales & Use Tax	**241375**	Sales Taxes Payable	**1809831**	4/20/2017	**04/13/17**	4/20/2017	4/20/2017	23,554.94	3/1/2017	3/31/2017	15.5	4/20/2017	35.50	836,200
DC Sales & Use Tax	**241375**	Sales Taxes Payable	**1815222**	5/22/2017	**05/11/17**	5/22/2017	5/22/2017	8,780.20	4/1/2017	4/30/2017	15	5/22/2017	37.00	324,867
DC Sales & Use Tax	**241375**	Sales Taxes Payable	**1819076**	6/20/2017	**06/12/17**	6/20/2017	6/20/2017	7,281.97	5/1/2017	5/31/2017	15.5	6/20/2017	35.50	258,510
DC Sales & Use Tax	**241375**	Sales Taxes Payable	**1822895**	7/20/2017	**07/17/17**	7/20/2017	7/20/2017	22,185.26	6/1/2017	6/30/2017	15	7/20/2017	35.00	776,484
DC Sales & Use Tax	**241375**	Sales Taxes Payable	**1825504**	8/21/2017	**08/10/17**	8/23/2017	8/23/2017	9,492.47	7/1/2017	7/31/2017	15.5	8/23/2017	38.50	365,460
DC Sales & Use Tax	**241375**	Sales Taxes Payable	**1828537**	9/20/2017	**09/12/17**	9/20/2017	9/20/2017	9,167.99	8/1/2017	8/31/2017	15.5	9/20/2017	35.50	325,464
DC Sales & Use Tax	**241375**	Sales Taxes Payable	**1831817**	10/20/2017	**10/12/17**	10/20/2017	10/20/2017	15,526.59	9/1/2017	9/30/2017	15	10/20/2017	35.00	543,431
DC Sales & Use Tax	**241375**	Sales Taxes Payable	**1834757**	11/20/2017	**11/15/17**	11/20/2017	11/20/2017	8,874.22	10/1/2017	10/31/2017	15.5	11/20/2017	35.50	315,035
DC Sales & Use Tax Total								**15,505,386.41** x					**35.69**	**553,448,505**
EATF, SETF	**236250**	Taxes Accrued - Taxes other than income taxes	**1801318**	1/20/2017	**01/18/17**	1/20/2017	1/20/2017	1,414,652.09	12/1/2016	12/31/2016	15.5	1/20/2017	35.50	50,220,149
EATF, SETF	**236250**	Taxes Accrued - Taxes other than income taxes	**1801873**	1/26/2017	**01/25/17**	1/26/2017	1/26/2017	170,556.10	12/1/2016	12/31/2016	15.5	1/26/2017	41.50	7,078,078
EATF, SETF	**236250**	Taxes Accrued - Taxes other than income taxes	**1803557**	2/21/2017	**02/13/17**	2/21/2017	2/21/2017	1,522,683.34	1/1/2017	1/31/2017	15.5	2/21/2017	36.50	55,577,942
EATF, SETF	**236250**	Taxes Accrued - Taxes other than income taxes	**1806425**	3/20/2017	**03/15/17**	3/20/2017	3/20/2017	1,463,774.17	2/1/2017	2/28/2017	14	3/20/2017	34.00	49,768,322
EATF, SETF	**236250**	Taxes Accrued - Taxes other than income taxes	**1810730**	4/20/2017	**04/17/17**	4/20/2017	4/20/2017	1,401,793.27	3/1/2017	3/31/2017	15.5	4/20/2017	35.50	49,763,661
EATF, SETF	**236250**	Taxes Accrued - Taxes other than income taxes	**1814988**	5/22/2017	**05/10/17**	5/22/2017	5/22/2017	1,256,789.16	4/1/2017	4/30/2017	15	5/22/2017	37.00	46,501,199
EATF, SETF	**236250**	Taxes Accrued - Taxes other than income taxes	**1818964**	6/20/2017	**06/09/17**	6/20/2017	6/20/2017	1,467,177.53	5/1/2017	5/31/2017	15.5	6/20/2017	35.50	52,084,802
EATF, SETF	**236250**	Taxes Accrued - Taxes other than income taxes	**1822908**	7/20/2017	**07/17/17**	7/20/2017	7/20/2017	1,478,906.71	6/1/2017	6/30/2017	15	7/20/2017	35.00	51,761,735
EATF, SETF	**236250**	Taxes Accrued - Taxes other than income taxes	**1825500**	8/21/2017	**08/10/17**	8/21/2017	8/21/2017	1,679,121.95	7/1/2017	7/31/2017	15.5	8/21/2017	36.50	61,287,951
EATF, SETF	**236250**	Taxes Accrued - Taxes other than income taxes	**1828961**	9/20/2017	**09/15/17**	9/20/2017	9/20/2017	1,856,117.05	8/1/2017	8/31/2017	15.5	9/20/2017	35.50	65,892,155
EATF, SETF	**236250**	Taxes Accrued - Taxes other than income taxes	**1831814**	10/20/2017	**10/12/17**	10/27/2017	10/27/2017	1,572,741.89	9/1/2017	9/30/2017	15	10/27/2017	42.00	66,055,159
EATF, SETF	**236250**	Taxes Accrued - Taxes other than income taxes	**1834756**	11/20/2017	**11/15/17**	11/20/2017	11/20/2017	1,670,753.36	10/1/2017	10/31/2017	15.5	11/20/2017	35.50	59,311,744
EATF, SETF	**236250**	Taxes Accrued - Taxes other than income taxes	**1838013**	12/20/2017	**12/20/17**	12/21/2017	12/21/2017	1,344,073.31	11/1/2017	11/30/2017	15	12/21/2017	36.00	48,386,639
EATF, SETF Total								**18,299,139.93** x					**36.27**	**663,689,536**
PSC Assessment	**236250**	Taxes Accrued - Taxes other than income taxes	**1829184**	9/19/2017	**09/19/17**	9/28/2017	9/20/2017	5,484,125.75	10/1/2016	9/30/2017	182.5	9/20/2017	172.50	946,011,692
PSC Assessment	**236250**	Taxes Accrued - Taxes other than income taxes	**1829186**	9/19/2017	**09/19/17**	9/28/2017	9/20/2017	3,092,428.25	10/1/2016	9/30/2017	182.5	9/20/2017	172.50	533,443,873
PSC Assessment Total								**8,576,554.00** x					**172.50**	**1,479,455,565**
Right of Way	**165100**	Prepayments - Other Taxes	**1807291**	3/31/2017	**03/24/17**	4/7/2017	3/31/2017	5,726,977.55	4/1/2017	6/30/2017	45.5	3/31/2017	(45.50)	(260,577,479)
Right of Way	**165100**	Prepayments - Other Taxes	**1821101**	6/28/2017	**06/28/17**	7/7/2017	6/29/2017	5,733,280.44	7/1/2017	9/30/2017	46	6/29/2017	(47.00)	(269,464,181)
Right of Way	**165100**	Prepayments - Other Taxes	**1830098**	9/26/2017	**09/26/17**	10/16/2017	9/27/2017	5,739,308.53	10/1/2017	12/31/2017	46	9/27/2017	(49.00)	(281,226,118)
Right of Way	**165100**	Prepayments - Other Taxes	**1838021**	12/20/2017	**12/20/17**	(blank)	12/21/2017	5,741,301.33	1/1/2018	3/31/2018	45	12/21/2017	(55.00)	(315,771,573)
Right of Way Total								**22,940,867.85** x					**(49.13)**	**(1,127,039,351)**
Grand Total								**147,784,675.70**					**30.27**	**4,473,790,591**

PEPCO
Cash Working Capital Analysis
Real Estate & Personal Property Tax - Lag Days
Year 2017

Type	VI
Category	Real Estate & Poperty Tax

Jurisdiction	Vendor Name	Document Header Text	DocumentNo	Doc. Date	Pstng Date	Encash Dt	Clearing	Sum of Amount in local cur.		Service Period Beginning	Service Period Ending	Service Period Midpoint	Clearing Date	Lag Days	Dollar Days
DC	**1919 PENNSYLVANIA ASSOCIATES LI**	RE TAX 4/1/16-3/31/17	**1806428**	03/01/17	**03/15/2017**	4/6/2017	3/31/2017	2,976.99		4/1/2016	3/31/2017	182.5	3/31/2017	182.50	543,301
	1919 PENNSYLVANIA ASSOCIATES LI	RE TAX 4/1/16-9/30/16	**1806428**	03/01/17	**03/15/2017**	4/6/2017	3/31/2017	210,032.67		4/1/2016	9/30/2016	91.5	3/31/2017	273.50	57,443,935
	1919 PENNSYLVANIA ASSOCIATES LI	Vault Tax 7/1/16-6/30/17	**1806428**	03/01/17	**03/15/2017**	4/6/2017	3/31/2017	10,318.44		7/1/2016	6/30/2017	182.5	3/31/2017	91.50	944,137
	1919 PENNSYLVANIA ASSOCIATES LI	GL and UMBRELLA 4/1/17-3/31/1	**1820907**	06/01/17	**06/27/2017**	7/7/2017	6/30/2017	2,166.05		4/1/2017	3/31/2018	182.5	6/30/2017	(91.50)	(198,194)
	1919 PENNSYLVANIA ASSOCIATES LI	BID TAX 4/1/17-9/30/17	**1820907**	06/01/17	**06/27/2017**	7/7/2017	6/30/2017	2,976.99		4/1/2017	9/30/2017	91.5	6/30/2017	(0.50)	(1,488)
	1919 PENNSYLVANIA ASSOCIATES LI	RE TAX 10/1/16-3/31/17	**1820907**	06/01/17	**06/27/2017**	7/7/2017	6/30/2017	215,087.46		10/1/2016	3/31/2017	91	6/30/2017	182.00	39,145,918
	DC TREASURER	DC 1ST HALF 10/16-9/30/17	**1807689**	03/31/17	**03/29/2017**	3/31/2017	3/31/2017	2,015,344.61		10/1/2016	3/31/2017	91	3/31/2017	91.00	183,396,360
	DC TREASURER	DC RE TAX 1ST1/2	**1810731**	04/27/17	**04/17/2017**	4/27/2017	4/27/2017	1,958,175.00		10/1/2016	3/31/2017	91	4/27/2017	118.00	231,064,650
	DC TREASURER	DC REAL PROPTAX 2ND HALF	**1828538**	09/15/17	**09/12/2017**	9/15/2017	9/15/2017	4,004,205.45		4/1/2017	9/30/2017	91.5	9/15/2017	76.50	306,321,717
DC Total								**8,421,283.66**	x					**97.21**	**818,660,336**

									Service Period Beginning	Service Period Ending	Service Period Midpoint	Clearing Date	Lag Days	Dollar Days
MD	MONTGOMERY COUNTY MARYLAND	/MONTGO CTY WATER	1829200	09/29/17	09/19/2017	9/29/2017	9/29/2017	179,884.13	7/1/2017	6/30/2018	182.5	9/29/2017	(91.50)	(16,459,398)
	MONTGOMERY COUNTY MARYLAND	MONTGO CTY WATER	1829199	09/29/17	09/19/2017	9/29/2017	9/29/2017	268,468.58	7/1/2017	6/30/2018	182.5	9/29/2017	(91.50)	(24,564,875)
	MONTGOMERY COUNTY MARYLAND	MONTGOMERY PERSOPERT TAX	1838152	12/29/17	12/21/2017	12/27/2017	12/27/2017	24,468,192.82	7/1/2017	6/30/2018	182.5	12/27/2017	(2.50)	(61,170,482.00)
								24,916,545.53					**(4.10)**	(102,194,755.00)
	PRINCE GEORGE'S COUNTY MD	PEPCO PG WATER 17-18	1830099	09/29/17	09/26/2017	9/29/2017	9/29/2017	66,927.52	7/1/2017	6/30/2018	182.5	9/29/2017	(91.50)	(6,123,868)
	PRINCE GEORGE'S COUNTY MD	PG WATER&REAL 17-18	1829198	09/29/17	09/19/2017	9/29/2017	9/29/2017	112,124.15	7/1/2017	6/30/2018	182.5	9/29/2017	(91.50)	(10,259,360)
	PRINCE GEORGE'S COUNTY MD	PRINCE GEORGE'S CTY MD	1832387	10/31/17	10/19/2017	10/31/2017	10/31/2017	21,807,658.13	7/1/2017	6/30/2018	182.5	10/31/2017	(59.50)	(1,297,555,659)
								21,986,709.80					**(59.76)**	(1,313,938,887.00)
	CHARLES COUNTY TREASURER	CHARLES CTY MD	1832390	10/31/17	10/19/2017	10/31/2017	10/31/2017	766,461.08	7/1/2017	6/30/2018	182.5	10/31/2017	(59.50)	(45,604,434)
	CHARLES COUNTY TREASURER	CHARLES CTY REAL PROPTAX	1828278	09/29/17	09/08/2017	9/29/2017	9/29/2017	2,328.45	7/1/2017	6/30/2018	182.5	9/29/2017	(91.50)	(213,053)
								768,789.53					**(59.60)**	(45,817,487.00)
MD Other								**141,347.06**					**(76.77)**	**(10,851,112.00)**
VA	ARLINGTON COUNTY TREASURER	ARLINGTON CTY VA	1835103	11/20/17	11/20/2017	11/28/2017	11/21/2017	57,100.00	10/1/2016	9/30/2017	182.5	11/21/2017	234.50	13,389,950
	CITY OF ALEXANDRIA	1ST HALF 2017 R EST TAX	1819074	06/12/17	06/12/2017	6/16/2017	6/13/2017	243,226.25	10/1/2016	9/30/2017	182.5	6/13/2017	73.50	17,877,129
	CITY OF ALEXANDRIA	2ND HALF R/E-POTOMAC RIVE	1834750	11/14/17	11/15/2017	11/21/2017	11/16/2017	240,678.31	10/1/2016	9/30/2017	182.5	11/16/2017	229.50	55,235,672
								483,904.56					**151.09**	**73,112,801.00**
	PRINCE WILLIAM CNTY GOVERNMENT	PRINCE WILLIAM CTY GOV'T	1821074	06/28/17	06/28/2017	7/17/2017	6/29/2017	5,787.43	10/1/2016	9/30/2017	182.5	6/29/2017	89.50	517,975
	PRINCE WILLIAM CNTY GOVERNMENT	PRINCE WILLIAM CTY GOV'T	1835104	11/20/17	11/20/2017	12/6/2017	11/21/2017	4,596.22	10/1/2016	9/30/2017	182.5	11/21/2017	234.50	1,077,814
								10,383.65					**153.68**	**1,595,789.00**

POTOMAC ELECTRIC POWER COMPANY

Cash Working Capital Analysis
Federal Income Tax Lag Days
January - December 2017

Service Period			Statutory	Percent	Lag	Dollar
Begin	End	Midpoint	Due Date	Paid	Days	Days
1/1/2015	12/31/2015	182.50	4/15/2015	22.5%	(77.50)	$ (17.44)
1/1/2015	12/31/2015	182.50	6/15/2015	22.5%	(16.50)	(3.71)
1/1/2015	12/31/2015	182.50	9/15/2015	22.5%	75.50	16.99
1/1/2015	12/31/2015	182.50	12/15/2015	22.5%	166.50	37.46
1/1/2015	12/31/2015	182.50	3/15/2016	10.0%	257.50	25.75
				100.0%	**59.05**	$ 59.05

POTOMAC ELECTRIC POWER COMPANY

Cash Working Capital Analysis
District of Columbia Income Tax Lag Days
January - December 2017

Service Period			Statutory	Percent	Lag	Dollar
Begin	End	Midpoint	Due Date	Paid	Days	Days
1/1/2015	12/31/2015	182.50	4/15/2015	22.5%	(77.50)	$ (17.44)
1/1/2015	12/31/2015	182.50	6/15/2015	22.5%	(16.50)	(3.71)
1/1/2015	12/31/2015	182.50	9/15/2015	22.5%	75.50	16.99
1/1/2015	12/31/2015	182.50	12/15/2015	22.5%	166.50	37.46
1/1/2015	12/31/2015	182.50	3/15/2016	10.0%	257.50	25.75
				100.0%	**59.05**	$ 59.05

J.C. Ziminsky
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (D) – 8

Pepco DC Distribution
12 Months Ended June 2019
Synergies

EBSC / PHI	Labor/Non-Labor	Function		Total Pepco (6+6)		Pepco DC Distribution (6+6)
PHI	Labor	FP&A	$	202,509	$	77,177
PHI	Labor	Shared Svs	$	544,410	$	207,478
PHI	Labor	Asset Management	$	481,503	$	183,503
PHI	Labor	Controller	$	1,402,297	$	534,423
PHI	Labor	Corporate Citizenship & Soc Resp	$	300,568	$	114,548
PHI	Labor	Corporate Communications	$	996,173	$	379,646
PHI	Labor	Federal Regulatory Policy	$	300,568	$	114,548
PHI	Labor	HR & Disbursement Services	$	1,498,348	$	571,028
PHI	Labor	Legal/Corp Secretary	$	578,246	$	220,372
PHI	Labor	People Strategy	$	1,615,418	$	615,644
PHI	Labor	Performance Management	$	656,054	$	250,026
PHI	Labor	PHI Executive Management	$	2,518,446	$	959,793
PHI	Labor	Regulatory Affairs	$	360,686	$	137,459
PHI	Labor	Strategic Initiative	$	507,230	$	193,308
PHI	Labor	Supply Chain	$	467,718	$	178,250
PHI	Labor	Total Govt & Public Policy	$	391,866	$	149,342
PHI	Labor Total		$	12,822,039	$	4,886,545
PHI	Non-Labor	Corporate Communications	$	55,377	$	21,104
PHI	Non-Labor	Electric & Gas Operations	$	670,464	$	255,517
PHI	Non-Labor	Electric Operations	$	1,542,832	$	587,981
PHI	Non-Labor	Executive Mgmt	$	533,380	$	203,274
PHI	Non-Labor	Gas Operations	$	-	$	-
PHI	Non-Labor	Government Affairs	$	71,816	$	27,369
PHI	Non-Labor	HR	$	958,686	$	365,360
PHI	Non-Labor	IT	$	2,655,292	$	1,011,945
PHI	Non-Labor	Performance Mgmt	$	546,256	$	208,181
PHI	Non-Labor	Strategic & Financial Planning	$	135,675	$	51,706
PHI	Non-Labor	Supply Chain	$	326,171	$	124,306
PHI	Non-Labor	Supply Enabled	$	3,126,220	$	1,191,419
PHI	Non-Labor	Treasury	$	3,002,770	$	1,144,371
PHI	Non-Labor Total			13,624,938		5,192,534
PHI Total				26,446,977		10,079,079
EBSC	Labor	EBSC		1,178,295	$	449,054
EBSC	Labor Total			1,178,295		449,054
EBSC	Non-Labor	EBSC		1,337,312	$	509,657
EBSC	Non-Labor Total			1,337,312		509,657
EBSC Total				2,515,607		958,711
Grand Total Synergies				**28,962,584**		**11,037,790**
				Pepco DC CTA (Thru June 2019)		**9,460,000**
				Amortize over 5 Years		**1,892,000**
				Net Synergies	**$**	**9,145,790**

J.C. Ziminsky
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (D) – 9

Monthly Activity Trial Balance for GL Account (Balance Sheet)

For the Period December 2018

HFM updated as of: 02/05/2019 09:22:30

HFM Connection: GAAPHFM

Business Unit: Potomac Electric Power Consol

Scenario: Actual

Period: December 2018

MergerCode: All Merger Codes

Currency: USD

GL Account	Subaccount	Ending Balance
Assets		**8,299,062,896.26**
Current Assets		**760,161,886.19**
Cash and Cash Equivalents		**15,804,641.39**
131000 - Cash - Checking Accounts	131000 - Cash - Checking Accounts	15,384,966.17
131100 - Cash- Payroll Accounts	131100 - Cash- Payroll Accounts	6,544.76
136000 - Temporary Cash Investment	136000 - Temporary Cash Investment	413,130.46
Restricted Cash and Investment		**37,193,848.73**
134000 - Restricted Cash	134000 - Restricted Cash	37,193,848.73
Accounts Receivable, net		**306,991,450.52**
Customer		**225,060,856.01**
142000 - Customer Accounts Receivable	142000 - Customer Accounts Receivable	143,179,324.30
	142020 - Misc Sales TIcket Receivable	20,893.88
	142030 - CIMS A/R Customer Credits	7,490,920.86
	142710 - A/R-Cust Refund Clear	236,935.47
142200 - Unapplied receipts & payments	142201 - Cust A/R-Unapplied Receipts	(2,414,682.16)
144000 - Allowance Doubtful Accts -Cust	144000 - Allow for Doubtful Accts -cust	(20,390,009.65)
173000 - Unbilled Customer Revenue	173000 - Unbilled Customer Revenue	96,937,473.31
Other - A/R		**80,695,031.90**
143000 - Other A/R	535178 - CIAC - Non-Taxable	1,835,129.40
	143000 - Other A/R	71,532,104.77
	143002 - Other A/R - Rents Receivable	870,588.82
	143004 - Current A/R-Workers Comp	1,817,176.66
	143005 - Accts Rec - Not Yet Billed	5,308,822.99
144100 - Allowance Doubtful Accts-Oth	144100 - Allow for Doubtful Accts- Othe	(704,029.53)
171000 - Interest & Dividend Receivable	171000 - Interest & Dividend Receivable	35,238.79
Intercompany - A/R		**1,235,562.61**
146000 - I/C Accounts Receivable	146000 - I/C Accounts Receivable	1,012,603.42
	146005 - I/C Acct Receivable-Not Settle	222,959.19
Inventories, at average cost		**93,057,001.85**
Materials and Supplies-		**93,057,001.85**
154000 - Materials & Supplies	154000 - Materials & Supplies	94,346,013.44
154100 - Allowance for Excess Material	154100 - Allowance for Excess Material.	(1,289,011.59)
163000 - Stores Handling Undistributed	510010 - Absent Time	11,258.31
	510020 - Regular Time	2,581,602.48
	510030 - Vacation Time	3,973.76
	510100 - Paid Time Off Allocation	551,961.52

GL Account	Subaccount	Ending Balance
	511000 - Overtime Wages	1,007,166.12
	512020 - Performance Based Awards	698.04
	512050 - Other Payroll Premiums	179,208.27
	515080 - Staff Augmentation	30,041.45
	521101 - Pension Alloc PensAlloc-SC	397,607.73
	521102 - Pension Alloc PensAlloc-NSC	(115,826.55)
	521201 - Post-Retirement Ben OPEB-SC	30,525.24
	521202 - Post-Retirement Ben OPEB-NSC	22,347.88
	520060 - Disability Plan	1,473.20
	520200 - Fringe Benefit Allocation	747,735.10
	513111 - AIP - KPI Allocation	199,672.55
	604100 - Payroll Taxes Allocation	299,800.02
	514094 - Materials-Contractor Supplied	2,012.25
	516010 - Contracting, Other	17,109.40
	514060 - Other Services	49,985.99
	515060 - Other Professional	354.00
	514050 - Guard/Security Services	8,500.00
	516020 - Outsourced Contracting, Other	558.00
	517010 - Materials	267,207.81
	517020 - Tools	59,848.52
	527000 - Telecommunications	127.18
	528000 - IT Licensing & Maintenance Fee	1,752.00
	538100 - IT Distributed BSC Services	249,632.93
	538000 - BSC Services other than IT	61,083.91
	529460 - Indir Bill - Supply Services	1,420,757.87
	544460 - Indir Bill-Supply Services-PHI	1,889,546.33
	535130 - Fleet Srv-Veh RaFleet Services	1,057,326.74
	535137 - Hired Hauling/Rental Veh Cost	7,843.20
	535199 - Fleet Services-Residual Alloc	4,085.02
	531030 - Facilities Rentals/Leases	4,022,939.23
	535030 - Utilities	1,722.48
	518030 - Office Supplies	1,490.74
	518040 - Other Office Expense	15,987.12
	519000 - Postage & Delivery	11,237.42
	535010 - Seminars and Training	666.00
	535160 - Other Expenses	8,927.16
	536100 - Allowance for Excess Material.	(2,216.23)
	524000 - Business Travel	5,428.32
	524020 - Nondeduct. Commuting	37.00
	526010 - 50% Deduct Meals & Entertain	27,215.95
	526020 - 100% Deduct Meals & Entertain	13,670.12
	163999 - Stores handling billed charges	(15,154,081.58)
Notes Receivable - CA		**0.98**
Intercompany - CANR		**0.98**
145000 - I/C Short Term Note Receivable	145000 - I/C Short Term Note Receivable	0.98
Current Regulatory Assets		**270,230,613.84**
174999 - Current Reg Asset Reclass	174999 - Current Reg Asset Reclass	270,230,613.84
Other Current Assets		**36,884,328.88**
Other - OCA		**36,884,328.88**

GL Account	Subaccount	Ending Balance
159000 - Renewable Energy Credits	159100 - Renewable Energy Credits	61,000.00
165100 - Prepayments	165100 - Other Prepayments	1,519,881.03
	165120 - Prepaid Rent	0.00
	165130 - Prepaid Insurance	1,025,065.92
165300 - Prepaid Taxes	165300 - Prepaid Taxes	923,349.18
	165320 - Prepaid Property Tax	32,434,829.27
165400 - Postage	165400 - Postage	170,203.46
174000 - Other Miscellaneous Curr Asset	174040 - CD Invsts-90 days to 1 year	750,000.00
174900 - Clearing Account - Current	174900 - Clearing Account - Current	0.02
Property, Plant and Equip, net		**6,459,650,422.00**
101000 - Plant in Service	101000 - Utility Plant in Service	8,170,269,011.27
	101001 - Utility Plant Add-Unitized	393,041,740.25
	101002 - Utility Plant Ret-Unitized	(26,094,536.44)
	101025 - ARC for FIN 47 - PPE	15,240,549.59
101100 - Leased Asset ROU-Finance	101100 - Leased Asset ROU-Finance	152,040,685.21
105000 - Plant Held for Future Use	105000 - Plant Held for Future Use	48,702,678.30
105001 - Plant Held Future Use-Not Clas	105001 - Plant Held Future Use-Not Clas	2,868,247.45
106000 - Non-Unitized Utility Plant	535178 - CIAC - Non-Taxable	(89,509.24)
	106001 - Utility Plant Add-Nonunitized	512,547,640.78
	106004 - Utiliity Plant Adj-Nonunitized	26,807.87
107000 - Construction Work in Progress	510010 - Absent Time	41,583.80
	510020 - Regular Time	39,160,029.66
	510030 - Vacation Time	(58.48)
	510050 - Base pay related to Temp labor	41,373.04
	510100 - Paid Time Off Allocation	8,255,681.08
	511000 - Overtime Wages	15,888,819.30
	512020 - Performance Based Awards	9,251.55
	512030 - Signing Bonuses	3,237.77
	512050 - Other Payroll Premiums	(598,507.13)
	512070 - Retention Incentive Awards	3,840.00
	515080 - Staff Augmentation	8,149,993.13
	521101 - Pension Alloc PensAlloc-SC	5,936,853.02
	521102 - Pension Alloc PensAlloc-NSC	(1,731,212.45)
	521201 - Post-Retirement Ben OPEB-SC	456,621.75
	521202 - Post-Retirement Ben OPEB-NSC	335,599.94
	520040 - Other Benefit Plans	468.12
	520060 - Disability Plan	5,654.10
	520100 - Workers' Compensation Expense	(208.42)
	520200 - Fringe Benefit Allocation	11,344,332.24
	513111 - AIP - KPI Allocation	2,998,416.26
	513113 - Annual Incentives	122,219.91
	604050 - Other Payroll Taxes	9,077.90
	604100 - Payroll Taxes Allocation	4,555,747.75
	514020 - IT Services	438,135.07
	514035 - Civil Subgrade Contract	24,560,930.89
	514082 - Calibration Services	572.82
	514083 - Electrical Contractor Services	536,091.14
	514084 - Mechanical Contractor Services	10,690,537.98
	514091 - Environmental - Services	2,965,614.01

GL Account	Subaccount	Ending Balance
	514094 - Materials-Contractor Supplied	4,316,333.64
	514200 - Contractor Accruals - No AFUDC	(1,031,873.63)
	515010 - Engineering	34,831,605.67
	515030 - Information Technology	163,751.36
	516010 - Contracting, Other	30,050,277.38
	516215 - Overhead Electrical Contractng	55,991,046.23
	516216 - Undergrnd Electric Contractng	96,417,132.77
	516218 - Trans Undg - Contracting	3,051,094.00
	516219 - Trans Ovhd - Contracting	12,137,924.40
	516220 - Non-core opr-I/C charge-COMED	138,898.69
	516221 - Non-core opr-I/C charge-PECO	14,165.51
	516222 - Non-core opr-I/C charge-GENCO	155,086.57
	516225 - Substation - Contracting	16,699,725.22
	516227 - Street Lighting	189,522.21
	516228 - Traffic control for C&M crews	2,996,820.02
	516236 - Non-core opr-I/C charge-BGE	10,646.15
	514060 - Other Services	13,100,041.78
	514070 - Communication/Publication Svcs	16,222.22
	514072 - Promotional Services	202.56
	515020 - Accounting and Audit	52,364.54
	515050 - Legal	202,788.31
	515060 - Other Professional	30,183,498.22
	514040 - Janitorial Services	222,009.48
	514050 - Guard/Security Services	3,477,891.61
	514062 - Outsourced Services, Other	(202,345.44)
	514063 - Contractor Matting	4,686.03
	516020 - Outsourced Contracting, Other	1,682,581.06
	517010 - Materials	138,802,106.20
	517020 - Tools	1,885,201.88
	517030 - Material Delivery	10,186.27
	517200 - Materials Accruals - No AFUDC	(1,892,558.27)
	527000 - Telecommunications	674,250.22
	528000 - IT Licensing & Maintenance Fee	2,621,921.64
	529375 - Indir Bill -BSC Exelon Utility	228,765.12
	529550 - Dir Bill - IT Non-Telecom Srvc	3,698,406.35
	529560 - Indir Bill - Non-IT Telcom Srv	33,470,469.41
	538100 - IT Distributed BSC Services	3,302,554.99
	538000 - BSC Services other than IT	808,100.73
	529360 - Indir Bill - Security Srvcs	297,815.02
	529460 - Indir Bill - Supply Services	707,017.49
	544560 - Indir Bill - IT Services - PHI	713,286.05
	544710 - Indir Bill - PHISCO Other	119,353.58
	544800 - Dir Bill-Utility Ops Serv-PH	24,861,863.07
	544810 - Indir Bill-Utility Ops Srv-PHI	1,116,421.75
	544900 - Dir Bill-Support Services-PHI	19,133.52
	544960 - Indir Bill - Customer Care-PHI	668,377.77
	535040 - Permits	458,022.94
	535060 - Regulatory Fees & Assessments	66,375.40
	535130 - Fleet Srv-Veh RaFleet Services	6,904,390.46

GL Account	Subaccount	Ending Balance
	535135 - Fleet Srv-Oth Veh Related Cost	12.04
	535137 - Hired Hauling/Rental Veh Cost	415,861.50
	535199 - Fleet Services-Residual Alloc	(83,992.08)
	531010 - Equipment Rentals/Leases	17,121.91
	531030 - Facilities Rentals/Leases	4,363,365.96
	531040 - Transmission Rent Expense	16,684.23
	535030 - Utilities	855.45
	518020 - Duplicating	6,789.92
	518030 - Office Supplies	42,699.98
	518040 - Other Office Expense	28,807.53
	519000 - Postage & Delivery	1,642.22
	518010 - Dues & Subscriptions	1,234.86
	535150 - Professional Memberships	166.53
	535010 - Seminars and Training	417.74
	535176 - CIAC - Taxable Billable	(25,390,395.04)
	535178 - CIAC - Non-Taxable	(2,270,419.74)
	535159 - PHI Conv - All O&M	(1,277,526.19)
	535160 - Other Expenses	478,595,386.20
	535183 - CIAC-Taxable Nonbillable	(3,320,116.74)
	535202 - E&S OH Allocation	(2,224,241.31)
	535210 - Infrastructure Allocation	59,649.00
	535275 - A&G and Other OH Allocations	706,870.53
	535605 - Reimbursements - Highway PHI	363,720.32
	524000 - Business Travel	95,107.74
	524020 - Nondeduct. Commuting	212.74
	525010 - Company-Furnished Autos	55,757.12
	525020 - Moving Expenses	8,460.00
	526010 - 50% Deduct Meals & Entertain	309,332.24
	526020 - 100% Deduct Meals & Entertain	137,979.49
	540020 - I/C Other Expense	2,252.36
	614000 - AFUDC Equity	22,317,170.76
	619000 - Capitalized Interest/AFUDC	12,207,942.20
	107000 - Construction Work in Progres	(607,696,680.87)
108000 - Accumulated Depreciation	108000 - Accumulated Depreciation	(3,205,035,165.39)
	108254 - Accum Depr-Reml Costs	25,869,219.47
108030 - Cost of Removal	510010 - Absent Time	7,079.96
	510020 - Regular Time	3,292,091.63
	510030 - Vacation Time	2.81
	510050 - Base pay related to Temp labor	1,384.35
	510100 - Paid Time Off Allocation	707,752.96
	511000 - Overtime Wages	1,485,566.72
	512020 - Performance Based Awards	(9.80)
	512030 - Signing Bonuses	487.72
	512050 - Other Payroll Premiums	(27,034.54)
	515080 - Staff Augmentation	365,376.70
	521101 - Pension Alloc PensAlloc-SC	623,592.58
	521102 - Pension Alloc PensAlloc-NSC	(181,496.40)
	521201 - Post-Retirement Ben OPEB-SC	47,840.14
	521202 - Post-Retirement Ben OPEB-NSC	34,897.28

GL Account	Subaccount	Ending Balance
	520040 - Other Benefit Plans	22.47
	520060 - Disability Plan	1,337.19
	520100 - Workers' Compensation Expense	52.42
	520200 - Fringe Benefit Allocation	948,588.42
	513111 - AIP - KPI Allocation	260,278.33
	604100 - Payroll Taxes Allocation	379,914.39
	514020 - IT Services	5,000.00
	514035 - Civil Subgrade Contract	2,308.12
	514082 - Calibration Services	27.18
	514084 - Mechanical Contractor Services	70,653.52
	514091 - Environmental - Services	302,472.59
	514094 - Materials-Contractor Supplied	2,184.56
	514200 - Contractor Accruals - No AFUDC	1,192,326.10
	515010 - Engineering	2,497,040.23
	516010 - Contracting, Other	1,223,980.05
	516215 - Overhead Electrical Contractng	12,910,014.21
	516216 - Undergrnd Electric Contractng	5,786,037.57
	516218 - Trans Undg - Contracting	22,797.74
	516219 - Trans Ovhd - Contracting	77,216.48
	516222 - Non-core opr-I/C charge-GENCO	21,398.14
	516225 - Substation - Contracting	346,942.40
	516227 - Street Lighting	20,877.70
	516228 - Traffic control for C&M crews	335,856.33
	514060 - Other Services	703,439.66
	514070 - Communication/Publication Svcs	121.66
	514072 - Promotional Services	65.39
	515020 - Accounting and Audit	2,182.02
	515050 - Legal	2,970.51
	515060 - Other Professional	481,786.90
	514050 - Guard/Security Services	27,514.56
	514062 - Outsourced Services, Other	52.07
	514063 - Contractor Matting	730.64
	516020 - Outsourced Contracting, Other	252,320.98
	517010 - Materials	8,658,985.93
	517020 - Tools	23,360.03
	517030 - Material Delivery	316.81
	517200 - Materials Accruals - No AFUDC	(16,884.96)
	527000 - Telecommunications	45,276.27
	528000 - IT Licensing & Maintenance Fee	26.10
	529550 - Dir Bill - IT Non-Telecom Srvc	63,451.06
	538100 - IT Distributed BSC Services	307,768.58
	538000 - BSC Services other than IT	75,039.27
	529460 - Indir Bill - Supply Services	65,595.46
	544800 - Dir Bill-Utility Ops Serv-PH	1,464,470.03
	544810 - Indir Bill-Utility Ops Srv-PHI	110.42
	544900 - Dir Bill-Support Services-PHI	4,727.06
	535040 - Permits	24,055.84
	535060 - Regulatory Fees & Assessments	1,354.60
	535130 - Fleet Srv-Veh RaFleet Services	845,381.97

GL Account	Subaccount	Ending Balance
	535135 - Fleet Srv-Oth Veh Related Cost	0.26
	535137 - Hired Hauling/Rental Veh Cost	16,945.18
	535199 - Fleet Services-Residual Alloc	2,220.93
	531010 - Equipment Rentals/Leases	3,663.62
	531030 - Facilities Rentals/Leases	390,617.84
	535030 - Utilities	81.96
	518020 - Duplicating	545.72
	518030 - Office Supplies	3,246.98
	518040 - Other Office Expense	1,326.68
	519000 - Postage & Delivery	210.12
	518010 - Dues & Subscriptions	16.94
	535150 - Professional Memberships	21.50
	535010 - Seminars and Training	(2.74)
	535176 - CIAC - Taxable Billable	(1,990,783.66)
	535178 - CIAC - Non-Taxable	(161,303.33)
	535160 - Other Expenses	21,010,682.14
	535183 - CIAC-Taxable Nonbillable	(23,087.63)
	535202 - E&S OH Allocation	2,254,384.30
	535210 - Infrastructure Allocation	7,087.15
	535275 - A&G and Other OH Allocations	82,533.11
	535608 - TPR Cost of Removal	(995,909.59)
	524000 - Business Travel	15,745.73
	524020 - Nondeduct. Commuting	3.87
	525010 - Company-Furnished Autos	1,412.25
	525020 - Moving Expenses	1,483.43
	526010 - 50% Deduct Meals & Entertain	28,363.96
	526020 - 100% Deduct Meals & Entertain	14,495.06
	614000 - AFUDC Equity	1.67
	619000 - Capitalized Interest/AFUDC	0.89
	108030 - Cost of Removal	(66,463,081.46)
108040 - Salvage	535600 - Reimbursements - Damage Claim	(4,824,625.63)
	535605 - Reimbursements - Highway PHI	51,872.73
	108040 - Salvage	(2,914,794.73)
111000 - Accum Amortization	111000 - Accum Amortization	(27,391,854.39)
	111010 - Accum Amortization Finance ROU	(138,114,266.05)
	111025 - Acc. Amort. - ARC - FIN 47	(710,534.69)
121002 - Non-Utility Plant- Classified	121002 - Non-Utility Plant- Classified	9,857,751.79
122000 - Accumulated Depr- Non-Utility	122000 - Accumulated Depr- Non-utility	(1,776,878.64)
Deferred Debits and Other		**1,079,250,588.07**
Regulatory Assets		**643,426,384.03**
182150 - ARO Regulatory Asset	182150 - ARO Regulatory Asset	886,966.02
182418 - RA-POLR Fuel Deferral	182418 - RA-POLR Fuel Deferral	34,997,424.79
182423 - RA-Storm Deferral	182423 - RA-Storm Deferral	5,201,852.79
182425 - RA-AMI Full Program	182451 - AMI Accumulating	62,531,609.70
	182452 - AMI Recovery	379,428.80
182427 - RA-Conservation Full Program	514020 - IT Services	(12,159.33)
	514200 - Contractor Accruals - No AFUDC	530,173.15
	515030 - Information Technology	4,052.00
	516010 - Contracting, Other	(665,268.28)

GL Account	Subaccount	Ending Balance
	514060 - Other Services	(17,026.45)
	515060 - Other Professional	59,453,740.06
	530000 - Other IT Costs	379,074.33
	544950 - Dir Bill - Customer Care - PHI	311,123.29
	535160 - Other Expenses	1,266,329.20
	182427 - RA-Conservation Full Program	103,969,530.64
182430 - RA-DRI Full Program	514200 - Contractor Accruals - No AFUDC	63,298.13
	516010 - Contracting, Other	(1,024,787.43)
	515060 - Other Professional	3,875,834.99
	517200 - Materials Accruals - No AFUDC	146,939.43
	182430 - RA-DRI Full Program	28,901,493.99
182432 - RA-POR Under Recovery	182432 - RA-POR Under Recovery	0.00
182434 - RA- Elec Trans Formula Rate TU	182434 - RA- Elec Trans Formula Rate TU	9,932,827.00
182436 - RA-Revenue Decoupling	182436 - RA-Revenue Decoupling	57,212,286.65
182444 - RA - FERC 494 settlement	182444 - RA - FERC 494 settlement	59,647,644.85
182959 - RA-Deferred Energy Supply Nett	182959 - RA-Deferred Energy Supply Nett	(10,233,932.38)
182966 - RA-Elec Recovery-DC Base Rates	182966 - RA-Elec Recovery-DC Base Rates	60,231,981.85
182967 - RA-Elec Recovery-MD Base Rates	182967 - RA-Elec Recovery-MD Base Rates	46,979,255.61
182973 - RA - DC PLUG (Pepco)	182973 - RA - DC PLUG (Pepco)	(688,354.86)
182974 - RA - DC PLUG (DDOT true-up)	182974 - RA - DC PLUG (DDOT true-up)	(21,963.64)
182985 - Reg Asset - Capital Leases	182985 - Reg Asset - Capital Leases	7,987,110.30
182989 - RA-Elec Accumulating DC	182989 - RA-Elec Accumulating DC	10,107,989.48
182991 - RA-Elec Accumulating MD	182991 - RA-Elec Accumulating MD	9,025,424.41
182993 - RA-DC PLUG	182993 - RA-DC PLUG	160,000,000.00
182995 - NonCurr Reg Asset Reclass	182995 - NonCurr Reg Asset Reclass	(279,192,056.13)
182996 - Regulatory Asset Removal Costs	182996 - Regulatory Asset Removal Costs	157,637,018.47
182998 - Residential Aid Program	182998 - Residential Aid Program	1,923,724.79
182999 - Regulatory Asset	182999 - Regulatory Asset	38,360,174.96
189000 - Unamort loss on reacquire debt	189000 - Unamort loss on reacquire debt	13,337,622.85
Investments		**105,409,647.51**
Other - Invest.		**105,409,647.51**
124400 - Corporate Life Insurance	124400 - Cash Surrender Value	58,938,147.82
124600 - Rabbi Trust	124601 - Rabbi Trust - Level 1	46,471,499.69
Pension Asset		**316,122,983.16**
186150 - Pension Asset	186150 - Pension Asset	316,122,983.16
Other - Def. Debits		**14,291,573.37**
181000 - Unamortized debt expense	181000 - Unamortized debt expense	819,759.02
184000 - Fleet Services	510010 - Absent Time	342.88
	510020 - Regular Time	1,538,478.13
	510100 - Paid Time Off Allocation	328,208.68
	511000 - Overtime Wages	616,734.22
	512020 - Performance Based Awards	1,000.00
	512050 - Other Payroll Premiums	47,183.66
	521101 - Pension Alloc PensAlloc-SC	238,961.71
	521102 - Pension Alloc PensAlloc-NSC	(69,661.57)
	521201 - Post-Retirement Ben OPEB-SC	18,363.92
	521202 - Post-Retirement Ben OPEB-NSC	13,482.73
	520060 - Disability Plan	1,543.60
	520200 - Fringe Benefit Allocation	445,995.43

GL Account	Subaccount	Ending Balance
	513111 - AIP - KPI Allocation	118,493.71
	604100 - Payroll Taxes Allocation	178,396.78
	514094 - Materials-Contractor Supplied	3,694.38
	514200 - Contractor Accruals - No AFUDC	5,796.85
	516010 - Contracting, Other	1,298,260.57
	514060 - Other Services	77,682.67
	514070 - Communication/Publication Svcs	797.62
	515060 - Other Professional	106,928.73
	514062 - Outsourced Services, Other	1,170.00
	517010 - Materials	1,078,425.48
	517020 - Tools	114,120.96
	517040 - Materials - Fuel	1,532,820.01
	517200 - Materials Accruals - No AFUDC	(151.55)
	527010 - Pass-through TC Charges - BSC	570.54
	528000 - IT Licensing & Maintenance Fee	364,383.92
	538100 - IT Distributed BSC Services	123,809.11
	538000 - BSC Services other than IT	30,301.41
	544910 - Indir Bill-Support Service-PHI	732,704.02
	532020 - Governmental Fines & Penalties	33.00
	535130 - Fleet Srv-Veh RaFleet Services	(17,939,374.21)
	535135 - Fleet Srv-Oth Veh Related Cost	(586,727.39)
	531010 - Equipment Rentals/Leases	7,142,633.78
	531020 - Property Rentals/Leases	105,393.61
	531030 - Facilities Rentals/Leases	1,725,737.13
	518020 - Duplicating	1,880.95
	518030 - Office Supplies	4,875.86
	518040 - Other Office Expense	1,506.64
	519000 - Postage & Delivery	9.87
	518010 - Dues & Subscriptions	605.29
	535150 - Professional Memberships	7,000.37
	535010 - Seminars and Training	2,236.98
	535160 - Other Expenses	(65,140.37)
	524000 - Business Travel	167,647.90
	524020 - Nondeduct. Commuting	(22.24)
	525010 - Company-Furnished Autos	128,427.83
	526010 - 50% Deduct Meals & Entertain	26,215.37
	526020 - 100% Deduct Meals & Entertain	5,494.96
	184999 - Fleet Services billed charges	322,726.07
184100 - Clearing Account	510010 - Absent Time	(4.32)
	510020 - Regular Time	785,365.46
	510030 - Vacation Time	2,096.80
	510100 - Paid Time Off Allocation	164,917.61
	511000 - Overtime Wages	136,759.52
	512020 - Performance Based Awards	10.59
	512050 - Other Payroll Premiums	1,757.05
	521101 - Pension Alloc PensAlloc-SC	123,656.67
	521102 - Pension Alloc PensAlloc-NSC	(36,106.30)
	521201 - Post-Retirement Ben OPEB-SC	9,524.15
	521202 - Post-Retirement Ben OPEB-NSC	7,037.09

GL Account	Subaccount	Ending Balance
	520200 - Fringe Benefit Allocation	227,740.02
	513111 - AIP - KPI Allocation	59,438.96
	604100 - Payroll Taxes Allocation	91,559.52
	514035 - Civil Subgrade Contract	196,481.56
	514083 - Electrical Contractor Services	221,752.52
	514084 - Mechanical Contractor Services	640,109.20
	514086 - Landscaping and snow removal	405,532.49
	514092 - Restoration Repave	12,627.00
	514094 - Materials-Contractor Supplied	7,658.48
	514200 - Contractor Accruals - No AFUDC	277,901.00
	515030 - Information Technology	8,450.35
	516010 - Contracting, Other	(137,853.51)
	516030 - Civil Subgrade Contracting	4,875.00
	514060 - Other Services	1,222,301.14
	514064 - Utility Elec and Gas Dist R&D	3,262.59
	514070 - Communication/Publication Svcs	(50.00)
	515060 - Other Professional	408,455.74
	514040 - Janitorial Services	2,135,396.00
	514050 - Guard/Security Services	1,173,858.95
	514062 - Outsourced Services, Other	334.32
	516020 - Outsourced Contracting, Other	(184,937.00)
	517010 - Materials	122,217.81
	517020 - Tools	101,494.74
	527000 - Telecommunications	1,332.48
	527010 - Pass-through TC Charges - BSC	5,656.22
	538100 - IT Distributed BSC Services	75,242.57
	538000 - BSC Services other than IT	18,434.28
	535130 - Fleet Srv-Veh RaFleet Services	104,781.84
	535199 - Fleet Services-Residual Alloc	(1,446.08)
	531030 - Facilities Rentals/Leases	(15,221,737.40)
	531031 - Allocated Facilities	(0.05)
	535030 - Utilities	752,849.75
	518020 - Duplicating	721.68
	518030 - Office Supplies	10,788.01
	518040 - Other Office Expense	35,161.25
	519000 - Postage & Delivery	6.90
	518010 - Dues & Subscriptions	138.96
	535010 - Seminars and Training	1,276.91
	535160 - Other Expenses	155,821.60
	524000 - Business Travel	2,223.38
	524020 - Nondeduct. Commuting	48.00
	525010 - Company-Furnished Autos	1,336.28
	525020 - Moving Expenses	44,986.00
	526010 - 50% Deduct Meals & Entertain	6,089.76
	526020 - 100% Deduct Meals & Entertain	541.67
	600010 - Depreciation	3,661,120.84
	601000 - Other Amortization	393,642.91
	607010 - Sales Tax	269.96
	608010 - Property Taxes - Utility	1,757,091.08

GL Account	Subaccount	Ending Balance
184150 - AIP Clearing Account	513010 - Annual Incentive	750.00
	513113 - Annual Incentives	7,706,719.44
	184151 - AIP - KPI Allocation Offset	(7,707,469.44)
184200 - Fringe Benefit Clearing Acct	510030 - Vacation Time	134,052.36
	512050 - Other Payroll Premiums	(63,444.97)
	520010 - Medical Insurance Plan	14,162,811.37
	520020 - Dental Insurance Plan	963,814.02
	520030 - Vision Insurance Plan	426,700.60
	520040 - Other Benefit Plans	3,219,366.02
	520050 - 401 K Benefit Plan	3,551,569.92
	520060 - Disability Plan	221,115.41
	520100 - Workers' Compensation Expense	6,838,222.17
	520200 - Fringe Benefit Allocation	(28,901.45)
	512075 - ESPP Discount Cost	60,784.85
	516010 - Contracting, Other	(28,159.00)
	515060 - Other Professional	1,667.00
	535159 - PHI Conv - All O&M	(526,124.88)
	535160 - Other Expenses	6,276.50
	525030 - Tuition Reimbursement	342,466.47
	184200 - Fringe Benefit Alloc Offset	(29,282,216.39)
184225 - Pension Clearing Account	521001 - Pension Ben-Service Annty-SC	15,846,359.95
	521002 - Pension Ben-Service Annty-NSC	(4,600,290.00)
	521100 - Pension Allocation	(17,564.26)
	522001 - Post-Retirement Benefits-SC	1,209,954.96
	522002 - Post-Retirement Benefits-NSC	865,980.00
	184225 - Pension Allocation Offset	(13,304,440.65)
184250 - Paid Time Off Clearing Account	510010 - Absent Time	10,093,306.17
	510020 - Regular Time	20,086.64
	510030 - Vacation Time	10,168,799.31
	520060 - Disability Plan	1,092,104.76
	184250 - Paid Time Off Allocat Offset	(21,374,296.88)
184275 - Payroll Tax Clearing Account	604010 - FICA	8,813,785.21
	604020 - FUTA	68,626.93
	604030 - SUTA	192,038.07
	604040 - Medicare Tax	2,395,155.17
	604050 - Other Payroll Taxes	269,612.49
	604100 - Payroll Taxes Allocation	(11,121.97)
	535160 - Other Expenses	1,676.97
	184275 - Payroll Tax Allocation Offset	(11,729,772.87)
184400 - Material Handling	517010 - Materials	13,090,704.39
	184400 - Material Handling	(13,090,704.39)
184900 - Clearing - RECLASS TO CURRENT	184900 - Clearing - RECLASS TO CURRENT	0.00
186000 - Deferred debit	521101 - Pension Alloc PensAlloc-SC	9.92
	521102 - Pension Alloc PensAlloc-NSC	(2.88)
	521201 - Post-Retirement Ben OPEB-SC	0.76
	521202 - Post-Retirement Ben OPEB-NSC	0.54
	517010 - Materials	0.00
	529550 - Dir Bill - IT Non-Telecom Srvc	0.64
	544800 - Dir Bill-Utility Ops Serv-PH	91.59

GL Account	Subaccount	Ending Balance
	535159 - PHI Conv - All O&M	3,879.79
	186000 - Misc Other Deferred Debits	2,723,850.92
	186001 - Other A/R-Workers Comp Insuran	10,732,656.04
	186020 - PCards	10,986.90
186975 - Proceeds - Property Sales	510020 - Regular Time	340.13
Liabilities and Equity		**(8,299,062,896.26)**
	[None]	**(210,085,720.29)**
Current Liabilities		**(628,118,245.39)**
Notes Payable		**(39,997,000.00)**
Other - NP		**(39,997,000.00)**
231100 - Commercial Paper	231100 - Commercial Paper	(40,000,000.00)
231200 - Discount on Short-Term Debt	231200 - Discount on Short-Term Debt	3,000.00
LT Debt & Cap Lses Due In 1 Yr		**(14,693,241.40)**
224100 - Current Maturities - Other LTD	224100 - Current Maturities - Other LTD	(766,822.21)
243000 - LTD & Cap Leases Due w/in 1yr	243010 - Cur Matur of Capital Lease Obl	(13,926,419.19)
Accounts Payable		**(276,116,047.33)**
Other - A/P		**(214,451,724.95)**
232000 - Accounts Payable- Systems	232000 - Accounts Payable - Systems	(70,921.31)
	232001 - A/P PassPort-CED Instance	(47,113,223.81)
	232008 - Epayables reclass clring acct	(0.00)
232100 - Account Payable - Other	232100 - Account Payable - Other	(38,544,571.42)
	232110 - Contractors not invoiced	(713,753.23)
	232111 - Contractors not invoiced-PPCED	(14,257,909.88)
	232121 - Materials not invoiced-PPCED	(4,044,520.47)
	232160 - Undistributed Customer Refunds	(7,490,920.86)
	232165 - A/P-Other	600.00
232200 - A/P to other energy suppliers	232200 - A/P to other energy suppliers	(57,894,179.65)
232600 - Purchased Power	232600 - Purchased Power	(44,322,324.32)
Intercompany - A/P		**(61,664,322.38)**
234000 - I/C Accounts Payable	234000 - I/C Accounts Payable	(33,339,045.79)
	234005 - I/C Acct Payable-Not Settle	(10,455,684.48)
234099 - Elim Out of Bal - Asset > Liab	234099 - Elim Out of Bal - Asset > Liab	(0.00)
234900 - I/C Accts Payable - Not Settle	234900 - I/C Accts Payable-Not Settle	(17,869,592.11)
Intercompany NCI Rule	123100 - Investmt in ConsolidatedSub	1,000.00
	201000 - Common Stock Issued	(1,000.00)
Accrued Expenses		**(126,310,685.84)**
228400 - Claim Accruals-current portion	228410 - Bodily Injuries	(1,196,068.00)
	228420 - Workers Comp - Short Term	(4,360,086.49)
228540 - Crnt Environmental Liab	515080 - Staff Augmentation	(64,318.15)
	514091 - Environmental - Services	88,679.88
	516010 - Contracting, Other	(625.00)
	514060 - Other Services	(1,250.00)
	514070 - Communication/Publication Svcs	75,000.00
	515050 - Legal	7,262.50
	228540 - Crnt Environmental Liab	(2,235,624.73)
232900 - Employee Withholdng-Oth Deduct	232910 - Payroll Deduction - 401K	(0.00)
	232920 - Payroll Deduction - Other	(1,745.47)
	232921 - Transit Flex Deductions	(6,331.87)
	232922 - Payroll Deduction - Union Dues	(17.00)

GL Account	Subaccount	Ending Balance
	232925 - Payroll Deduction - PAC	(917.37)
	232926 - Dependent Care Flex Deduction	(92,070.00)
	232927 - Payroll Ddct - Emp Stck Pr Pln	(1,261.33)
	232929 - Payroll Deduction - Garnishmnt	2,018.15
	232930 - Payroll Deduction - Medical	(24.69)
	232933 - Payroll Deduction - LT Disblty	(0.00)
236000 - Federal Income Taxes Payable	236000 - FIT Payable - Previous Years	(0.00)
	236001 - FIT Payable - Prior Year	1,828,773.00
	236002 - FIT Payable - Current Year	(9,780,088.67)
236170 - OT Sep Co Inc Taxes Pay	236171 - OT Separate Co Pay - Prior Yr	(0.00)
236200 - Property Taxes Payable	236200 - Property Taxes Payable	(2,265,489.55)
236300 - Gross Receipts Tax Payable	236300 - Gross Receipts Tax Payable	(8,182,731.89)
236500 - Sales Tax Payable	236500 - Sales Tax Payable	(12,336,344.04)
236600 - Use Tax Payable	236600 - Use Tax Payable	(240,822.61)
236650 - Use/Sales Tax Reserve	236650 - Use/Sales Tax Reserve	(1,192,233.76)
236800 - Payroll Taxes - Employer	236800 - FICA Taxes Payable- Employer	(162,785.46)
	236810 - Other Payroll Taxes	(1,093,821.18)
	236811 - Other Payroll Taxes - AIP	(638,327.88)
	236820 - FUTA Taxes Payable-Employer	(1,196.48)
	236830 - SUTA Taxes Payable - Employer	(3,790.49)
236900 - Other Taxes Payable	236900 - Other Taxes Payable	(24,098,036.45)
237000 - Interest Accrued	237000 - Accrued Interest-Other	(24,859,444.50)
	237010 - Interest Accr Customer Deposit	(0.14)
	237030 - Interest Accr-State Inc Tax	56.00
241000 - Employee Withholding-Tax	241000 - FIT Withheld-Employee Paychcks	11,980.14
	241010 - FICA Tax Deduct-Employ Paychck	73.23
	241020 - SIT Withheld-Employee Paychcks	3,205.31
	241040 - Local Income Tax Withholding	(44.09)
	241050 - Medicare Tax Withholding	653.44
242000 - Accrued Payroll	242000 - Accrued Payroll	(3,076,822.83)
242100 - Accrued Severance Plans	242160 - Severence Liability - Specific	(0.00)
242200 - Accrued Bonuses & Incentives	242200 - Accrued Bonuses & Incentives	(8,721,401.29)
	242210 - Other Accrued Incentive Plans	(603,696.66)
	242220 - Accrued Retention	(12,291.67)
242300 - Accrued Benefits	242300 - Accrued Benefits	(7,994,032.30)
242400 - Accrued Vacation	242400 - Accrued Vacation	(8,345,654.70)
242500 - Other Accrued Expenses	242500 - Other Accrued Expenses	(6,758,990.75)
Current Regulatory Liabilities		**(7,121,249.92)**
242999 - Current Reg Liability Reclass	242999 - Current Reg Liability Reclass	(7,121,249.92)
Other - Curr. Liab.		**(163,880,020.90)**
235000 - Customer Deposits	235000 - Customer Deposits	(53,924,242.03)
242605 - Def Comp Liab - Current	242607 - Def Comp Plan Current - Lev 2	(1,015,000.00)
242610 - FAS 158 Current Liability	242615 - ASC 712 OPEB Obligation - Curr	(917,225.12)
242800 - Unclaimed checks	242800 - Other Unclaimed Checks	(239,872.21)
	242810 - Unclaimed Customer Refunds	(1,984,980.06)
242920 - DC PLUG-DDOT Current Liability	242920 - DC PLUG-DDOT Current Liability	(30,000,000.00)
242950 - Other Current Liabilities	242950 - Other Current Liabilities	(1,733,448.47)
	242958 - Negative Cash - Current	(35,549,325.22)
	242967 - Merger Commitments	(38,359,122.84)

GL Account	Subaccount	Ending Balance
	242968 - Acc Liab MD OHEP	(156,804.95)
Long-Term Debt & Capital Lses		**(2,704,368,221.30)**
221000 - Long Term Debt (Bonds)	221000 - Long Term Debt (Bonds)	(2,734,500,000.00)
224000 - Other Long Term Debt	224000 - Other Long Term Debt	(1,612,148.77)
225000 - Unamortized Premium on LTD	225000 - Unamortized Premium on LTD	(11,669,888.76)
226000 - Unamortized Discount on LTD	226000 - Unamortized Discount on LTD	9,575,784.10
227000 - Finance Lease Liab NonCurrent	227000 - Fin Lease Liab-NonCurrent	0.05
229000 - Unamortized Debt Expense	229000 - Unamortized Debt Expense	33,838,032.08
Def Credits and Other Liab		**(2,227,023,500.56)**
Regulatory Liabilities		**(822,058,482.32)**
254000 - FASB 109 Requlatory Liability	254000 - FASB 109 Requlatory Liab-Fed	(798,450,285.00)
254120 - Reg Liability - Removal Costs	254120 - Regulatory Liab-Removal Reserv	(18,779,626.14)
254306 - RL-POLR Residential Inc Costs	254306 - RL-POLR Residential Inc Costs	(5,816,789.38)
254307 - RL-POLR Fuel Deferral	254307 - RL-POLR Fuel Deferral	(4,417,143.00)
254309 - RL-POR Over Recovery	254309 - RL-POR Over Recovery	(2,408,615.50)
254310 - RL - DRI Over Recovery	254310 - RL - DRI Over Recovery	(3,762,514.43)
254311 - RL- Conservation Over Recovery	254311 - RL- Conservation Over Recovery	(14,579,471.30)
254438 - RL-Smart Energy Rewards	254438 - RL - Smart Energy Rewards	(782,954.54)
254443 - Tax Reform 2018 Impact	254443 - Tax Reform 2018 Impact	(868,433.92)
254444 - RL ? Revenue Excess Dfd	254444 - RL ? Revenue Excess Dfd	(4,390,093.00)
254975 - RL - DC Right of Way	254975 - RL - DC Right of Way	(1,614,445.06)
254980 - RL-Deferred Energy Supply Nett	254980 - RL-Deferred Energy Supply Nett	10,233,932.38
254984 - RL-MD Grid Resiliency Charge	254984 - RL-MD Grid Resiliency Charge	(1,072,286.99)
254995 - NonCurr Reg Liability Reclass	254995 - NonCurr Reg Liability Reclass	25,307,083.96
254999 - Regulatory Liability	254999 - Regulatory Liability	(656,840.40)
Deferred Income Taxes - DC		**(1,062,423,150.00)**
283100 - Deferred FIT - NonCurrent	283100 - Deferred FIT - NonCurrent	(90,225,956.00)
	283101 - Deferred FIT - Property	(805,495,628.00)
283200 - Deferred SIT - Other - Noncur	283210 - Deferred SIT Tax MD - NC	(12,171,119.00)
	283211 - Deferred SIT Tax MD - Property	(48,667,873.00)
	283270 - Def SIT Tax OT Unitary - NC	(8,634,305.00)
	283271 - Def SIT Tax OT Unitary - Prop	(97,228,269.00)
Unamortized Investment Tax Cr		**(1,804,377.00)**
255000 - Unamort Investment Tax Credit	255000 - Unamortized Invest Tax Credits	(1,804,377.00)
Asset Retirement Obligation		**(37,191,606.07)**
253600 - Asset Retirement Obligation	253600 - Asset Retirement Obligation	(37,116,931.02)
	253630 - FIN 47 Conditional AROs	(74,675.05)
253650 - ARO Settlement Costs	516010 - Contracting, Other	166,966.81
	253650 - ARO Settlement Costs	(166,966.81)
Non-Pension Postretire Bene Ob		**(28,502,992.91)**
228050 - Non-Pension PostRetire BenfObl	228050 - Non-Pension PostRetire BenfObl	(28,502,992.91)
Other - LT Liab.		**(275,042,892.26)**
228200 - Non-pension beneft liabilities	228252 - Deferred Comp Plan - Level 2	(1,714,712.62)
	228270 - Mgmt. Retention Incentive Plan	(15,416.64)
	228290 - FASB 112 Liability	(3,331,483.68)
	228295 - Long-term Incentive Plans	(81,059.85)
228300 - Claims - Long Term	228310 - Bodily Injuries	(1,157,962.46)
	228320 - Workers Comp - Long Term	(46,614,738.51)
228530 - Other Environmentl Liabilities	515080 - Staff Augmentation	36,875.00

GL Account	Subaccount	Ending Balance
	514080 - Contract Operator Service	(1,250.00)
	514091 - Environmental - Services	1,011,064.13
	516010 - Contracting, Other	12,500.00
	514060 - Other Services	14,855.24
	514070 - Communication/Publication Svcs	36,250.00
	515050 - Legal	86,502.72
	515060 - Other Professional	13,068.15
	532020 - Governmental Fines & Penalties	475,000.00
	535110 - Environmental Remediation	235,973.38
	228530 - Other Environmentl Liabilities	(24,445,889.56)
252000 - Customer Adv for Construction	535178 - CIAC - Non-Taxable	(400,414.89)
	252000 - Customer Adv for Construction	(4,550,782.85)
253000 - Other Deferred Credits	253000 - Other Deferred Credits	(46,872,698.61)
	253025 - Supplier Deposits	(1,133,753.72)
253055 - NonCurrent Liability	253055 - Non Current Liability	(16,484,555.26)
253080 - FIN 48 Tax Liab - NC	253085 - FIN 48 NC Tax Liability - MD	(0.00)
253110 - DC PLUG-DDOT NonCurr Liability	253110 - DC PLUG-DDOT NonCurr Liability	(130,000,000.00)
253900 - Deferred Rents	253900 - Deferred Rents	(160,262.23)
Equity		**(2,739,552,929.01)**
	[None]	**(210,085,720.29)**
Common Stock		**(1.00)**
201000 - Common Stock Issued	201000 - Common Stock Issued	(1.00)
Other Paid-in Capital		**(1,635,907,422.30)**
211000 - Other Paid in Capital	211000 - Other Paid in Capital	(1,627,806,958.55)
	211010 - Premium on Capital Stock	(8,100,463.75)
201100 - Membership Interest	201100 - Membership Interest	1,000.00
	201101 - Membership Int for End CEG RE	(1,000.00)
Retained/Undist Earnings		**(1,103,645,505.71)**
	[None]	**(210,085,720.29)**
Retained Earn not incl Net Inc		**(893,559,785.42)**
216000 - Retained Earnings	216000 - Unappropriated Retaind Earning	(1,063,359,785.42)
216100 - Dividend Declr on Common Stock	216100 - Dividend Declr on Common Stock	169,800,000.00
CYRE - Current Year Retained Earnings	[None]	(210,085,720.29)

J.C. Ziminsky
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (D) – 10

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Analysis of Account 928 - Regulatory Expense
Twelve Months Ended June 30, 2019 (6+6)

Description	Deposit Orders	Other, including Outside Experts and Consultants	Total
Cases			
1103 2013 Rate Case	(290,246)		$ (290,246)
1139 2016 Rate Case		1,101,263	1,101,263
1130 MEDSIS		315,710	315,710
1150 2017 Rate Case		537,724	537,724
Retail Regulation DC (Charges to PC16EH103)		1,416,262	1,416,262
2019 Rate Case		333,780	333,780
Total	**$ (290,246)**	**$ 3,704,739**	**$ 3,414,493**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Analysis of Account 928 - Regulatory Expense
Twelve Months Ended December 31, 2018

Description	Deposit Orders	Other, including Outside Experts and Consultants	Total
Cases			
1103 2013 Rate Case	$ -	$ (387,885)	$ (387,885)
1139 2016 Rate Case	$ -	$ 1,181,624	$ 1,181,624
1130 MEDSIS	$ 134,120	$ 315,710	$ 449,830
1150 2017 Rate Case	$ 1,393,512	$ (1,413,312)	$ (19,800)
Retail Regulation DC (Charges to PC16EH103)	$ -	$ 709,010	$ 709,010
2019 Rate Case	$ -	$ 333,780	$ 333,780
1017 Standard Offer Service	$ 41,660	$ -	$ 41,660
1125 Promotion of Utility Discount Programs	$ 127,904	$ -	$ 127,904
1144 Capital Grid Project Underground Circuits	$ 189,955	$ -	$ 189,955
1148 Energy Efficiency and Energy Conservation Programs	$ 9,880	$ -	$ 9,880
1151 Impact of the Tax Cuts and Jobs Act	$ 75,000	$ -	$ 75,000
1050 Investigation of the Implementation of Interconnection Standards	$ 22,000	$ -	$ 22,000
1149 Investigation of the Structure and Application of an Experimental Rate	$ 50,000	$ -	$ 50,000
PEPACR-2017-01-E	$ 39,650	$ -	$ 39,650
	$ 2,083,681	**$ 738,926**	**$ 2,822,607**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Analysis of Account 928 - Regulatory Expense
Twelve Months Ended December 31, 2017

Description	Deposit Orders	Other, including Outside Experts and Consultants	Total
Cases			
1017 Standard Offer Service	120,000		$ 120,000
1103 2013 Rate Case		$ 319,738	$ 319,738
1116 DC Undergrounding	$ 570,000		570,000
1119 Application for Authorization of Proposed Merger Transaction	118,050		118,050
1121 Application of DC Plug Financing	(20,000)		(20,000)
1125 Promotion of Utility Discount Programs	60,469		60,469
1139 2016 Rate Case	398,438	(1,718,347)	(1,319,909)
1144 Capital Grid Project Underground Circuits	154,365	400,000	554,365
PEPACR-2017-01-E	279,500		279,500
1150 2017 Rate Case		759,926	759,926
Retail Regulation DC (Charges to Order 5247583, 5247584, 5247395)		766,925	766,925
Total	**$ 1,560,822**	**$ 528,242**	**$ 2,209,063**

POTOMAC ELECTRIC POWER COMPANY

District of Columbia
Analysis of Account 928 - Regulatory Expense
Twelve Months Ended December 31, 2016

Description	Deposit Orders	Other, including Outside Experts and Consultants	Total
Cases			
766 Productivity Improvement Plan	$ 25,000		$ 25,000
945 Electric Service Market Competition	$ (337,227)		$ (337,227)
991 Investigation into Explosions in or around UG Distribution System	215,000		$ 215,000
1017 Standard Offer Service	150,000		$ 150,000
1103 2013 Rate Case		$ 1,091,158	$ 1,091,158
1116 DC Undergrounding	29,800		$ 29,800
1119 Application for Authorization of Proposed Merger Transaction	30,000		$ 30,000
1121 Application of DC Plug Financing	20,000		$ 20,000
1125 Promotion of Utility Discount Programs	93,631		$ 93,631
1139 2016 Rate Case	1,463,912	1,884,091	$ 3,348,003
Retail Regulation DC (Charges to Order 5247583, 5247584, 5249908)		354,096	$ 354,096
Total	**$ 1,690,117**	**$ 3,329,344**	**$ 5,019,461**

L. Schafer
Direct Testimony
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (E)

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EXECUTIVE SUMMARY- LANCE C. SCHAFER

This testimony supports the District of Columbia Class Cost of Service Study (CCOSS) for the distribution service of Potomac Electric Power Company (Pepco or the Company) that reflects ratemaking adjustments and is based on the Jurisdictional Cost of Service Study presented by Company Witness Ziminsky. The CCOSS is substantially similar to that used by the Company in prior proceedings with the exception that the present study is designed to be even more accessible and transparent than those previously filed with the Public Service Commission of the District of Columbia.

A summary of the rate-class contributions to the Company's revenue requirement for the test period (the 12 months ended June 30, 2019) is provided in Table 1.

Table 1

Summary of Rates of Return at Present Rates

Description	Rate of Return at Present Rates	Unitized Rate of Return
Total District-of-Columbia Distribution	4.87%	1.00
Residential (R)	-4.87%	-1.00
Master-Metered Accounts (MMA)	8.90%	1.83
General Service Low Voltage (GS-LV)	10.84%	2.23
General Service High Voltage (GS-HV)	23.40%	4.81
Time-Metered Medium General Service Low Voltage (MGT-LV)	12.37%	2.54
Time-Metered General Service Low Voltage (GT-LV)	9.89%	2.03
Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	10.51%	2.16
Time-Metered General Service High Voltage Other (GT-HV-OTHER)	11.03%	2.27
Metro	8.22%	1.69
Street Lighting S Service	3.00%	0.62
Street Lighting E Service	-5.05%	-1.04
Traffic Signal	9.25%	1.90
Tele-Communication Network Service	17.34%	3.56

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF LANCE C. SCHAFER
FORMAL CASE NO. 1156

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q1. Please state your name and position.

A1. My name is Lance C. Schafer, and I am a Senior Rate Analyst with Pepco. I am testifying on behalf of the Company.

Q2. What are your responsibilities in your role as Senior Rate Analyst?

A2. I have responsibility for developing and conducting Class Cost of Service Studies and assisting with rate-related analyses for Pepco.

Q3. Please state your educational background and professional experience.

A3. I received my Master of Business Administration, with an Emphasis in Finance, from the University of Missouri, Crosby MBA Program, in 2014. I also have a Master of Arts in French Literature from the University of California, Irvine and a Bachelor of Arts in English from the University of Missouri, Columbia.

I joined Pepco as a Senior Rate Analyst in November 2018. Prior to joining Pepco, I was a Rate and Regulatory Analyst and a Rate and Financial Analyst with Power System Engineering, Inc. In those capacities, I filed revenue requirements analyses and testimony on behalf of regulated electric cooperatives in Kentucky. I also built Power System Engineering, Inc.'s depreciation model, with which I conducted depreciation studies. I worked on revenue requirements, cost of service, and rate design studies for both regulated and self-regulated electric cooperatives. I also participated in rate design-related projects, such as solar cost-shift studies and fixed-cost recovery case studies.

Prior to my work with electric cooperatives, I was with the Division of Energy and Office of the Public Counsel of the Missouri Department of Economic Development, where I served first as a Public Utility Financial Analyst and then as a Planner III. In those roles I was responsible for financial analyses and testimony. I also monitored financial and energy-related policy pertaining to regulated public utilities, such as energy efficiency programs, utility rate structure, revenue adjustment mechanisms, cost of capital, and credit standing. I edited and wrote content for Missouri's first-ever Comprehensive State Energy Plan.

Q4. Have you previously testified before the Public Service Commission of the District of Columbia (Commission)?

A4. No.

Q5. Have you previously testified before any other public service commission?

A5. Yes. I have previously been a witness on revenue requirements before the Kentucky Public Service Commission on behalf of regulated electric cooperatives in Kentucky. When I served with the Office of Public Counsel at the Missouri Department of Economic Development, I testified before the Missouri Public Service Commission on cost of capital for regulated public utilities.

Q6. What is the purpose of your Direct Testimony?

A6. I am sponsoring a District of Columbia Class Cost of Service Study for Pepco's distribution service that reflects ratemaking adjustments. The CCOSS Model is deemed confidential and proprietary. This CCOSS is substantially similar to that used by the Company in prior proceedings, with the exception that the present study is designed to be even more accessible and transparent than those previously filed with the Commission. In

particular, the study features a new CCOSS model that meets the Commission's objectives, as stated in Formal Case No. 1139, that Pepco proffer a "flexible" cost of service model that the parties could more readily utilize. In addition to the CCOSS, I have prepared an Instruction Manual that explains how the CCOSS model works. The Company will also hold a technical conference for the Commission Staff and all parties to help them understand how the model works and how their experts can make use of it.

The CCOSS results presented in my Direct Testimony and exhibits are based on the Jurisdictional Cost of Service Study presented by Company Witness Ziminsky.[1]

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

II. DESCRIPTION OF EMBEDDED CLASS COST OF SERVICE STUDIES

Q7. Please describe the organization of your Direct Testimony.

A7. I first discuss the purpose of developing embedded class cost of service studies and the goals that are sought through these analyses. I also outline the basic processes involved in developing the CCOSS I am sponsoring in this proceeding.

Next, I describe the CCOSS, included with my Direct Testimony as PEPCO (E)-1, which takes the Pepco distribution system costs allocated and assigned to the Company's District of Columbia jurisdiction in the Jurisdictional Cost of Service Study and allocates and assigns them to the Company's various District of Columbia customer classes. The CCOSS submitted in this case incorporates the ratemaking adjustments proposed by

[1] The Jurisdictional Cost of Service Study (COSS) is included in the Direct Testimony of Company Witness Ziminsky at PEPCO (D)-3.

Company Witness Ziminsky in his Direct Testimony and exhibits in connection with the traditional test period compliance filing.

Finally, I discuss how the Company has complied with the cost-of-service directives issued in Order No. 18846 in Formal Case No. 1139.

The remaining schedules presented with my testimony are organized as follows:

PEPCO (E)-2: CCOSS Summary of Results;

PEPCO (E)-3: CCOSS Summary of Allocators;

PEPCO (E)-4: Unbundled Cost, Revenue; and

PEPCO (E)-5: Unbundled Cost, Unit.

A. Purpose of Performing a Class Cost of Service Study

Q8. Please summarize the purpose of performing embedded class cost of service analyses.

A8. Class cost of service analyses are developed to assign and allocate the Company's rate base, revenues, and expenses amongst its customer classes based upon the principle of cost causation. The term "embedded" means that the study relies principally on historical or known costs. Elements of the Company's cost of service are directly assigned when cost causation is traceable to a particular customer class. Costs are otherwise allocated in a manner that embodies the means through which the costs are incurred by the Company.

Q9. What is the primary objective of the class cost of service study you are presenting?

A9. The primary objective of the CCOSS is to present a reasonable representation of the Company's District of Columbia distribution-related costs during the test period at the level of its customer classes. The CCOSS included with my Direct Testimony provides a view of the Company's rates of return for its operations in the District of Columbia for each of its customer classes during the 12-month period ending June 30, 2019. These rates

of return serve as an important guide in the assessment of the contribution of each customer class to the Company's earned rate of return and in the apportionment of necessary revenue changes in rate design.

B. Key Processes Involved in Class Cost of Service Studies

Q10. Please summarize the key processes involved in cost allocation.

A10. There are three basic steps required to properly apportion rate base and expense responsibilities to customer classes: functionalization, classification, and allocation.

Q11. Please describe cost functionalization.

A11. The functionalization of costs is the process of dividing rate base and expense elements of the cost of service into categories related to the operations of the Company. The two main functional categories included in Pepco's distribution cost of service are subtransmission and distribution. Distribution functional costs can be further divided into a number of sub-functions, including common-use costs (general- and intangible-related costs). The functional and sub-functional assignments of electric plant in service (EPIS or plant) can be found in the description columns of PEPCO (E)-1.

Q12. Please describe cost classification.

A12. Cost classification is the process of dividing functionalized rate base and expense elements into demand- and customer-related components based upon the principles of cost causation. Demand cost components, such as substations, are related to system equipment that is designed in accordance with demands on the Company's distribution system. Customer cost components, such as meters, are associated with the number of customers served by the Company. A summary of the unbundled demand- and customer-related costs by customer class for the test period can be found in PEPCO (E)-2.

Q13. Please describe cost allocation.

A13. Cost allocation is the process of allocating functionalized and classified costs to customer classes based upon cost causation. Direct assignments are made when possible for costs that are related to investments or expenses that serve only a particular customer or group of customers. The remaining costs are allocated based upon a method that reflects how each customer group contributes to how costs are imposed on the Company's system.

III. CLASS COST OF SERVICE STUDY IN THE CONTEXT OF THE MULTIYEAR RATE PLAN (MRP)

Q14. Are you submitting multiple class cost of service studies in the instant case?

A14. No.

Q15. Does the CCOSS you are filing in the instant case inform both the MRP and the traditional test period compliance filing?

A15. Yes. The CCOSS I am submitting in the instant case is based on the 12-month period ending June 30, 2019 and provides both a reasonable representation of each rate class's contribution to the Company's revenue requirement and a calculation of unit costs. As described in the testimony of Company Witness Blazunas, both the unit costs and the rate-class contributions to the Company's revenue requirement serve as valuable guides when designing new rates. The rate design for both the traditional test period compliance filing and the MRP (including the initial rate design and the step increases) is guided by the results of the same CCOSS.

IV. CLASS COST OF SERVICE STUDY

Q16. Please summarize the Company's Class Cost of Service Model.

A16. The CCOSS presented as PEPCO (E)-1 was developed to assign and allocate each element of rate base, revenues, and expenses to the Company's customer classes in the District of Columbia. Assignments and allocations are made in a manner that embodies the principles of cost causation. Many allocations in the CCOSS are driven by the class allocations of EPIS, depreciation expense, and operation and maintenance expense. Allocations are identified in the "allocator" columns of PEPCO (E)-1 and are consistent with those previously approved by the Commission.

PEPCO (E)-1 incorporates the unadjusted District of Columbia results of the Company's Jurisdictional Cost of Service Study along with the ratemaking adjustments proposed by Company Witness Ziminsky. The inclusion of ratemaking adjustments in the CCOSS provides a more accurate portrayal of the cost of service to each customer class as a result of this application, as any irregularities are adjusted to provide a more typical view of the Company's operating environment.

A. Overview of New Model

Q17. Are you submitting a new CCOSS model in the instant case?

A17. Yes. In Order No. 18846 of Formal Case No. 1139, Pepco was ordered to provide "switches" within Pepco's CCOSS model to allow a party to "turn on" reasonable allocation methodologies within Pepco's CCOSS.[2]

[2] Formal Case No. 1139, Order No. 18846 at ¶433.

Q18. In Formal Case No. 1150, the Company filed a new CCOSS model to address the issue cited above. Is the new model you are filing in the instant case different from the CCOSS model filed in Formal Case No. 1150?

A18. Yes.

Q19. Why are you filing a new CCOSS model in the instant case?

A19. Although the CCOSS model filed in Formal Case No. 1150 accomplished the directives set forth in Order No. 18846, the creation of a new model provided an opportunity to go even further in providing a transparent and accessible model.

Q20. In what way is the new model transparent and accessible?

A20. Generally, the new model is compact and easy to review. All calculations occur openly by means of accessible formulas in the cells of the worksheets. Important structural information is conveyed visually by means of cell conventions. These conventions differentiate between cells that contain manually input data, cells that contain formulas, and cells that contain references to other worksheets. The sections of the model containing inputs, allocators, revenue-requirement calculations, and results summaries are clearly delineated. The model provides indications of where inputted data is being used, thus making it easy to review all calculations that involve a given input.

Accessibility regarding the allocators was an important design goal of the new model. During the Class Cost of Service Study Technical Conference held on September 18, 2017 in accordance with the Commission's directive in Order No. 18846 in Formal Case No. 1139,[3] intervenors' "…main interest in the new model dealt with making changes to the model and ensuring that such changes flowed through the model properly."[4] During

[3] Formal Case No. 1139, Order No. 18846 at ¶422.
[4] Formal Case No. 1139: September 18, 2017 Technical Conference, Meeting Minutes at 2 (Sept. 25, 2017).

the technical conference, the Company representative explained that if a party desired to make a change to an allocator in the model, that change would need to be made in each relevant functional worksheet and cell.[5] Depending on the allocation in question, making an allocation change could have necessitated making changes on as many as 15 separate worksheets.

Q21. How has the new model you are filing in the instant case made allocation changes convenient?

A21. First, the number of worksheets in the new model has been greatly reduced. The functional components, which used to occupy 14 worksheets, are now displayed on one dynamic worksheet. Second, allocators appearing throughout the model have been linked to a main worksheet. When an allocator is changed on the main worksheet, that change is automatically made throughout the model. In this way, changes to the new model can be made easily and reliably.

Q22. Have you prepared instructions explaining how to make changes to the allocators?

A22. Yes. The Pepco CCOSS Model Instruction Manual will be provided to parties with the CCOSS Model. Section three of the Instruction Manual explains how to make changes to the allocators. As explained above, we will also host a technical conference to further explain the new model.

[5] *Id.*

Q23. Does the new model you are filing in the instant case represent a departure from historically filed CCOSS?

A23. No. No material changes to the Company's allocation practices have been made between Formal Case No. 1139 and the instant case, with two exceptions. First, the allocation of the miscellaneous rate base item "Service Company Assets - Plant Related" was updated as discussed below. Second, the allocation practices related to excess deferred income taxes described in Formal Case No. 1150 have been continued.[6]

B. Customer Classes

Q24. For the purpose of customer class cost allocation, how are Pepco's customers organized into classes?

A24. Customers are classified in accordance with the base-rate schedules in Pepco's Tariffs. In Order No. 18846 in Formal Case No. 1139, the Commission directed Pepco to create new classes for LED street lighting and LED traffic signal service.[7] This change was reflected in Pepco's Tariffs filed pursuant to the Non-Unanimous Full Settlement Agreement and Stipulation (Formal Case No. 1150 Settlement Agreement) approved by the Commission in Formal Case Nos. 1150 and 1151 and is incorporated into the CCOSS that I present.[8] The Formal Case No. 1150 Settlement Agreement also directed the Company to create the MGT-LV rate class.[9] This class has been included in the present study.

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6 Formal Case No. 1150, PEPCO (2F): Murphy Supplemental Direct Testimony at 2-4.
7 Formal Case No. 1139, Order No. 18846 at ¶431.
8 Formal Case No. 1150, Order No. 19433 at ¶18.
9 *Id*. at ¶13.

V. COMPLIANCE WITH COMMISSION DIRECTIVES REGARDING COST OF SERVICE STUDIES IN ORDER NO. 18846, FORMAL CASE NO. 1139

Q25. In Order No. 18846 in Formal Case No. 1139, did the Commission direct Pepco to address certain CCOSS-related issues?

A25. Yes. In Order No. 18846 in Formal Case No. 1139, the Commission ordered that Pepco's next CCOSS filing should do the following: First, "show rate base and associated contribution in aid of construction ("CIAC") separately (not netted), and . . . file with its CCOSS the workpapers used by the Company to develop the allocation of CIAC."[10] Second, "analyze major software and associated equipment such as (but not limited to) [Advanced Meter Infrastructure] and interval billing, and allocate . . . costs based on studies specific to each of the major systems."[11] Third, "provide a more refined cost of service for [Traffic Signals] and [Streetlights] costs, including 'per lamp' charges that distinguish between LED and conventional lamps . . ."[12]

As discussed below, each of these Commission directives is accomplished in the new CCOSS. In addition, the costs associated with new rate classes MGT-LV and OL-LED are also addressed in the new CCOSS.

A. CIAC by Rate Class

Q26. Does the CCOSS show the CIAC amounts collected from the customer classes?

A26. The CCOSS does not show these amounts because CIAC is never included in electric plant in service at any point and is, therefore, not a component of the Company's revenue requirement. However, CIAC can be made available as a standalone workpaper.

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[10] Formal Case No. 1139, Order No. 18846 at ¶426.
[11] *Id.* at ¶428.
[12] *Id.* at ¶431.

B. Software/Associated Equipment Allocations

Q27. What is intangible plant and where is it included in the CCOSS?

A27. Intangible plant includes software and associated equipment used in the Company's provision of electric service. The costs of intangible plant that provide services to Pepco customers only are included in FERC Account 303. Pepco's District of Columbia allocated share of net intangible plant that provides services to the PHI utilities[13] is included in miscellaneous rate base, "Service Company Assets - Plant Related."

Q28. Was the allocation of intangible plant a contested issue in Formal Case No. 1139?

A28. Yes. In Formal Case No. 1139, certain parties took issue with Pepco's allocation of interval billing software system costs.

Q29. What did the Commission decide?

A29. In Order No. 18846, the Commission directed Pepco in its next CCOSS to analyze major software and associated equipment and allocate these costs based on studies specific to each of these major systems.[14]

Q30. Please explain how Pepco has complied with the Commission's directive in the CCOSS.

A30. The directive was first implemented in the CCOSS submitted in Formal Case No. 1150. The methodology employed in that CCOSS has been reproduced with minor modifications in presentation in the new CCOSS I present in this proceeding. Based on an analysis of itemized costs in the workpapers supporting the Jurisdictional Cost of Service Study presented by Company Witness Ziminsky, the District of Columbia share of Pepco

[13] Recorded on PHI Service Company's balance sheet.
[14] Formal Case No. 1139, Order No. 18846 at ¶428.

Holdings LLC (PHI) net plant costs associated with certain systems has been identified, as shown in Table 2.[15]

Table 2

System	Net plant cost
Customer Relationship Mgmt & Billing System (CRMB)	$17,111,425
Interval Billing Software System	$3,323,400
Spectrum frequencies	$2,973,147
Net energy metering	$374,931
AMI software systems	$372,749
Network operations center	$197,001
Outage management system	$44,961
Geospatial information system	$38,037
Load settlement database	$30,546
Plant maintenance/accounting	$0

Q31. How are the costs of the major systems allocated among classes?

A31. Spectrum frequency, network operations center, outage management system, geospatial information system, and plant maintenance system net plant costs are allocated among classes in proportion to STDPLT. Net energy metering net plant costs are allocated in proportion to the number of net energy metering customers. Load settlement database net plant costs are allocated in proportion to the number of customers. CRMB net plant costs are allocated in proportion to the sum of customer expense accounts 903, 908 and 909 based on the results of the detailed analysis discussed above. AMI software system net plant costs are allocated based on customer count. Pepco's District of Columbia

[15] Net plant is original cost of plant less accumulated depreciation.

remaining share of PHI utilities' net intangible plant costs is allocated in proportion to STDPLT.

The interval billing software system regulatory asset is allocated based on the number of customers receiving interval billing.

C. Refined COS for TS/SL LED Customers

Q32. In Order No. 18846 in Formal Case No. 1139, was Pepco given a directive relating to TS and SL customers?

A32. Yes. Pepco was asked to provide a more refined cost of service for TS and SL customers, including charges that distinguish between light-emitting diode (LED) and conventional lamps based on actual lamp (and ballast) wattage.[16]

Q33. How was this directive implemented?

A33. In Formal Case No. 1150, the Company used actual lamp wattage and burn-hour information to develop lighting demand data in the CCOSS. Additionally, separate CCOSS classes for LED lamps were developed.

Q34. Does the new CCOSS in this case continue these practices?

A34. First, the new CCOSS continues to use actual lamp wattage and burn-hour information. Second, LED lamps have not been shown under separate rate classes in the new CCOSS. As a result of the Formal Case No. 1150 Settlement Agreement, the Street Lighting (SL) and Traffic Signal (TS) rate designs were changed to incorporate a volumetric charge,[17] thereby making the separation of LED and non-LED SL and TS rate classes unnecessary. Since LED lights consume less energy than equivalent non-LED

[16] Formal Case No. 1139, Order No. 18846 at ¶431.

[17] Formal Case No. 1150, Order No. 19433, ¶49, Section p. ("Street Light and Traffic Signal Rate Design will be in accordance with paragraph 11 of the Settlement Agreement").

ones, a volumetric charge allows cost savings to accrue to lower usage lights without the creation of separate rate classes.

D. Use of AMI Data

Q35. In Order No. 18846 in Formal Case No. 1139, was Pepco given a directive to make more extensive use of AMI data?

A35. Yes. The Company implemented this directive in Formal Case No. 1150. In that case, AMI data was used to develop all demand allocation factors in the CCOSS. Additionally, AMI data was used to identify class demands coincident with substation peak demands at Pepco's District of Columbia substations.

Q36. Does the CCOSS in this case continue the above-described AMI-related practices implemented in Formal Case No. 1150?

A36. Yes.

VI. OVERVIEW OF RESULTS IN THE CCOSS

Q37. What is each class's rate of return at present rates determined by the CCOSS, and how is this information used?

A37. The rate of return at present rates provides a reasonable representation of each class's contribution to the Company's revenue requirement. It provides a convenient way of comparing an individual rate class's rate of return to the system-average rate of return. This information is used as a guide in rate design. The exact manner in which this information is used ultimately depends on the principles used to guide rate design, which are discussed in this case by Company Witness Blazunas.

Table 3 provides the rates of return at present rates.

Table 3
Summary of Rates of Return at Present Rates

Description	Rate of Return at Present Rates	Unitized Rate of Return
Total District-of-Columbia Distribution	4.87%	1.00
Residential (R)	-4.87%	-1.00
Master-Metered Accounts (MMA)	8.90%	1.83
General Service Low Voltage (GS-LV)	10.84%	2.23
General Service High Voltage (GS-HV)	23.40%	4.81
Time-Metered Medium General Service Low Voltage (MGT-LV)	12.37%	2.54
Time-Metered General Service Low Voltage (GT-LV)	9.89%	2.03
Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	10.51%	2.16
Time-Metered General Service High Voltage Other (GT-HV-OTHER)	11.03%	2.27
Metro	8.22%	1.69
Street Lighting S Service	3.00%	0.62
Street Lighting E Service	-5.05%	-1.04
Traffic Signal	9.25%	1.90
Tele-Communication Network Service	17.34%	3.56

Q38. What are the unit costs determined by the CCOSS, and how are these costs used?

A38. For each class, the customer unit cost is the monthly level of customer-related costs the Company incurs to serve a customer in that class. The demand unit cost is the level of demand-related costs Pepco incurs when a customer in that class imposes a kilowatt of demand on the system. The energy unit cost is the level of energy-related costs Pepco incurs when a customer in that class consumes one kilowatt hour of energy.

Unit costs (shown in PEPCO (E)-4 and PEPCO (E)-5)) determined by the CCOSS are used as guides during the rate design process. Generally, a comparison between present rates and unit costs at an equalized rate of return allows the rate design expert to determine if the present rates are aligned with principles of cost causation. Ultimately, how this information is used depends on the principles of rate design employed by the rate-design

expert. Company Witness Blazunas discusses the principles he used in designing the rates proposed in this proceeding.

Table 4 provides a summary of customer unit costs ($/month/customer) at both present and proposed rates.

Table 4
Summary of Customer Unit Costs

Description	$/Month/Customer (Customer Unit Cost at Present Rate of Return)	$/Month/Customer (Customer Unit Cost at Proposed Rate of Return)
Total District-of-Columbia Distribution	26.65	34.74
Residential (R)	17.40	27.67
Master-Metered Accounts (MMA)	79.65	74.18
General Service Low Voltage (GS-LV)	43.16	38.75
General Service High Voltage (GS-HV)	216.54	163.90
Time-Metered Medium General Service Low Voltage (MGT-LV)	308.92	237.00
Time-Metered General Service Low Voltage (GT-LV)	4,057.41	3,816.50
Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	338.10	311.66
Time-Metered General Service High Voltage Other (GT-HV-OTHER)	213.49	197.49
Metro	86.73	85.45
Street Lighting S Service	0.00	0.00
Street Lighting E Service	27.20	34.90
Traffic Signal	4.33	4.26
Tele-Communication Network Service	18.65	17.00

Q39. Does this conclude your Direct Testimony?

A39. Yes, it does.

L. Schafer
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (E) – 1

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	**Total** DC Distribution	**Total** Residential Service	**Total** GS	**Total** GT-LV	**Total** GT-HV	**Total** GT	**Total** Metro	**Total** Street Lighting	**Total** TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
	Summary Of Results										
	Rate Base										
1	Total System Electric Distribution		3,962,869,750	1,539,299,603	332,586,164	1,571,244,763	416,620,510	1,987,865,273	63,439,990	39,254,121	424,599
2	Less: Depreciation Reserve		1,160,830,526	450,221,439	97,352,245	460,008,068	122,926,744	582,934,812	18,655,061	11,542,709	124,260
3	Total Net Plant		2,802,039,225	1,089,078,164	235,233,920	1,111,236,695	293,693,766	1,404,930,461	44,784,929	27,711,412	300,339
4											
5	ADD:										
6	CWIP		0	0	0	0	0	0	0	0	0
7	Working Capital		9,568,585	3,724,480	803,719	3,792,558	999,672	4,792,230	152,286	94,846	1,023
8	Plant Held for Future Use		0	0	0	0	0	0	0	0	0
9	Materials & Supplies		38,541,419	14,947,273	3,233,584	15,343,215	4,030,047	19,373,262	615,367	367,738	4,194
10	Regulatory Assets		58,021,936	42,390,470	5,417,705	7,795,486	1,937,996	9,733,482	328,231	150,253	1,795
11	Net Service Company Assets - Plant Related		28,016,556	20,090,121	2,039,757	4,552,023	1,066,228	5,618,251	164,105	103,046	1,277
12	Net Service Company Assets - CWIP Related		0	0	0	0	0	0	0	0	0
13	Net of Tax Prepaid Pension/OPEB		69,022,907	37,112,109	5,543,467	19,986,215	5,250,977	25,237,192	809,724	315,511	4,904
14	Credit Facility Costs		364,485	141,872	30,615	144,466	38,079	182,545	5,801	3,613	39
15	DEDUCT:										
16	Accumulated Amortization		(13,574,326)	(5,209,941)	(1,133,825)	(5,390,807)	(1,480,269)	(6,871,076)	(224,162)	(133,854)	(1,469)
17	Customer Deposits		(8,770,607)	(2,626,389)	(961,260)	(3,757,395)	(1,424,705)	(5,182,100)	0	0	(858)
18	Deferred FIT		(688,744,121)	(268,087,078)	(57,851,455)	(272,987,266)	(71,956,124)	(344,943,389)	(10,961,521)	(6,827,025)	(73,652)
19	Deferred SIT		(112,099,907)	(43,633,819)	(9,415,896)	(44,431,373)	(11,711,570)	(56,142,943)	(1,784,096)	(1,111,166)	(11,988)
20	Deferred Tax Adjustments		1,434,463	558,351	120,489	568,557	149,865	718,421	22,830	14,219	153
21	**Total Rate Base**		2,183,820,615	888,485,613	183,060,821	836,852,373	220,593,962	1,057,446,335	33,913,495	20,688,594	225,758
22											
23											
24	**Development Of Return at Present Rates**										
25	Revenue - Retail Sales		528,475,591	115,676,220	56,692,489	260,456,123	82,613,157	343,069,280	10,631,794	2,303,631	102,177
26	Other Operating Revenue		6,788,765	4,637,033	581,988	1,105,306	421,835	1,527,141	27,491	14,493	619
27	Total Electric Operating Revenue		535,264,357	120,313,253	57,274,477	261,561,429	83,034,992	344,596,421	10,659,285	2,318,124	102,796
28											
29	LESS:										
30	Operating & Maintenance Expense		172,632,290	92,738,790	13,866,723	50,046,127	13,148,804	63,194,932	2,027,497	792,065	12,284
31	Depreciation & Amortization Expense		127,710,169	53,887,931	10,827,363	47,638,278	12,243,491	59,881,769	1,870,864	1,229,708	12,534
32	Other Taxes		145,786,223	34,817,432	11,616,874	61,909,712	32,090,843	94,000,556	4,156,480	1,163,098	31,783
33	Total State Income Taxes		(7,016,000)	(8,923,942)	271,770	1,585,645	282,006	1,867,650	(85,468)	(148,313)	2,303
34	Total Federal Income Taxes		(10,163,000)	(16,122,159)	840,456	4,535,732	940,085	5,475,818	(98,131)	(263,730)	4,747
35											
36	Total Operating Expenses		428,949,682	156,398,052	37,423,187	165,715,494	58,705,230	224,420,724	7,871,242	2,772,827	63,650
37											
38	**Operating Income**		106,314,674	(36,084,799)	19,851,290	95,845,934	24,329,762	120,175,697	2,788,043	(454,703)	39,146
39	AFUDC		0	0	0	0	0	0	0	0	0
40	**Operating Income For ROR Calculation**		106,314,674	(36,084,799)	19,851,290	95,845,934	24,329,762	120,175,697	2,788,043	(454,703)	39,146
41											
42	**Rate Of Return**		4.87%	-4.06%	10.84%	11.45%	11.03%	11.36%	8.22%	-2.20%	17.34%
43	**Relative Rate Of Return**		1.00	-0.83	2.23	2.35	2.27	2.33	1.69	-0.45	3.56

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[C]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]
	Summary Of Results										
	Rate Base										
1	Total System Electric Distribution		1,441,669,682	97,629,921	332,393,414	192,750	994,064,557	577,180,206	4,804,400	411,816,110	63,439,990
2	Less: Depreciation Reserve		421,629,820	28,591,619	97,295,470	56,774	291,013,572	168,994,496	1,828,749	121,097,995	18,655,061
3	Total Net Plant		1,020,039,862	69,038,302	235,097,944	135,976	703,050,985	408,185,710	2,975,651	290,718,115	44,784,929
4											
5	ADD:										
6	CWIP		0	0	0	0	0	0	0	0	0
7	Working Capital		3,488,896	235,584	803,255	463	2,399,519	1,393,039	11,175	988,497	152,286
8	Plant Held for Future Use		0	0	0	0	0	0	0	0	0
9	Materials & Supplies		13,994,564	952,709	3,231,745	1,839	9,707,332	5,635,883	33,247	3,996,800	615,367
10	Regulatory Assets		41,769,425	621,045	5,414,796	2,909	4,914,146	2,881,340	29,564	1,908,431	328,231
11	Net Service Company Assets - Plant Related		19,815,272	274,849	2,038,757	1,001	3,046,391	1,505,632	11,873	1,054,354	164,105
12	Net Service Company Assets - CWIP Related		0	0	0	0	0	0	0	0	0
13	Net of Tax Prepaid Pension/OPEB		36,041,569	1,070,540	5,538,122	5,345	10,901,742	9,084,473	18,792	5,232,186	809,724
14	Credit Facility Costs		132,899	8,974	30,597	18	91,402	53,063	426	37,654	5,801
15	DEDUCT:										
16	Accumulated Amortization		(4,874,407)	(335,534)	(1,133,148)	(677)	(3,409,519)	(1,981,288)	(24,670)	(1,455,599)	(224,162)
17	Customer Deposits		(2,413,820)	(212,569)	(960,316)	(944)	(2,410,821)	(1,346,574)	0	(1,424,705)	0
18	Deferred FIT		(251,129,772)	(16,957,306)	(57,818,102)	(33,352)	(172,716,723)	(100,270,543)	(804,403)	(71,151,720)	(10,961,521)
19	Deferred SIT		(40,873,851)	(2,759,969)	(9,410,467)	(5,428)	(28,111,352)	(16,320,021)	(130,925)	(11,580,645)	(1,784,096)
20	Deferred Tax Adjustments		523,034	35,317	120,419	69	359,721	208,836	1,675	148,189	22,830
21	**Total Rate Base**		836,513,670	51,971,942	182,953,603	107,218	527,822,823	309,029,550	2,122,406	218,471,556	33,913,495
22											
23											
24	**Development Of Return at Present Rates**										
25	Revenue - Retail Sales		101,836,108	13,840,112	56,627,278	65,211	152,329,951	108,126,172	2,491,481	80,121,676	10,631,794
26	Other Operating Revenue		4,556,757	80,276	581,812	175	732,710	372,595	13	421,822	27,491
27	Total Electric Operating Revenue		106,392,866	13,920,387	57,209,091	65,386	153,062,661	108,498,767	2,491,494	80,543,498	10,659,285
28											
29	LESS:										
30	Operating & Maintenance Expense		90,056,255	2,682,535	13,853,371	13,352	27,317,371	22,728,757	47,493	13,101,311	2,027,497
31	Depreciation & Amortization Expense		50,919,306	2,968,625	10,821,124	6,239	30,059,069	17,579,209	142,788	12,100,703	1,870,864
32	Other Taxes		31,012,436	3,804,996	11,602,356	14,518	24,666,179	37,243,533	2,084,493	30,006,350	4,156,480
33	Total State Income Taxes		(8,834,750)	(89,193)	269,688	2,082	1,655,007	(69,363)	(3,803)	285,809	(85,468)
34	Total Federal Income Taxes		(16,051,204)	(70,956)	836,353	4,103	4,094,547	441,185	(2,562)	942,648	(98,131)
35											
36	Total Operating Expenses		147,102,044	9,296,008	37,382,893	40,294	87,792,173	77,923,321	2,268,409	56,436,821	7,871,242
37											
38	**Operating Income**		(40,709,179)	4,624,380	19,826,198	25,092	65,270,488	30,575,446	223,085	24,106,678	2,788,043
39	AFUDC		0	0	0	0	0	0	0	0	0
40	**Operating Income For ROR Calculation**		(40,709,179)	4,624,380	19,826,198	25,092	65,270,488	30,575,446	223,085	24,106,678	2,788,043
41											
42	**Rate Of Return**		-4.87%	8.90%	10.84%	23.40%	12.37%	9.89%	10.51%	11.03%	8.22%
43	**Relative Rate Of Return**		-1.00	1.83	2.23	4.81	2.54	2.03	2.16	2.27	1.69

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[V]	[W]	[X]	[Y]
	Summary Of Results					
	Rate Base					
1	Total System Electric Distribution		11,210,734	26,361,444	1,681,944	424,599
2	Less: Depreciation Reserve		3,338,911	7,711,543	492,255	124,260
3	Total Net Plant		7,871,823	18,649,901	1,189,688	300,339
4						
5	ADD:					
6	CWIP		0	0	0	0
7	Working Capital		27,262	63,531	4,053	1,023
8	Plant Held for Future Use		0	0	0	0
9	Materials & Supplies		90,626	260,498	16,614	4,194
10	Regulatory Assets		29,757	113,481	7,016	1,795
11	Net Service Company Assets - Plant Related		28,853	69,843	4,349	1,277
12	Net Service Company Assets - CWIP Related		0	0	0	0
13	Net of Tax Prepaid Pension/OPEB		2,983	293,957	18,571	4,904
14	Credit Facility Costs		1,038	2,420	154	39
15	DEDUCT:					
16	Accumulated Amortization		(36,897)	(91,137)	(5,819)	(1,469)
17	Customer Deposits		0	0	0	(858)
18	Deferred FIT		(1,962,326)	(4,572,948)	(291,751)	(73,652)
19	Deferred SIT		(319,388)	(744,292)	(47,485)	(11,988)
20	Deferred Tax Adjustments		4,087	9,524	608	153
21	**Total Rate Base**		5,737,819	14,054,777	895,998	225,758
22						
23						
24	**Development Of Return at Present Rates**					
25	Revenue - Retail Sales		631,344	1,340,533	331,754	102,177
26	Other Operating Revenue		0	13,676	817	619
27	Total Electric Operating Revenue		631,344	1,354,209	332,571	102,796
28						
29	LESS:					
30	Operating & Maintenance Expense		9,008	736,523	46,533	12,284
31	Depreciation & Amortization Expense		402,080	778,033	49,595	12,534
32	Other Taxes		43,233	990,221	129,644	31,783
33	Total State Income Taxes		219	(156,625)	8,093	2,303
34	Total Federal Income Taxes		4,717	(284,295)	15,848	4,747
35						
36	Total Operating Expenses		459,257	2,063,858	249,712	63,650
37						
38	**Operating Income**		172,087	(709,649)	82,859	39,146
39	AFUDC		0	0	0	0
40	**Operating Income For ROR Calculation**		172,087	(709,649)	82,859	39,146
41						
42	**Rate Of Return**		3.00%	-5.05%	9.25%	17.34%
43	**Relative Rate Of Return**		0.62	-1.04	1.90	3.56

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	**Total** DC Distribution	**Total** Residential Service	**Total** GS	**Total** GT-LV	**Total** GT-HV	**Total** GT	**Total** Metro	**Total** Street Lighting	**Total** TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
	Development Of Rate Base										
	Electric Plant In Service										
	Subtransmission Plant										
1	3600 Land and Land Rights	SUBTAED	0	0	0	0	0	0	0	0	0
2	3600 Land and Land Rights - Substations	SUBTAED	1,010,501	273,949	74,583	417,603	206,111	623,714	29,234	8,885	136
3	3600 Land and Land Rights - OH Lines	SUBTAED	0	0	0	0	0	0	0	0	0
4	3610 Structures and Improvements	SUBTAED	2,444,905	662,820	180,454	1,010,389	498,686	1,509,075	70,731	21,497	329
5	3620 Station Equipment	SUBTAED	109,904,720	29,795,431	8,111,861	45,419,549	22,417,215	67,836,765	3,179,522	966,333	14,808
6	3627 Station Equipment	SUBTAED	2	1	0	1	0	1	0	0	0
7	3640 Poles, Towers and Fixtures	SUBTAED	18,413,408	4,991,919	1,359,059	7,609,579	3,755,774	11,365,354	532,696	161,899	2,481
8	3650 Overhead Conductors and Devices	SUBTAED	17,693,956	4,796,873	1,305,958	7,312,256	3,609,028	10,921,284	511,883	155,573	2,384
9	3660 Underground Conduit	SUBTAED	57,510,488	15,591,230	4,244,741	23,766,954	11,730,388	35,497,342	1,663,767	505,659	7,749
10	3670 Underground Conductors and Devices	SUBTAED	63,068,360	17,097,982	4,654,957	26,063,817	12,864,024	38,927,841	1,824,555	554,526	8,497
11	3680 Line Transformers	SUBTAED	0	0	0	0	0	0	0	0	0
12	**Total Subtransmission**		270,046,339	73,210,205	19,931,614	111,600,148	55,081,228	166,681,376	7,812,389	2,374,372	36,384
13											
14											
15	**Distribution Plant**										
16	**Distribution**										
17	3600 Land and Land Rights - Substations	NCAPSUBS	44,194,009	12,202,054	3,308,786	18,530,915	8,452,861	26,983,776	1,298,033	395,397	5,964
18	3600 Land and Land Rights - OH Lines	NCAPPRIM	243,306	67,154	18,211	102,030	46,555	148,584	7,146	2,178	33
19	3600 Land and Land Rights - UG Lines	NCAPPRIM	25,250	6,969	1,890	10,589	4,831	15,420	742	226	3
20	3610 Structures and Improvements	NCAPSUBS	65,102,119	17,974,824	4,874,166	27,297,859	12,451,894	39,749,754	1,912,130	582,459	8,786
21	3620 Station Equipment	NCAPSUBS	410,193,160	113,255,147	30,710,978	171,997,400	78,456,462	250,453,862	12,047,879	3,669,938	55,357
22	3627 Station Equipment	NCAPSUBS	0	0	0	0	0	0	0	0	0
23	Total Acct 3620		410,193,160	113,255,147	30,710,978	171,997,400	78,456,462	250,453,862	12,047,879	3,669,938	55,357
24	3640 Poles, Towers and Fixtures										
25	Demand Primary	NCAPPRIM	52,621,299	14,523,719	3,938,547	22,066,615	10,068,656	32,135,271	1,545,556	471,066	7,140
26	Demand Secondary	SMX2ND	67,605,627	36,173,330	6,321,011	24,732,010	0	24,732,010	0	373,628	5,648
27	Total Acct 3640		120,226,926	50,697,049	10,259,558	46,798,625	10,068,656	56,867,281	1,545,556	844,694	12,788
28	3650 Overhead Conductors and Devices										
29	Demand Primary	NCAPPRIM	87,924,538	24,267,574	6,580,889	36,870,943	16,823,643	53,694,586	2,582,458	787,100	11,930
30	Demand Secondary	SMX2ND	44,802,848	23,972,386	4,188,990	16,390,122	0	16,390,122	0	247,607	3,743
31	Total Acct 3650		132,727,385	48,239,960	10,769,879	53,261,065	16,823,643	70,084,708	2,582,458	1,034,707	15,673
32	3660 Underground Conduit										
33	Demand Primary	NCAPPRIM	475,355,804	131,200,373	35,578,963	199,339,312	90,955,454	290,294,766	13,961,819	4,255,383	64,499
34	Demand Secondary	SMX2ND	327,658,153	175,318,048	30,635,478	119,866,423	0	119,866,423	0	1,810,831	27,373
35	Total Acct 3660		803,013,957	306,518,421	66,214,441	319,205,734	90,955,454	410,161,189	13,961,819	6,066,215	91,872
36	3670 Underground Conductors and Devices										
37	Demand Primary	NCAPPRIM	508,905,062	140,460,122	38,090,025	213,408,112	97,374,831	310,782,943	14,947,204	4,555,716	69,051
38	Demand Secondary	SMX2ND	272,115,403	145,599,127	25,442,326	99,547,347	0	99,547,347	0	1,503,870	22,733
39	Total Acct 3670		781,020,464	286,059,249	63,532,350	312,955,459	97,374,831	410,330,290	14,947,204	6,059,586	91,784
40	3680 Line Transformers	SMXNCAP	540,388,296	257,524,536	51,034,432	227,751,852	0	227,751,852	0	4,016,791	60,686
41	3691 Services	CUST369	18,123,096	9,751,723	1,704,038	6,667,335	0	6,667,335	0	0	0
42	3692 Services	CUST369	117,410,790	63,176,704	11,039,642	43,194,444	0	43,194,444	0	0	0
43	3693 Services	CUST369	166,996,697	89,858,019	15,701,996	61,436,683	0	61,436,683	0	0	0
44	3700 Meters	CUST370	7,001,304	1,103,354	2,667,448	2,187,574	772,210	2,959,784	267,929	2,789	0
45	3701 AMI Meters	CUST3701	59,032,405	51,072,857	6,086,312	1,698,205	98,337	1,796,542	71,527	5,168	0
46	3711 Installations on Customer Premises	CUST371	1,367,203	3,015	94,957	1,262,621	6,610	1,269,231	0	0	0
47	3731 Street Lighting and Signal Systems	CUST373	57,256	0	0	0	0	0	0	57,256	0
48	3732 Street Lighting and Signal Systems	CUST373	9,999,466	0	0	0	0	0	0	9,999,466	0
49	3734 Street Lighting and Signal Systems	CUST373	49,789	0	0	0	0	0	0	49,789	0
50	**Total Distribution**		3,277,172,881	1,307,511,035	278,019,084	1,294,358,389	315,512,345	1,609,870,734	48,642,423	32,786,658	342,946
51											
52	**Subtransmission & Distribution Total**		3,547,219,220	1,380,721,240	297,950,698	1,405,958,536	370,593,573	1,776,552,110	56,454,811	35,161,031	379,330

Potomac Electric Power Company
District of Columbia
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For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[C]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]
	Development Of Rate Base										
	Electric Plant In Service										
	Subtransmission Plant										
1	3600 Land and Land Rights	SUBTAED	0	0	0	0	0	0	0	0	0
2	3600 Land and Land Rights - Substations	SUBTAED	246,923	27,026	74,503	81	262,273	155,330	15,454	190,658	29,234
3	3600 Land and Land Rights - OH Lines	SUBTAED	0	0	0	0	0	0	0	0	0
4	3610 Structures and Improvements	SUBTAED	597,431	65,389	180,259	195	634,568	375,820	37,390	461,296	70,731
5	3620 Station Equipment	SUBTAED	26,856,040	2,939,391	8,103,098	8,763	28,525,468	16,894,082	1,680,777	20,736,439	3,179,522
6	3627 Station Equipment	SUBTAED	1	0	0	0	1	0	0	0	0
7	3640 Poles, Towers and Fixtures	SUBTAED	4,499,454	492,465	1,357,591	1,468	4,779,149	2,830,430	281,597	3,474,177	532,696
8	3650 Overhead Conductors and Devices	SUBTAED	4,323,650	473,223	1,304,547	1,411	4,592,417	2,719,839	270,594	3,338,434	511,883
9	3660 Underground Conduit	SUBTAED	14,053,118	1,538,112	4,240,156	4,586	14,926,689	8,840,265	879,510	10,850,878	1,663,767
10	3670 Underground Conductors and Devices	SUBTAED	15,411,225	1,686,757	4,649,929	5,029	16,369,219	9,694,597	964,507	11,899,518	1,824,555
11	3680 Line Transformers	SUBTAED	0	0	0	0	0	0	0	0	0
12	**Total Subtransmission**		65,987,842	7,222,362	19,910,082	21,532	70,089,784	41,510,364	4,129,828	50,951,400	7,812,389
13											
14											
15	**Distribution Plant**										
16	**Distribution**										
17	3600 Land and Land Rights - Substations	NCAPSUBS	11,001,771	1,200,282	3,305,218	3,568	11,642,508	6,888,407	0	8,452,861	1,298,033
18	3600 Land and Land Rights - OH Lines	NCAPPRIM	60,548	6,605	18,191	20	64,123	37,907	0	46,555	7,146
19	3600 Land and Land Rights - UG Lines	NCAPPRIM	6,284	685	1,888	2	6,655	3,934	0	4,831	742
20	3610 Structures and Improvements	NCAPSUBS	16,206,690	1,768,134	4,868,911	5,256	17,150,559	10,147,300	0	12,451,894	1,912,130
21	3620 Station Equipment	NCAPSUBS	102,114,550	11,140,596	30,677,865	33,114	108,061,643	63,935,757	0	78,456,462	12,047,879
22	3627 Station Equipment	NCAPSUBS	0	0	0	0	0	0	0	0	0
23	Total Acct 3620		102,114,550	11,140,596	30,677,865	33,114	108,061,643	63,935,757	0	78,456,462	12,047,879
24	3640 Poles, Towers and Fixtures										
25	Demand Primary	NCAPPRIM	13,095,185	1,428,534	3,934,319	4,228	13,868,179	8,198,436	0	10,068,656	1,545,556
26	Demand Secondary	SMX2ND	34,774,155	1,399,175	6,321,011	0	15,868,561	8,863,449	0	0	0
27	Total Acct 3640		47,869,340	2,827,709	10,255,330	4,228	29,736,739	17,061,886	0	10,068,656	1,545,556
28	3650 Overhead Conductors and Devices										
29	Demand Primary	NCAPPRIM	21,880,647	2,386,927	6,573,825	7,064	23,172,237	13,698,706	0	16,823,643	2,582,458
30	Demand Secondary	SMX2ND	23,045,140	927,246	4,188,990	0	10,516,236	5,873,886	0	0	0
31	Total Acct 3650		44,925,788	3,314,172	10,762,815	7,064	33,688,473	19,572,593	0	16,823,643	2,582,458
32	3660 Underground Conduit										
33	Demand Primary	NCAPPRIM	118,295,677	12,904,696	35,540,770	38,193	125,278,535	74,060,776	0	90,955,454	13,961,819
34	Demand Secondary	SMX2ND	168,536,791	6,781,257	30,635,478	0	76,908,734	42,957,688	0	0	0
35	Total Acct 3660		286,832,468	19,685,953	66,176,248	38,193	202,187,270	117,018,465	0	90,955,454	13,961,819
36	3670 Underground Conductors and Devices										
37	Demand Primary	NCAPPRIM	126,644,649	13,815,473	38,049,136	40,888	134,120,338	79,287,775	0	97,374,831	14,947,204
38	Demand Secondary	SMX2ND	139,967,391	5,631,737	25,442,326	0	63,871,602	35,675,745	0	0	0
39	Total Acct 3670		266,612,040	19,447,210	63,491,462	40,888	197,991,940	114,963,520	0	97,374,831	14,947,204
40	3680 Line Transformers	SMXNCAP	243,788,293	13,736,244	51,034,432	0	144,442,724	83,309,127	0	0	0
41	3691 Services	CUST369	9,374,528	377,194	1,704,038	0	4,277,898	2,389,437	0	0	0
42	3692 Services	CUST369	60,733,046	2,443,659	11,039,642	0	27,714,433	15,480,010	0	0	0
43	3693 Services	CUST369	86,382,334	3,475,685	15,701,996	0	39,419,025	22,017,658	0	0	0
44	3700 Meters	CUST370	762,737	340,617	2,652,399	15,048	1,688,699	498,875	13,067	759,143	267,929
45	3701 AMI Meters	CUST3701	50,727,047	345,810	6,083,451	2,861	1,375,546	322,658	0	98,337	71,527
46	3711 Installations on Customer Premises	CUST371	1,205	1,811	94,957	0	0	1,262,621	0	6,610	0
47	3731 Street Lighting and Signal Systems	CUST373	0	0	0	0	0	0	0	0	0
48	3732 Street Lighting and Signal Systems	CUST373	0	0	0	0	0	0	0	0	0
49	3734 Street Lighting and Signal Systems	CUST373	0	0	0	0	0	0	0	0	0
50	**Total Distribution**		1,227,398,669	80,112,366	277,868,843	150,241	819,448,233	474,910,155	13,067	315,499,278	48,642,423
51											
52	**Subtransmission & Distribution Total**		1,293,386,511	87,334,729	297,778,925	171,774	889,538,017	516,420,519	4,142,895	366,450,678	56,454,811

Potomac Electric Power Company
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For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[V]	[W]	[X]	[Y]
	Development Of Rate Base					
	Electric Plant In Service					
	Subtransmission Plant					
1	3600 Land and Land Rights	SUBTAED	0	0	0	0
2	3600 Land and Land Rights - Substations	SUBTAED	0	8,344	540	136
3	3600 Land and Land Rights - OH Lines	SUBTAED	0	0	0	0
4	3610 Structures and Improvements	SUBTAED	0	20,189	1,308	329
5	3620 Station Equipment	SUBTAED	0	907,555	58,778	14,808
6	3627 Station Equipment	SUBTAED	0	0	0	0
7	3640 Poles, Towers and Fixtures	SUBTAED	0	152,052	9,848	2,481
8	3650 Overhead Conductors and Devices	SUBTAED	0	146,111	9,463	2,384
9	3660 Underground Conduit	SUBTAED	0	474,902	30,757	7,749
10	3670 Underground Conductors and Devices	SUBTAED	0	520,797	33,729	8,497
11	3680 Line Transformers	SUBTAED	0	0	0	0
12	**Total Subtransmission**		0	2,229,949	144,423	36,384
13						
14						
15	**Distribution Plant**					
16	**Distribution**					
17	3600 Land and Land Rights - Substations	NCAPSUBS	0	371,703	23,694	5,964
18	3600 Land and Land Rights - OH Lines	NCAPPRIM	0	2,048	130	33
19	3600 Land and Land Rights - UG Lines	NCAPPRIM	0	212	14	3
20	3610 Structures and Improvements	NCAPSUBS	0	547,555	34,904	8,786
21	3620 Station Equipment	NCAPSUBS	0	3,450,016	219,922	55,357
22	3627 Station Equipment	NCAPSUBS	0	0	0	0
23	Total Acct 3620		0	3,450,016	219,922	55,357
24	3640 Poles, Towers and Fixtures					
25	Demand Primary	NCAPPRIM	0	442,851	28,215	7,140
26	Demand Secondary	SMX2ND	0	351,250	22,378	5,648
27	Total Acct 3640		0	794,101	50,593	12,788
28	3650 Overhead Conductors and Devices					
29	Demand Primary	NCAPPRIM	0	739,956	47,144	11,930
30	Demand Secondary	SMX2ND	0	232,777	14,830	3,743
31	Total Acct 3650		0	972,733	61,974	15,673
32	3660 Underground Conduit					
33	Demand Primary	NCAPPRIM	0	4,000,504	254,879	64,499
34	Demand Secondary	SMX2ND	0	1,702,373	108,459	27,373
35	Total Acct 3660		0	5,702,877	363,338	91,872
36	3670 Underground Conductors and Devices					
37	Demand Primary	NCAPPRIM	0	4,282,849	272,867	69,051
38	Demand Secondary	SMX2ND	0	1,413,796	90,073	22,733
39	Total Acct 3670		0	5,696,645	362,941	91,784
40	3680 Line Transformers	SMXNCAP	0	3,776,127	240,663	60,686
41	3691 Services	CUST369	0	0	0	0
42	3692 Services	CUST369	0	0	0	0
43	3693 Services	CUST369	0	0	0	0
44	3700 Meters	CUST370	0	2,789	0	0
45	3701 AMI Meters	CUST3701	0	5,168	0	0
46	3711 Installations on Customer Premises	CUST371	0	0	0	0
47	3731 Street Lighting and Signal Systems	CUST373	57,256	0	0	0
48	3732 Street Lighting and Signal Systems	CUST373	9,999,466	0	0	0
49	3734 Street Lighting and Signal Systems	CUST373	49,789	0	0	0
50	**Total Distribution**		10,106,511	21,321,975	1,358,173	342,946
51						
52	**Subtransmission & Distribution Total**		10,106,511	23,551,924	1,502,596	379,330

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	**Total** DC Distribution	**Total** Residential Service	**Total** GS	**Total** GT-LV	**Total** GT-HV	**Total** GT	**Total** Metro	**Total** Street Lighting	**Total** TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
	Development Of Rate Base, Cont'd.										
	Electric Plant In Service										
	General Plant										
1	3890 Land and Land Rights	STDPLT	3,107,228	1,209,459	260,993	1,231,566	324,626	1,556,191	49,452	30,800	332
2	3900 Structures and Improvements	STDPLT	51,519,481	20,053,466	4,327,408	20,420,011	5,382,466	25,802,477	819,944	510,676	5,509
3	3903 Structures and Improvements	STDPLT	5,009,192	1,949,780	420,750	1,985,419	523,332	2,508,751	79,722	49,653	536
4	3911 Office Furniture and Equipment	STDPLT	3,561,594	1,386,317	299,158	1,411,656	372,095	1,783,752	56,684	35,304	381
5	3913 Office Furniture and Equipment	STDPLT	8,895,825	3,462,615	747,210	3,525,906	929,386	4,455,292	141,579	88,178	951
6	3915 Office Furniture and Equipment	STDPLT	0	0	0	0	0	0	0	0	0
7	3920 Transportation Equipment	STDPLT	0	0	0	0	0	0	0	0	0
8	3930 Stores Equipment	STDPLT	83,889	32,653	7,046	33,250	8,764	42,014	1,335	832	9
9	3940 Tools, Shop and Garage Equipment	STDPLT	4,570,610	1,779,066	383,911	1,811,585	477,512	2,289,096	72,742	45,305	489
10	3950 Laboratory Equipment	STDPLT	505,364	196,708	42,448	200,304	52,798	253,101	8,043	5,009	54
11	3960 Power Operated Equipment	STDPLT	957,501	372,698	80,426	379,510	100,034	479,545	15,239	9,491	102
12	3970 Communication Equipment	STDPLT	75,621,377	29,434,900	6,351,861	29,972,921	7,900,497	37,873,418	1,203,532	749,580	8,087
13	3980 Miscellaneous Equipment	STDPLT	4,463,154	1,737,240	374,885	1,768,994	466,285	2,235,279	71,032	44,240	477
14	3990 Other Tangible Property	STDPLT	0	0	0	0	0	0	0	0	0
15	**Total General Plant**		158,295,215	61,614,902	13,296,097	62,741,120	16,537,796	79,278,917	2,519,305	1,569,067	16,928
16											
17	**Intangible Plant**										
18	3020 Franchises and Consents	STDPLT	0	0	0	0	0	0	0	0	0
19	3030 Miscellaneous Intangible Plant	STDPLT	20,976,387	8,164,859	1,761,924	8,314,099	2,191,495	10,505,594	333,844	207,924	2,243
20	**Total Intangible Plant**		20,976,387	8,164,859	1,761,924	8,314,099	2,191,495	10,505,594	333,844	207,924	2,243
21											
22	**AFUDC**										
23	**Subtransmission AFUDC**										
24	3600 Land and Land Rights - Substations	SUBTAED	0	0	0	0	0	0	0	0	0
25	3600 Land and Land Rights - OH Lines	SUBTAED	0	0	0	0	0	0	0	0	0
26	3600 Land and Land Rights - UG Lines	SUBTAED	0	0	0	0	0	0	0	0	0
27	3610 Structures and Improvements	SUBTAED	61,087	16,561	4,509	25,245	12,460	37,705	1,767	537	8
28	3620 Station Equipment	SUBTAED	975,716	264,519	72,016	403,227	199,016	602,244	28,227	8,579	131
29	3640 Poles, Towers and Fixtures	SUBTAED	297,115	80,549	21,929	122,787	60,602	183,389	8,595	2,612	40
30	3650 Overhead Conductors and Devices	SUBTAED	298,704	80,979	22,047	123,443	60,926	184,370	8,641	2,626	40
31	3660 Underground Conduit	SUBTAED	4,252,373	1,152,828	313,860	1,757,348	867,355	2,624,703	123,020	37,389	573
32	3670 Underground Conductors and Devices	SUBTAED	623,281	168,973	46,003	257,579	127,130	384,710	18,031	5,480	84
33	3680 Line Transformers	SUBTAED	0	0	0	0	0	0	0	0	0
34	3691 Services	SUBTAED	0	0	0	0	0	0	0	0	0
35	3692 Services	SUBTAED	0	0	0	0	0	0	0	0	0
36	3693 Services	SUBTAED	0	0	0	0	0	0	0	0	0
37	3700 Meters	SUBTAED	0	0	0	0	0	0	0	0	0
38	3701 AMI Meters	SUBTAED	0	0	0	0	0	0	0	0	0
39	3711 Installations on Customer Premises	SUBTAED	0	0	0	0	0	0	0	0	0
40	3731 Street Lighting and Signal Systems	SUBTAED	0	0	0	0	0	0	0	0	0
41	3732 Street Lighting and Signal Systems	SUBTAED	0	0	0	0	0	0	0	0	0
42	3734 Street Lighting and Signal Systems	SUBTAED	0	0	0	0	0	0	0	0	0
43	**Total Subtransmission AFUDC**		6,508,276	1,764,409	480,364	2,689,630	1,327,490	4,017,120	188,283	57,224	877

Potomac Electric Power Company
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Line No.	Description	Allocator	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[C]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]
	Development Of Rate Base, Cont'd.										
	Electric Plant In Service										
	General Plant										
1	3890 Land and Land Rights	STDPLT	1,132,957	76,502	260,843	150	779,201	452,365	3,629	320,997	49,452
2	3900 Structures and Improvements	STDPLT	18,785,025	1,268,441	4,324,913	2,495	12,919,567	7,500,443	60,171	5,322,295	819,944
3	3903 Structures and Improvements	STDPLT	1,826,451	123,329	420,507	243	1,256,158	729,261	5,850	517,482	79,722
4	3911 Office Furniture and Equipment	STDPLT	1,298,628	87,689	298,986	172	893,143	518,513	4,160	367,936	56,684
5	3913 Office Furniture and Equipment	STDPLT	3,243,594	219,021	746,779	431	2,230,811	1,295,095	10,390	918,996	141,579
6	3915 Office Furniture and Equipment	STDPLT	0	0	0	0	0	0	0	0	0
7	3920 Transportation Equipment	STDPLT	0	0	0	0	0	0	0	0	0
8	3930 Stores Equipment	STDPLT	30,588	2,065	7,042	4	21,037	12,213	98	8,666	1,335
9	3940 Tools, Shop and Garage Equipment	STDPLT	1,666,535	112,531	383,690	221	1,146,174	665,410	5,338	472,174	72,742
10	3950 Laboratory Equipment	STDPLT	184,266	12,442	42,424	24	126,730	73,573	590	52,207	8,043
11	3960 Power Operated Equipment	STDPLT	349,124	23,574	80,379	46	240,113	139,397	1,118	98,916	15,239
12	3970 Communication Equipment	STDPLT	27,573,055	1,861,845	6,348,199	3,662	18,963,612	11,009,309	88,320	7,812,177	1,203,532
13	3980 Miscellaneous Equipment	STDPLT	1,627,355	109,886	374,669	216	1,119,228	649,767	5,213	461,073	71,032
14	3990 Other Tangible Property	STDPLT	0	0	0	0	0	0	0	0	0
15	**Total General Plant**		57,717,576	3,897,326	13,288,431	7,665	39,695,774	23,045,347	184,877	16,352,919	2,519,305
16											
17	**Intangible Plant**										
18	3020 Franchises and Consents	STDPLT	0	0	0	0	0	0	0	0	0
19	3030 Miscellaneous Intangible Plant	STDPLT	7,648,407	516,452	1,760,908	1,016	5,260,260	3,053,839	24,499	2,166,996	333,844
20	**Total Intangible Plant**		7,648,407	516,452	1,760,908	1,016	5,260,260	3,053,839	24,499	2,166,996	333,844
21											
22	**AFUDC**										
23	**Subtransmission AFUDC**										
24	3600 Land and Land Rights - Substations	SUBTAED	0	0	0	0	0	0	0	0	0
25	3600 Land and Land Rights - OH Lines	SUBTAED	0	0	0	0	0	0	0	0	0
26	3600 Land and Land Rights - UG Lines	SUBTAED	0	0	0	0	0	0	0	0	0
27	3610 Structures and Improvements	SUBTAED	14,927	1,634	4,504	5	15,855	9,390	934	11,526	1,767
28	3620 Station Equipment	SUBTAED	238,424	26,095	71,938	78	253,244	149,983	14,922	184,095	28,227
29	3640 Poles, Towers and Fixtures	SUBTAED	72,602	7,946	21,906	24	77,115	45,671	4,544	56,059	8,595
30	3650 Overhead Conductors and Devices	SUBTAED	72,991	7,989	22,023	24	77,528	45,915	4,568	56,358	8,641
31	3660 Underground Conduit	SUBTAED	1,039,099	113,729	313,521	339	1,103,692	653,657	65,032	802,323	123,020
32	3670 Underground Conductors and Devices	SUBTAED	152,303	16,670	45,954	50	161,771	95,808	9,532	117,599	18,031
33	3680 Line Transformers	SUBTAED	0	0	0	0	0	0	0	0	0
34	3691 Services	SUBTAED	0	0	0	0	0	0	0	0	0
35	3692 Services	SUBTAED	0	0	0	0	0	0	0	0	0
36	3693 Services	SUBTAED	0	0	0	0	0	0	0	0	0
37	3700 Meters	SUBTAED	0	0	0	0	0	0	0	0	0
38	3701 AMI Meters	SUBTAED	0	0	0	0	0	0	0	0	0
39	3711 Installations on Customer Premises	SUBTAED	0	0	0	0	0	0	0	0	0
40	3731 Street Lighting and Signal Systems	SUBTAED	0	0	0	0	0	0	0	0	0
41	3732 Street Lighting and Signal Systems	SUBTAED	0	0	0	0	0	0	0	0	0
42	3734 Street Lighting and Signal Systems	SUBTAED	0	0	0	0	0	0	0	0	0
43	**Total Subtransmission AFUDC**		1,590,346	174,063	479,845	519	1,689,205	1,000,424	99,531	1,227,959	188,283

Potomac Electric Power Company
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Line No.	Description	Allocator	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[V]	[W]	[X]	[Y]
	Development Of Rate Base, Cont'd.					
	Electric Plant In Service					
	General Plant					
1	3890 Land and Land Rights	STDPLT	8,853	20,631	1,316	332
2	3900 Structures and Improvements	STDPLT	146,786	342,066	21,824	5,509
3	3903 Structures and Improvements	STDPLT	14,272	33,259	2,122	536
4	3911 Office Furniture and Equipment	STDPLT	10,147	23,647	1,509	381
5	3913 Office Furniture and Equipment	STDPLT	25,345	59,064	3,768	951
6	3915 Office Furniture and Equipment	STDPLT	0	0	0	0
7	3920 Transportation Equipment	STDPLT	0	0	0	0
8	3930 Stores Equipment	STDPLT	239	557	36	9
9	3940 Tools, Shop and Garage Equipment	STDPLT	13,022	30,347	1,936	489
10	3950 Laboratory Equipment	STDPLT	1,440	3,355	214	54
11	3960 Power Operated Equipment	STDPLT	2,728	6,357	406	102
12	3970 Communication Equipment	STDPLT	215,456	502,092	32,033	8,087
13	3980 Miscellaneous Equipment	STDPLT	12,716	29,633	1,891	477
14	3990 Other Tangible Property	STDPLT	0	0	0	0
15	**Total General Plant**		451,005	1,051,008	67,054	16,928
16						
17	**Intangible Plant**					
18	3020 Franchises and Consents	STDPLT	0	0	0	0
19	3030 Miscellaneous Intangible Plant	STDPLT	59,765	139,274	8,886	2,243
20	**Total Intangible Plant**		59,765	139,274	8,886	2,243
21						
22	**AFUDC**					
23	**Subtransmission AFUDC**					
24	3600 Land and Land Rights - Substations	SUBTAED	0	0	0	0
25	3600 Land and Land Rights - OH Lines	SUBTAED	0	0	0	0
26	3600 Land and Land Rights - UG Lines	SUBTAED	0	0	0	0
27	3610 Structures and Improvements	SUBTAED	0	504	33	8
28	3620 Station Equipment	SUBTAED	0	8,057	522	131
29	3640 Poles, Towers and Fixtures	SUBTAED	0	2,453	159	40
30	3650 Overhead Conductors and Devices	SUBTAED	0	2,467	160	40
31	3660 Underground Conduit	SUBTAED	0	35,115	2,274	573
32	3670 Underground Conductors and Devices	SUBTAED	0	5,147	333	84
33	3680 Line Transformers	SUBTAED	0	0	0	0
34	3691 Services	SUBTAED	0	0	0	0
35	3692 Services	SUBTAED	0	0	0	0
36	3693 Services	SUBTAED	0	0	0	0
37	3700 Meters	SUBTAED	0	0	0	0
38	3701 AMI Meters	SUBTAED	0	0	0	0
39	3711 Installations on Customer Premises	SUBTAED	0	0	0	0
40	3731 Street Lighting and Signal Systems	SUBTAED	0	0	0	0
41	3732 Street Lighting and Signal Systems	SUBTAED	0	0	0	0
42	3734 Street Lighting and Signal Systems	SUBTAED	0	0	0	0
43	**Total Subtransmission AFUDC**		0	53,743	3,481	877

Potomac Electric Power Company
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Line No.	Description	Allocator	Total DC Distribution	Total Residential Service	Total GS	Total GT-LV	Total GT-HV	Total GT	Total Metro	Total Street Lighting	Total TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
	Development Of Rate Base, Cont'd.										
	AFUDC (cont'd.)										
	Distribution AFUDC										
1	3600 Land and Land Rights - Substations	NCAPSUBS	0	0	0	0	0	0	0	0	0
2	3600 Land and Land Rights - OH Lines	NCAPPRIM	0	0	0	0	0	0	0	0	0
3	3600 Land and Land Rights - UG Lines	NCAPPRIM	0	0	0	0	0	0	0	0	0
4	3610 Structures and Improvements	NCAPSUBS	3,323,472	917,617	248,827	1,393,559	635,671	2,029,230	97,614	29,735	449
5	3620 Station Equipment	NCAPSUBS	9,063,627	2,502,485	678,590	3,800,454	1,733,574	5,534,028	266,210	81,091	1,223
6	3627 Station Equipment	NCAPSUBS	0	0	0	0	0	0	0	0	0
7	Total Acct 3620		9,063,627	2,502,485	678,590	3,800,454	1,733,574	5,534,028	266,210	81,091	1,223
8	3640 Poles, Towers and Fixtures										
9	Demand Primary	NCAPPRIM	55,437	15,301	4,149	23,247	10,607	33,855	1,628	496	8
10	Demand Secondary	SMX2ND	71,223	38,109	6,659	26,055	0	26,055	0	394	6
11	Total Acct 3640		126,660	53,410	10,809	49,303	10,607	59,910	1,628	890	13
12	3650 Overhead Conductors and Devices										
13	Demand Primary	NCAPPRIM	197,433	54,492	14,777	82,793	37,777	120,570	5,799	1,767	27
14	Demand Secondary	SMX2ND	100,604	53,829	9,406	36,804	0	36,804	0	556	8
15	Total Acct 3650		298,037	108,322	24,184	119,597	37,777	157,374	5,799	2,323	35
16	3660 Underground Conduit										
17	Demand Primary	NCAPPRIM	3,141,011	866,933	235,095	1,317,175	601,007	1,918,182	92,256	28,118	426
18	Demand Secondary	SMX2ND	2,165,069	1,158,450	202,430	792,042	0	792,042	0	11,965	181
19	Total Acct 3660		5,306,080	2,025,383	437,526	2,109,217	601,007	2,710,224	92,256	40,084	607
20	3670 Underground Conductors and Devices										
21	Demand Primary	NCAPPRIM	2,330,969	643,358	174,466	977,486	446,012	1,423,498	68,464	20,867	316
22	Demand Secondary	SMX2ND	1,246,387	666,897	116,535	455,963	0	455,963	0	6,888	104
23	Total Acct 3670		3,577,356	1,310,255	291,001	1,433,449	446,012	1,879,461	68,464	27,755	420
24	3680 Line Transformers	SMXNCAP	109,757	52,305	10,365	46,258	0	46,258	0	816	12
25	3691 Services	CUST369	4,426	2,382	416	1,628	0	1,628	0	0	0
26	3692 Services	CUST369	133	72	13	49	0	49	0	0	0
27	3693 Services	CUST369	13,871	7,464	1,304	5,103	0	5,103	0	0	0
28	3700 Meters	CUST370	0	0	0	0	0	0	0	0	0
29	3701 AMI Meters	CUST3701	0	0	0	0	0	0	0	0	0
30	3711 Installations on Customer Premises	CUST371	0	0	0	0	0	0	0	0	0
31	3731 Street Lighting and Signal Systems	CUST373	111	0	0	0	0	0	0	111	0
32	3732 Street Lighting and Signal Systems	CUST373	22,242	0	0	0	0	0	0	22,242	0
33	3734 Street Lighting and Signal Systems	CUST373	526	0	0	0	0	0	0	526	0
34	**Total Distribution AFUDC**		21,846,296	6,979,694	1,703,034	8,958,617	3,464,648	12,423,265	531,971	205,573	2,760
35											
36	**Electric Plant In Service**										
37	**General Plant - AFUDC**										
38	3890 Land and Land Rights	STAFUDC	0	0	0	0	0	0	0	0	0
39	3900 Structures and Improvements	STAFUDC	3,379,283	916,132	249,419	1,396,533	689,271	2,085,803	97,762	29,712	455
40	3903 Structures and Improvements	STAFUDC	298,672	80,971	22,044	123,430	60,920	184,350	8,641	2,626	40
41	3911 Office Furniture and Equipment	STAFUDC	14,515	3,935	1,071	5,999	2,961	8,959	420	128	2
42	3913 Office Furniture and Equipment	STAFUDC	112,537	30,509	8,306	46,507	22,954	69,461	3,256	989	15
43	3915 Office Furniture and Equipment	STAFUDC	4	1	0	2	1	2	0	0	0
44	3920 Transportation Equipment	STAFUDC	0	0	0	0	0	0	0	0	0
45	3930 Stores Equipment	STAFUDC	0	0	0	0	0	0	0	0	0
46	3940 Tools, Shop and Garage Equipment	STAFUDC	70,787	19,191	5,225	29,254	14,438	43,692	2,048	622	10
47	3950 Laboratory Equipment	STAFUDC	0	0	0	0	0	0	0	0	0
48	3960 Power Operated Equipment	STAFUDC	0	0	0	0	0	0	0	0	0
49	3970 Communication Equipment	STAFUDC	3,168,764	859,060	233,881	1,309,533	646,331	1,955,864	91,672	27,861	427
50	3980 Miscellaneous Equipment	STAFUDC	63,353	17,175	4,676	26,182	12,922	39,104	1,833	557	9
51	3990 Other Tangible Property	STAFUDC	0	0	0	0	0	0	0	0	0
52	**Total General Plant AFUDC**		7,107,916	1,926,973	524,622	2,937,439	1,449,798	4,387,237	205,631	62,496	958
53											
54	**Intangible Plant - AFUDC**										
55	3020 Franchises and Consents	STAFUDC	0	0	0	0	0	0	0	0	0
56	3030 Miscellaneous Intangible Plant	STAFUDC	654,162	177,345	48,282	270,341	133,429	403,770	18,925	5,752	88
57	**Total Intangible Plant AFUDC**		654,162	177,345	48,282	270,341	133,429	403,770	18,925	5,752	88
58											
59	**Total AFUDC**		36,116,651	10,848,421	2,756,302	14,856,026	6,375,366	21,231,392	944,809	331,044	4,683

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Line No.	Description	Allocator	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[C]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]
	Development Of Rate Base, Cont'd.										
	AFUDC (cont'd.)										
	Distribution AFUDC										
1	3600 Land and Land Rights - Substations	NCAPSUBS	0	0	0	0	0	0	0	0	0
2	3600 Land and Land Rights - OH Lines	NCAPPRIM	0	0	0	0	0	0	0	0	0
3	3600 Land and Land Rights - UG Lines	NCAPPRIM	0	0	0	0	0	0	0	0	0
4	3610 Structures and Improvements	NCAPSUBS	827,354	90,263	248,559	268	875,538	518,021	0	635,671	97,614
5	3620 Station Equipment	NCAPSUBS	2,256,323	246,163	677,858	732	2,387,730	1,412,724	0	1,733,574	266,210
6	3627 Station Equipment	NCAPSUBS	0	0	0	0	0	0	0	0	0
7	Total Acct 3620		2,256,323	246,163	677,858	732	2,387,730	1,412,724	0	1,733,574	266,210
8	3640 Poles, Towers and Fixtures										
9	Demand Primary	NCAPPRIM	13,796	1,505	4,145	4	14,610	8,637	0	10,607	1,628
10	Demand Secondary	SMX2ND	36,635	1,474	6,659	0	16,718	9,338	0	0	0
11	Total Acct 3640		50,431	2,979	10,804	4	31,328	17,975	0	10,607	1,628
12	3650 Overhead Conductors and Devices										
13	Demand Primary	NCAPPRIM	49,133	5,360	14,761	16	52,033	30,760	0	37,777	5,799
14	Demand Secondary	SMX2ND	51,747	2,082	9,406	0	23,614	13,190	0	0	0
15	Total Acct 3650		100,880	7,442	24,168	16	75,647	43,950	0	37,777	5,799
16	3660 Underground Conduit										
17	Demand Primary	NCAPPRIM	781,663	85,270	234,843	252	827,804	489,372	0	601,007	92,256
18	Demand Secondary	SMX2ND	1,113,641	44,809	202,430	0	508,190	283,852	0	0	0
19	Total Acct 3660		1,895,304	130,079	437,273	252	1,335,994	773,224	0	601,007	92,256
20	3670 Underground Conductors and Devices										
21	Demand Primary	NCAPPRIM	580,078	63,280	174,279	187	614,320	363,167	0	446,012	68,464
22	Demand Secondary	SMX2ND	641,101	25,795	116,535	0	292,555	163,408	0	0	0
23	Total Acct 3670		1,221,179	89,075	290,814	187	906,875	526,574	0	446,012	68,464
24	3680 Line Transformers	SMXNCAP	49,515	2,790	10,365	0	29,337	16,921	0	0	0
25	3691 Services	CUST369	2,289	92	416	0	1,045	584	0	0	0
26	3692 Services	CUST369	69	3	13	0	31	18	0	0	0
27	3693 Services	CUST369	7,175	289	1,304	0	3,274	1,829	0	0	0
28	3700 Meters	CUST370	0	0	0	0	0	0	0	0	0
29	3701 AMI Meters	CUST3701	0	0	0	0	0	0	0	0	0
30	3711 Installations on Customer Premises	CUST371	0	0	0	0	0	0	0	0	0
31	3731 Street Lighting and Signal Systems	CUST373	0	0	0	0	0	0	0	0	0
32	3732 Street Lighting and Signal Systems	CUST373	0	0	0	0	0	0	0	0	0
33	3734 Street Lighting and Signal Systems	CUST373	0	0	0	0	0	0	0	0	0
34	**Total Distribution AFUDC**		6,410,519	569,175	1,701,574	1,460	5,646,799	3,311,818	0	3,464,648	531,971
35											
36	**Electric Plant In Service**										
37	**General Plant - AFUDC**										
38	3890 Land and Land Rights	STAFUDC	0	0	0	0	0	0	0	0	0
39	3900 Structures and Improvements	STAFUDC	825,753	90,379	249,149	269	877,084	519,449	51,680	637,591	97,762
40	3903 Structures and Improvements	STAFUDC	72,983	7,988	22,021	24	77,520	45,911	4,568	56,352	8,641
41	3911 Office Furniture and Equipment	STAFUDC	3,547	388	1,070	1	3,767	2,231	222	2,739	420
42	3913 Office Furniture and Equipment	STAFUDC	27,499	3,010	8,297	9	29,209	17,299	1,721	21,233	3,256
43	3915 Office Furniture and Equipment	STAFUDC	1	0	0	0	1	1	0	1	0
44	3920 Transportation Equipment	STAFUDC	0	0	0	0	0	0	0	0	0
45	3930 Stores Equipment	STAFUDC	0	0	0	0	0	0	0	0	0
46	3940 Tools, Shop and Garage Equipment	STAFUDC	17,297	1,893	5,219	6	18,373	10,881	1,083	13,356	2,048
47	3950 Laboratory Equipment	STAFUDC	0	0	0	0	0	0	0	0	0
48	3960 Power Operated Equipment	STAFUDC	0	0	0	0	0	0	0	0	0
49	3970 Communication Equipment	STAFUDC	774,311	84,748	233,628	253	822,444	487,089	48,460	597,871	91,672
50	3980 Miscellaneous Equipment	STAFUDC	15,481	1,694	4,671	5	16,443	9,738	969	11,953	1,833
51	3990 Other Tangible Property	STAFUDC	0	0	0	0	0	0	0	0	0
52	**Total General Plant AFUDC**		1,736,873	190,101	524,055	567	1,844,840	1,092,598	108,702	1,341,097	205,631
53											
54	**Intangible Plant - AFUDC**										
55	3020 Franchises and Consents	STAFUDC	0	0	0	0	0	0	0	0	0
56	3030 Miscellaneous Intangible Plant	STAFUDC	159,849	17,495	48,230	52	169,786	100,555	10,004	123,425	18,925
57	**Total Intangible Plant AFUDC**		159,849	17,495	48,230	52	169,786	100,555	10,004	123,425	18,925
58											
59	**Total AFUDC**		9,897,587	950,834	2,753,704	2,598	9,350,630	5,505,396	218,237	6,157,128	944,809

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Line No.	Description	Allocator	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[V]	[W]	[X]	[Y]
	Development Of Rate Base, Cont'd.					
	AFUDC (cont'd.)					
	Distribution AFUDC					
1	3600 Land and Land Rights - Substations	NCAPSUBS	0	0	0	0
2	3600 Land and Land Rights - OH Lines	NCAPPRIM	0	0	0	0
3	3600 Land and Land Rights - UG Lines	NCAPPRIM	0	0	0	0
4	3610 Structures and Improvements	NCAPSUBS	0	27,953	1,782	449
5	3620 Station Equipment	NCAPSUBS	0	76,232	4,859	1,223
6	3627 Station Equipment	NCAPSUBS	0	0	0	0
7	Total Acct 3620		0	76,232	4,859	1,223
8	3640 Poles, Towers and Fixtures					
9	Demand Primary	NCAPPRIM	0	467	30	8
10	Demand Secondary	SMX2ND	0	370	24	6
11	Total Acct 3640		0	837	53	13
12	3650 Overhead Conductors and Devices					
13	Demand Primary	NCAPPRIM	0	1,662	106	27
14	Demand Secondary	SMX2ND	0	523	33	8
15	Total Acct 3650		0	2,184	139	35
16	3660 Underground Conduit					
17	Demand Primary	NCAPPRIM	0	26,434	1,684	426
18	Demand Secondary	SMX2ND	0	11,249	717	181
19	Total Acct 3660		0	37,683	2,401	607
20	3670 Underground Conductors and Devices					
21	Demand Primary	NCAPPRIM	0	19,617	1,250	316
22	Demand Secondary	SMX2ND	0	6,476	413	104
23	Total Acct 3670		0	26,093	1,662	420
24	3680 Line Transformers	SMXNCAP	0	767	49	12
25	3691 Services	CUST369	0	0	0	0
26	3692 Services	CUST369	0	0	0	0
27	3693 Services	CUST369	0	0	0	0
28	3700 Meters	CUST370	0	0	0	0
29	3701 AMI Meters	CUST3701	0	0	0	0
30	3711 Installations on Customer Premises	CUST371	0	0	0	0
31	3731 Street Lighting and Signal Systems	CUST373	111	0	0	0
32	3732 Street Lighting and Signal Systems	CUST373	22,242	0	0	0
33	3734 Street Lighting and Signal Systems	CUST373	526	0	0	0
34	**Total Distribution AFUDC**		22,879	171,748	10,946	2,760
35						
36	**Electric Plant In Service**					
37	**General Plant - AFUDC**					
38	3890 Land and Land Rights	STAFUDC	0	0	0	0
39	3900 Structures and Improvements	STAFUDC	0	27,905	1,807	455
40	3903 Structures and Improvements	STAFUDC	0	2,466	160	40
41	3911 Office Furniture and Equipment	STAFUDC	0	120	8	2
42	3913 Office Furniture and Equipment	STAFUDC	0	929	60	15
43	3915 Office Furniture and Equipment	STAFUDC	0	0	0	0
44	3920 Transportation Equipment	STAFUDC	0	0	0	0
45	3930 Stores Equipment	STAFUDC	0	0	0	0
46	3940 Tools, Shop and Garage Equipment	STAFUDC	0	585	38	10
47	3950 Laboratory Equipment	STAFUDC	0	0	0	0
48	3960 Power Operated Equipment	STAFUDC	0	0	0	0
49	3970 Communication Equipment	STAFUDC	0	26,167	1,695	427
50	3980 Miscellaneous Equipment	STAFUDC	0	523	34	9
51	3990 Other Tangible Property	STAFUDC	0	0	0	0
52	**Total General Plant AFUDC**		0	58,695	3,801	958
53						
54	**Intangible Plant - AFUDC**					
55	3020 Franchises and Consents	STAFUDC	0	0	0	0
56	3030 Miscellaneous Intangible Plant	STAFUDC	0	5,402	350	88
57	**Total Intangible Plant AFUDC**		0	5,402	350	88
58						
59	**Total AFUDC**		22,879	289,587	18,578	4,683

Potomac Electric Power Company
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Line No.	Description	Allocator	**Total** DC Distribution	**Total** Residential Service	**Total** GS	**Total** GT-LV	**Total** GT-HV	**Total** GT	**Total** Metro	**Total** Street Lighting	**Total** TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
	Development Of Rate Base, Cont'd.										
	Electric Plant In Service										
1	**Adjustments to Plant In Service**	STDPLT	200,262,278	77,950,181	16,821,144	79,374,981	20,922,280	100,297,261	3,187,220	1,985,056	21,415
2											
3	**Total System Electric Distribution**		3,962,869,750	1,539,299,603	332,586,164	1,571,244,763	416,620,510	1,987,865,273	63,439,990	39,254,121	424,599
4											
5											
6											
7											
8											
9											
10											
11	**Depreciation Reserve**										
12	Subtransmission	SUBTAED	97,457,644	26,420,999	7,193,166	40,275,634	19,878,391	60,154,025	2,819,431	856,893	13,131
13	Distribution - Primary	PLTPRIM	484,454,434	133,726,545	36,263,417	203,148,789	92,684,968	295,833,756	14,229,047	4,336,047	65,622
14	Distribution - Secondary	PLTSEC	379,169,305	193,308,708	35,605,779	147,811,044	0	147,811,044	0	2,407,394	36,381
15	Distribution - Customer	PLTCUST	118,579,940	67,073,861	11,636,644	36,333,897	273,692	36,607,589	105,917	3,155,929	0
16	General	DPPLTG	64,269,812	25,109,861	5,405,927	25,454,812	6,642,733	32,097,545	1,011,769	637,859	6,850
17	**Depreciation Reserve Less AFUDC**		1,143,931,136	445,639,974	96,104,932	453,024,176	119,479,783	572,503,959	18,166,165	11,394,122	121,983
18	**AFUDC**										
19	Distribution	STAFUDC	13,070,737	3,543,508	964,727	5,401,652	2,666,032	8,067,684	378,134	114,924	1,761
20	General	STAFUDC	3,828,653	1,037,957	282,586	1,582,240	780,929	2,363,169	110,762	33,663	516
21	**Depreciation Reserve AFUDC**		16,899,390	4,581,465	1,247,312	6,983,892	3,446,961	10,430,853	488,896	148,587	2,277
22											
23	**Total Depreciation Reserve**		1,160,830,526	450,221,439	97,352,245	460,008,068	122,926,744	582,934,812	18,655,061	11,542,709	124,260
24											
25											
26	**Total Net Plant**		2,802,039,225	1,089,078,164	235,233,920	1,111,236,695	293,693,766	1,404,930,461	44,784,929	27,711,412	300,339

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Line No.	Description	Allocator	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[C]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]
	Development Of Rate Base, Cont'd.										
	Electric Plant In Service										
1	**Adjustments to Plant In Service**	STDPLT	73,019,600	4,930,581	16,811,446	9,698	50,219,876	29,155,105	233,892	20,688,388	3,187,220
2											
3	**Total System Electric Distribution**		1,441,669,682	97,629,921	332,393,414	192,750	994,064,557	577,180,206	4,804,400	411,816,110	63,439,990
4											
5											
6											
7											
8											
9											
10											
11	**Depreciation Reserve**										
12	Subtransmission	SUBTAED	23,814,504	2,606,495	7,185,395	7,771	25,294,863	14,980,771	1,490,423	18,387,968	2,819,431
13	Distribution - Primary	PLTPRIM	120,573,017	13,153,528	36,224,435	38,982	127,660,229	75,488,559	0	92,684,968	14,229,047
14	Distribution - Secondary	PLTSEC	184,688,756	8,619,952	35,605,779	0	94,327,745	53,483,299	0	0	0
15	Distribution - Customer	PLTCUST	64,894,462	2,179,398	11,631,056	5,588	23,237,971	13,095,926	4,077	269,615	105,917
16	General	DPPLTG	23,529,588	1,580,273	5,402,841	3,086	16,106,573	9,348,240	75,806	6,566,927	1,011,769
17	**Depreciation Reserve Less AFUDC**		417,500,328	28,139,647	96,049,506	55,427	286,627,382	166,396,795	1,570,306	117,909,477	18,166,165
18	**AFUDC**										
19	Distribution	STAFUDC	3,193,932	349,576	963,684	1,042	3,392,474	2,009,178	199,891	2,466,141	378,134
20	General	STAFUDC	935,560	102,397	282,280	305	993,716	588,524	58,552	722,377	110,762
21	**Depreciation Reserve AFUDC**		4,129,492	451,972	1,245,965	1,347	4,386,190	2,597,702	258,443	3,188,518	488,896
22											
23	**Total Depreciation Reserve**		421,629,820	28,591,619	97,295,470	56,774	291,013,572	168,994,496	1,828,749	121,097,995	18,655,061
24											
25											
26	**Total Net Plant**		1,020,039,862	69,038,302	235,097,944	135,976	703,050,985	408,185,710	2,975,651	290,718,115	44,784,929

Potomac Electric Power Company
District of Columbia
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For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[V]	[W]	[X]	[Y]
	Development Of Rate Base, Cont'd.					
	Electric Plant In Service					
1	**Adjustments to Plant In Service**	STDPLT	570,575	1,329,651	84,831	21,415
2						
3	**Total System Electric Distribution**		11,210,734	26,361,444	1,681,944	424,599
4						
5						
6						
7						
8						
9						
10						
11	**Depreciation Reserve**					
12	Subtransmission	SUBTAED	0	804,772	52,121	13,131
13	Distribution - Primary	PLTPRIM	0	4,076,296	259,751	65,622
14	Distribution - Secondary	PLTSEC	0	2,263,180	144,214	36,381
15	Distribution - Customer	PLTCUST	3,153,446	2,483	0	0
16	General	DPPLTG	185,465	425,263	27,132	6,850
17	**Depreciation Reserve Less AFUDC**		3,338,911	7,571,993	483,217	121,983
18	**AFUDC**					
19	Distribution	STAFUDC	0	107,934	6,990	1,761
20	General	STAFUDC	0	31,616	2,048	516
21	**Depreciation Reserve AFUDC**		0	139,549	9,038	2,277
22						
23	**Total Depreciation Reserve**		3,338,911	7,711,543	492,255	124,260
24						
25						
26	**Total Net Plant**		7,871,823	18,649,901	1,189,688	300,339

Potomac Electric Power Company
District of Columbia
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For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Total DC Distribution	Total Residential Service	Total GS	Total GT-LV	Total GT-HV	Total GT	Total Metro	Total Street Lighting	Total TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
	Development Of Rate Base, Cont'd.										
	Additions & Deductions To Rate Base										
	ADD:										
	CWIP										
1	Subtransmission	SUBTAED	0	0	0	0	0	0	0	0	0
2	Distribution	DISTPLT	0	0	0	0	0	0	0	0	0
3	General	STDPLT	0	0	0	0	0	0	0	0	0
4	**Total CWIP Less AFUDC**		0	0	0	0	0	0	0	0	0
5	**CWIP AFUDC**										
6	Subtransmission	SUBTAED	0	0	0	0	0	0	0	0	0
7	Distribution	CWIPDIST	0	0	0	0	0	0	0	0	0
8	General	CWIPAF	0	0	0	0	0	0	0	0	0
9	**Total CWIP AFUDC**		0	0	0	0	0	0	0	0	0
10	**Total CWIP**		0	0	0	0	0	0	0	0	0
11											
12	**Cash Working Capital**										
13	District of Columbia	STDPLT	9,177,800	3,572,371	770,895	3,637,668	958,845	4,596,513	146,067	90,973	981
14	Imprest Funds	STDPLT	390,785	152,109	32,824	154,890	40,827	195,717	6,219	3,874	42
15	**Total Cash Working Capital**		9,568,585	3,724,480	803,719	3,792,558	999,672	4,792,230	152,286	94,846	1,023
16											
17	**Plant Held For Future Use**										
18	District of Columbia	PLTPRIM	0	0	0	0	0	0	0	0	0
19	AFUDC	STAFUDC	0	0	0	0	0	0	0	0	0
20	**Total Plant Held For Future Use**		0	0	0	0	0	0	0	0	0
21											
22	**Materials & Supplies**										
23	Subtransmission	SUBTAED	2,166,336	587,299	159,893	895,267	441,867	1,337,133	62,672	19,047	292
24	Demand - Prim	PLTPRIM	18,713,921	5,165,704	1,400,814	7,847,405	3,580,314	11,427,720	549,652	167,497	2,535
25	Demand - Sec	PLTSEC	14,253,318	7,266,650	1,338,454	5,556,351	0	5,556,351	0	90,496	1,368
26	Customer	PLTCUST	3,407,843	1,927,621	334,423	1,044,192	7,866	1,052,058	3,044	90,698	0
27	**Total Materials & Supplies**		38,541,419	14,947,273	3,233,584	15,343,215	4,030,047	19,373,262	615,367	367,738	4,194
28											
29	**Regulatory Assets**										
30	DC FC 1150 Costs	OMLESAG	1,451,418	780,396	116,568	420,271	110,418	530,689	17,027	6,635	103
31	DC FC 1139 Excess Rate Case Costs	OMLESAG	(754,054)	(405,438)	(60,561)	(218,343)	(57,365)	(275,709)	(8,846)	(3,447)	(54)
32	DC I Street Substation Rent	OMLESAG	2,797,208	1,503,998	224,653	809,957	212,800	1,022,757	32,815	12,786	199
33	DC Benning RI Costs	OMLESAG	5,480,718	2,946,862	440,175	1,586,992	416,950	2,003,942	64,296	25,053	389
34	DC Over-Collected Depreciation Expense	OMLESAG	(527,379)	(283,560)	(42,356)	(152,707)	(40,121)	(192,828)	(6,187)	(2,411)	(37)
35	DC AMI (FC 1076)	CUST3701	379,429	328,269	39,120	10,915	632	11,547	460	33	0
36	DC AMI Expense (FC 1087)	CUST3701	29,013,672	25,101,656	2,991,344	834,646	48,332	882,978	35,154	2,540	0
37	DC AMI Return (FC 1087)	CUST3701	(38,674)	(33,460)	(3,987)	(1,113)	(64)	(1,177)	(47)	(3)	0
38	DC FC 1139 Costs	OMLESAG	2,384,417	1,282,049	191,501	690,430	181,397	871,826	27,972	10,899	169
39	DLC Program Costs	STDPLT	10,325,450	4,019,083	867,292	4,092,545	1,078,745	5,171,290	164,332	102,349	1,104
40	DC Interval Billing Costs	INTERVBILL	3,323,400	3,139,620	183,153	398	24	422	0	205	0
41	DC AMI True-Up Costs	CUST3701	6,192,950	5,357,933	638,501	178,155	10,316	188,471	7,504	542	0
42	DC Third Party Audit Costs	OMLESAG	57,417	30,872	4,611	16,626	4,368	20,994	674	262	4
43	DC 1076 Management Audit Costs	OMLESAG	941,417	506,179	75,608	272,596	71,619	344,215	11,044	4,303	67
44	DC CRM&B Stabilization Expense	OMLESAG	1,770,450	951,932	142,191	512,650	134,689	647,339	20,770	8,093	126
45	DC Legacy Billing System Expense	OMLESAG	216,775	116,555	17,410	62,769	16,491	79,261	2,543	991	15
46	DC Tax Prep	OMLESAG	71,050	38,202	5,706	20,573	5,405	25,978	834	325	5
47	ADIT on DC Regulatory Assets in Rate Base	OMLESAG	(16,292,053)	(8,759,881)	(1,308,471)	(4,717,513)	(1,239,432)	(5,956,945)	(191,126)	(74,473)	(1,157)
48	District of Columbia Current Rate Case Costs	OMLESAG	2,254,682	1,212,293	181,081	652,864	171,527	824,391	26,450	10,306	160
49	Annualization of regulatory assets	OMLESAG	(50,518)	(27,162)	(4,057)	(14,628)	(3,843)	(18,471)	(593)	(231)	(4)
50	Reflection of the Frederick Douglass Bridge Pr	SUBTAED	1,005,424	272,573	74,208	415,505	205,076	620,580	29,087	8,840	135
51	Amortization of PHISCO Deficient Deferred Ir	OMLESAG	1,038,674	558,472	83,420	300,758	79,018	379,776	12,185	4,748	74
52	Reflection of CTA Regulatory Asset	OMLESAG	6,171,160	3,318,098	495,627	1,786,916	469,476	2,256,392	72,395	28,209	438
53	Reflection of CTO Regulatory Asset	OMLESAG	808,905	434,930	64,966	234,226	61,538	295,764	9,489	3,698	57
54	**Total Regulatory Assets**		58,021,936	42,390,470	5,417,705	7,795,486	1,937,996	9,733,482	328,231	150,253	1,795

Potomac Electric Power Company
District of Columbia
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For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[C]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]
	Development Of Rate Base, Cont'd.										
	Additions & Deductions To Rate Base										
	ADD:										
	CWIP										
1	Subtransmission	SUBTAED	0	0	0	0	0	0	0	0	0
2	Distribution	DISTPLT	0	0	0	0	0	0	0	0	0
3	General	STDPLT	0	0	0	0	0	0	0	0	0
4	**Total CWIP Less AFUDC**		0	0	0	0	0	0	0	0	0
5	**CWIP AFUDC**										
6	Subtransmission	SUBTAED	0	0	0	0	0	0	0	0	0
7	Distribution	CWIPDIST	0	0	0	0	0	0	0	0	0
8	General	CWIPAF	0	0	0	0	0	0	0	0	0
9	**Total CWIP AFUDC**		0	0	0	0	0	0	0	0	0
10	**Total CWIP**		0	0	0	0	0	0	0	0	0
11											
12	**Cash Working Capital**										
13	District of Columbia	STDPLT	3,346,408	225,963	770,450	444	2,301,522	1,336,146	10,719	948,126	146,067
14	Imprest Funds	STDPLT	142,488	9,621	32,805	19	97,997	56,892	456	40,371	6,219
15	**Total Cash Working Capital**		3,488,896	235,584	803,255	463	2,399,519	1,393,039	11,175	988,497	152,286
16											
17	**Plant Held For Future Use**										
18	District of Columbia	PLTPRIM	0	0	0	0	0	0	0	0	0
19	AFUDC	STAFUDC	0	0	0	0	0	0	0	0	0
20	**Total Plant Held For Future Use**		0	0	0	0	0	0	0	0	0
21											
22	**Materials & Supplies**										
23	Subtransmission	SUBTAED	529,361	57,938	159,720	173	562,267	333,000	33,130	408,737	62,672
24	Demand - Prim	PLTPRIM	4,657,598	508,106	1,399,309	1,506	4,931,369	2,916,037	0	3,580,314	549,652
25	Demand - Sec	PLTSEC	6,942,618	324,032	1,338,454	0	3,545,866	2,010,486	0	0	0
26	Customer	PLTCUST	1,864,988	62,633	334,262	161	667,831	376,361	117	7,748	3,044
27	**Total Materials & Supplies**		13,994,564	952,709	3,231,745	1,839	9,707,332	5,635,883	33,247	3,996,800	615,367
28											
29	**Regulatory Assets**										
30	DC FC 1150 Costs	OMLESAG	757,884	22,511	116,456	112	229,242	191,029	395	110,023	17,027
31	DC FC 1139 Excess Rate Case Costs	OMLESAG	(393,743)	(11,695)	(60,502)	(58)	(119,098)	(99,245)	(205)	(57,160)	(8,846)
32	DC I Street Substation Rent	OMLESAG	1,460,613	43,384	224,437	217	441,802	368,155	762	212,038	32,815
33	DC Benning RI Costs	OMLESAG	2,861,857	85,005	439,751	424	865,646	721,347	1,492	415,458	64,296
34	DC Over-Collected Depreciation Expense	OMLESAG	(275,380)	(8,180)	(42,315)	(41)	(83,296)	(69,411)	(144)	(39,977)	(6,187)
35	DC AMI (FC 1076)	CUST3701	326,046	2,223	39,101	18	8,841	2,074	0	632	460
36	DC AMI Expense (FC 1087)	CUST3701	24,931,695	169,961	2,989,938	1,406	676,063	158,582	0	48,332	35,154
37	DC AMI Return (FC 1087)	CUST3701	(33,233)	(227)	(3,985)	(2)	(901)	(211)	0	(64)	(47)
38	DC FC 1139 Costs	OMLESAG	1,245,067	36,982	191,316	185	376,604	313,826	649	180,747	27,972
39	DLC Program Costs	STDPLT	3,764,864	254,219	866,792	500	2,589,318	1,503,227	12,059	1,066,686	164,332
40	DC Interval Billing Costs	INTERVBILL	3,129,211	10,408	183,153	0	398	0	0	24	0
41	DC AMI True-Up Costs	CUST3701	5,321,654	36,278	638,200	300	144,305	33,849	0	10,316	7,504
42	DC Third Party Audit Costs	OMLESAG	29,981	891	4,607	4	9,069	7,557	16	4,352	674
43	DC 1076 Management Audit Costs	OMLESAG	491,578	14,601	75,536	73	148,691	123,905	256	71,363	11,044
44	DC CRM&B Stabilization Expense	OMLESAG	924,473	27,460	142,054	137	279,632	233,018	482	134,207	20,770
45	DC Legacy Billing System Expense	OMLESAG	113,193	3,362	17,393	17	34,238	28,531	59	16,432	2,543
46	DC Tax Prep	OMLESAG	37,100	1,102	5,701	6	11,222	9,351	19	5,386	834
47	ADIT on DC Regulatory Assets in Rate Base	OMLESAG	(8,507,192)	(252,688)	(1,307,209)	(1,262)	(2,573,229)	(2,144,284)	(4,436)	(1,234,996)	(191,126)
48	District of Columbia Current Rate Case Costs	OMLESAG	1,177,323	34,970	180,907	175	356,113	296,751	614	170,913	26,450
49	Annualization of regulatory assets	OMLESAG	(26,379)	(784)	(4,053)	(4)	(7,979)	(6,649)	(14)	(3,829)	(593)
50	Reflection of the Frederick Douglass Bridge Pr	SUBTAED	245,683	26,890	74,128	80	260,955	154,549	15,376	189,700	29,087
51	Amortization of PHISCO Deficient Deferred Ir	OMLESAG	542,363	16,110	83,339	80	164,052	136,705	283	78,735	12,185
52	Reflection of CTA Regulatory Asset	OMLESAG	3,222,384	95,714	495,149	478	974,697	812,219	1,680	467,796	72,395
53	Reflection of CTO Regulatory Asset	OMLESAG	422,384	12,546	64,903	63	127,762	106,464	220	61,318	9,489
54	**Total Regulatory Assets**		41,769,425	621,045	5,414,796	2,909	4,914,146	2,881,340	29,564	1,908,431	328,231

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[V]	[W]	[X]	[Y]
	Development Of Rate Base, Cont'd.					
	Additions & Deductions To Rate Base					
	ADD:					
	CWIP					
1	Subtransmission	SUBTAED	0	0	0	0
2	Distribution	DISTPLT	0	0	0	0
3	General	STDPLT	0	0	0	0
4	**Total CWIP Less AFUDC**		0	0	0	0
5	**CWIP AFUDC**					
6	Subtransmission	SUBTAED	0	0	0	0
7	Distribution	CWIPDIST	0	0	0	0
8	General	CWIPAF	0	0	0	0
9	**Total CWIP AFUDC**		0	0	0	0
10	**Total CWIP**		0	0	0	0
11						
12	**Cash Working Capital**					
13	District of Columbia	STDPLT	26,149	60,936	3,888	981
14	Imprest Funds	STDPLT	1,113	2,595	166	42
15	**Total Cash Working Capital**		27,262	63,531	4,053	1,023
16						
17	**Plant Held For Future Use**					
18	District of Columbia	PLTPRIM	0	0	0	0
19	AFUDC	STAFUDC	0	0	0	0
20	**Total Plant Held For Future Use**		0	0	0	0
21						
22	**Materials & Supplies**					
23	Subtransmission	SUBTAED	0	17,889	1,159	292
24	Demand - Prim	PLTPRIM	0	157,463	10,034	2,535
25	Demand - Sec	PLTSEC	0	85,075	5,421	1,368
26	Customer	PLTCUST	90,626	71	0	0
27	**Total Materials & Supplies**		90,626	260,498	16,614	4,194
28						
29	**Regulatory Assets**					
30	DC FC 1150 Costs	OMLESAG	63	6,181	391	103
31	DC FC 1139 Excess Rate Case Costs	OMLESAG	(33)	(3,211)	(203)	(54)
32	DC I Street Substation Rent	OMLESAG	121	11,913	753	199
33	DC Benning RI Costs	OMLESAG	237	23,341	1,475	389
34	DC Over-Collected Depreciation Expense	OMLESAG	(23)	(2,246)	(142)	(37)
35	DC AMI (FC 1076)	CUST3701	0	33	0	0
36	DC AMI Expense (FC 1087)	CUST3701	0	2,540	0	0
37	DC AMI Return (FC 1087)	CUST3701	0	(3)	0	0
38	DC FC 1139 Costs	OMLESAG	103	10,155	642	169
39	DLC Program Costs	STDPLT	29,419	68,556	4,374	1,104
40	DC Interval Billing Costs	INTERVBILL	0	205	0	0
41	DC AMI True-Up Costs	CUST3701	0	542	0	0
42	DC Third Party Audit Costs	OMLESAG	2	245	15	4
43	DC 1076 Management Audit Costs	OMLESAG	41	4,009	253	67
44	DC CRM&B Stabilization Expense	OMLESAG	77	7,540	476	126
45	DC Legacy Billing System Expense	OMLESAG	9	923	58	15
46	DC Tax Prep	OMLESAG	3	303	19	5
47	ADIT on DC Regulatory Assets in Rate Base	OMLESAG	(704)	(69,385)	(4,383)	(1,157)
48	District of Columbia Current Rate Case Costs	OMLESAG	97	9,602	607	160
49	Annualization of regulatory assets	OMLESAG	(2)	(215)	(14)	(4)
50	Reflection of the Frederick Douglass Bridge Pr	SUBTAED	0	8,302	538	135
51	Amortization of PHISCO Deficient Deferred Ir	OMLESAG	45	4,424	279	74
52	Reflection of CTA Regulatory Asset	OMLESAG	267	26,282	1,660	438
53	Reflection of CTO Regulatory Asset	OMLESAG	35	3,445	218	57
54	**Total Regulatory Assets**		29,757	113,481	7,016	1,795

Potomac Electric Power Company
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For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	**Total** DC Distribution	**Total** Residential Service	**Total** GS	**Total** GT-LV	**Total** GT-HV	**Total** GT	**Total** Metro	**Total** Street Lighting	**Total** TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
	Development Of Rate Base, Cont'd.										
	Misc. Rate Base Items										
1	Service Company Assets - Plant Related										
2	Customer Rel. Mgmt & Billing (CRMB)	CRMB	17,111,425	15,438,690	1,139,637	520,512	6,970	527,482	2,803	2,623	190
3	Spectrum Frequencies	STDPLT	2,973,147	1,157,269	249,731	1,178,422	310,618	1,489,040	47,318	29,471	318
4	Advanced Metering Infrastructure (AMI) Softwa	CUSTSAMI	372,749	340,006	28,046	4,342	193	4,536	120	38	4
5	Net Energy Metering	CUSTSNEM	374,931	341,761	19,161	12,962	1,047	14,009	0	0	0
6	Plant Maintenance/Accounting	STDPLT	0	0	0	0	0	0	0	0	0
7	Load Settlement Database	CUSTSLS	30,546	27,863	2,298	356	16	372	10	3	0
8	Network Operations Center	STDPLT	197,001	76,681	16,547	78,082	20,582	98,664	3,135	1,953	21
9	Outage Management System	STDPLT	44,961	17,500	3,776	17,820	4,697	22,518	716	446	5
10	Geospatial Information System	STDPLT	38,037	14,805	3,195	15,076	3,974	19,050	605	377	4
11	Other	STDPLT	6,873,761	2,675,546	577,365	2,724,450	718,132	3,442,582	109,397	68,135	735
12	Service Company Assets - CWIP Related	CWIPSTD	0	0	0	0	0	0	0	0	0
13	Total Service Company Assets		28,016,556	20,090,121	2,039,757	4,552,023	1,066,228	5,618,251	164,105	103,046	1,277
14	Prepaid Pension	OMLESAG	69,022,907	37,112,109	5,543,467	19,986,215	5,250,977	25,237,192	809,724	315,511	4,904
15	Credit Facility Costs	STDPLT	364,485	141,872	30,615	144,466	38,079	182,545	5,801	3,613	39
16	**Total Misc. Rate Base Items**		97,403,948	57,344,102	7,613,840	24,682,703	6,355,284	31,037,988	979,630	422,169	6,219
17											
18	**DEDUCT:**										
19	**Amortization Reserve**										
20	Distribution	STDPLT	(12,950,176)	(5,040,732)	(1,087,757)	(5,132,869)	(1,352,962)	(6,485,830)	(206,105)	(128,366)	(1,385)
21	AFUDC	STAFUDC	(624,150)	(169,209)	(46,067)	(257,938)	(127,308)	(385,246)	(18,057)	(5,488)	(84)
22	**Total Amortization Reserve**		(13,574,326)	(5,209,941)	(1,133,825)	(5,390,807)	(1,480,269)	(6,871,076)	(224,162)	(133,854)	(1,469)
23											
24	**Customer Deposits**										
25	Customer Deposits	CUSTDEP	(8,770,607)	(2,626,389)	(961,260)	(3,757,395)	(1,424,705)	(5,182,100)	0	0	(858)
26	**Total Customer Deposits**		(8,770,607)	(2,626,389)	(961,260)	(3,757,395)	(1,424,705)	(5,182,100)	0	0	(858)
27											
28											
29	Deferred Taxes										
30	**Deferred Federal Income Tax (FIT)**										
31	Removal Post-80 Plant	DEPRE	0	0	0	0	0	0	0	0	0
32	Plant-Related	STDPLT	(414,712,959)	(161,423,063)	(34,834,051)	(164,373,609)	(43,326,884)	(207,700,493)	(6,600,252)	(4,110,751)	(44,348)
33	State Depreciation Adjustment	STDPLT	0	0	0	0	0	0	0	0	0
34	Bonus Depreciation Federal	STDPLT	0	0	0	0	0	0	0	0	0
35	Loss on Debt Reacquisition	STDPLT	(1,094,628)	(426,073)	(91,944)	(433,861)	(114,361)	(548,222)	(17,421)	(10,850)	(117)
36	Deferred Income Tax Federal NOL	STDPLT	384,038	149,483	32,258	152,216	40,122	192,338	6,112	3,807	41
37	Deferred Income Tax State NOL	STDPLT	0	0	0	0	0	0	0	0	0
38	Fed Exc. DIT - Protected/Non-Protected	STDPLT	(272,266,873)	(105,977,283)	(22,869,211)	(107,914,372)	(28,444,916)	(136,359,288)	(4,333,190)	(2,698,786)	(29,115)
39	Removal Pre-81 Plant	DEPRE	0	0	0	0	0	0	0	0	0
40	DC NOL	STDPLT	0	0	0	0	0	0	0	0	0
41	DC Benefit NOL	STDPLT	(1,053,700)	(410,143)	(88,506)	(417,639)	(110,085)	(527,724)	(16,770)	(10,445)	(113)
42	ITC	STDPLT	0	0	0	0	0	0	0	0	0
43	**Total Deferred FIT**		(688,744,121)	(268,087,078)	(57,851,455)	(272,987,266)	(71,956,124)	(344,943,389)	(10,961,521)	(6,827,025)	(73,652)
44											
45	**Deferred State Income Tax (SIT)**										
46	Plant-Related	STDPLT	(102,114,606)	(39,747,136)	(8,577,174)	(40,473,648)	(10,668,361)	(51,142,009)	(1,625,177)	(1,012,189)	(10,920)
47	Loss on Debt Reacquisition	STDPLT	(348,583)	(135,683)	(29,279)	(138,163)	(36,418)	(174,581)	(5,548)	(3,455)	(37)
48	Excess DIT - Order No. 188446	STDPLT	(9,736,463)	(3,789,825)	(817,820)	(3,859,097)	(1,017,211)	(4,876,308)	(154,958)	(96,511)	(1,041)
49	Excess DIT - Order No. 19247	STDPLT	(4,917,876)	(1,914,236)	(413,080)	(1,949,225)	(513,792)	(2,463,017)	(78,269)	(48,747)	(526)
50	DC Benefit NOL	STDPLT	5,017,620	1,953,061	421,458	1,988,759	524,213	2,512,972	79,857	49,736	537
51	**Total Deferred SIT**		(112,099,907)	(43,633,819)	(9,415,896)	(44,431,373)	(11,711,570)	(56,142,943)	(1,784,096)	(1,111,166)	(11,988)
52											
53	**Adjustments to Deferred Taxes**	DEFTAX	1,434,463	558,351	120,489	568,557	149,865	718,421	22,830	14,219	153
54											
55	**Total Rate Base**		2,183,820,615	888,485,613	183,060,821	836,852,373	220,593,962	1,057,446,335	33,913,495	20,688,594	225,758

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[C]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]
	Development Of Rate Base, Cont'd.										
	Misc. Rate Base Items										
1	Service Company Assets - Plant Related										
2	Customer Rel. Mgmt & Billing (CRMB)	CRMB	15,418,424	20,265	1,139,134	503	489,730	30,782	45	6,925	2,803
3	Spectrum Frequencies	STDPLT	1,084,068	73,201	249,587	144	745,578	432,844	3,472	307,145	47,318
4	Advanced Metering Infrastructure (AMI) Softwa	CUSTSAMI	338,797	1,209	28,039	7	4,003	339	1	192	120
5	Net Energy Metering	CUSTSNEM	337,816	3,945	19,161	0	12,801	161	0	1,047	0
6	Plant Maintenance/Accounting	STDPLT	0	0	0	0	0	0	0	0	0
7	Load Settlement Database	CUSTSLS	27,764	99	2,298	1	328	28	0	16	10
8	Network Operations Center	STDPLT	71,830	4,850	16,538	10	49,402	28,680	230	20,351	3,135
9	Outage Management System	STDPLT	16,394	1,107	3,774	2	11,275	6,546	53	4,645	716
10	Geospatial Information System	STDPLT	13,869	936	3,193	2	9,539	5,538	44	3,929	605
11	Other	STDPLT	2,506,310	169,236	577,033	333	1,723,737	1,000,714	8,028	710,104	109,397
12	Service Company Assets - CWIP Related	CWIPSTD	0	0	0	0	0	0	0	0	0
13	Total Service Company Assets		19,815,272	274,849	2,038,757	1,001	3,046,391	1,505,632	11,873	1,054,354	164,105
14	Prepaid Pension	OMLESAG	36,041,569	1,070,540	5,538,122	5,345	10,901,742	9,084,473	18,792	5,232,186	809,724
15	Credit Facility Costs	STDPLT	132,899	8,974	30,597	18	91,402	53,063	426	37,654	5,801
16	**Total Misc. Rate Base Items**		55,989,740	1,354,363	7,607,476	6,363	14,039,535	10,643,168	31,091	6,324,194	979,630
17											
18	**DEDUCT:**										
19	**Amortization Reserve**										
20	Distribution	STDPLT	(4,721,891)	(318,841)	(1,087,130)	(627)	(3,247,522)	(1,885,346)	(15,125)	(1,337,837)	(206,105)
21	AFUDC	STAFUDC	(152,516)	(16,693)	(46,018)	(50)	(161,996)	(95,942)	(9,545)	(117,762)	(18,057)
22	**Total Amortization Reserve**		(4,874,407)	(335,534)	(1,133,148)	(677)	(3,409,519)	(1,981,288)	(24,670)	(1,455,599)	(224,162)
23											
24	**Customer Deposits**										
25	Customer Deposits	CUSTDEP	(2,413,820)	(212,569)	(960,316)	(944)	(2,410,821)	(1,346,574)	0	(1,424,705)	0
26	**Total Customer Deposits**		(2,413,820)	(212,569)	(960,316)	(944)	(2,410,821)	(1,346,574)	0	(1,424,705)	0
27											
28											
29	Deferred Taxes										
30	**Deferred Federal Income Tax (FIT)**										
31	Removal Post-80 Plant	DEPRE	0	0	0	0	0	0	0	0	0
32	Plant-Related	STDPLT	(151,212,573)	(10,210,489)	(34,813,969)	(20,082)	(103,997,785)	(60,375,823)	(484,355)	(42,842,530)	(6,600,252)
33	State Depreciation Adjustment	STDPLT	0	0	0	0	0	0	0	0	0
34	Bonus Depreciation Federal	STDPLT	0	0	0	0	0	0	0	0	0
35	Loss on Debt Reacquisition	STDPLT	(399,123)	(26,950)	(91,891)	(53)	(274,500)	(159,361)	(1,278)	(113,082)	(17,421)
36	Deferred Income Tax Federal NOL	STDPLT	140,028	9,455	32,239	19	96,306	55,910	449	39,674	6,112
37	Deferred Income Tax State NOL	STDPLT	0	0	0	0	0	0	0	0	0
38	Fed Exc. DIT - Protected/Non-Protected	STDPLT	(99,273,904)	(6,703,379)	(22,856,027)	(13,184)	(68,276,506)	(39,637,866)	(317,988)	(28,126,928)	(4,333,190)
39	Removal Pre-81 Plant	DEPRE	0	0	0	0	0	0	0	0	0
40	DC NOL	STDPLT	0	0	0	0	0	0	0	0	0
41	DC Benefit NOL	STDPLT	(384,200)	(25,943)	(88,455)	(51)	(264,237)	(153,403)	(1,231)	(108,854)	(16,770)
42	ITC	STDPLT	0	0	0	0	0	0	0	0	0
43	**Total Deferred FIT**		(251,129,772)	(16,957,306)	(57,818,102)	(33,352)	(172,716,723)	(100,270,543)	(804,403)	(71,151,720)	(10,961,521)
44											
45	**Deferred State Income Tax (SIT)**										
46	Plant-Related	STDPLT	(37,233,011)	(2,514,125)	(8,572,230)	(4,945)	(25,607,333)	(14,866,315)	(119,262)	(10,549,099)	(1,625,177)
47	Loss on Debt Reacquisition	STDPLT	(127,100)	(8,582)	(29,263)	(17)	(87,414)	(50,748)	(407)	(36,011)	(5,548)
48	Excess DIT - Order No. 188446	STDPLT	(3,550,108)	(239,718)	(817,348)	(471)	(2,441,618)	(1,417,479)	(11,371)	(1,005,840)	(154,958)
49	Excess DIT - Order No. 19247	STDPLT	(1,793,155)	(121,081)	(412,842)	(238)	(1,233,258)	(715,967)	(5,744)	(508,048)	(78,269)
50	DC Benefit NOL	STDPLT	1,829,524	123,537	421,215	243	1,258,271	730,488	5,860	518,353	79,857
51	**Total Deferred SIT**		(40,873,851)	(2,759,969)	(9,410,467)	(5,428)	(28,111,352)	(16,320,021)	(130,925)	(11,580,645)	(1,784,096)
52											
53	**Adjustments to Deferred Taxes**	DEFTAX	523,034	35,317	120,419	69	359,721	208,836	1,675	148,189	22,830
54											
55	**Total Rate Base**		836,513,670	51,971,942	182,953,603	107,218	527,822,823	309,029,550	2,122,406	218,471,556	33,913,495

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[V]	[W]	[X]	[Y]
	Development Of Rate Base, Cont'd.					
	Misc. Rate Base Items					
1	Service Company Assets - Plant Related					
2	Customer Rel. Mgmt & Billing (CRMB)	CRMB	0	2,568	56	190
3	Spectrum Frequencies	STDPLT	8,471	19,740	1,259	318
4	Advanced Metering Infrastructure (AMI) Softwa	CUSTSAMI	0	35	4	4
5	Net Energy Metering	CUSTSNEM	0	0	0	0
6	Plant Maintenance/Accounting	STDPLT	0	0	0	0
7	Load Settlement Database	CUSTSLS	0	3	0	0
8	Network Operations Center	STDPLT	561	1,308	83	21
9	Outage Management System	STDPLT	128	299	19	5
10	Geospatial Information System	STDPLT	108	253	16	4
11	Other	STDPLT	19,584	45,639	2,912	735
12	Service Company Assets - CWIP Related	CWIPSTD	0	0	0	0
13	Total Service Company Assets		28,853	69,843	4,349	1,277
14	Prepaid Pension	OMLESAG	2,983	293,957	18,571	4,904
15	Credit Facility Costs	STDPLT	1,038	2,420	154	39
16	**Total Misc. Rate Base Items**		32,875	366,220	23,075	6,219
17						
18	**DEDUCT:**					
19	**Amortization Reserve**					
20	Distribution	STDPLT	(36,897)	(85,983)	(5,486)	(1,385)
21	AFUDC	STAFUDC	0	(5,154)	(334)	(84)
22	**Total Amortization Reserve**		(36,897)	(91,137)	(5,819)	(1,469)
23						
24	**Customer Deposits**					
25	Customer Deposits	CUSTDEP	0	0	0	(858)
26	**Total Customer Deposits**		0	0	0	(858)
27						
28						
29	Deferred Taxes					
30	**Deferred Federal Income Tax (FIT)**					
31	Removal Post-80 Plant	DEPRE	0	0	0	0
32	Plant-Related	STDPLT	(1,181,574)	(2,753,506)	(175,672)	(44,348)
33	State Depreciation Adjustment	STDPLT	0	0	0	0
34	Bonus Depreciation Federal	STDPLT	0	0	0	0
35	Loss on Debt Reacquisition	STDPLT	(3,119)	(7,268)	(464)	(117)
36	Deferred Income Tax Federal NOL	STDPLT	1,094	2,550	163	41
37	Deferred Income Tax State NOL	STDPLT	0	0	0	0
38	Fed Exc. DIT - Protected/Non-Protected	STDPLT	(775,725)	(1,807,728)	(115,332)	(29,115)
39	Removal Pre-81 Plant	DEPRE	0	0	0	0
40	DC NOL	STDPLT	0	0	0	0
41	DC Benefit NOL	STDPLT	(3,002)	(6,996)	(446)	(113)
42	ITC	STDPLT	0	0	0	0
43	**Total Deferred FIT**		(1,962,326)	(4,572,948)	(291,751)	(73,652)
44						
45	**Deferred State Income Tax (SIT)**					
46	Plant-Related	STDPLT	(290,938)	(677,995)	(43,256)	(10,920)
47	Loss on Debt Reacquisition	STDPLT	(993)	(2,314)	(148)	(37)
48	Excess DIT - Order No. 188446	STDPLT	(27,741)	(64,646)	(4,124)	(1,041)
49	Excess DIT - Order No. 19247	STDPLT	(14,012)	(32,652)	(2,083)	(526)
50	DC Benefit NOL	STDPLT	14,296	33,315	2,125	537
51	**Total Deferred SIT**		(319,388)	(744,292)	(47,485)	(11,988)
52						
53	**Adjustments to Deferred Taxes**	DEFTAX	4,087	9,524	608	153
54						
55	**Total Rate Base**		5,737,819	14,054,777	895,998	225,758

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	**Total** DC Distribution	**Total** Residential Service	**Total** GS	**Total** GT-LV	**Total** GT-HV	**Total** GT	**Total** Metro	**Total** Street Lighting	**Total** TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
	Operating Revenues										
	Electric Sales Revenues										
1	**Revenue - Retail Sales**		528,475,591	115,676,220	56,692,489	260,456,123	82,613,157	343,069,280	10,631,794	2,303,631	102,177
2											
3	**Revenue - Other**										
4	Late Payment Revenue (Forfeited Discounts)		1,367,791	534,859	161,751	420,201	248,811	669,012	0	1,774	395
5	Miscellaneous Service Revenue	CUSTLMSL	(673)	(615)	(51)	(8)	(0)	(8)	0	(0)	(0)
6	Other Electric Revenues	CUSTS	3,846,803	3,508,895	289,433	44,815	1,993	46,808	1,235	395	38
7	CEO Onlines Revenues	CEOCUSTS	0	0	0	0	0	0	0	0	0
8	Billing Services Revenues	BILSVC	0	0	0	0	0	0	0	0	0
9	Rent from Electric Property										
10	Demand	PLTDEM	1,574,845	593,894	130,855	640,298	171,032	811,329	26,257	12,324	186
11	Customer	CUSTSRESLV	0	0	0	0	0	0	0	0	0
12	**Total Other Revenue**		6,788,765	4,637,033	581,988	1,105,306	421,835	1,527,141	27,491	14,493	619
13											
14	**Total Revenue**		535,264,357	120,313,253	57,274,477	261,561,429	83,034,992	344,596,421	10,659,285	2,318,124	102,796

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[C]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]
	Operating Revenues										
	Electric Sales Revenues										
1	**Revenue - Retail Sales**		101,836,108	13,840,112	56,627,278	65,211	152,329,951	108,126,172	2,491,481	80,121,676	10,631,794
2											
3	**Revenue - Other**										
4	Late Payment Revenue (Forfeited Discounts)		506,809	28,050	161,717	34	286,445	133,756	0	248,811	0
5	Miscellaneous Service Revenue	CUSTLMSL	(612)	(2)	(51)	(0)	(7)	(1)	(0)	(0)	0
6	Other Electric Revenues	CUSTS	3,496,419	12,476	289,364	69	41,315	3,500	13	1,980	1,235
7	CEO Onlines Revenues	CEOCUSTS	0	0	0	0	0	0	0	0	0
8	Billing Services Revenues	BILSVC	0	0	0	0	0	0	0	0	0
9	Rent from Electric Property										
10	Demand	PLTDEM	554,142	39,751	130,783	72	404,958	235,340	0	171,032	26,257
11	Customer	CUSTSRESLV	0	0	0	0	0	0	0	0	0
12	**Total Other Revenue**		4,556,757	80,276	581,812	175	732,710	372,595	13	421,822	27,491
13											
14	**Total Revenue**		106,392,866	13,920,387	57,209,091	65,386	153,062,661	108,498,767	2,491,494	80,543,498	10,659,285

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[V]	[W]	[X]	[Y]
	Operating Revenues					
	Electric Sales Revenues					
1	**Revenue - Retail Sales**		631,344	1,340,533	331,754	102,177
2						
3	**Revenue - Other**					
4	Late Payment Revenue (Forfeited Discounts)		0	1,734	40	395
5	Miscellaneous Service Revenue	CUSTLMSL	0	0	(0)	(0)
6	Other Electric Revenues	CUSTS	0	356	38	38
7	CEO Onlines Revenues	CEOCUSTS	0	0	0	0
8	Billing Services Revenues	BILSVC	0	0	0	0
9	Rent from Electric Property					
10	Demand	PLTDEM	0	11,586	738	186
11	Customer	CUSTSRESLV	0	0	0	0
12	**Total Other Revenue**		0	13,676	817	619
13						
14	**Total Revenue**		631,344	1,354,209	332,571	102,796

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	**Total** DC Distribution	**Total** Residential Service	**Total** GS	**Total** GT-LV	**Total** GT-HV	**Total** GT	**Total** Metro	**Total** Street Lighting	**Total** TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
	Operation & Maintenance Expense										
	Distribution Expenses										
	Operation										
1	958000 Operation Supervision & Engineering	OMOPS	2,153,436	802,822	187,374	920,674	198,660	1,119,333	31,166	12,559	181
2	958100 Load dispatching	PLTDACTS	3,314,545	1,249,956	275,408	1,347,621	359,967	1,707,588	55,262	25,939	392
3	958200 Station expenses										
4	Subtranmission	SUBTAED	133,718	36,251	9,869	55,261	27,274	82,535	3,868	1,176	18
5	Substations	NCAPSUBS	829,071	228,908	62,072	347,637	158,574	506,211	24,351	7,418	112
6	Total		962,789	265,159	71,942	402,897	185,848	588,746	28,219	8,593	130
7	958300 Overhead line expenses										
8	Subtranmission	SUBTAED	11,716	3,176	865	4,842	2,390	7,232	339	103	2
9	OH Lines - Prim	NCAPPRIM	813,993	224,666	60,925	341,346	155,751	497,097	23,908	7,287	110
10	OH Lines - Sec	SMX2ND	651,031	348,343	60,870	238,165	0	238,165	0	3,598	54
11	Total		1,476,740	576,185	122,660	584,353	158,141	742,494	24,247	10,988	166
12	958400 Underground line expenses										
13	Subtranmission	SUBTAED	37,495	10,165	2,767	15,495	7,648	23,143	1,085	330	5
14	UG Lines - Prim	NCAPPRIM	4,633,116	1,278,761	346,775	1,942,886	886,509	2,829,395	136,081	41,476	629
15	UG Lines - Sec	SMX2ND	2,823,256	1,510,622	263,970	1,032,825	0	1,032,825	0	15,603	236
16	UG Svcs	CUST369	86,237	46,402	8,108	31,726	0	31,726	0	0	0
17	Total		7,580,103	2,845,951	621,620	3,022,932	894,157	3,917,089	137,165	57,408	870
18	958500 Street lighting	PLANT373	0	0	0	0	0	0	0	0	0
19	958600 Meter expenses	PLANT370	3,439,815	2,717,953	455,999	202,417	45,348	247,766	17,683	415	0
20	958700 Customer installations expenses	PLANT371	3,414,877	7,531	237,174	3,153,662	16,510	3,170,172	0	0	0
21	958800 Miscellaneous distribution expenses	OMOPS	6,638,255	2,474,806	577,607	2,838,100	612,395	3,450,495	96,073	38,715	558
22	958900 Rents										
23	Distribution	STDPLT	2,173,429	845,986	182,558	861,450	227,068	1,088,517	34,591	21,544	232
24	Subs	NCAPSUBS	1,776,894	490,604	133,035	745,066	339,861	1,084,928	52,190	15,898	240
25	Total		3,950,322	1,336,590	315,594	1,606,516	566,929	2,173,445	86,780	37,441	472
26	**Total Operation**		32,930,882	12,276,953	2,865,378	14,079,171	3,037,956	17,117,127	476,596	192,059	2,770
27	**Maintenance**										
28	959000 Maintenance Supervision & Engineering	OMMAINT	281,685	99,283	22,773	113,721	37,892	151,613	5,801	2,182	34
29	959100 Maintenance Structure	PLANT361	54,056	14,915	4,045	22,654	10,364	33,018	1,587	483	7
30	959200 Maintain equipment										
31	Subtranmission	SUBTAED	842,506	228,406	62,184	348,177	171,846	520,022	24,374	7,408	114
32	Substations	NCAPSUBS	7,710,511	2,128,887	577,283	3,233,081	1,474,767	4,707,849	226,467	68,985	1,041
33	Total		8,553,018	2,357,293	639,466	3,581,258	1,646,613	5,227,871	250,841	76,393	1,154
34	959300 Maintain overhead lines										
35	Subtranmission	SUBTAED	1,320	358	97	546	269	815	38	12	0
36	OH Lines - Prim	NCAPPRIM	5,495,241	1,516,712	411,302	2,304,416	1,051,469	3,355,885	161,402	49,193	746
37	OH Lines - Sec	SMX2ND	2,800,156	1,498,262	261,810	1,024,375	0	1,024,375	0	15,475	234
38	OH Svcs	CUST369	672	362	63	247	0	247	0	0	0
39	Total		8,297,389	3,015,693	673,273	3,329,583	1,051,739	4,381,322	161,441	64,680	980
40	959400 Maintain underground line										
41	Subtranmission	SUBTAED	246,219	66,750	18,173	101,753	50,221	151,974	7,123	2,165	33
42	UG Lines - Prim	NCAPPRIM	6,601,291	1,821,986	494,087	2,768,235	1,263,103	4,031,338	193,889	59,095	896
43	UG Lines - Sec	SMX2ND	3,529,760	1,888,647	330,027	1,291,284	0	1,291,284	0	19,508	295
44	UG Svcs	CUST369	566,292	304,712	53,246	208,334	0	208,334	0	0	0
45	Total		10,943,561	4,082,096	895,532	4,369,606	1,313,324	5,682,930	201,012	80,767	1,224
46	959500 Maintain line transformers	SMXNCAP	1,809,123	862,146	170,854	762,472	0	762,472	0	13,447	203
47	959600 Maintain street lighting & signal systems	PLANT373	(3,991)	0	0	0	0	0	0	(3,991)	0
48	959700 Maintain meters	PLANT370	272,928	215,653	36,181	16,061	3,598	19,659	1,403	33	0
49	959800 Maintain distribution plant	OMMAINT	1,672,801	589,598	135,236	675,336	225,024	900,361	34,449	12,958	199
50	**Total Maintenance**		31,880,570	11,236,677	2,577,360	12,870,692	4,288,554	17,159,246	656,532	246,952	3,801
51	**Total Distribution Expenses**		64,811,452	23,513,631	5,442,738	26,949,863	7,326,510	34,276,373	1,133,128	439,011	6,571

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Line No.	Description	Allocator	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[C]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]
	Operation & Maintenance Expense										
	Distribution Expenses										
	Operation										
1	958000 Operation Supervision & Engineering	OMOPS	760,474	42,347	187,209	165	407,005	513,668	537	198,123	31,166
2	958100 Load dispatching	PLTDACTS	1,166,292	83,664	275,256	151	852,306	495,315	0	359,967	55,262
3	958200 Station expenses										
4	Subtranmission	SUBTAED	32,675	3,576	9,859	11	34,706	20,555	2,045	25,229	3,868
5	Substations	NCAPSUBS	206,391	22,517	62,005	67	218,411	129,225	0	158,574	24,351
6	Total		239,066	26,093	71,864	78	253,117	149,780	2,045	183,803	28,219
7	958300 Overhead line expenses										
8	Subtranmission	SUBTAED	2,863	313	864	1	3,041	1,801	179	2,211	339
9	OH Lines - Prim	NCAPPRIM	202,568	22,098	60,860	65	214,525	126,821	0	155,751	23,908
10	OH Lines - Sec	SMX2ND	334,869	13,474	60,870	0	152,812	85,354	0	0	0
11	Total		540,300	35,885	122,594	66	370,378	213,975	179	157,961	24,247
12	958400 Underground line expenses										
13	Subtranmission	SUBTAED	9,162	1,003	2,764	3	9,732	5,764	573	7,074	1,085
14	UG Lines - Prim	NCAPPRIM	1,152,984	125,777	346,403	372	1,221,043	721,843	0	886,509	136,081
15	UG Lines - Sec	SMX2ND	1,452,192	58,430	263,970	0	662,682	370,144	0	0	0
16	UG Svcs	CUST369	44,608	1,795	8,108	0	20,356	11,370	0	0	0
17	Total		2,658,945	187,005	621,245	375	1,913,812	1,109,120	573	893,583	137,165
18	958500 Street lighting	PLANT373	0	0	0	0	0	0	0	0	0
19	958600 Meter expenses	PLANT370	2,682,196	35,757	455,066	933	159,622	42,795	681	44,668	17,683
20	958700 Customer installations expenses	PLANT371	3,009	4,522	237,174	0	0	3,153,662	0	16,510	0
21	958800 Miscellaneous distribution expenses	OMOPS	2,344,265	130,541	577,098	509	1,254,648	1,583,451	1,655	610,741	96,073
22	958900 Rents										
23	Distribution	STDPLT	792,475	53,511	182,453	105	545,032	316,418	2,538	224,529	34,591
24	Subs	NCAPSUBS	442,345	48,259	132,892	143	468,106	276,960	0	339,861	52,190
25	Total		1,234,820	101,771	315,345	249	1,013,138	593,378	2,538	564,391	86,780
26	**Total Operation**		11,629,367	647,586	2,862,851	2,527	6,224,027	7,855,144	8,208	3,029,748	476,596
27	**Maintenance**										
28	959000 Maintenance Supervision & Engineering	OMMAINT	92,129	7,154	22,756	17	71,840	41,881	158	37,734	5,801
29	959100 Maintenance Structure	PLANT361	13,448	1,467	4,041	4	14,233	8,421	30	10,334	1,587
30	959200 Maintain equipment										
31	Subtranmission	SUBTAED	205,873	22,533	62,117	67	218,670	129,506	12,884	158,961	24,374
32	Substations	NCAPSUBS	1,919,475	209,413	576,660	622	2,031,264	1,201,818	0	1,474,767	226,467
33	Total		2,125,347	231,946	638,777	690	2,249,934	1,331,324	12,884	1,633,728	250,841
34	959300 Maintain overhead lines										
35	Subtranmission	SUBTAED	323	35	97	0	343	203	20	249	38
36	OH Lines - Prim	NCAPPRIM	1,367,530	149,182	410,861	442	1,448,253	856,162	0	1,051,469	161,402
37	OH Lines - Sec	SMX2ND	1,440,310	57,952	261,810	0	657,260	367,115	0	0	0
38	OH Svcs	CUST369	348	14	63	0	159	89	0	0	0
39	Total		2,808,510	207,183	672,831	442	2,106,014	1,223,569	20	1,051,719	161,441
40	959400 Maintain underground line										
41	Subtranmission	SUBTAED	60,165	6,585	18,153	20	63,905	37,848	3,765	46,456	7,123
42	UG Lines - Prim	NCAPPRIM	1,642,778	179,208	493,557	530	1,739,749	1,028,486	0	1,263,103	193,889
43	UG Lines - Sec	SMX2ND	1,815,595	73,052	330,027	0	828,514	462,770	0	0	0
44	UG Svcs	CUST369	292,926	11,786	53,246	0	133,671	74,663	0	0	0
45	Total		3,811,464	270,632	894,982	550	2,765,840	1,603,766	3,765	1,309,559	201,012
46	959500 Maintain line transformers	SMXNCAP	816,159	45,986	170,854	0	483,568	278,904	0	0	0
47	959600 Maintain street lighting & signal systems	PLANT373	0	0	0	0	0	0	0	0	0
48	959700 Maintain meters	PLANT370	212,816	2,837	36,107	74	12,665	3,396	54	3,544	1,403
49	959800 Maintain distribution plant	OMMAINT	547,113	42,485	135,138	98	426,626	248,710	937	224,088	34,449
50	**Total Maintenance**		10,426,986	809,691	2,575,486	1,875	8,130,721	4,739,971	17,848	4,270,706	656,532
51	**Total Distribution Expenses**		22,056,354	1,457,277	5,438,337	4,401	14,354,748	12,595,115	26,056	7,300,454	1,133,128

Potomac Electric Power Company
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Line No.	Description	Allocator	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[V]	[W]	[X]	[Y]
	Operation & Maintenance Expense					
	Distribution Expenses					
	Operation					
1	958000 Operation Supervision & Engineering	OMOPS	552	11,290	717	181
2	958100 Load dispatching	PLTDACTS	0	24,385	1,554	392
3	958200 Station expenses					
4	Subtranmission	SUBTAED	0	1,104	72	18
5	Substations	NCAPSUBS	0	6,973	445	112
6	Total		0	8,077	516	130
7	958300 Overhead line expenses					
8	Subtranmission	SUBTAED	0	97	6	2
9	OH Lines - Prim	NCAPPRIM	0	6,850	436	110
10	OH Lines - Sec	SMX2ND	0	3,382	215	54
11	Total		0	10,330	658	166
12	958400 Underground line expenses					
13	Subtranmission	SUBTAED	0	310	20	5
14	UG Lines - Prim	NCAPPRIM	0	38,991	2,484	629
15	UG Lines - Sec	SMX2ND	0	14,668	935	236
16	UG Svcs	CUST369	0	0	0	0
17	Total		0	53,969	3,439	870
18	958500 Street lighting	PLANT373	0	0	0	0
19	958600 Meter expenses	PLANT370	0	415	0	0
20	958700 Customer installations expenses	PLANT371	0	0	0	0
21	958800 Miscellaneous distribution expenses	OMOPS	1,703	34,801	2,211	558
22	958900 Rents					
23	Distribution	STDPLT	6,192	14,431	921	232
24	Subs	NCAPSUBS	0	14,945	953	240
25	Total		6,192	29,376	1,873	472
26	**Total Operation**		8,448	172,642	10,969	2,770
27	**Maintenance**					
28	959000 Maintenance Supervision & Engineering	OMMAINT	(38)	2,087	133	34
29	959100 Maintenance Structure	PLANT361	0	454	29	7
30	959200 Maintain equipment					
31	Subtranmission	SUBTAED	0	6,957	451	114
32	Substations	NCAPSUBS	0	64,851	4,134	1,041
33	Total		0	71,808	4,585	1,154
34	959300 Maintain overhead lines					
35	Subtranmission	SUBTAED	0	11	1	0
36	OH Lines - Prim	NCAPPRIM	0	46,247	2,946	746
37	OH Lines - Sec	SMX2ND	0	14,548	927	234
38	OH Svcs	CUST369	0	0	0	0
39	Total		0	60,806	3,874	980
40	959400 Maintain underground line					
41	Subtranmission	SUBTAED	0	2,033	132	33
42	UG Lines - Prim	NCAPPRIM	0	55,555	3,540	896
43	UG Lines - Sec	SMX2ND	0	18,339	1,168	295
44	UG Svcs	CUST369	0	0	0	0
45	Total		0	75,928	4,840	1,224
46	959500 Maintain line transformers	SMXNCAP	0	12,642	806	203
47	959600 Maintain street lighting & signal systems	PLANT373	(3,991)	0	0	0
48	959700 Maintain meters	PLANT370	0	33	0	0
49	959800 Maintain distribution plant	OMMAINT	(223)	12,391	790	199
50	**Total Maintenance**		(4,252)	236,148	15,056	3,801
51	**Total Distribution Expenses**		4,196	408,791	26,024	6,571

Potomac Electric Power Company
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For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	**Total** DC Distribution	**Total** Residential Service	**Total** GS	**Total** GT-LV	**Total** GT-HV	**Total** GT	**Total** Metro	**Total** Street Lighting	**Total** TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
	Operation & Maintenance Expense, Cont'd.										
	Customer Accounts Expenses										
1	990200 Meter reading expenses	CUST902	382,133	131,113	81,300	121,976	46,579	168,555	920	246	0
2	990300 Cust records and collection exp	ACCT903	27,587,759	24,842,114	1,877,840	848,357	10,480	858,837	4,712	3,959	298
3	990500 Miscellaneous cust accounts exp		0	0	0	0	0	0	0	0	0
4	990400 Uncollectible accounts	CUST904	2,516,865	2,054,835	316,740	144,959	331	145,291	0	0	0
5	**Total Customer Accounts Expenses**		30,486,758	27,028,062	2,275,879	1,115,293	57,390	1,172,683	5,632	4,205	298
6											
7	**Customer Service Expenses**										
8	990700 Supervision	CUST907	0	0	0	0	0	0	0	0	0
9	990800 Customer assistance expenses	ACCT908	1,382,213	1,291,699	53,404	35,219	1,375	36,594	25	467	24
10	990900 Informational & instructional adv	CUST909	398,755	363,961	24,742	9,790	108	9,898	74	77	4
11	991000 Miscellaneous customer service & informa	CUST910	0	0	0	0	0	0	0	0	0
12	**Total Customer Service Expenses**		1,780,968	1,655,660	78,145	45,009	1,483	46,492	99	544	28
13											
14	**Sales Expense**										
15	991200 Demonstrating & selling expenses										
16	991300 Advertising expense	CUST913	0	0	0	0	0	0	0	0	0
17	**Total Sales Expense**		0	0	0	0	0	0	0	0	0
18											
19											
20	**Administrative & General Expense**										
21	**Operation**										
22	992000 Administrative & General salaries	OMLESAG	5,612,770	3,017,864	450,781	1,625,229	426,996	2,052,225	65,845	25,657	399
23	992100 Office supplies & expenses	OMLESAG	4,564,032	2,453,980	366,553	1,321,557	347,213	1,668,770	53,542	20,863	324
24	992300 Outside services employed	OMLESAG	50,317,218	27,054,468	4,041,149	14,569,811	3,827,926	18,397,737	590,283	230,005	3,575
25	992400 Property insurance	STDPLT	551,209	214,553	46,299	218,474	57,587	276,062	8,773	5,464	59
26	992500 Injuries & damages	OMLESAG	2,434,345	1,308,894	195,511	704,887	185,195	890,082	28,558	11,128	173
27	992600 Employee pensions & benefits	OMLESAG	5,959,348	3,204,211	478,616	1,725,584	453,363	2,178,946	69,911	27,241	423
28	992800 Regulatory commission expenses	OMLESAG	4,097,916	2,203,360	329,118	1,186,589	311,752	1,498,342	48,074	18,732	291
29	992900 Duplicate charges-Credit	OMLESAG	6	3	0	2	0	2	0	0	0
30	993010 General ad expenses	OMLESAG	99,733	53,624	8,010	28,878	7,587	36,466	1,170	456	7
31	993020 Miscellaneous general expenses	OMLESAG	1,101,503	592,254	88,465	318,950	83,798	402,748	12,922	5,035	78
32	993100 Rents	OMLESAG	0	0	0	0	0	0	0	0	0
33	**Total Operation**		74,738,078	40,103,212	6,004,502	21,699,962	5,701,417	27,401,379	879,077	344,580	5,329
34	**Maintenance**										
35	993500 Maintenance of general plant	OMLESAG	(225)	(121)	(18)	(65)	(17)	(82)	(3)	(1)	(0)
36	**Total Maintenance**		(225)	(121)	(18)	(65)	(17)	(82)	(3)	(1)	(0)
37	**Total Administrative & General Exp**		74,737,853	40,103,090	6,004,484	21,699,897	5,701,400	27,401,297	879,074	344,579	5,329
38											
39	**Adjustments to O&M**	OMLESAG	815,260	438,347	65,476	236,066	62,022	298,087	9,564	3,727	58
40											
41	**Total Operation & Maintenance Expense**		172,632,290	92,738,790	13,866,723	50,046,127	13,148,804	63,194,932	2,027,497	792,065	12,284

Potomac Electric Power Company
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Line No.	Description	Allocator	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[C]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]
	Operation & Maintenance Expense, Cont'd.										
	Customer Accounts Expenses										
1	990200 Meter reading expenses	CUST902	129,162	1,951	81,116	184	87,196	34,780	297	46,281	920
2	990300 Cust records and collection exp	ACCT903	24,809,197	32,917	1,877,014	826	797,980	50,378	67	10,413	4,712
3	990500 Miscellaneous cust accounts exp										
4	990400 Uncollectible accounts	CUST904	2,043,155	11,680	314,671	2,069	50,578	94,382	0	331	0
5	**Total Customer Accounts Expenses**		26,981,514	46,548	2,272,801	3,079	935,754	179,539	364	57,025	5,632
6											
7	**Customer Service Expenses**										
8	990700 Supervision	CUST907	0	0	0	0	0	0	0	0	0
9	990800 Customer assistance expenses	ACCT908	1,290,254	1,445	53,369	35	33,035	2,184	9	1,367	25
10	990900 Informational & instructional adv	CUST909	363,541	420	24,739	2	9,520	270	1	107	74
11	991000 Miscellaneous customer service & informa	CUST910	0	0	0	0	0	0	0	0	0
12	**Total Customer Service Expenses**		1,653,795	1,865	78,108	37	42,554	2,454	9	1,473	99
13											
14	**Sales Expense**										
15	991200 Demonstrating & selling expenses										
16	991300 Advertising expense	CUST913	0	0	0	0	0	0	0	0	0
17	**Total Sales Expense**		0	0	0	0	0	0	0	0	0
18											
19											
20	**Administrative & General Expense**										
21	**Operation**										
22	992000 Administrative & General salaries	OMLESAG	2,930,810	87,054	450,346	435	886,502	738,727	1,528	425,468	65,845
23	992100 Office supplies & expenses	OMLESAG	2,383,192	70,788	366,200	353	720,861	600,697	1,243	345,970	53,542
24	992300 Outside services employed	OMLESAG	26,274,052	780,416	4,037,253	3,896	7,947,294	6,622,517	13,699	3,814,227	590,283
25	992400 Property insurance	STDPLT	200,982	13,571	46,272	27	138,227	80,247	644	56,943	8,773
26	992500 Injuries & damages	OMLESAG	1,271,138	37,756	195,322	189	384,490	320,397	663	184,532	28,558
27	992600 Employee pensions & benefits	OMLESAG	3,111,782	92,429	478,154	461	941,242	784,342	1,622	451,740	69,911
28	992800 Regulatory commission expenses	OMLESAG	2,139,801	63,558	328,800	317	647,240	539,349	1,116	310,637	48,074
29	992900 Duplicate charges-Credit	OMLESAG	3	0	0	0	1	1	0	0	0
30	993010 General ad expenses	OMLESAG	52,077	1,547	8,002	8	15,752	13,126	27	7,560	1,170
31	993020 Miscellaneous general expenses	OMLESAG	575,170	17,084	88,380	85	173,976	144,975	300	83,498	12,922
32	993100 Rents	OMLESAG	0	0	0	0	0	0	0	0	0
33	**Total Operation**		38,939,008	1,164,204	5,998,730	5,771	11,855,585	9,844,377	20,841	5,680,576	879,077
34	**Maintenance**										
35	993500 Maintenance of general plant	OMLESAG	(118)	(3)	(18)	(0)	(36)	(30)	(0)	(17)	(3)
36	**Total Maintenance**		(118)	(3)	(18)	(0)	(36)	(30)	(0)	(17)	(3)
37	**Total Administrative & General Exp**		38,938,890	1,164,200	5,998,712	5,771	11,855,549	9,844,348	20,841	5,680,559	879,074
38											
39	**Adjustments to O&M**	OMLESAG	425,703	12,645	65,413	63	128,765	107,301	222	61,800	9,564
40											
41	**Total Operation & Maintenance Expense**		90,056,255	2,682,535	13,853,371	13,352	27,317,371	22,728,757	47,493	13,101,311	2,027,497

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[V]	[W]	[X]	[Y]
	Operation & Maintenance Expense, Cont'd.					
	Customer Accounts Expenses					
1	990200 Meter reading expenses	CUST902	0	246	0	0
2	990300 Cust records and collection exp	ACCT903	0	3,882	77	298
3	990500 Miscellaneous cust accounts exp					
4	990400 Uncollectible accounts	CUST904	0	0	0	0
5	**Total Customer Accounts Expenses**		0	4,128	77	298
6						
7	**Customer Service Expenses**					
8	990700 Supervision	CUST907	0	0	0	0
9	990800 Customer assistance expenses	ACCT908	0	449	18	24
10	990900 Informational & instructional adv	CUST909	0	76	1	4
11	991000 Miscellaneous customer service & informa	CUST910	0	0	0	0
12	**Total Customer Service Expenses**		0	525	19	28
13						
14	**Sales Expense**					
15	991200 Demonstrating & selling expenses					
16	991300 Advertising expense	CUST913	0	0	0	0
17	**Total Sales Expense**		0	0	0	0
18						
19						
20	**Administrative & General Expense**					
21	**Operation**					
22	992000 Administrative & General salaries	OMLESAG	243	23,904	1,510	399
23	992100 Office supplies & expenses	OMLESAG	197	19,437	1,228	324
24	992300 Outside services employed	OMLESAG	2,175	214,292	13,538	3,575
25	992400 Property insurance	STDPLT	1,570	3,660	233	59
26	992500 Injuries & damages	OMLESAG	105	10,367	655	173
27	992600 Employee pensions & benefits	OMLESAG	258	25,380	1,603	423
28	992800 Regulatory commission expenses	OMLESAG	177	17,452	1,103	291
29	992900 Duplicate charges-Credit	OMLESAG	0	0	0	0
30	993010 General ad expenses	OMLESAG	4	425	27	7
31	993020 Miscellaneous general expenses	OMLESAG	48	4,691	296	78
32	993100 Rents	OMLESAG	0	0	0	0
33	**Total Operation**		4,777	319,609	20,194	5,329
34	**Maintenance**					
35	993500 Maintenance of general plant	OMLESAG	(0)	(1)	(0)	(0)
36	**Total Maintenance**		(0)	(1)	(0)	(0)
37	**Total Administrative & General Exp**		4,777	319,608	20,194	5,329
38						
39	**Adjustments to O&M**	OMLESAG	35	3,472	219	58
40						
41	**Total Operation & Maintenance Expense**		9,008	736,523	46,533	12,284

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	**Total** DC Distribution	**Total** Residential Service	**Total** GS	**Total** GT-LV	**Total** GT-HV	**Total** GT	**Total** Metro	**Total** Street Lighting	**Total** TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
	Depreciation & Amortization Expense										
	Depreciation & Amortization										
	Depreciation Expense										
1	Subtransmission	SUBTAED	7,059,170	1,913,758	521,024	2,917,294	1,439,856	4,357,149	204,220	62,067	951
2	Distribution - Primary	PLTPRIM	45,461,260	12,548,914	3,402,963	19,063,506	8,697,568	27,761,074	1,335,255	406,895	6,158
3	Distribution - Secondary	PLTSEC	35,581,291	18,140,111	3,341,250	13,870,605	0	13,870,605	0	225,910	3,414
4	Distribution - Customer	PLTCUST	13,551,061	7,665,057	1,329,811	4,152,160	31,277	4,183,437	12,104	360,653	0
5	General	DPPLTG	6,529,102	2,550,884	549,182	2,585,927	674,828	3,260,756	102,785	64,799	696
6	**Depreciation LESS AFUDC**		108,181,884	42,818,725	9,144,231	42,589,492	10,843,529	53,433,021	1,654,364	1,120,325	11,219
7	**AFUDC**										
8	Distribution	STAFUDC	654,037	177,311	48,273	270,289	133,404	403,693	18,921	5,751	88
9	General	STAFUDC	297,479	80,647	21,956	122,937	60,677	183,614	8,606	2,616	40
10	**AFUDC**		951,516	257,958	70,230	393,226	194,080	587,307	27,527	8,366	128
11	**Depreciation Expense Total**		109,133,401	43,076,683	9,214,460	42,982,718	11,037,609	54,020,328	1,681,892	1,128,691	11,347
12											
13	**Amortization Expense**										
14	Software	STDPLT	4,853,936	1,889,348	407,709	1,923,883	507,112	2,430,995	77,252	48,114	519
15	AMI Software	STDPLT	0	0	0	0	0	0	0	0	0
16	General	STDPLT	173,194	67,414	14,547	68,646	18,094	86,740	2,756	1,717	19
17	Credit Facility	STDPLT	82,575	32,141	6,936	32,729	8,627	41,356	1,314	819	9
18	Reg Assets - District of Columbia			0	0	0	0	0	0	0	0
19	DC AMI (2008)	CUST3701	60,708	52,523	6,259	1,746	101	1,848	74	5	0
20	DC AMI Expense	CUST3701	3,295,734	2,851,359	339,794	94,809	5,490	100,300	3,993	289	0
21	DC DLC Program Costs	STDPLT	2,848,400	1,108,713	239,253	1,128,978	297,585	1,426,563	45,333	28,234	305
22	DC Interval Billing Costs	INTERVBILL	916,800	866,102	50,525	110	7	116	0	57	0
23	DC AMI True Up	CUST3701	1,708,400	1,478,050	176,138	49,146	2,846	51,992	2,070	150	0
24	Annualization of regulatory assets	OMLESAG	(56,878)	(30,582)	(4,568)	(16,470)	(4,327)	(20,797)	(667)	(260)	(4)
25	Inclusion of Benning environmental Re	OMLESAG	288,000	154,851	23,130	83,393	21,910	105,303	3,379	1,316	20
26	Inclusion of Benning environmental Re	OMLESAG	48,000	25,809	3,855	13,899	3,652	17,550	563	219	3
27	Reflection of the Frederick Douglass B	SUBTAED	39,371	10,674	2,906	16,271	8,031	24,301	1,139	346	5
28	Amortization of PHISCO Deficient Del	OMLESAG	870,000	467,780	69,873	251,916	66,186	318,102	10,206	3,977	62
29	Reflection of Current Rate Case Costs	OMLESAG	1,244,263	669,013	99,931	360,288	94,658	454,946	14,597	5,688	88
30	Reflection of CTA Regulatory Asset	OMLESAG	1,892,000	1,017,287	151,953	547,846	143,936	691,781	22,196	8,649	134
31	Reflection of CTO Regulatory Asset	OMLESAG	248,000	133,344	19,918	71,811	18,867	90,677	2,909	1,134	18
32	AFUDC	STAFUDC	64,265	17,422	4,743	26,558	13,108	39,666	1,859	565	9
33	**Amortization Expense Total**		18,576,768	10,811,248	1,612,903	4,655,559	1,205,882	5,861,441	188,972	101,017	1,187
34											
35	**Total Depreciation and Amortization**		127,710,169	53,887,931	10,827,363	47,638,278	12,243,491	59,881,769	1,870,864	1,229,708	12,534

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[C]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]
	Depreciation & Amortization Expense										
	Depreciation & Amortization										
	Depreciation Expense										
1	Subtransmission	SUBTAED	1,724,961	188,797	520,461	563	1,832,188	1,085,105	107,956	1,331,900	204,220
2	Distribution - Primary	PLTPRIM	11,314,586	1,234,329	3,399,305	3,658	11,979,651	7,083,855	0	8,697,568	1,335,255
3	Distribution - Secondary	PLTSEC	17,331,214	808,897	3,341,250	0	8,851,726	5,018,879	0	0	0
4	Distribution - Customer	PLTCUST	7,416,000	249,057	1,329,172	639	2,655,585	1,496,574	466	30,811	12,104
5	General	DPPLTG	2,390,346	160,538	548,869	313	1,636,250	949,678	7,701	667,127	102,785
6	**Depreciation LESS AFUDC**		40,177,107	2,641,618	9,139,058	5,173	26,955,400	15,634,091	116,123	10,727,406	1,654,364
7	**AFUDC**										
8	Distribution	STAFUDC	159,819	17,492	48,221	52	169,754	100,536	10,002	123,401	18,921
9	General	STAFUDC	72,691	7,956	21,933	24	77,210	45,727	4,549	56,127	8,606
10	**AFUDC**		232,510	25,448	70,154	76	246,963	146,263	14,552	179,529	27,527
11	**Depreciation Expense Total**		40,409,617	2,667,066	9,209,211	5,249	27,202,364	15,780,354	130,675	10,906,935	1,681,892
12											
13	**Amortization Expense**										
14	Software	STDPLT	1,769,842	119,507	407,474	235	1,217,224	706,658	5,669	501,443	77,252
15	AMI Software	STDPLT	0	0	0	0	0	0	0	0	0
16	General	STDPLT	63,150	4,264	14,539	8	43,432	25,214	202	17,892	2,756
17	Credit Facility	STDPLT	30,108	2,033	6,932	4	20,707	12,022	96	8,530	1,314
18	Reg Assets - District of Columbia										
19	DC AMI (2008)	CUST3701	52,167	356	6,256	3	1,415	332	0	101	74
20	DC AMI Expense	CUST3701	2,832,052	19,306	339,634	160	76,796	18,014	0	5,490	3,993
21	DC DLC Program Costs	STDPLT	1,038,583	70,129	239,115	138	714,295	414,683	3,327	294,258	45,333
22	DC Interval Billing Costs	INTERVBILL	863,231	2,871	50,525	0	110	0	0	7	0
23	DC AMI True Up	CUST3701	1,468,043	10,008	176,055	83	39,808	9,338	0	2,846	2,070
24	Annualization of regulatory assets	OMLESAG	(29,700)	(882)	(4,564)	(4)	(8,984)	(7,486)	(15)	(4,312)	(667)
25	Inclusion of Benning environmental Re	OMLESAG	150,384	4,467	23,108	22	45,488	37,905	78	21,831	3,379
26	Inclusion of Benning environmental Re	OMLESAG	25,064	744	3,851	4	7,581	6,318	13	3,639	563
27	Reflection of the Frederick Douglass B	SUBTAED	9,621	1,053	2,903	3	10,219	6,052	602	7,428	1,139
28	Amortization of PHISCO Deficient Del	OMLESAG	454,286	13,494	69,805	67	137,411	114,505	237	65,949	10,206
29	Reflection of Current Rate Case Costs	OMLESAG	649,714	19,298	99,835	96	196,524	163,764	339	94,320	14,597
30	Reflection of CTA Regulatory Asset	OMLESAG	987,942	29,345	151,807	147	298,830	249,016	515	143,420	22,196
31	Reflection of CTO Regulatory Asset	OMLESAG	129,498	3,846	19,899	19	39,170	32,641	68	18,799	2,909
32	AFUDC	STAFUDC	15,704	1,719	4,738	5	16,680	9,879	983	12,125	1,859
33	**Amortization Expense Total**		10,509,690	301,559	1,611,913	990	2,856,705	1,798,854	12,114	1,193,768	188,972
34											
35	**Total Depreciation and Amortization**		50,919,306	2,968,625	10,821,124	6,239	30,059,069	17,579,209	142,788	12,100,703	1,870,864

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[V]	[W]	[X]	[Y]
	Depreciation & Amortization Expense					
	Depreciation & Amortization					
	Depreciation Expense					
1	Subtransmission	SUBTAED	0	58,292	3,775	951
2	Distribution - Primary	PLTPRIM	0	382,520	24,375	6,158
3	Distribution - Secondary	PLTSEC	0	212,377	13,533	3,414
4	Distribution - Customer	PLTCUST	360,369	284	0	0
5	General	DPPLTG	18,841	43,202	2,756	696
6	**Depreciation LESS AFUDC**		379,210	696,675	44,440	11,219
7	**AFUDC**					
8	Distribution	STAFUDC	0	5,401	350	88
9	General	STAFUDC	0	2,456	159	40
10	**AFUDC**		0	7,857	509	128
11	**Depreciation Expense Total**		379,210	704,532	44,949	11,347
12						
13	**Amortization Expense**					
14	Software	STDPLT	13,830	32,228	2,056	519
15	AMI Software	STDPLT	0	0	0	0
16	General	STDPLT	493	1,150	73	19
17	Credit Facility	STDPLT	235	548	35	9
18	Reg Assets - District of Columbia					
19	DC AMI (2008)	CUST3701	0	5	0	0
20	DC AMI Expense	CUST3701	0	289	0	0
21	DC DLC Program Costs	STDPLT	8,115	18,912	1,207	305
22	DC Interval Billing Costs	INTERVBILL	0	57	0	0
23	DC AMI True Up	CUST3701	0	150	0	0
24	Annualization of regulatory assets	OMLESAG	(2)	(242)	(15)	(4)
25	Inclusion of Benning environmental Re	OMLESAG	12	1,227	77	20
26	Inclusion of Benning environmental Re	OMLESAG	2	204	13	3
27	Reflection of the Frederick Douglass B	SUBTAED	0	325	21	5
28	Amortization of PHISCO Deficient Del	OMLESAG	38	3,705	234	62
29	Reflection of Current Rate Case Costs	OMLESAG	54	5,299	335	88
30	Reflection of CTA Regulatory Asset	OMLESAG	82	8,058	509	134
31	Reflection of CTO Regulatory Asset	OMLESAG	11	1,056	67	18
32	AFUDC	STAFUDC	0	531	34	9
33	**Amortization Expense Total**		22,870	73,501	4,646	1,187
34						
35	**Total Depreciation and Amortization**		402,080	778,033	49,595	12,534

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	**Total** DC Distribution	**Total** Residential Service	**Total** GS	**Total** GT-LV	**Total** GT-HV	**Total** GT	**Total** Metro	**Total** Street Lighting	**Total** TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
	Other Taxes & Expenses										
	Other Taxes										
1	Payroll Taxes - FICA	OMLESAG	2,641,102	1,420,063	212,116	764,755	200,924	965,680	30,983	12,073	188
2	PSOS	DCPSOS	22,836,435	5,162,886	1,777,776	9,678,673	5,354,192	15,032,865	682,278	175,338	5,293
3	RETF/EATF/SETF	DCEASETF	20,011,407	4,275,950	1,596,275	8,690,072	4,674,368	13,364,440	612,570	157,424	4,750
4	Bus Improvement	STDPLT	0	0	0	0	0	0	0	0	0
5	PSC	STDPLT	9,549,070	3,716,884	802,080	3,784,823	997,633	4,782,456	151,976	94,653	1,021
6	Delivery Tax	DELIV	83,200,953	17,459,601	6,612,855	36,002,330	19,916,351	55,918,681	2,537,910	652,216	19,688
7	DC Ballpark Fee	STDPLT	175,011	68,121	14,700	69,366	18,284	87,651	2,785	1,735	19
8	Use	OMLESAG	282,238	151,753	22,668	81,725	21,471	103,196	3,311	1,290	20
9	Federal Highway Use Tax	OMLESAG	5,430	2,920	436	1,572	413	1,985	64	25	0
10	Property Taxes										
11	Subtransmission	SUBTAED	2,090,488	566,736	154,295	863,921	426,396	1,290,317	60,477	18,381	282
12	Distribution	DISTPLT	4,994,089	1,992,518	423,674	1,972,475	480,810	2,453,284	74,126	49,964	523
13	**Total Other Taxes Less Gross Receipts**		145,786,223	34,817,432	11,616,874	61,909,712	32,090,843	94,000,556	4,156,480	1,163,098	31,783
14	Gross Receipts	ELECSAL	0	0	0	0	0	0	0	0	0
15	**Total Other Taxes**		145,786,223	34,817,432	11,616,874	61,909,712	32,090,843	94,000,556	4,156,480	1,163,098	31,783

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[C]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]
	Other Taxes & Expenses										
	Other Taxes										
1	Payroll Taxes - FICA	OMLESAG	1,379,100	40,963	211,912	205	417,146	347,610	719	200,205	30,983
2	PSOS	DCPSOS	4,529,837	633,048	1,775,386	2,390	3,555,585	6,123,088	386,852	4,967,340	682,278
3	RETF/EATF/SETF	DCEASETF	3,707,561	568,388	1,594,129	2,146	3,192,223	5,497,849	214,499	4,459,869	612,570
4	Bus Improvement	STDPLT	0	0	0	0	0	0	0	0	0
5	PSC	STDPLT	3,481,780	235,104	801,617	462	2,394,625	1,390,198	11,153	986,481	151,976
6	Delivery Tax	DELIV	15,318,873	2,140,729	6,603,966	8,889	13,225,938	22,776,392	1,438,997	18,477,354	2,537,910
7	DC Ballpark Fee	STDPLT	63,812	4,309	14,692	8	43,888	25,479	204	18,080	2,785
8	Use	OMLESAG	147,376	4,377	22,646	22	44,578	37,147	77	21,395	3,311
9	Federal Highway Use Tax	OMLESAG	2,835	84	436	0	858	715	1	412	64
10	Property Taxes										
11	Subtransmission	SUBTAED	510,826	55,910	154,128	167	542,580	321,341	31,970	394,426	60,477
12	Distribution	DISTPLT	1,870,435	122,083	423,445	229	1,248,758	723,716	20	480,790	74,126
13	**Total Other Taxes Less Gross Receipts**		31,012,436	3,804,996	11,602,356	14,518	24,666,179	37,243,533	2,084,493	30,006,350	4,156,480
14	Gross Receipts	ELECSAL	0	0	0	0	0	0	0	0	0
15	**Total Other Taxes**		31,012,436	3,804,996	11,602,356	14,518	24,666,179	37,243,533	2,084,493	30,006,350	4,156,480

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[V]	[W]	[X]	[Y]
	Other Taxes & Expenses					
	Other Taxes					
1	Payroll Taxes - FICA	OMLESAG	114	11,248	711	188
2	PSOS	DCPSOS	0	153,701	21,637	5,293
3	RETF/EATF/SETF	DCEASETF	0	137,997	19,427	4,750
4	Bus Improvement	STDPLT	0	0	0	0
5	PSC	STDPLT	27,207	63,401	4,045	1,021
6	Delivery Tax	DELIV	0	571,731	80,485	19,688
7	DC Ballpark Fee	STDPLT	499	1,162	74	19
8	Use	OMLESAG	12	1,202	76	20
9	Federal Highway Use Tax	OMLESAG	0	23	1	0
10	Property Taxes					
11	Subtransmission	SUBTAED	0	17,263	1,118	282
12	Distribution	DISTPLT	15,401	32,493	2,070	523
13	**Total Other Taxes Less Gross Receipts**		43,233	990,221	129,644	31,783
14	Gross Receipts	ELECSAL	0	0	0	0
15	**Total Other Taxes**		43,233	990,221	129,644	31,783

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	**Total** DC Distribution	**Total** Residential Service	**Total** GS	**Total** GT-LV	**Total** GT-HV	**Total** GT	**Total** Metro	**Total** Street Lighting	**Total** TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
	Development Of Income Taxes										
	Federal & State Tax Calculation										
1	**Operating Revenues**		535,264,357	120,313,253	57,274,477	261,561,429	83,034,992	344,596,421	10,659,285	2,318,124	102,796
2	**Operating Expenses**										
3	Operation & Maintenance Expense		172,632,290	92,738,790	13,866,723	50,046,127	13,148,804	63,194,932	2,027,497	792,065	12,284
4	Depreciation and Amortization		127,710,169	53,887,931	10,827,363	47,638,278	12,243,491	59,881,769	1,870,864	1,229,708	12,534
5	Taxes Other than Income Tax		145,786,223	34,817,432	11,616,874	61,909,712	32,090,843	94,000,556	4,156,480	1,163,098	31,783
6	OPERATING INC BEFORE FED TAX		89,135,674	(61,130,901)	20,963,517	101,967,311	25,551,853	127,519,165	2,604,444	(866,746)	46,196
7											
8	**Taxable Income before FIT Adjustments**		89,135,674	(61,130,901)	20,963,517	101,967,311	25,551,853	127,519,165	2,604,444	(866,746)	46,196
9	Interest Expense	STDPLT	56,668,810	22,057,793	4,759,929	22,460,973	5,920,439	28,381,413	901,897	561,717	6,060
10	Interest on Customer Deps	CUSTDEP	329,490	98,667	36,112	141,156	53,523	194,679	0	0	32
11	LESS: Total Interest Expense		56,998,300	22,156,460	4,796,041	22,602,129	5,973,962	28,576,092	901,897	561,717	6,092
12	**Schedule M**										
13	MD Prop Tax Adjustment - MD	MDPTAX	0	0	0	0	0	0	0	0	0
14	MD Prop Tax Adjustment - Subt	SUBTAED	47,909	12,988	3,536	19,799	9,772	29,571	1,386	421	6
15	Removal Cost Adjustment	DEPRE	0	0	0	0	0	0	0	0	0
16	Tax Allocation from Service Co.	STDPLT	0	0	0	0	0	0	0	0	0
17	Software Amortization	STDPLT	0	0	0	0	0	0	0	0	0
18	Tax Depreciation	DEPRE	0	0	0	0	0	0	0	0	0
19	Tax Depreciation AFUDC DC	STAFUDC	0	0	0	0	0	0	0	0	0
20	Excess Tax/Book Depreciation	DEPRE	(2,306,925)	(913,088)	(194,996)	(908,200)	(231,233)	(1,139,433)	(35,278)	(23,890)	(239)
21	Normalization Adjustment	STDPLT	0	0	0	0	0	0	0	0	0
22	Non-Deductible Meal Exp	OMLESAG	(428,370)	(230,325)	(34,404)	(124,038)	(32,589)	(156,627)	(5,025)	(1,958)	(30)
23	OPEB Medicare Subsidy	OMLESAG	0	0	0	0	0	0	0	0	0
24	Diesel Fuel Credit	OMLESAG	0	0	0	0	0	0	0	0	0
25	Control Center AFUDC	STAFUDC	0	0	0	0	0	0	0	0	0
26	**Total Schedule M**		(2,687,385)	(1,130,425)	(225,864)	(1,012,439)	(254,049)	(1,266,488)	(38,918)	(25,427)	(263)
27	TAXABLE INCOME FOR STATE		34,824,760	(82,156,937)	16,393,340	80,377,621	19,831,941	100,209,562	1,741,465	(1,403,036)	40,367
28	State Income Taxes (taxable amount * rate)		3,495,040	(8,245,334)	1,645,248	8,066,761	1,990,349	10,057,110	174,775	(140,810)	4,051
29	Reflection of Additional Subtraction Modificat	STDPLT	(757,000)	(294,655)	(63,585)	(300,041)	(79,087)	(379,128)	(12,048)	(7,504)	(81)
30	Excess Deferred State Tax Amortization	STDPLT-LESSRSL	(9,754,040)	(383,953)	(1,309,893)	(6,181,075)	(1,629,256)	(7,810,331)	(248,195)	0	(1,668)
31	Total State Income Taxes		(7,016,000)	(8,923,942)	271,770	1,585,645	282,006	1,867,650	(85,468)	(148,313)	2,303
32	TAXABLE INCOME FOR FEDERAL		41,840,760	(73,232,994)	16,121,569	78,791,976	19,549,935	98,341,911	1,826,933	(1,254,723)	38,064
33	**Federal Income Taxes**		8,771,360	(15,352,325)	3,379,673	16,517,692	4,098,384	20,616,076	382,992	(263,036)	7,980
34	ITC Adjustment	STDPLT	(70,057)	(27,269)	(5,884)	(27,767)	(7,319)	(35,087)	(1,115)	(694)	(7)
35	Excess Deferred Income Tax	STDPLT-LESSRSL	(18,864,303)	(742,565)	(2,533,332)	(11,954,192)	(3,150,980)	(15,105,172)	(480,008)	0	(3,225)
36	**Total Federal Income Taxes**		(10,163,000)	(16,122,159)	840,456	4,535,732	940,085	5,475,818	(98,131)	(263,730)	4,747
37	**Total Income Taxes**		(17,179,000)	(25,046,102)	1,112,227	6,121,377	1,222,091	7,343,468	(183,599)	(412,044)	7,050
38	**Total Expenses**		428,949,682	156,398,052	37,423,187	165,715,494	58,705,230	224,420,724	7,871,242	2,772,827	63,650
39	**Net Operating Income**		106,314,674	(36,084,799)	19,851,290	95,845,934	24,329,762	120,175,697	2,788,043	(454,703)	39,146
40	AFUDC at Present ROR	CWIPSTD	0	0	0	0	0	0	0	0	0
41	**Net Operating Income for ROR Calculation**		106,314,674	(36,084,799)	19,851,290	95,845,934	24,329,762	120,175,697	2,788,043	(454,703)	39,146

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[C]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]
	Development Of Income Taxes										
	Federal & State Tax Calculation										
1	**Operating Revenues**		106,392,866	13,920,387	57,209,091	65,386	153,062,661	108,498,767	2,491,494	80,543,498	10,659,285
2	**Operating Expenses**										
3	Operation & Maintenance Expense		90,056,255	2,682,535	13,853,371	13,352	27,317,371	22,728,757	47,493	13,101,311	2,027,497
4	Depreciation and Amortization		50,919,306	2,968,625	10,821,124	6,239	30,059,069	17,579,209	142,788	12,100,703	1,870,864
5	Taxes Other than Income Tax		31,012,436	3,804,996	11,602,356	14,518	24,666,179	37,243,533	2,084,493	30,006,350	4,156,480
6	OPERATING INC BEFORE FED TAX		(65,595,132)	4,464,231	20,932,239	31,278	71,020,043	30,947,269	216,719	25,335,134	2,604,444
7											
8	**Taxable Income before FIT Adjustments**		(65,595,132)	4,464,231	20,932,239	31,278	71,020,043	30,947,269	216,719	25,335,134	2,604,444
9	Interest Expense	STDPLT	20,662,572	1,395,221	4,757,185	2,744	14,210,867	8,250,106	66,185	5,854,254	901,897
10	Interest on Customer Deps	CUSTDEP	90,681	7,986	36,077	35	90,569	50,587	0	53,523	0
11	LESS: Total Interest Expense		20,753,254	1,403,207	4,793,261	2,780	14,301,436	8,300,694	66,185	5,907,777	901,897
12	**Schedule M**										
13	MD Prop Tax Adjustment - MD	MDPTAX	0	0	0	0	0	0	0	0	0
14	MD Prop Tax Adjustment - Subt	SUBTAED	11,707	1,281	3,532	4	12,435	7,364	733	9,039	1,386
15	Removal Cost Adjustment	DEPRE	0	0	0	0	0	0	0	0	0
16	Tax Allocation from Service Co.	STDPLT	0	0	0	0	0	0	0	0	0
17	Software Amortization	STDPLT	0	0	0	0	0	0	0	0	0
18	Tax Depreciation	DEPRE	0	0	0	0	0	0	0	0	0
19	Tax Depreciation AFUDC DC	STAFUDC	0	0	0	0	0	0	0	0	0
20	Excess Tax/Book Depreciation	DEPRE	(856,757)	(56,331)	(194,886)	(110)	(574,811)	(333,389)	(2,476)	(228,757)	(35,278)
21	Normalization Adjustment	STDPLT	0	0	0	0	0	0	0	0	0
22	Non-Deductible Meal Exp	OMLESAG	(223,681)	(6,644)	(34,371)	(33)	(67,658)	(56,380)	(117)	(32,472)	(5,025)
23	OPEB Medicare Subsidy	OMLESAG	0	0	0	0	0	0	0	0	0
24	Diesel Fuel Credit	OMLESAG	0	0	0	0	0	0	0	0	0
25	Control Center AFUDC	STAFUDC	0	0	0	0	0	0	0	0	0
26	**Total Schedule M**		(1,068,731)	(61,694)	(225,724)	(140)	(630,034)	(382,405)	(1,860)	(252,189)	(38,918)
27	TAXABLE INCOME FOR STATE		(85,279,655)	3,122,718	16,364,702	28,638	57,348,641	23,028,980	152,394	19,679,546	1,741,465
28	State Income Taxes (taxable amount * rate)		(8,558,732)	313,398	1,642,374	2,874	5,755,554	2,311,206	15,294	1,975,055	174,775
29	Reflection of Additional Subtraction Modificat	STDPLT	(276,017)	(18,638)	(63,548)	(37)	(189,833)	(110,208)	(884)	(78,203)	(12,048)
30	Excess Deferred State Tax Amortization	STDPLT-LESSRSL	0	(383,953)	(1,309,138)	(755)	(3,910,714)	(2,270,361)	(18,214)	(1,611,043)	(248,195)
31	Total State Income Taxes		(8,834,750)	(89,193)	269,688	2,082	1,655,007	(69,363)	(3,803)	285,809	(85,468)
32	TAXABLE INCOME FOR FEDERAL		(76,444,905)	3,211,911	16,095,014	26,555	55,693,634	23,098,342	156,198	19,393,737	1,826,933
33	**Federal Income Taxes**		(16,025,659)	673,334	3,374,106	5,567	11,675,431	4,842,261	32,745	4,065,640	382,992
34	ITC Adjustment	STDPLT	(25,544)	(1,725)	(5,881)	(3)	(17,568)	(10,199)	(82)	(7,237)	(1,115)
35	Excess Deferred Income Tax	STDPLT-LESSRSL	0	(742,565)	(2,531,872)	(1,461)	(7,563,316)	(4,390,876)	(35,225)	(3,115,755)	(480,008)
36	**Total Federal Income Taxes**		(16,051,204)	(70,956)	836,353	4,103	4,094,547	441,185	(2,562)	942,648	(98,131)
37	**Total Income Taxes**		(24,885,953)	(160,148)	1,106,041	6,185	5,749,554	371,823	(6,365)	1,228,457	(183,599)
38	**Total Expenses**		147,102,044	9,296,008	37,382,893	40,294	87,792,173	77,923,321	2,268,409	56,436,821	7,871,242
39	**Net Operating Income**		(40,709,179)	4,624,380	19,826,198	25,092	65,270,488	30,575,446	223,085	24,106,678	2,788,043
40	AFUDC at Present ROR	CWIPSTD	0	0	0	0	0	0	0	0	0
41	**Net Operating Income for ROR Calculation**		(40,709,179)	4,624,380	19,826,198	25,092	65,270,488	30,575,446	223,085	24,106,678	2,788,043

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[V]	[W]	[X]	[Y]
	Development Of Income Taxes					
	Federal & State Tax Calculation					
1	**Operating Revenues**		631,344	1,354,209	332,571	102,796
2	**Operating Expenses**					
3	Operation & Maintenance Expense		9,008	736,523	46,533	12,284
4	Depreciation and Amortization		402,080	778,033	49,595	12,534
5	Taxes Other than Income Tax		43,233	990,221	129,644	31,783
6	OPERATING INC BEFORE FED TAX		177,023	(1,150,569)	106,800	46,196
7						
8	**Taxable Income before FIT Adjustments**		177,023	(1,150,569)	106,800	46,196
9	Interest Expense	STDPLT	161,457	376,255	24,005	6,060
10	Interest on Customer Deps	CUSTDEP	0	0	0	32
11	LESS: Total Interest Expense		161,457	376,255	24,005	6,092
12	**Schedule M**					
13	MD Prop Tax Adjustment - MD	MDPTAX	0	0	0	0
14	MD Prop Tax Adjustment - Subt	SUBTAED	0	396	26	6
15	Removal Cost Adjustment	DEPRE	0	0	0	0
16	Tax Allocation from Service Co.	STDPLT	0	0	0	0
17	Software Amortization	STDPLT	0	0	0	0
18	Tax Depreciation	DEPRE	0	0	0	0
19	Tax Depreciation AFUDC DC	STAFUDC	0	0	0	0
20	Excess Tax/Book Depreciation	DEPRE	(8,086)	(14,856)	(948)	(239)
21	Normalization Adjustment	STDPLT	0	0	0	0
22	Non-Deductible Meal Exp	OMLESAG	(19)	(1,824)	(115)	(30)
23	OPEB Medicare Subsidy	OMLESAG	0	0	0	0
24	Diesel Fuel Credit	OMLESAG	0	0	0	0
25	Control Center AFUDC	STAFUDC	0	0	0	0
26	**Total Schedule M**		(8,105)	(16,285)	(1,037)	(263)
27	TAXABLE INCOME FOR STATE		23,671	(1,510,539)	83,832	40,367
28	State Income Taxes (taxable amount * rate)		2,376	(151,599)	8,413	4,051
29	Reflection of Additional Subtraction Modificat	STDPLT	(2,157)	(5,026)	(321)	(81)
30	Excess Deferred State Tax Amortization	STDPLT-LESSRSL	0	0	0	(1,668)
31	Total State Income Taxes		219	(156,625)	8,093	2,303
32	TAXABLE INCOME FOR FEDERAL		23,452	(1,353,914)	75,739	38,064
33	**Federal Income Taxes**		4,916	(283,830)	15,878	7,980
34	ITC Adjustment	STDPLT	(200)	(465)	(30)	(7)
35	Excess Deferred Income Tax	STDPLT-LESSRSL	0	0	0	(3,225)
36	**Total Federal Income Taxes**		4,717	(284,295)	15,848	4,747
37	**Total Income Taxes**		4,936	(440,920)	23,941	7,050
38	**Total Expenses**		459,257	2,063,858	249,712	63,650
39	**Net Operating Income**		172,087	(709,649)	82,859	39,146
40	AFUDC at Present ROR	CWIPSTD	0	0	0	0
41	**Net Operating Income for ROR Calculation**		172,087	(709,649)	82,859	39,146

L. Schafer
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (E) – 2

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Total DC Distribution	Total Residential Service	Total GS	Total GT-LV	Total GT-HV	Total GT	Total Metro	Total Street Lighting	Total TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
	Total Company - All Functions									
	Present Rates									
1	Rate Base	2,183,820,615	888,485,613	183,060,821	836,852,373	220,593,962	1,057,446,335	33,913,495	20,688,594	225,758
2	Net Operating Income (Present Rates)	106,314,674	(36,084,799)	19,851,290	95,845,934	24,329,762	120,175,697	2,788,043	(454,703)	39,146
3	Rate of Return (Present Rates)	4.87%	-4.06%	10.84%	11.45%	11.03%	11.36%	8.22%	-2.20%	17.34%
4	Relative Rate of Return	1.00	-0.83	2.23	2.35	2.27	2.33	1.69	-0.45	3.56
5	Sales Revenue (Present Rates)	528,475,591	115,676,220	56,692,489	260,456,123	82,613,157	343,069,280	10,631,794	2,303,631	102,177
6	Revenue Present Rates $/kWh	$0.0476	$0.0466	$0.0653	$0.0542	$0.0329	$0.0469	$0.0319	$0.0257	$0.0392
7	Revenue Required - $/Mo/Customer	$145.71	$34.97	$207.76	$6,164.35	$43,966.56	$7,773.88	$9,133.84	$6,192.56	$2,838.25
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
13	Return Required Proposed Rate of Return	170,556,390	69,390,726	14,297,050	65,358,170	17,228,388	82,586,559	2,648,644	1,615,779	17,632
14	Sales Revenue Required Proposed ROR	617,106,248	261,194,829	49,029,619	218,393,882	72,815,794	291,209,676	10,439,473	5,160,157	72,494
15	Revenue Deficiency Sales Revenue	88,630,657	145,518,609	(7,662,870)	(42,062,241)	(9,797,363)	(51,859,605)	(192,321)	2,856,526	(29,682)
16	Percent Increase Required	16.77%	125.80%	-13.52%	-16.15%	-11.86%	-15.12%	-1.81%	124.00%	-29.05%
17	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
18	Sales Revenue Required $/kWh	$0.0556	$0.1052	$0.0564	$0.0454	$0.0290	$0.0398	$0.0313	$0.0575	$0.0278
19	Revenue Deficiency $/kWh	$0.0080	$0.0586	($0.0088)	($0.0088)	($0.0039)	($0.0071)	($0.0006)	$0.0318	($0.0114)
20										
21										
22										
23										
24										
25										
26										
27	**Demand Total**									
28										
29	**Present Rates**									
30										
31	Rate Base	1,878,250,279	690,667,958	154,224,429	764,632,153	219,913,765	984,545,918	33,650,611	14,936,057	225,306
32	Net Operating Income (Present Rates)	103,708,428	(27,048,803)	16,724,368	87,598,678	24,254,752	111,853,430	2,766,431	(626,066)	39,068
33	Rate of Return (Present Rates)	5.52%	-3.92%	10.84%	11.46%	11.03%	11.36%	8.22%	-4.19%	17.34%
34	Relative Rate of Return	1.00	-0.71	1.96	2.07	2.00	2.06	1.49	-0.76	3.14
35	Sales Revenue (Present Rates)	431,817,133	57,374,187	44,903,472	235,033,627	82,210,511	317,244,138	10,530,840	1,662,990	101,505
36	Revenue Present Rates $/kWh	$0.0389	$0.0231	$0.0517	$0.0489	$0.0327	$0.0434	$0.0316	$0.0185	$0.0390
37	Revenue Required - $/Mo/Customer	$119.06	$17.34	$164.55	$5,562.66	$43,752.27	$7,188.69	$9,047.11	$4,470.40	$2,819.59
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	146,691,347	53,941,168	12,044,928	59,717,771	17,175,265	76,893,036	2,628,113	1,166,506	17,596
44	Sales Revenue Required Proposed ROR	491,118,231	169,111,463	38,447,513	196,567,920	72,443,344	269,011,263	10,340,010	4,136,100	71,882
45	Revenue Deficiency Sales Revenue	59,301,098	111,737,275	(6,455,959)	(38,465,707)	(9,767,168)	(48,232,875)	(190,830)	2,473,110	(29,623)
46	Percent Increase Required	13.73%	194.75%	-14.38%	-16.37%	-11.88%	-15.20%	-1.81%	148.71%	-29.18%
47	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
48	Sales Revenue Required $/kWh	$0.0443	$0.0681	$0.0443	$0.0409	$0.0288	$0.0368	$0.0310	$0.0461	$0.0276
49	Revenue Deficiency $/kWh	$0.0053	$0.0450	($0.0074)	($0.0080)	($0.0039)	($0.0066)	($0.0006)	$0.0275	($0.0114)

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]
	Total Company - All Functions									
	Present Rates									
1	Rate Base	836,513,670	51,971,942	182,953,603	107,218	527,822,823	309,029,550	2,122,406	218,471,556	33,913,495
2	Net Operating Income (Present Rates)	(40,709,179)	4,624,380	19,826,198	25,092	65,270,488	30,575,446	223,085	24,106,678	2,788,043
3	Rate of Return (Present Rates)	-4.87%	8.90%	10.84%	23.40%	12.37%	9.89%	10.51%	11.03%	8.22%
4	Relative Rate of Return	-1.00	1.83	2.23	4.81	2.54	2.03	2.16	2.27	1.69
5	Sales Revenue (Present Rates)	101,836,108	13,840,112	56,627,278	65,211	152,329,951	108,126,172	2,491,481	80,121,676	10,631,794
6	Revenue Present Rates $/kWh	$0.0466	$0.0469	$0.0653	$0.0573	$0.0515	$0.0586	$0.0130	$0.0345	$0.0319
7	Revenue Required - $/Mo/Customer	$30.89	$1,176.58	$207.57	$1,003.25	$3,910.71	$32,765.51	$207,623.42	$42,914.66	$9,133.84
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
13	Return Required Proposed Rate of Return	65,331,718	4,059,009	14,288,676	8,374	41,222,962	24,135,208	165,760	17,062,629	2,648,644
14	Sales Revenue Required Proposed ROR	248,134,727	13,060,101	48,987,474	42,145	119,152,942	99,240,940	2,412,393	70,403,400	10,439,473
15	Revenue Deficiency Sales Revenue	146,298,619	(780,010)	(7,639,805)	(23,066)	(33,177,009)	(8,885,232)	(79,088)	(9,718,276)	(192,321)
16	Percent Increase Required	143.66%	-5.64%	-13.49%	-35.37%	-21.78%	-8.22%	-3.17%	-12.13%	-1.81%
17	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
18	Sales Revenue Required $/kWh	$0.1134	$0.0443	$0.0565	$0.0371	$0.0402	$0.0538	$0.0126	$0.0303	$0.0313
19	Revenue Deficiency $/kWh	$0.0669	($0.0026)	($0.0088)	($0.0203)	($0.0112)	($0.0048)	($0.0004)	($0.0042)	($0.0006)
20										
21										
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25										
26										
27	**Demand Total**									
28										
29	**Present Rates**									
30										
31	Rate Base	642,988,674	47,679,284	154,133,114	91,315	483,252,045	281,380,108	2,113,891	217,799,875	33,650,611
32	Net Operating Income (Present Rates)	(31,291,229)	4,242,426	16,702,998	21,371	59,758,873	27,839,805	222,190	24,032,563	2,766,431
33	Rate of Return (Present Rates)	-4.87%	8.90%	10.84%	23.40%	12.37%	9.89%	10.51%	11.03%	8.22%
34	Relative Rate of Return	-0.88	1.61	1.96	4.24	2.24	1.79	1.90	2.00	1.49
35	Sales Revenue (Present Rates)	44,471,044	12,903,143	44,852,336	51,136	140,296,893	94,736,734	2,487,424	79,723,087	10,530,840
36	Revenue Present Rates $/kWh	$0.0203	$0.0437	$0.0517	$0.0450	$0.0474	$0.0513	$0.0130	$0.0344	$0.0316
37	Revenue Required - $/Mo/Customer	$13.49	$1,096.93	$164.41	$786.71	$3,601.79	$28,708.10	$207,285.32	$42,701.17	$9,047.11
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	50,217,415	3,723,752	12,037,796	7,132	37,741,985	21,975,786	165,095	17,010,170	2,628,113
44	Sales Revenue Required Proposed ROR	156,923,904	12,187,558	38,416,022	31,492	109,921,439	86,646,481	2,408,653	70,034,690	10,340,010
45	Revenue Deficiency Sales Revenue	112,452,860	(715,585)	(6,436,314)	(19,644)	(30,375,454)	(8,090,254)	(78,770)	(9,688,397)	(190,830)
46	Percent Increase Required	252.87%	-5.55%	-14.35%	-38.42%	-21.65%	-8.54%	-3.17%	-12.15%	-1.81%
47	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
48	Sales Revenue Required $/kWh	$0.0717	$0.0413	$0.0443	$0.0277	$0.0371	$0.0470	$0.0126	$0.0302	$0.0310
49	Revenue Deficiency $/kWh	$0.0514	($0.0024)	($0.0074)	($0.0173)	($0.0103)	($0.0044)	($0.0004)	($0.0042)	($0.0006)

Potomac Electric Power Company
District of Columbia
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For the Twelve Months Ended June 30, 2019

Line No.	Description	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[U]	[V]	[W]	[X]
	Total Company - All Functions				
	Present Rates				
1	Rate Base	5,737,819	14,054,777	895,998	225,758
2	Net Operating Income (Present Rates)	172,087	(709,649)	82,859	39,146
3	Rate of Return (Present Rates)	3.00%	-5.05%	9.25%	17.34%
4	Relative Rate of Return	0.62	-1.04	1.90	3.56
5	Sales Revenue (Present Rates)	631,344	1,340,533	331,754	102,177
6	Revenue Present Rates $/kWh	$0.0000	$0.0169	$0.0317	$0.0392
7	Revenue Required - $/Mo/Customer	$0.00	$3,989.68	$9,215.40	$2,838.25
8					
9					
10	**Proposed Rate of Return**				
11					
12	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%
13	Return Required Proposed Rate of Return	448,124	1,097,678	69,977	17,632
14	Sales Revenue Required Proposed ROR	1,012,176	3,833,999	313,982	72,494
15	Revenue Deficiency Sales Revenue	380,832	2,493,466	(17,772)	(29,682)
16	Percent Increase Required	60.32%	186.01%	-5.36%	-29.05%
17	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
18	Sales Revenue Required $/kWh	$0.0000	$0.0483	$0.0300	$0.0278
19	Revenue Deficiency $/kWh	$0.0000	$0.0314	($0.0017)	($0.0114)
20					
21					
22					
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24					
25					
26					
27	**Demand Total**				
28					
29	**Present Rates**				
30					
31	Rate Base	0	14,040,194	895,863	225,306
32	Net Operating Income (Present Rates)	0	(708,912)	82,846	39,068
33	Rate of Return (Present Rates)	0.00%	-5.05%	9.25%	17.34%
34	Relative Rate of Return	0.00	-0.91	1.67	3.14
35	Sales Revenue (Present Rates)	0	1,331,392	331,598	101,505
36	Revenue Present Rates $/kWh	$0.0000	$0.0168	$0.0317	$0.0390
37	Revenue Required - $/Mo/Customer	$0.00	$3,962.48	$9,211.06	$2,819.59
38					
39					
40	**Proposed Rate of Return**				
41					
42	Proposed Rate of Return	0.00%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	0	1,096,539	69,967	17,596
44	Sales Revenue Required Proposed ROR	0	3,822,271	313,829	71,882
45	Revenue Deficiency Sales Revenue	(0)	2,490,879	(17,769)	(29,623)
46	Percent Increase Required	0.00%	187.09%	-5.36%	-29.18%
47	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
48	Sales Revenue Required $/kWh	$0.0000	$0.0482	$0.0300	$0.0276
49	Revenue Deficiency $/kWh	$0.0000	$0.0314	($0.0017)	($0.0114)

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Total DC Distribution	Total Residential Service	Total GS	Total GT-LV	Total GT-HV	Total GT	Total Metro	Total Street Lighting	Total TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
	Energy Total									
	Present Rates									
1	Rate Base	0	0	0	0	0	0	0	0	0
2	Net Operating Income (Present Rates)	0	0	0	0	0	0	0	0	0
3	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	Relative Rate of Return	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	Sales Revenue (Present Rates)	(0)	0	0	0	0	0	0	0	0
6	Revenue Present Rates $/kWh	($0.0000)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	($0.00)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	Return Required Proposed Rate of Return	0	0	0	0	0	0	0	0	0
14	Sales Revenue Required Proposed ROR	(0)	0	0	0	0	0	0	0	0
15	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
16	Percent Increase Required	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
17	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
18	Sales Revenue Required $/kWh	($0.0000)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)
20										
21										
22										
23										
24										
25										
26										
27	**Customer Total**									
28										
29	**Present Rates**									
30										
31	Rate Base	305,570,336	197,817,654	28,836,392	72,220,220	680,197	72,900,417	262,884	5,752,537	452
32	Net Operating Income (Present Rates)	2,606,246	(9,035,996)	3,126,922	8,247,257	75,010	8,322,267	21,612	171,363	78
33	Rate of Return (Present Rates)	0.85%	-4.57%	10.84%	11.42%	11.03%	11.42%	8.22%	2.98%	17.34%
34	Relative Rate of Return	1.00	-5.36	12.71	13.39	12.93	13.38	9.64	3.49	20.33
35	Sales Revenue (Present Rates)	96,658,458	58,302,033	11,789,017	25,422,496	402,646	25,825,142	100,954	640,641	672
36	Revenue Present Rates $/kWh	$0.0087	$0.0235	$0.0136	$0.0053	$0.0002	$0.0035	$0.0003	$0.0071	$0.0003
37	Revenue Required - $/Mo/Customer	$26.65	$17.62	$43.20	$601.69	$214.29	$585.19	$86.73	$1,722.15	$18.65
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	23,865,043	15,449,559	2,252,122	5,640,399	53,123	5,693,523	20,531	449,273	35
44	Sales Revenue Required Proposed ROR	125,988,016	92,083,366	10,582,106	21,825,962	372,450	22,198,412	99,463	1,024,057	612
45	Revenue Deficiency Sales Revenue	29,329,558	33,781,333	(1,206,912)	(3,596,534)	(30,196)	(3,626,730)	(1,491)	383,416	(59)
46	Percent Increase Required	30.34%	57.94%	-10.24%	-14.15%	-7.50%	-14.04%	-1.48%	59.85%	-8.84%
47	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
48	Sales Revenue Required $/kWh	$0.0114	$0.0371	$0.0122	$0.0045	$0.0001	$0.0030	$0.0003	$0.0114	$0.0002
49	Revenue Deficiency $/kWh	$0.0026	$0.0136	($0.0014)	($0.0007)	($0.0000)	($0.0005)	($0.0000)	$0.0043	($0.0000)

Potomac Electric Power Company
District of Columbia
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Line No.	Description	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]
	Energy Total									
	Present Rates									
1	Rate Base	0	0	0	0	0	0	0	0	0
2	Net Operating Income (Present Rates)	0	0	0	0	0	0	0	0	0
3	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	Relative Rate of Return	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	Sales Revenue (Present Rates)	0	0	0	0	0	0	0	0	0
6	Revenue Present Rates $/kWh	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	Return Required Proposed Rate of Return	0	0	0	0	0	0	0	0	0
14	Sales Revenue Required Proposed ROR	0	0	0	0	0	0	0	0	0
15	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
16	Percent Increase Required	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
17	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
18	Sales Revenue Required $/kWh	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)
20										
21										
22										
23										
24										
25										
26										
27	**Customer Total**									
28										
29	**Present Rates**									
30										
31	Rate Base	193,524,996	4,292,658	28,820,489	15,903	44,570,778	27,649,442	8,516	671,681	262,884
32	Net Operating Income (Present Rates)	(9,417,950)	381,954	3,123,200	3,722	5,511,615	2,735,641	895	74,115	21,612
33	Rate of Return (Present Rates)	-4.87%	8.90%	10.84%	23.40%	12.37%	9.89%	10.51%	11.03%	8.22%
34	Relative Rate of Return	-5.71	10.43	12.71	27.44	14.50	11.60	12.32	12.94	9.64
35	Sales Revenue (Present Rates)	57,365,064	936,969	11,774,942	14,075	12,033,059	13,389,438	4,057	398,589	100,954
36	Revenue Present Rates $/kWh	$0.0262	$0.0032	$0.0136	$0.0124	$0.0041	$0.0073	$0.0000	$0.0002	$0.0003
37	Revenue Required - $/Mo/Customer	$17.40	$79.65	$43.16	$216.54	$308.92	$4,057.41	$338.10	$213.49	$86.73
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	15,114,302	335,257	2,250,880	1,242	3,480,978	2,159,421	665	52,458	20,531
44	Sales Revenue Required Proposed ROR	91,210,823	872,543	10,571,452	10,654	9,231,503	12,594,460	3,740	368,710	99,463
45	Revenue Deficiency Sales Revenue	33,845,759	(64,425)	(1,203,490)	(3,421)	(2,801,556)	(794,978)	(317)	(29,878)	(1,491)
46	Percent Increase Required	59.00%	-6.88%	-10.22%	-24.31%	-23.28%	-5.94%	-7.82%	-7.50%	-1.48%
47	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
48	Sales Revenue Required $/kWh	$0.0417	$0.0030	$0.0122	$0.0094	$0.0031	$0.0068	$0.0000	$0.0002	$0.0003
49	Revenue Deficiency $/kWh	$0.0155	($0.0002)	($0.0014)	($0.0030)	($0.0009)	($0.0004)	($0.0000)	($0.0000)	($0.0000)

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[U]	[V]	[W]	[X]
	Energy Total				
	Present Rates				
1	Rate Base	0	0	0	0
2	Net Operating Income (Present Rates)	0	0	0	0
3	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%
4	Relative Rate of Return	0.00	0.00	0.00	0.00
5	Sales Revenue (Present Rates)	0	0	0	0
6	Revenue Present Rates $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$0.00	$0.00	$0.00	$0.00
8					
9					
10	**Proposed Rate of Return**				
11					
12	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%
13	Return Required Proposed Rate of Return	0	0	0	0
14	Sales Revenue Required Proposed ROR	0	0	0	0
15	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)
16	Percent Increase Required	0.00%	0.00%	0.00%	0.00%
17	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
18	Sales Revenue Required $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	$0.0000	($0.0000)	($0.0000)	($0.0000)
20					
21					
22					
23					
24					
25					
26					
27	**Customer Total**				
28					
29	**Present Rates**				
30					
31	Rate Base	5,737,819	14,583	135	452
32	Net Operating Income (Present Rates)	172,087	(736)	12	78
33	Rate of Return (Present Rates)	3.00%	-5.05%	9.25%	17.34%
34	Relative Rate of Return	3.52	-5.92	10.84	20.33
35	Sales Revenue (Present Rates)	631,344	9,141	156	672
36	Revenue Present Rates $/kWh	$0.0000	$0.0001	$0.0000	$0.0003
37	Revenue Required - $/Mo/Customer	$0.00	$27.20	$4.33	$18.65
38					
39					
40	**Proposed Rate of Return**				
41					
42	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	448,124	1,139	11	35
44	Sales Revenue Required Proposed ROR	1,012,176	11,728	153	612
45	Revenue Deficiency Sales Revenue	380,832	2,587	(3)	(59)
46	Percent Increase Required	60.32%	28.30%	-1.72%	-8.84%
47	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
48	Sales Revenue Required $/kWh	$0.0000	$0.0001	$0.0000	$0.0002
49	Revenue Deficiency $/kWh	$0.0000	$0.0000	($0.0000)	($0.0000)

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Total DC Distribution	Total Residential Service	Total GS	Total GT-LV	Total GT-HV	Total GT	Total Metro	Total Street Lighting	Total TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
	Demand Distribution Subtransmission									
	Present Rates									
1	Rate Base	138,225,701	37,473,316	10,202,180	57,123,561	28,193,833	85,317,394	3,998,843	1,215,344	18,624
2	Net Operating Income (Present Rates)	9,711,918	(1,314,804)	1,106,968	6,538,661	3,099,913	9,638,574	328,747	(50,796)	3,229
3	Rate of Return (Present Rates)	7.03%	-3.51%	10.85%	11.45%	11.00%	11.30%	8.22%	-4.18%	17.34%
4	Relative Rate of Return	1.00	-0.50	1.54	1.63	1.56	1.61	1.17	-0.59	2.47
5	Sales Revenue (Present Rates)	23,553,675	1,632,973	2,200,548	12,812,911	6,138,753	18,951,665	716,950	45,831	5,710
6	Revenue Present Rates $/kWh	$0.0021	$0.0007	$0.0025	$0.0027	$0.0024	$0.0026	$0.0022	$0.0005	$0.0022
7	Revenue Required - $/Mo/Customer	$6.49	$0.49	$8.06	$303.25	$3,267.03	$429.44	$615.94	$123.20	$158.60
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
13	Return Required Proposed Rate of Return	10,795,427	2,926,666	796,790	4,461,350	2,201,938	6,663,288	312,310	94,918	1,454
14	Sales Revenue Required Proposed ROR	25,048,531	7,484,689	1,772,613	9,946,963	4,899,868	14,846,831	694,273	246,864	3,261
15	Revenue Deficiency Sales Revenue	1,494,856	5,851,716	(427,935)	(2,865,948)	(1,238,885)	(4,104,833)	(22,677)	201,034	(2,449)
16	Percent Increase Required	6.35%	358.35%	-19.45%	-22.37%	-20.18%	-21.66%	-3.16%	438.65%	-42.89%
17	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
18	Sales Revenue Required $/kWh	$0.0023	$0.0030	$0.0020	$0.0021	$0.0020	$0.0020	$0.0021	$0.0027	$0.0013
19	Revenue Deficiency $/kWh	$0.0001	$0.0024	($0.0005)	($0.0006)	($0.0005)	($0.0006)	($0.0001)	$0.0022	($0.0009)
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26										
27	**Demand Distribution Substations**									
28										
29	**Present Rates**									
30										
31	Rate Base	327,437,938	90,406,265	24,515,132	137,297,447	62,628,110	199,925,557	9,617,256	2,929,539	44,189
32	Net Operating Income (Present Rates)	22,786,968	(3,175,580)	2,659,962	15,716,567	6,910,536	22,627,103	790,639	(122,819)	7,662
33	Rate of Return (Present Rates)	6.96%	-3.51%	10.85%	11.45%	11.03%	11.32%	8.22%	-4.19%	17.34%
34	Relative Rate of Return	1.00	-0.50	1.56	1.64	1.59	1.63	1.18	-0.60	2.49
35	Sales Revenue (Present Rates)	64,637,527	6,089,994	6,007,506	34,833,304	15,506,233	50,339,537	2,007,560	178,089	14,842
36	Revenue Present Rates $/kWh	$0.0058	$0.0025	$0.0069	$0.0072	$0.0062	$0.0069	$0.0060	$0.0020	$0.0057
37	Revenue Required - $/Mo/Customer	$17.82	$1.84	$22.02	$824.42	$8,252.39	$1,140.68	$1,724.71	$478.73	$412.28
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	25,572,903	7,060,729	1,914,632	10,722,931	4,891,255	15,614,186	751,108	228,797	3,451
44	Sales Revenue Required Proposed ROR	68,481,125	20,212,450	4,979,216	27,943,867	12,720,346	40,664,212	1,953,021	663,193	9,032
45	Revenue Deficiency Sales Revenue	3,843,597	14,122,456	(1,028,289)	(6,889,437)	(2,785,888)	(9,675,325)	(54,539)	485,104	(5,810)
46	Percent Increase Required	5.95%	231.90%	-17.12%	-19.78%	-17.97%	-19.22%	-2.72%	272.39%	-39.14%
47	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
48	Sales Revenue Required $/kWh	$0.0062	$0.0081	$0.0057	$0.0058	$0.0051	$0.0056	$0.0059	$0.0074	$0.0035
49	Revenue Deficiency $/kWh	$0.0003	$0.0057	($0.0012)	($0.0014)	($0.0011)	($0.0013)	($0.0002)	$0.0054	($0.0022)

Potomac Electric Power Company
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Line No.	Description	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]
	Demand Distribution Subtransmission									
	Present Rates									
1	Rate Base	33,776,484	3,696,832	10,191,158	11,021	35,876,100	21,247,461	2,113,891	26,079,942	3,998,843
2	Net Operating Income (Present Rates)	(1,643,742)	328,938	1,104,389	2,579	4,436,433	2,102,228	222,190	2,877,724	328,747
3	Rate of Return (Present Rates)	-4.87%	8.90%	10.84%	23.40%	12.37%	9.89%	10.51%	11.03%	8.22%
4	Relative Rate of Return	-0.69	1.27	1.54	3.33	1.76	1.41	1.50	1.57	1.17
5	Sales Revenue (Present Rates)	936,360	696,613	2,196,220	4,328	8,508,526	4,304,386	447,075	5,691,678	716,950
6	Revenue Present Rates $/kWh	$0.0004	$0.0024	$0.0025	$0.0038	$0.0029	$0.0023	$0.0023	$0.0025	$0.0022
7	Revenue Required - $/Mo/Customer	$0.28	$59.22	$8.05	$66.58	$218.44	$1,304.36	$37,256.27	$3,048.57	$615.94
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
13	Return Required Proposed Rate of Return	2,637,943	288,723	795,929	861	2,801,923	1,659,427	165,095	2,036,843	312,310
14	Sales Revenue Required Proposed ROR	6,843,559	641,130	1,770,656	1,957	6,253,485	3,693,478	368,305	4,531,563	694,273
15	Revenue Deficiency Sales Revenue	5,907,199	(55,483)	(425,564)	(2,371)	(2,255,040)	(610,908)	(78,770)	(1,160,115)	(22,677)
16	Percent Increase Required	630.87%	-7.96%	-19.38%	-54.79%	-26.50%	-14.19%	-17.62%	-20.38%	-3.16%
17	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
18	Sales Revenue Required $/kWh	$0.0031	$0.0022	$0.0020	$0.0017	$0.0021	$0.0020	$0.0019	$0.0020	$0.0021
19	Revenue Deficiency $/kWh	$0.0027	($0.0002)	($0.0005)	($0.0021)	($0.0008)	($0.0003)	($0.0004)	($0.0005)	($0.0001)
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25										
26										
27	**Demand Distribution Substations**									
28										
29	**Present Rates**									
30										
31	Rate Base	81,513,250	8,893,015	24,488,699	26,433	86,260,535	51,036,912	0	62,628,110	9,617,256
32	Net Operating Income (Present Rates)	(3,966,866)	791,286	2,653,775	6,186	10,666,964	5,049,602	0	6,910,536	790,639
33	Rate of Return (Present Rates)	-4.87%	8.90%	10.84%	23.40%	12.37%	9.89%	0.00%	11.03%	8.22%
34	Relative Rate of Return	-0.70	1.28	1.56	3.36	1.78	1.42	0.00	1.59	1.18
35	Sales Revenue (Present Rates)	4,152,843	1,937,151	5,996,348	11,157	22,992,730	11,840,573	0	15,506,233	2,007,560
36	Revenue Present Rates $/kWh	$0.0019	$0.0066	$0.0069	$0.0098	$0.0078	$0.0064	$0.0000	$0.0067	$0.0060
37	Revenue Required - $/Mo/Customer	$1.26	$164.68	$21.98	$171.65	$590.28	$3,588.05	$0.00	$8,305.43	$1,724.71
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	0.00%	7.81%	7.81%
43	Return Required Proposed Rate of Return	6,366,185	694,544	1,912,567	2,064	6,736,948	3,985,983	0	4,891,255	751,108
44	Sales Revenue Required Proposed ROR	18,408,768	1,803,682	4,973,746	5,471	17,570,709	10,373,157	0	12,720,346	1,953,021
45	Revenue Deficiency Sales Revenue	14,255,925	(133,469)	(1,022,603)	(5,687)	(5,422,021)	(1,467,416)	(0)	(2,785,888)	(54,539)
46	Percent Increase Required	343.28%	-6.89%	-17.05%	-50.97%	-23.58%	-12.39%	0.00%	-17.97%	-2.72%
47	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
48	Sales Revenue Required $/kWh	$0.0084	$0.0061	$0.0057	$0.0048	$0.0059	$0.0056	$0.0000	$0.0055	$0.0059
49	Revenue Deficiency $/kWh	$0.0065	($0.0005)	($0.0012)	($0.0050)	($0.0018)	($0.0008)	($0.0000)	($0.0012)	($0.0002)

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Line No.	Description	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[U]	[V]	[W]	[X]
	Demand Distribution Subtransmission				
	Present Rates				
1	Rate Base	0	1,141,420	73,924	18,624
2	Net Operating Income (Present Rates)	0	(57,632)	6,836	3,229
3	Rate of Return (Present Rates)	0.00%	-5.05%	9.25%	17.34%
4	Relative Rate of Return	0.00	-0.72	1.32	2.47
5	Sales Revenue (Present Rates)	0	29,079	16,752	5,710
6	Revenue Present Rates $/kWh	$0.0000	$0.0004	$0.0016	$0.0022
7	Revenue Required - $/Mo/Customer	$0.00	$86.54	$465.33	$158.60
8					
9					
10	**Proposed Rate of Return**				
11					
12	Proposed Rate of Return	0.00%	7.81%	7.81%	7.81%
13	Return Required Proposed Rate of Return	0	89,145	5,773	1,454
14	Sales Revenue Required Proposed ROR	0	231,579	15,286	3,261
15	Revenue Deficiency Sales Revenue	(0)	202,500	(1,466)	(2,449)
16	Percent Increase Required	0.00%	696.39%	-8.75%	-42.89%
17	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
18	Sales Revenue Required $/kWh	$0.0000	$0.0029	$0.0015	$0.0013
19	Revenue Deficiency $/kWh	$0.0000	$0.0026	($0.0001)	($0.0009)
20					
21					
22					
23					
24					
25					
26					
27	**Demand Distribution Substations**				
28					
29	**Present Rates**				
30					
31	Rate Base	0	2,753,986	175,553	44,189
32	Net Operating Income (Present Rates)	0	(139,053)	16,235	7,662
33	Rate of Return (Present Rates)	0.00%	-5.05%	9.25%	17.34%
34	Relative Rate of Return	0.00	-0.73	1.33	2.49
35	Sales Revenue (Present Rates)	0	134,222	43,867	14,842
36	Revenue Present Rates $/kWh	$0.0000	$0.0017	$0.0042	$0.0057
37	Revenue Required - $/Mo/Customer	$0.00	$399.47	$1,218.53	$412.28
38					
39					
40	**Proposed Rate of Return**				
41					
42	Proposed Rate of Return	0.00%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	0	215,086	13,711	3,451
44	Sales Revenue Required Proposed ROR	0	622,808	40,385	9,032
45	Revenue Deficiency Sales Revenue	(0)	488,586	(3,482)	(5,810)
46	Percent Increase Required	0.00%	364.01%	-7.94%	-39.14%
47	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
48	Sales Revenue Required $/kWh	$0.0000	$0.0079	$0.0039	$0.0035
49	Revenue Deficiency $/kWh	$0.0000	$0.0062	($0.0003)	($0.0022)

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For the Twelve Months Ended June 30, 2019

Line No.	Description	Total DC Distribution	Total Residential Service	Total GS	Total GT-LV	Total GT-HV	Total GT	Total Metro	Total Street Lighting	Total TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
	Demand Distribution Primary									
	Present Rates									
1	Rate Base	673,341,197	185,639,585	50,092,772	282,284,548	129,091,823	411,376,371	20,034,512	6,106,262	91,695
2	Net Operating Income (Present Rates)	46,885,286	(6,514,633)	5,435,189	32,313,507	14,244,303	46,557,810	1,647,046	(256,026)	15,900
3	Rate of Return (Present Rates)	6.96%	-3.51%	10.85%	11.45%	11.03%	11.32%	8.22%	-4.19%	17.34%
4	Relative Rate of Return	1.00	-0.50	1.56	1.64	1.58	1.63	1.18	-0.60	2.49
5	Sales Revenue (Present Rates)	252,567,359	37,847,955	21,774,348	123,215,054	60,565,524	183,780,578	7,806,330	1,298,671	59,476
6	Revenue Present Rates $/kWh	$0.0228	$0.0152	$0.0251	$0.0256	$0.0241	$0.0251	$0.0234	$0.0145	$0.0228
7	Revenue Required - $/Mo/Customer	$69.64	$11.44	$79.79	$2,916.19	$32,232.85	$4,164.43	$6,706.47	$3,491.05	$1,652.11
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
13	Return Required Proposed Rate of Return	52,587,947	14,498,452	3,912,246	22,046,423	10,082,071	32,128,495	1,564,695	476,899	7,161
14	Sales Revenue Required Proposed ROR	260,434,998	66,838,518	19,673,228	109,050,140	54,823,130	163,873,270	7,692,716	2,309,846	47,420
15	Revenue Deficiency Sales Revenue	7,867,640	28,990,563	(2,101,120)	(14,164,914)	(5,742,395)	(19,907,309)	(113,614)	1,011,175	(12,056)
16	Percent Increase Required	3.12%	76.60%	-9.65%	-11.50%	-9.48%	-10.83%	-1.46%	77.86%	-20.27%
17	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
18	Sales Revenue Required $/kWh	$0.0235	$0.0269	$0.0226	$0.0227	$0.0218	$0.0224	$0.0231	$0.0257	$0.0182
19	Revenue Deficiency $/kWh	$0.0007	$0.0117	($0.0024)	($0.0029)	($0.0023)	($0.0027)	($0.0003)	$0.0113	($0.0046)
20										
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26										
27	**Demand Distribution Secondary**									
28										
29	**Present Rates**									
30										
31	Rate Base	424,855,063	227,324,605	39,723,223	155,423,743	0	155,423,743	0	2,347,999	35,493
32	Net Operating Income (Present Rates)	12,202,645	(9,852,536)	4,304,701	17,842,774	0	17,842,774	0	(98,448)	6,154
33	Rate of Return (Present Rates)	2.87%	-4.33%	10.84%	11.48%	0.00%	11.48%	0.00%	-4.19%	17.34%
34	Relative Rate of Return	1.00	-1.51	3.77	4.00	0.00	4.00	0.00	-1.46	6.04
35	Sales Revenue (Present Rates)	56,927,622	10,253,726	9,181,337	37,367,182	0	37,367,182	0	113,942	11,435
36	Revenue Present Rates $/kWh	$0.0051	$0.0041	$0.0106	$0.0078	$0.0000	$0.0051	$0.0000	$0.0013	$0.0044
37	Revenue Required - $/Mo/Customer	$15.70	$3.10	$33.65	$884.39	$0.00	$846.73	$0.00	$306.30	$317.64
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	0.00%	7.81%	0.00%	7.81%	7.81%
43	Return Required Proposed Rate of Return	33,181,180	17,754,052	3,102,384	12,138,594	0	12,138,594	0	183,379	2,772
44	Sales Revenue Required Proposed ROR	85,870,519	48,340,971	7,522,569	29,497,448	0	29,497,448	0	502,763	6,768
45	Revenue Deficiency Sales Revenue	28,942,897	38,087,246	(1,658,768)	(7,869,734)	(0)	(7,869,734)	(0)	388,821	(4,667)
46	Percent Increase Required	50.84%	371.45%	-18.07%	-21.06%	0.00%	-21.06%	0.00%	341.24%	-40.81%
47	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
48	Sales Revenue Required $/kWh	$0.0077	$0.0195	$0.0087	$0.0061	$0.0000	$0.0040	$0.0000	$0.0056	$0.0026
49	Revenue Deficiency $/kWh	$0.0026	$0.0153	($0.0019)	($0.0016)	($0.0000)	($0.0011)	($0.0000)	$0.0043	($0.0018)

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Line No.	Description	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]
	Demand Distribution Primary									
	Present Rates									
1	Rate Base	167,334,560	18,305,025	50,038,912	53,860	177,357,612	104,926,936	0	129,091,823	20,034,512
2	Net Operating Income (Present Rates)	(8,143,385)	1,628,752	5,422,584	12,605	21,932,015	10,381,492	(0)	14,244,303	1,647,046
3	Rate of Return (Present Rates)	-4.87%	8.90%	10.84%	23.40%	12.37%	9.89%	0.00%	11.03%	8.22%
4	Relative Rate of Return	-0.70	1.28	1.56	3.36	1.78	1.42	0.00	1.58	1.18
5	Sales Revenue (Present Rates)	30,701,424	7,146,531	21,738,697	35,651	65,520,984	57,694,070	2,040,349	58,525,176	7,806,330
6	Revenue Present Rates $/kWh	$0.0140	$0.0242	$0.0251	$0.0314	$0.0221	$0.0313	$0.0107	$0.0252	$0.0234
7	Revenue Required - $/Mo/Customer	$9.31	$607.54	$79.68	$548.48	$1,682.10	$17,483.05	$170,029.06	$31,347.18	$6,706.47
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	0.00%	7.81%	7.81%
13	Return Required Proposed Rate of Return	13,068,829	1,429,622	3,908,039	4,206	13,851,629	8,194,794	0	10,082,071	1,564,695
14	Sales Revenue Required Proposed ROR	59,966,714	6,871,804	19,649,164	24,064	54,372,934	54,677,205	2,040,349	52,782,781	7,692,716
15	Revenue Deficiency Sales Revenue	29,265,290	(274,727)	(2,089,533)	(11,587)	(11,148,050)	(3,016,864)	0	(5,742,395)	(113,614)
16	Percent Increase Required	95.32%	-3.84%	-9.61%	-32.50%	-17.01%	-5.23%	0.00%	-9.81%	-1.46%
17	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
18	Sales Revenue Required $/kWh	$0.0274	$0.0233	$0.0226	$0.0212	$0.0184	$0.0296	$0.0107	$0.0227	$0.0231
19	Revenue Deficiency $/kWh	$0.0134	($0.0009)	($0.0024)	($0.0102)	($0.0038)	($0.0016)	$0.0000	($0.0025)	($0.0003)
20										
21										
22										
23										
24										
25										
26										
27	**Demand Distribution Secondary**									
28										
29	**Present Rates**									
30										
31	Rate Base	218,531,748	8,792,857	39,723,223	0	99,723,034	55,700,709	0	0	0
32	Net Operating Income (Present Rates)	(10,634,910)	782,374	4,304,701	0	12,331,735	5,511,039	0	0	0
33	Rate of Return (Present Rates)	-4.87%	8.90%	10.84%	0.00%	12.37%	9.89%	0.00%	0.00%	0.00%
34	Relative Rate of Return	-1.69	3.10	3.77	0.00	4.31	3.44	0.00	0.00	0.00
35	Sales Revenue (Present Rates)	8,459,249	1,794,476	9,181,337	0	25,210,821	12,156,361	0	0	0
36	Revenue Present Rates $/kWh	$0.0039	$0.0061	$0.0106	$0.0000	$0.0085	$0.0066	$0.0000	$0.0000	$0.0000
37	Revenue Required - $/Mo/Customer	$2.57	$152.55	$33.65	$0.00	$647.23	$3,683.75	$0.00	$0.00	$0.00
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	7.81%	7.81%	7.81%	0.00%	7.81%	7.81%	0.00%	0.00%	0.00%
43	Return Required Proposed Rate of Return	17,067,330	686,722	3,102,384	0	7,788,369	4,350,225	0	0	0
44	Sales Revenue Required Proposed ROR	46,678,461	1,662,511	7,522,569	0	18,942,596	10,554,851	0	0	0
45	Revenue Deficiency Sales Revenue	38,219,212	(131,966)	(1,658,768)	(0)	(6,268,225)	(1,601,509)	(0)	(0)	(0)
46	Percent Increase Required	451.80%	-7.35%	-18.07%	0.00%	-24.86%	-13.17%	0.00%	0.00%	0.00%
47	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
48	Sales Revenue Required $/kWh	$0.0213	$0.0056	$0.0087	$0.0000	$0.0064	$0.0057	$0.0000	$0.0000	$0.0000
49	Revenue Deficiency $/kWh	$0.0175	($0.0004)	($0.0019)	($0.0000)	($0.0021)	($0.0009)	($0.0000)	($0.0000)	($0.0000)

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[U]	[V]	[W]	[X]
	Demand Distribution Primary				
	Present Rates				
1	Rate Base	0	5,740,524	365,738	91,695
2	Net Operating Income (Present Rates)	0	(289,848)	33,822	15,900
3	Rate of Return (Present Rates)	0.00%	-5.05%	9.25%	17.34%
4	Relative Rate of Return	0.00	-0.73	1.33	2.49
5	Sales Revenue (Present Rates)	0	1,089,167	209,504	59,476
6	Revenue Present Rates $/kWh	$0.0000	$0.0137	$0.0200	$0.0228
7	Revenue Required - $/Mo/Customer	$0.00	$3,241.57	$5,819.56	$1,652.11
8					
9					
10	**Proposed Rate of Return**				
11					
12	Proposed Rate of Return	0.00%	7.81%	7.81%	7.81%
13	Return Required Proposed Rate of Return	0	448,335	28,564	7,161
14	Sales Revenue Required Proposed ROR	0	2,107,596	202,250	47,420
15	Revenue Deficiency Sales Revenue	(0)	1,018,430	(7,254)	(12,056)
16	Percent Increase Required	0.00%	93.51%	-3.46%	-20.27%
17	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
18	Sales Revenue Required $/kWh	$0.0000	$0.0266	$0.0193	$0.0182
19	Revenue Deficiency $/kWh	$0.0000	$0.0128	($0.0007)	($0.0046)
20					
21					
22					
23					
24					
25					
26					
27	**Demand Distribution Secondary**				
28					
29	**Present Rates**				
30					
31	Rate Base	0	2,207,367	140,632	35,493
32	Net Operating Income (Present Rates)	0	(111,454)	13,005	6,154
33	Rate of Return (Present Rates)	0.00%	-5.05%	9.25%	17.34%
34	Relative Rate of Return	0.00	-1.76	3.22	6.04
35	Sales Revenue (Present Rates)	0	80,526	33,417	11,435
36	Revenue Present Rates $/kWh	$0.0000	$0.0010	$0.0032	$0.0044
37	Revenue Required - $/Mo/Customer	$0.00	$239.66	$928.24	$317.64
38					
39					
40	**Proposed Rate of Return**				
41					
42	Proposed Rate of Return	0.00%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	0	172,395	10,983	2,772
44	Sales Revenue Required Proposed ROR	0	472,136	30,627	6,768
45	Revenue Deficiency Sales Revenue	(0)	391,610	(2,789)	(4,667)
46	Percent Increase Required	0.00%	486.32%	-8.35%	-40.81%
47	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
48	Sales Revenue Required $/kWh	$0.0000	$0.0060	$0.0029	$0.0026
49	Revenue Deficiency $/kWh	$0.0000	$0.0049	($0.0003)	($0.0018)

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Total DC Distribution	Total Residential Service	Total GS	Total GT-LV	Total GT-HV	Total GT	Total Metro	Total Street Lighting	Total TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
	Demand Distribution Transformers									
	Present Rates									
1	Rate Base	314,390,381	149,824,187	29,691,121	132,502,854	0	132,502,854	0	2,336,913	35,306
2	Net Operating Income (Present Rates)	12,121,612	(6,191,250)	3,217,548	15,187,168	0	15,187,168	0	(97,977)	6,122
3	Rate of Return (Present Rates)	3.86%	-4.13%	10.84%	11.46%	0.00%	11.46%	0.00%	-4.19%	17.34%
4	Relative Rate of Return	1.00	-1.07	2.81	2.97	0.00	2.97	0.00	-1.09	4.50
5	Sales Revenue (Present Rates)	34,130,950	1,549,539	5,739,734	26,805,177	0	26,805,177	0	26,458	10,043
6	Revenue Present Rates $/kWh	$0.0031	$0.0006	$0.0066	$0.0056	$0.0000	$0.0037	$0.0000	$0.0003	$0.0039
7	Revenue Required - $/Mo/Customer	$9.41	$0.47	$21.03	$634.41	$0.00	$607.40	$0.00	$71.12	$278.96
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	0.00%	7.81%	0.00%	7.81%	7.81%
13	Return Required Proposed Rate of Return	24,553,889	11,701,269	2,318,877	10,348,473	0	10,348,473	0	182,513	2,757
14	Sales Revenue Required Proposed ROR	51,283,058	26,234,835	4,499,887	20,129,502	0	20,129,502	0	413,433	5,401
15	Revenue Deficiency Sales Revenue	17,152,108	24,685,295	(1,239,846)	(6,675,674)	(0)	(6,675,674)	(0)	386,976	(4,642)
16	Percent Increase Required	50.25%	1593.07%	-21.60%	-24.90%	0.00%	-24.90%	0.00%	1462.63%	-46.22%
17	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
18	Sales Revenue Required $/kWh	$0.0046	$0.0106	$0.0052	$0.0042	$0.0000	$0.0028	$0.0000	$0.0046	$0.0021
19	Revenue Deficiency $/kWh	$0.0015	$0.0099	($0.0014)	($0.0014)	($0.0000)	($0.0009)	($0.0000)	$0.0043	($0.0018)
20										
21										
22										
23										
24										
25										
26										
27	**Demand Distribution Services**									
28										
29	**Present Rates**									
30										
31	Rate Base	0	0	0	0	0	0	0	0	0
32	Net Operating Income (Present Rates)	0	0	0	0	0	0	0	0	0
33	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	Relative Rate of Return	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	Sales Revenue (Present Rates)	(0)	0	0	0	0	0	0	0	0
36	Revenue Present Rates $/kWh	($0.0000)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
37	Revenue Required - $/Mo/Customer	($0.00)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
43	Return Required Proposed Rate of Return	0	0	0	0	0	0	0	0	0
44	Sales Revenue Required Proposed ROR	(0)	0	0	0	0	0	0	0	0
45	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
46	Percent Increase Required	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
47	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
48	Sales Revenue Required $/kWh	($0.0000)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
49	Revenue Deficiency $/kWh	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]
	Demand Distribution Transformers									
	Present Rates									
1	Rate Base	141,832,632	7,991,555	29,691,121	0	84,034,764	48,468,089	0	0	0
2	Net Operating Income (Present Rates)	(6,902,326)	711,076	3,217,548	0	10,391,726	4,795,443	0	0	0
3	Rate of Return (Present Rates)	-4.87%	8.90%	10.84%	0.00%	12.37%	9.89%	0.00%	0.00%	0.00%
4	Relative Rate of Return	-1.26	2.31	2.81	0.00	3.21	2.57	0.00	0.00	0.00
5	Sales Revenue (Present Rates)	221,167	1,328,372	5,739,734	0	18,063,831	8,741,345	0	0	0
6	Revenue Present Rates $/kWh	$0.0001	$0.0045	$0.0066	$0.0000	$0.0061	$0.0047	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$0.07	$112.93	$21.04	$0.00	$463.75	$2,648.89	$0.00	$0.00	$0.00
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	0.00%	7.81%	7.81%	0.00%	0.00%	0.00%
13	Return Required Proposed Rate of Return	11,077,129	624,140	2,318,877	0	6,563,115	3,785,358	0	0	0
14	Sales Revenue Required Proposed ROR	25,026,402	1,208,432	4,499,887	0	12,781,714	7,347,789	0	0	0
15	Revenue Deficiency Sales Revenue	24,805,235	(119,940)	(1,239,846)	(0)	(5,282,117)	(1,393,557)	(0)	(0)	(0)
16	Percent Increase Required	11215.60%	-9.03%	-21.60%	0.00%	-29.24%	-15.94%	0.00%	0.00%	0.00%
17	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
18	Sales Revenue Required $/kWh	$0.0114	$0.0041	$0.0052	$0.0000	$0.0043	$0.0040	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	$0.0113	($0.0004)	($0.0014)	($0.0000)	($0.0018)	($0.0008)	($0.0000)	($0.0000)	($0.0000)
20										
21										
22										
23										
24										
25										
26										
27	**Demand Distribution Services**									
28										
29	**Present Rates**									
30										
31	Rate Base	0	0	0	0	0	0	0	0	0
32	Net Operating Income (Present Rates)	0	0	0	0	0	0	0	0	0
33	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	Relative Rate of Return	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	Sales Revenue (Present Rates)	0	0	0	0	0	0	0	0	0
36	Revenue Present Rates $/kWh	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
37	Revenue Required - $/Mo/Customer	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
43	Return Required Proposed Rate of Return	0	0	0	0	0	0	0	0	0
44	Sales Revenue Required Proposed ROR	0	0	0	0	0	0	0	0	0
45	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
46	Percent Increase Required	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
47	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
48	Sales Revenue Required $/kWh	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
49	Revenue Deficiency $/kWh	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[U]	[V]	[W]	[X]
	Demand Distribution Transformers				
	Present Rates				
1	Rate Base	0	2,196,898	140,015	35,306
2	Net Operating Income (Present Rates)	0	(110,925)	12,948	6,122
3	Rate of Return (Present Rates)	0.00%	-5.05%	9.25%	17.34%
4	Relative Rate of Return	0.00	-1.31	2.40	4.50
5	Sales Revenue (Present Rates)	0	(1,601)	28,058	10,043
6	Revenue Present Rates $/kWh	$0.0000	($0.0000)	$0.0027	$0.0039
7	Revenue Required - $/Mo/Customer	$0.00	($4.76)	$779.40	$278.96
8					
9					
10	**Proposed Rate of Return**				
11					
12	Proposed Rate of Return	0.00%	7.81%	7.81%	7.81%
13	Return Required Proposed Rate of Return	0	171,578	10,935	2,757
14	Sales Revenue Required Proposed ROR	0	388,152	25,281	5,401
15	Revenue Deficiency Sales Revenue	(0)	389,753	(2,777)	(4,642)
16	Percent Increase Required	0.00%	-24346.10%	-9.90%	-46.22%
17	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
18	Sales Revenue Required $/kWh	$0.0000	$0.0049	$0.0024	$0.0021
19	Revenue Deficiency $/kWh	$0.0000	$0.0049	($0.0003)	($0.0018)
20					
21					
22					
23					
24					
25					
26					
27	**Demand Distribution Services**				
28					
29	**Present Rates**				
30					
31	Rate Base	0	0	0	0
32	Net Operating Income (Present Rates)	0	0	0	0
33	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%
34	Relative Rate of Return	0.00	0.00	0.00	0.00
35	Sales Revenue (Present Rates)	0	0	0	0
36	Revenue Present Rates $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
37	Revenue Required - $/Mo/Customer	$0.00	$0.00	$0.00	$0.00
38					
39					
40	**Proposed Rate of Return**				
41					
42	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%
43	Return Required Proposed Rate of Return	0	0	0	0
44	Sales Revenue Required Proposed ROR	0	0	0	0
45	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)
46	Percent Increase Required	0.00%	0.00%	0.00%	0.00%
47	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
48	Sales Revenue Required $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
49	Revenue Deficiency $/kWh	$0.0000	($0.0000)	($0.0000)	($0.0000)

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Total DC Distribution	Total Residential Service	Total GS	Total GT-LV	Total GT-HV	Total GT	Total Metro	Total Street Lighting	Total TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
	Customer Services (369)									
	Present Rates									
1	Rate Base	171,762,678	92,422,510	16,150,121	63,190,047	0	63,190,047	0	0	0
2	Net Operating Income (Present Rates)	4,998,707	(4,005,709)	1,750,146	7,254,270	0	7,254,270	0	0	0
3	Rate of Return (Present Rates)	2.91%	-4.33%	10.84%	11.48%	0.00%	11.48%	0.00%	0.00%	0.00%
4	Relative Rate of Return	1.00	-1.49	3.72	3.94	0.00	3.94	0.00	0.00	0.00
5	Sales Revenue (Present Rates)	17,732,701	1,342,406	3,217,380	13,172,915	0	13,172,915	0	0	0
6	Revenue Present Rates $/kWh	$0.0016	$0.0005	$0.0037	$0.0027	$0.0000	$0.0018	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$4.89	$0.41	$11.79	$311.77	$0.00	$298.50	$0.00	$0.00	$0.00
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	0.00%	7.81%	0.00%	0.00%	0.00%
13	Return Required Proposed Rate of Return	13,414,665	7,218,198	1,261,324	4,935,143	0	4,935,143	0	0	0
14	Sales Revenue Required Proposed ROR	29,343,722	16,827,394	2,542,981	9,973,347	0	9,973,347	0	0	0
15	Revenue Deficiency Sales Revenue	11,611,021	15,484,988	(674,399)	(3,199,568)	(0)	(3,199,568)	(0)	(0)	(0)
16	Percent Increase Required	65.48%	1153.53%	-20.96%	-24.29%	0.00%	-24.29%	0.00%	0.00%	0.00%
17	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
18	Sales Revenue Required $/kWh	$0.0026	$0.0068	$0.0029	$0.0021	$0.0000	$0.0014	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	$0.0010	$0.0062	($0.0008)	($0.0007)	($0.0000)	($0.0004)	($0.0000)	($0.0000)	($0.0000)
20										
21										
22										
23										
24										
25										
26										
27	**Customer Meters (370)**									
28										
29	**Present Rates**									
30										
31	Rate Base	76,854,119	63,392,717	9,140,806	3,453,314	603,778	4,057,092	255,414	8,090	0
32	Net Operating Income (Present Rates)	(1,508,372)	(2,997,260)	992,189	409,530	66,580	476,109	20,998	(408)	0
33	Rate of Return (Present Rates)	-1.96%	-4.73%	10.85%	11.86%	11.03%	11.74%	8.22%	-5.05%	0.00%
34	Relative Rate of Return	1.00	2.41	-5.53	-6.04	-5.62	-5.98	-4.19	2.57	0.00
35	Sales Revenue (Present Rates)	14,464,549	9,453,345	3,327,436	1,349,267	242,494	1,591,761	90,715	1,292	0
36	Revenue Present Rates $/kWh	$0.0013	$0.0038	$0.0038	$0.0003	$0.0001	$0.0002	$0.0003	$0.0000	$0.0000
37	Revenue Required - $/Mo/Customer	$3.99	$2.86	$12.19	$31.93	$129.05	$36.07	$77.93	$3.47	$0.00
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	0.00%
43	Return Required Proposed Rate of Return	6,002,307	4,950,971	713,897	269,704	47,155	316,859	19,948	632	0
44	Sales Revenue Required Proposed ROR	24,826,607	20,419,069	2,943,492	1,156,357	215,695	1,372,052	89,267	2,727	0
45	Revenue Deficiency Sales Revenue	10,362,058	10,965,725	(383,944)	(192,910)	(26,799)	(219,709)	(1,448)	1,435	(0)
46	Percent Increase Required	71.64%	116.00%	-11.54%	-14.30%	-11.05%	-13.80%	-1.60%	111.07%	0.00%
47	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
48	Sales Revenue Required $/kWh	$0.0022	$0.0082	$0.0034	$0.0002	$0.0001	$0.0002	$0.0003	$0.0000	$0.0000
49	Revenue Deficiency $/kWh	$0.0009	$0.0044	($0.0004)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	$0.0000	($0.0000)

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Line No.	Description	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]
	Customer Services (369)									
	Present Rates									
1	Rate Base	88,847,631	3,574,879	16,150,121	0	40,544,019	22,646,028	0	0	0
2	Net Operating Income (Present Rates)	(4,323,796)	318,087	1,750,146	0	5,013,667	2,240,603	0	0	0
3	Rate of Return (Present Rates)	-4.87%	8.90%	10.84%	0.00%	12.37%	9.89%	0.00%	0.00%	0.00%
4	Relative Rate of Return	-1.67	3.06	3.72	0.00	4.25	3.40	0.00	0.00	0.00
5	Sales Revenue (Present Rates)	727,058	615,348	3,217,380	0	8,954,722	4,218,193	0	0	0
6	Revenue Present Rates $/kWh	$0.0003	$0.0021	$0.0037	$0.0000	$0.0030	$0.0023	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$0.22	$52.31	$11.79	$0.00	$229.89	$1,278.24	$0.00	$0.00	$0.00
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	0.00%	7.81%	7.81%	0.00%	0.00%	0.00%
13	Return Required Proposed Rate of Return	6,939,000	279,198	1,261,324	0	3,166,488	1,768,655	0	0	0
14	Sales Revenue Required Proposed ROR	16,265,699	561,695	2,542,981	0	6,406,274	3,567,074	0	0	0
15	Revenue Deficiency Sales Revenue	15,538,641	(53,653)	(674,399)	(0)	(2,548,449)	(651,120)	(0)	(0)	(0)
16	Percent Increase Required	2137.19%	-8.72%	-20.96%	0.00%	-28.46%	-15.44%	0.00%	0.00%	0.00%
17	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
18	Sales Revenue Required $/kWh	$0.0074	$0.0019	$0.0029	$0.0000	$0.0022	$0.0019	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	$0.0071	($0.0002)	($0.0008)	($0.0000)	($0.0009)	($0.0004)	($0.0000)	($0.0000)	($0.0000)
20										
21										
22										
23										
24										
25										
26										
27	**Customer Meters (370)**									
28										
29	**Present Rates**									
30										
31	Rate Base	62,755,094	637,623	9,127,880	12,926	2,745,118	708,197	8,174	595,604	255,414
32	Net Operating Income (Present Rates)	(3,053,995)	56,735	989,164	3,025	339,461	70,069	859	65,720	20,998
33	Rate of Return (Present Rates)	-4.87%	8.90%	10.84%	23.40%	12.37%	9.89%	10.51%	11.03%	8.22%
34	Relative Rate of Return	2.48	-4.53	-5.52	-11.92	-6.30	-5.04	-5.36	-5.62	-4.19
35	Sales Revenue (Present Rates)	9,233,023	220,322	3,320,035	7,400	1,090,137	259,129	3,327	239,167	90,715
36	Revenue Present Rates $/kWh	$0.0042	$0.0007	$0.0038	$0.0065	$0.0004	$0.0001	$0.0000	$0.0001	$0.0003
37	Revenue Required - $/Mo/Customer	$2.80	$18.73	$12.17	$113.85	$27.99	$78.52	$277.27	$128.10	$77.93
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	4,901,173	49,798	712,887	1,010	214,394	55,310	638	46,517	19,948
44	Sales Revenue Required Proposed ROR	20,208,317	210,752	2,938,872	4,620	917,589	238,767	3,023	212,672	89,267
45	Revenue Deficiency Sales Revenue	10,975,294	(9,570)	(381,163)	(2,781)	(172,548)	(20,362)	(305)	(26,494)	(1,448)
46	Percent Increase Required	118.87%	-4.34%	-11.48%	-37.58%	-15.83%	-7.86%	-9.15%	-11.08%	-1.60%
47	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
48	Sales Revenue Required $/kWh	$0.0092	$0.0007	$0.0034	$0.0041	$0.0003	$0.0001	$0.0000	$0.0001	$0.0003
49	Revenue Deficiency $/kWh	$0.0050	($0.0000)	($0.0004)	($0.0024)	($0.0001)	($0.0000)	($0.0000)	($0.0000)	($0.0000)

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Line No.	Description	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[U]	[V]	[W]	[X]
	Customer Services (369)				
	Present Rates				
1	Rate Base	0	0	0	0
2	Net Operating Income (Present Rates)	0	0	0	0
3	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%
4	Relative Rate of Return	0.00	0.00	0.00	0.00
5	Sales Revenue (Present Rates)	0	0	0	0
6	Revenue Present Rates $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$0.00	$0.00	$0.00	$0.00
8					
9					
10	**Proposed Rate of Return**				
11					
12	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%
13	Return Required Proposed Rate of Return	0	0	0	0
14	Sales Revenue Required Proposed ROR	0	0	0	0
15	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)
16	Percent Increase Required	0.00%	0.00%	0.00%	0.00%
17	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
18	Sales Revenue Required $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	$0.0000	($0.0000)	($0.0000)	($0.0000)
20					
21					
22					
23					
24					
25					
26					
27	**Customer Meters (370)**				
28					
29	**Present Rates**				
30					
31	Rate Base	0	8,090	0	0
32	Net Operating Income (Present Rates)	0	(408)	0	0
33	Rate of Return (Present Rates)	0.00%	-5.05%	0.00%	0.00%
34	Relative Rate of Return	0.00	2.57	0.00	0.00
35	Sales Revenue (Present Rates)	0	1,292	0	0
36	Revenue Present Rates $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
37	Revenue Required - $/Mo/Customer	$0.00	$3.85	$0.00	$0.00
38					
39					
40	**Proposed Rate of Return**				
41					
42	Proposed Rate of Return	0.00%	7.81%	0.00%	0.00%
43	Return Required Proposed Rate of Return	0	632	0	0
44	Sales Revenue Required Proposed ROR	0	2,727	0	0
45	Revenue Deficiency Sales Revenue	(0)	1,435	(0)	(0)
46	Percent Increase Required	0.00%	111.07%	0.00%	0.00%
47	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
48	Sales Revenue Required $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
49	Revenue Deficiency $/kWh	$0.0000	$0.0000	($0.0000)	($0.0000)

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Line No.	Description	Total DC Distribution	Total Residential Service	Total GS	Total GT-LV	Total GT-HV	Total GT	Total Metro	Total Street Lighting	Total TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
	Customer Installations (371)									
	Present Rates									
1	Rate Base	4,461,094	9,838	309,837	4,119,850	21,569	4,141,419	0	0	0
2	Net Operating Income (Present Rates)	443,909	334	33,576	407,619	2,380	409,999	0	0	0
3	Rate of Return (Present Rates)	9.95%	3.40%	10.84%	9.89%	11.03%	9.90%	0.00%	0.00%	0.00%
4	Relative Rate of Return	1.00	0.34	1.09	0.99	1.11	0.99	0.00	0.00	0.00
5	Sales Revenue (Present Rates)	9,265,586	19,535	646,242	8,554,773	45,036	8,599,809	0	0	0
6	Revenue Present Rates $/kWh	$0.0008	$0.0000	$0.0007	$0.0018	$0.0000	$0.0012	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$2.55	$0.01	$2.37	$202.47	$23.97	$194.87	$0.00	$0.00	$0.00
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	0.00%	0.00%	0.00%
13	Return Required Proposed Rate of Return	348,411	768	24,198	321,760	1,685	323,445	0	0	0
14	Sales Revenue Required Proposed ROR	9,133,833	20,134	633,303	8,436,318	44,077	8,480,395	0	0	0
15	Revenue Deficiency Sales Revenue	(131,753)	599	(12,938)	(118,454)	(959)	(119,414)	(0)	(0)	(0)
16	Percent Increase Required	-1.42%	3.06%	-2.00%	-1.38%	-2.13%	-1.39%	0.00%	0.00%	0.00%
17	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
18	Sales Revenue Required $/kWh	$0.0008	$0.0000	$0.0007	$0.0018	$0.0000	$0.0012	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	($0.0000)	$0.0000	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)
20										
21										
22										
23										
24										
25										
26										
27	**Customer Street Lighting (373)**									
28										
29	**Present Rates**									
30										
31	Rate Base	5,737,819	0	0	0	0	0	0	5,737,819	0
32	Net Operating Income (Present Rates)	172,087	0	0	0	0	0	0	172,087	0
33	Rate of Return (Present Rates)	3.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	3.00%	0.00%
34	Relative Rate of Return	1.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.00
35	Sales Revenue (Present Rates)	631,344	0	0	0	0	0	0	631,344	0
36	Revenue Present Rates $/kWh	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0070	$0.0000
37	Revenue Required - $/Mo/Customer	$0.17	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,697.16	$0.00
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	7.81%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.81%	0.00%
43	Return Required Proposed Rate of Return	448,124	0	0	0	0	0	0	448,124	0
44	Sales Revenue Required Proposed ROR	1,012,176	0	0	0	0	0	0	1,012,176	0
45	Revenue Deficiency Sales Revenue	380,832	(0)	(0)	(0)	(0)	(0)	(0)	380,832	(0)
46	Percent Increase Required	60.32%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	60.32%	0.00%
47	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
48	Sales Revenue Required $/kWh	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0113	$0.0000
49	Revenue Deficiency $/kWh	$0.0000	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	$0.0042	($0.0000)

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Line No.	Description	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]
	Customer Installations (371)									
	Present Rates									
1	Rate Base	3,930	5,908	309,837	0	0	4,119,850	0	21,569	0
2	Net Operating Income (Present Rates)	(191)	526	33,576	0	0	407,619	0	2,380	0
3	Rate of Return (Present Rates)	-4.87%	8.90%	10.84%	0.00%	0.00%	9.89%	0.00%	11.03%	0.00%
4	Relative Rate of Return	-0.49	0.89	1.09	0.00	0.00	0.99	0.00	1.11	0.00
5	Sales Revenue (Present Rates)	7,360	12,175	646,242	0	0	8,554,773	0	45,036	0
6	Revenue Present Rates $/kWh	$0.0000	$0.0000	$0.0007	$0.0000	$0.0000	$0.0046	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$0.00	$1.04	$2.37	$0.00	$0.00	$2,592.36	$0.00	$24.12	$0.00
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	0.00%	0.00%	7.81%	0.00%	7.81%	0.00%
13	Return Required Proposed Rate of Return	307	461	24,198	0	0	321,760	0	1,685	0
14	Sales Revenue Required Proposed ROR	8,047	12,087	633,303	0	0	8,436,318	0	44,077	0
15	Revenue Deficiency Sales Revenue	687	(89)	(12,938)	(0)	(0)	(118,454)	(0)	(959)	(0)
16	Percent Increase Required	9.34%	-0.73%	-2.00%	0.00%	0.00%	-1.38%	0.00%	-2.13%	0.00%
17	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
18	Sales Revenue Required $/kWh	$0.0000	$0.0000	$0.0007	$0.0000	$0.0000	$0.0046	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	$0.0000	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0001)	($0.0000)	($0.0000)	($0.0000)
20										
21										
22										
23										
24										
25										
26										
27	**Customer Street Lighting (373)**									
28										
29	**Present Rates**									
30										
31	Rate Base	0	0	0	0	0	0	0	0	0
32	Net Operating Income (Present Rates)	0	0	0	0	0	0	0	0	0
33	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	Relative Rate of Return	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	Sales Revenue (Present Rates)	0	0	0	0	0	0	0	0	0
36	Revenue Present Rates $/kWh	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
37	Revenue Required - $/Mo/Customer	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
43	Return Required Proposed Rate of Return	0	0	0	0	0	0	0	0	0
44	Sales Revenue Required Proposed ROR	0	0	0	0	0	0	0	0	0
45	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
46	Percent Increase Required	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
47	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
48	Sales Revenue Required $/kWh	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
49	Revenue Deficiency $/kWh	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)

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Line No.	Description	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[U]	[V]	[W]	[X]
	Customer Installations (371)				
	Present Rates				
1	Rate Base	0	0	0	0
2	Net Operating Income (Present Rates)	0	0	0	0
3	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%
4	Relative Rate of Return	0.00	0.00	0.00	0.00
5	Sales Revenue (Present Rates)	0	0	0	0
6	Revenue Present Rates $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$0.00	$0.00	$0.00	$0.00
8					
9					
10	**Proposed Rate of Return**				
11					
12	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%
13	Return Required Proposed Rate of Return	0	0	0	0
14	Sales Revenue Required Proposed ROR	0	0	0	0
15	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)
16	Percent Increase Required	0.00%	0.00%	0.00%	0.00%
17	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
18	Sales Revenue Required $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	$0.0000	($0.0000)	($0.0000)	($0.0000)
20					
21					
22					
23					
24					
25					
26					
27	**Customer Street Lighting (373)**				
28					
29	**Present Rates**				
30					
31	Rate Base	5,737,819	0	0	0
32	Net Operating Income (Present Rates)	172,087	0	0	0
33	Rate of Return (Present Rates)	3.00%	0.00%	0.00%	0.00%
34	Relative Rate of Return	1.00	0.00	0.00	0.00
35	Sales Revenue (Present Rates)	631,344	0	0	0
36	Revenue Present Rates $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
37	Revenue Required - $/Mo/Customer	$0.00	$0.00	$0.00	$0.00
38					
39					
40	**Proposed Rate of Return**				
41					
42	Proposed Rate of Return	7.81%	0.00%	0.00%	0.00%
43	Return Required Proposed Rate of Return	448,124	0	0	0
44	Sales Revenue Required Proposed ROR	1,012,176	0	0	0
45	Revenue Deficiency Sales Revenue	380,832	(0)	(0)	(0)
46	Percent Increase Required	60.32%	0.00%	0.00%	0.00%
47	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
48	Sales Revenue Required $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
49	Revenue Deficiency $/kWh	$0.0000	($0.0000)	($0.0000)	($0.0000)

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Line No.	Description	Total DC Distribution	Total Residential Service	Total GS	Total GT-LV	Total GT-HV	Total GT	Total Metro	Total Street Lighting	Total TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
	Customer Meter Reading (902)									
	Present Rates									
1	Rate Base	3,625,878	3,243,402	247,506	96,949	36,894	133,842	728	399	0
2	Net Operating Income (Present Rates)	(113,938)	(156,196)	26,840	11,308	4,070	15,378	60	(20)	0
3	Rate of Return (Present Rates)	-3.14%	-4.82%	10.84%	11.66%	11.03%	11.49%	8.22%	-5.05%	0.00%
4	Relative Rate of Return	1.00	1.53	-3.45	-3.71	-3.51	-3.66	-2.62	1.61	0.00
5	Sales Revenue (Present Rates)	1,459,452	886,188	238,028	241,325	91,643	332,968	1,787	483	0
6	Revenue Present Rates $/kWh	$0.0001	$0.0004	$0.0003	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$0.40	$0.27	$0.87	$5.71	$48.77	$7.54	$1.53	$1.30	$0.00
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	0.00%
13	Return Required Proposed Rate of Return	283,181	253,310	19,330	7,572	2,881	10,453	57	31	0
14	Sales Revenue Required Proposed ROR	2,007,336	1,451,159	227,667	236,170	90,004	326,174	1,782	553	0
15	Revenue Deficiency Sales Revenue	547,883	564,972	(10,361)	(5,155)	(1,639)	(6,794)	(4)	71	(0)
16	Percent Increase Required	37.54%	63.75%	-4.35%	-2.14%	-1.79%	-2.04%	-0.23%	14.68%	0.00%
17	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
18	Sales Revenue Required $/kWh	$0.0002	$0.0006	$0.0003	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	$0.0000	$0.0002	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	$0.0000	($0.0000)
20										
21										
22										
23										
24										
25										
26										
27	**Customer Records & Collections (903)**									
28										
29	**Present Rates**									
30										
31	Rate Base	38,314,194	34,505,722	2,610,857	1,170,505	14,610	1,185,115	6,605	5,482	413
32	Net Operating Income (Present Rates)	(1,244,760)	(1,672,825)	283,075	143,024	1,612	144,636	543	(261)	72
33	Rate of Return (Present Rates)	-3.25%	-4.85%	10.84%	12.22%	11.03%	12.20%	8.22%	-4.76%	17.34%
34	Relative Rate of Return	1.00	1.49	-3.34	-3.76	-3.40	-3.76	-2.53	1.47	-5.34
35	Sales Revenue (Present Rates)	49,203,409	43,534,961	3,862,070	1,767,693	21,593	1,789,286	9,487	6,958	648
36	Revenue Present Rates $/kWh	$0.0044	$0.0175	$0.0044	$0.0004	$0.0000	$0.0002	$0.0000	$0.0001	$0.0002
37	Revenue Required - $/Mo/Customer	$13.57	$13.16	$14.15	$41.84	$11.49	$40.54	$8.15	$18.70	$18.01
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	2,992,339	2,694,897	203,908	91,416	1,141	92,557	516	428	32
44	Sales Revenue Required Proposed ROR	55,049,095	49,560,859	3,752,847	1,696,492	20,944	1,717,436	9,449	7,909	594
45	Revenue Deficiency Sales Revenue	5,845,685	6,025,898	(109,223)	(71,200)	(649)	(71,849)	(37)	951	(54)
46	Percent Increase Required	11.88%	13.84%	-2.83%	-4.03%	-3.01%	-4.02%	-0.39%	13.67%	-8.37%
47	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
48	Sales Revenue Required $/kWh	$0.0050	$0.0200	$0.0043	$0.0004	$0.0000	$0.0002	$0.0000	$0.0001	$0.0002
49	Revenue Deficiency $/kWh	$0.0005	$0.0024	($0.0001)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	$0.0000	($0.0000)

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Line No.	Description	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]
	Customer Meter Reading (902)									
	Present Rates									
1	Rate Base	3,231,449	11,953	247,361	146	69,418	27,530	235	36,658	728
2	Net Operating Income (Present Rates)	(157,259)	1,064	26,806	34	8,584	2,724	25	4,045	60
3	Rate of Return (Present Rates)	-4.87%	8.90%	10.84%	23.40%	12.37%	9.89%	10.51%	11.03%	8.22%
4	Relative Rate of Return	1.55	-2.83	-3.45	-7.45	-3.94	-3.15	-3.34	-3.51	-2.62
5	Sales Revenue (Present Rates)	878,225	7,963	237,640	388	173,198	68,127	585	91,058	1,787
6	Revenue Present Rates $/kWh	$0.0004	$0.0000	$0.0003	$0.0003	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$0.27	$0.68	$0.87	$5.97	$4.45	$20.64	$48.79	$48.77	$1.53
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
13	Return Required Proposed Rate of Return	252,376	934	19,319	11	5,422	2,150	18	2,863	57
14	Sales Revenue Required Proposed ROR	1,443,376	7,783	227,310	357	168,835	67,335	577	89,427	1,782
15	Revenue Deficiency Sales Revenue	565,151	(179)	(10,329)	(31)	(4,363)	(792)	(9)	(1,631)	(4)
16	Percent Increase Required	64.35%	-2.25%	-4.35%	-8.07%	-2.52%	-1.16%	-1.50%	-1.79%	-0.23%
17	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
18	Sales Revenue Required $/kWh	$0.0007	$0.0000	$0.0003	$0.0003	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	$0.0003	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)
20										
21										
22										
23										
24										
25										
26										
27	**Customer Records & Collections (903)**									
28										
29	**Present Rates**									
30										
31	Rate Base	34,459,180	46,542	2,609,715	1,143	1,100,910	69,595	93	14,517	6,605
32	Net Operating Income (Present Rates)	(1,676,966)	4,141	282,808	267	136,138	6,886	10	1,602	543
33	Rate of Return (Present Rates)	-4.87%	8.90%	10.84%	23.40%	12.37%	9.89%	10.51%	11.03%	8.22%
34	Relative Rate of Return	1.50	-2.74	-3.34	-7.20	-3.81	-3.05	-3.24	-3.40	-2.53
35	Sales Revenue (Present Rates)	43,468,341	66,619	3,860,166	1,904	1,664,883	102,809	138	21,456	9,487
36	Revenue Present Rates $/kWh	$0.0199	$0.0002	$0.0044	$0.0017	$0.0006	$0.0001	$0.0000	$0.0000	$0.0000
37	Revenue Required - $/Mo/Customer	$13.19	$5.66	$14.15	$29.29	$42.74	$31.15	$11.47	$11.49	$8.15
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	2,691,262	3,635	203,819	89	85,981	5,435	7	1,134	516
44	Sales Revenue Required Proposed ROR	49,494,938	65,921	3,751,189	1,658	1,595,684	100,808	134	20,810	9,449
45	Revenue Deficiency Sales Revenue	6,026,597	(699)	(108,977)	(246)	(69,199)	(2,001)	(3)	(646)	(37)
46	Percent Increase Required	13.86%	-1.05%	-2.82%	-12.91%	-4.16%	-1.95%	-2.53%	-3.01%	-0.39%
47	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
48	Sales Revenue Required $/kWh	$0.0226	$0.0002	$0.0043	$0.0015	$0.0005	$0.0001	$0.0000	$0.0000	$0.0000
49	Revenue Deficiency $/kWh	$0.0028	($0.0000)	($0.0001)	($0.0002)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)

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Line No.	Description	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[U]	[V]	[W]	[X]
	Customer Meter Reading (902)				
	Present Rates				
1	Rate Base	0	399	0	0
2	Net Operating Income (Present Rates)	0	(20)	0	0
3	Rate of Return (Present Rates)	0.00%	-5.05%	0.00%	0.00%
4	Relative Rate of Return	0.00	1.61	0.00	0.00
5	Sales Revenue (Present Rates)	0	483	0	0
6	Revenue Present Rates $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$0.00	$1.44	$0.00	$0.00
8					
9					
10	**Proposed Rate of Return**				
11					
12	Proposed Rate of Return	0.00%	7.81%	0.00%	0.00%
13	Return Required Proposed Rate of Return	0	31	0	0
14	Sales Revenue Required Proposed ROR	0	553	0	0
15	Revenue Deficiency Sales Revenue	(0)	71	(0)	(0)
16	Percent Increase Required	0.00%	14.68%	0.00%	0.00%
17	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
18	Sales Revenue Required $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	$0.0000	$0.0000	($0.0000)	($0.0000)
20					
21					
22					
23					
24					
25					
26					
27	**Customer Records & Collections (903)**				
28					
29	**Present Rates**				
30					
31	Rate Base	0	5,372	109	413
32	Net Operating Income (Present Rates)	0	(271)	10	72
33	Rate of Return (Present Rates)	0.00%	-5.05%	9.25%	17.34%
34	Relative Rate of Return	0.00	1.55	-2.85	-5.34
35	Sales Revenue (Present Rates)	0	6,802	156	648
36	Revenue Present Rates $/kWh	$0.0000	$0.0001	$0.0000	$0.0002
37	Revenue Required - $/Mo/Customer	$0.00	$20.24	$4.33	$18.01
38					
39					
40	**Proposed Rate of Return**				
41					
42	Proposed Rate of Return	0.00%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	0	420	9	32
44	Sales Revenue Required Proposed ROR	0	7,755	154	594
45	Revenue Deficiency Sales Revenue	(0)	953	(2)	(54)
46	Percent Increase Required	0.00%	14.01%	-1.39%	-8.37%
47	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
48	Sales Revenue Required $/kWh	$0.0000	$0.0001	$0.0000	$0.0002
49	Revenue Deficiency $/kWh	$0.0000	$0.0000	($0.0000)	($0.0000)

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Line No.	Description	Total DC Distribution	Total Residential Service	Total GS	Total GT-LV	Total GT-HV	Total GT	Total Metro	Total Street Lighting	Total TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
	Customer Uncollectibles (904)									
	Present Rates									
1	Rate Base	1,992,229	1,626,508	250,716	114,743	262	115,005	0	0	0
2	Net Operating Income (Present Rates)	(38,136)	(77,882)	27,375	12,342	29	12,371	0	0	0
3	Rate of Return (Present Rates)	-1.91%	-4.79%	10.92%	10.76%	11.03%	10.76%	0.00%	0.00%	0.00%
4	Relative Rate of Return	1.00	2.50	-5.70	-5.62	-5.76	-5.62	0.00	0.00	0.00
5	Sales Revenue (Present Rates)	4,595,097	3,686,362	622,852	285,231	652	285,883	0	0	0
6	Revenue Present Rates $/kWh	$0.0004	$0.0015	$0.0007	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$1.27	$1.11	$2.28	$6.75	$0.35	$6.48	$0.00	$0.00	$0.00
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	0.00%	0.00%	0.00%
13	Return Required Proposed Rate of Return	155,593	127,030	19,581	8,961	20	8,982	0	0	0
14	Sales Revenue Required Proposed ROR	4,862,373	3,969,067	612,099	280,567	640	281,207	0	0	0
15	Revenue Deficiency Sales Revenue	267,276	282,706	(10,753)	(4,664)	(12)	(4,676)	(0)	(0)	(0)
16	Percent Increase Required	5.82%	7.67%	-1.73%	-1.64%	-1.79%	-1.64%	0.00%	0.00%	0.00%
17	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
18	Sales Revenue Required $/kWh	$0.0004	$0.0016	$0.0007	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	$0.0000	$0.0001	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)
20										
21										
22										
23										
24										
25										
26										
27	**Customer Service Expense**									
28										
29	**Present Rates**									
30										
31	Rate Base	2,822,324	2,616,956	126,548	74,813	3,084	77,897	137	747	39
32	Net Operating Income (Present Rates)	(103,251)	(126,459)	13,720	9,164	340	9,504	11	(34)	7
33	Rate of Return (Present Rates)	-3.66%	-4.83%	10.84%	12.25%	11.03%	12.20%	8.22%	-4.56%	17.34%
34	Relative Rate of Return	1.00	1.32	-2.96	-3.35	-3.02	-3.34	-2.25	1.25	-4.74
35	Sales Revenue (Present Rates)	3,144,233	2,880,365	163,440	95,996	3,213	99,209	200	958	61
36	Revenue Present Rates $/kWh	$0.0003	$0.0012	$0.0002	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
37	Revenue Required - $/Mo/Customer	$0.87	$0.87	$0.60	$2.27	$1.71	$2.25	$0.17	$2.58	$1.70
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	220,423	204,384	9,883	5,843	241	6,084	11	58	3
44	Sales Revenue Required Proposed ROR	3,590,788	3,336,811	158,147	91,414	3,076	94,490	199	1,086	56
45	Revenue Deficiency Sales Revenue	446,555	456,446	(5,293)	(4,582)	(137)	(4,719)	(1)	127	(5)
46	Percent Increase Required	14.20%	15.85%	-3.24%	-4.77%	-4.27%	-4.76%	-0.39%	13.30%	-8.31%
47	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
48	Sales Revenue Required $/kWh	$0.0003	$0.0013	$0.0002	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
49	Revenue Deficiency $/kWh	$0.0000	$0.0002	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	$0.0000	($0.0000)

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For the Twelve Months Ended June 30, 2019

Line No.	Description	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]
	Customer Uncollectibles (904)									
	Present Rates									
1	Rate Base	1,617,263	9,245	249,078	1,637	40,035	74,708	0	262	0
2	Net Operating Income (Present Rates)	(78,705)	823	26,992	383	4,951	7,392	0	29	0
3	Rate of Return (Present Rates)	-4.87%	8.90%	10.84%	23.40%	12.37%	9.89%	0.00%	11.03%	0.00%
4	Relative Rate of Return	2.54	-4.65	-5.66	-12.23	-6.46	-5.17	0.00	-5.76	0.00
5	Sales Revenue (Present Rates)	3,663,631	22,731	618,487	4,365	100,359	184,873	0	652	0
6	Revenue Present Rates $/kWh	$0.0017	$0.0001	$0.0007	$0.0038	$0.0000	$0.0001	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$1.11	$1.93	$2.27	$67.16	$2.58	$56.02	$0.00	$0.35	$0.00
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	0.00%	7.81%	0.00%
13	Return Required Proposed Rate of Return	126,308	722	19,453	128	3,127	5,835	0	20	0
14	Sales Revenue Required Proposed ROR	3,946,475	22,592	608,086	4,013	97,842	182,725	0	640	0
15	Revenue Deficiency Sales Revenue	282,845	(139)	(10,401)	(352)	(2,516)	(2,148)	(0)	(12)	(0)
16	Percent Increase Required	7.72%	-0.61%	-1.68%	-8.07%	-2.51%	-1.16%	0.00%	-1.79%	0.00%
17	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
18	Sales Revenue Required $/kWh	$0.0018	$0.0001	$0.0007	$0.0035	$0.0000	$0.0001	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	$0.0001	($0.0000)	($0.0000)	($0.0003)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)
20										
21										
22										
23										
24										
25										
26										
27	**Customer Service Expense**									
28										
29	**Present Rates**									
30										
31	Rate Base	2,610,448	6,508	126,497	51	71,279	3,534	13	3,071	137
32	Net Operating Income (Present Rates)	(127,038)	579	13,708	12	8,814	350	1	339	11
33	Rate of Return (Present Rates)	-4.87%	8.90%	10.84%	23.40%	12.37%	9.89%	10.51%	11.03%	8.22%
34	Relative Rate of Return	1.33	-2.43	-2.96	-6.40	-3.38	-2.70	-2.87	-3.02	-2.25
35	Sales Revenue (Present Rates)	2,876,107	4,258	163,354	86	90,967	5,029	19	3,193	200
36	Revenue Present Rates $/kWh	$0.0013	$0.0000	$0.0002	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
37	Revenue Required - $/Mo/Customer	$0.87	$0.36	$0.60	$1.32	$2.34	$1.52	$1.62	$1.71	$0.17
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	203,876	508	9,879	4	5,567	276	1	240	11
44	Sales Revenue Required Proposed ROR	3,332,651	4,161	158,072	75	86,487	4,927	19	3,057	199
45	Revenue Deficiency Sales Revenue	456,544	(98)	(5,282)	(11)	(4,480)	(102)	(0)	(137)	(1)
46	Percent Increase Required	15.87%	-2.29%	-3.23%	-12.84%	-4.93%	-2.02%	-2.49%	-4.28%	-0.39%
47	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
48	Sales Revenue Required $/kWh	$0.0015	$0.0000	$0.0002	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
49	Revenue Deficiency $/kWh	$0.0002	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[U]	[V]	[W]	[X]
	Customer Uncollectibles (904)				
	Present Rates				
1	Rate Base	0	0	0	0
2	Net Operating Income (Present Rates)	0	0	0	0
3	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%
4	Relative Rate of Return	0.00	0.00	0.00	0.00
5	Sales Revenue (Present Rates)	0	0	0	0
6	Revenue Present Rates $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$0.00	$0.00	$0.00	$0.00
8					
9					
10	**Proposed Rate of Return**				
11					
12	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%
13	Return Required Proposed Rate of Return	0	0	0	0
14	Sales Revenue Required Proposed ROR	0	0	0	0
15	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)
16	Percent Increase Required	0.00%	0.00%	0.00%	0.00%
17	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
18	Sales Revenue Required $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	$0.0000	($0.0000)	($0.0000)	($0.0000)
20					
21					
22					
23					
24					
25					
26					
27	**Customer Service Expense**				
28					
29	**Present Rates**				
30					
31	Rate Base	0	721	26	39
32	Net Operating Income (Present Rates)	0	(36)	2	7
33	Rate of Return (Present Rates)	0.00%	-5.05%	9.25%	17.34%
34	Relative Rate of Return	0.00	1.38	-2.53	-4.74
35	Sales Revenue (Present Rates)	0	920	38	61
36	Revenue Present Rates $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
37	Revenue Required - $/Mo/Customer	$0.00	$2.74	$1.06	$1.70
38					
39					
40	**Proposed Rate of Return**				
41					
42	Proposed Rate of Return	0.00%	7.81%	7.81%	7.81%
43	Return Required Proposed Rate of Return	0	56	2	3
44	Sales Revenue Required Proposed ROR	0	1,048	38	56
45	Revenue Deficiency Sales Revenue	(0)	128	(1)	(5)
46	Percent Increase Required	0.00%	13.91%	-1.34%	-8.31%
47	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
48	Sales Revenue Required $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
49	Revenue Deficiency $/kWh	$0.0000	$0.0000	($0.0000)	($0.0000)

Potomac Electric Power Company
District of Columbia
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Line No.	Description	Total DC Distribution	Total Residential Service	Total GS	Total GT-LV	Total GT-HV	Total GT	Total Metro	Total Street Lighting	Total TN Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]
	Customer Sales Expense									
	Present Rates									
1	Rate Base	0	0	0	0	0	0	0	0	0
2	Net Operating Income (Present Rates)	0	0	0	0	0	0	0	0	0
3	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	Relative Rate of Return	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	Sales Revenue (Present Rates)	(0)	0	0	0	0	0	0	0	0
6	Revenue Present Rates $/kWh	($0.0000)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	($0.00)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	Return Required Proposed Rate of Return	0	0	0	0	0	0	0	0	0
14	Sales Revenue Required Proposed ROR	(0)	0	0	0	0	0	0	0	0
15	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
16	Percent Increase Required	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
17	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
18	Sales Revenue Required $/kWh	($0.0000)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)
20										
21										
22										
23										
24										
25										
26										
27	**Customer Other**									
28										
29	**Present Rates**									
30										
31	Rate Base	0	0	0	0	0	0	0	0	0
32	Net Operating Income (Present Rates)	0	0	0	0	0	0	0	0	0
33	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	Relative Rate of Return	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	Sales Revenue (Present Rates)	(3,837,914)	(3,501,128)	(288,430)	(44,703)	(1,986)	(46,689)	(1,235)	(394)	(38)
36	Revenue Present Rates $/kWh	($0.0003)	($0.0014)	($0.0003)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)
37	Revenue Required - $/Mo/Customer	($1.06)	($1.06)	($1.06)	($1.06)	($1.06)	($1.06)	($1.06)	($1.06)	($1.05)
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
43	Return Required Proposed Rate of Return	0	0	0	0	0	0	0	0	0
44	Sales Revenue Required Proposed ROR	(3,837,914)	(3,501,128)	(288,430)	(44,703)	(1,986)	(46,689)	(1,235)	(394)	(38)
45	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
46	Percent Increase Required	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
47	Annual Booked kWh Sales	11,094,090,621	2,482,650,181	868,690,622	4,805,590,854	2,511,463,911	7,317,054,765	333,318,925	89,772,894	2,603,234
48	Sales Revenue Required $/kWh	($0.0003)	($0.0014)	($0.0003)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)
49	Revenue Deficiency $/kWh	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro
[A]	[B]	[L]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]
	Customer Sales Expense									
	Present Rates									
1	Rate Base	0	0	0	0	0	0	0	0	0
2	Net Operating Income (Present Rates)	0	0	0	0	0	0	0	0	0
3	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4	Relative Rate of Return	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	Sales Revenue (Present Rates)	0	0	0	0	0	0	0	0	0
6	Revenue Present Rates $/kWh	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
8										
9										
10	**Proposed Rate of Return**									
11										
12	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	Return Required Proposed Rate of Return	0	0	0	0	0	0	0	0	0
14	Sales Revenue Required Proposed ROR	0	0	0	0	0	0	0	0	0
15	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
16	Percent Increase Required	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
17	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
18	Sales Revenue Required $/kWh	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)
20										
21										
22										
23										
24										
25										
26										
27	**Customer Other**									
28										
29	**Present Rates**									
30										
31	Rate Base	0	0	0	0	0	0	0	0	0
32	Net Operating Income (Present Rates)	0	0	0	0	0	0	0	0	0
33	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	Relative Rate of Return	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	Sales Revenue (Present Rates)	(3,488,681)	(12,448)	(288,361)	(69)	(41,208)	(3,495)	(13)	(1,973)	(1,235)
36	Revenue Present Rates $/kWh	($0.0016)	($0.0000)	($0.0003)	($0.0001)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)
37	Revenue Required - $/Mo/Customer	($1.06)	($1.06)	($1.06)	($1.06)	($1.06)	($1.06)	($1.06)	($1.06)	($1.06)
38										
39										
40	**Proposed Rate of Return**									
41										
42	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
43	Return Required Proposed Rate of Return	0	0	0	0	0	0	0	0	0
44	Sales Revenue Required Proposed ROR	(3,488,681)	(12,448)	(288,361)	(69)	(41,208)	(3,495)	(13)	(1,973)	(1,235)
45	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
46	Percent Increase Required	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
47	Annual Booked kWh Sales	2,187,618,636	295,031,545	867,553,528	1,137,095	2,960,342,217	1,845,248,637	191,149,448	2,320,314,463	333,318,925
48	Sales Revenue Required $/kWh	($0.0016)	($0.0000)	($0.0003)	($0.0001)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)
49	Revenue Deficiency $/kWh	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)	($0.0000)

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[U]	[V]	[W]	[X]
	Customer Sales Expense				
	Present Rates				
1	Rate Base	0	0	0	0
2	Net Operating Income (Present Rates)	0	0	0	0
3	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%
4	Relative Rate of Return	0.00	0.00	0.00	0.00
5	Sales Revenue (Present Rates)	0	0	0	0
6	Revenue Present Rates $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
7	Revenue Required - $/Mo/Customer	$0.00	$0.00	$0.00	$0.00
8					
9					
10	**Proposed Rate of Return**				
11					
12	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%
13	Return Required Proposed Rate of Return	0	0	0	0
14	Sales Revenue Required Proposed ROR	0	0	0	0
15	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)
16	Percent Increase Required	0.00%	0.00%	0.00%	0.00%
17	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
18	Sales Revenue Required $/kWh	$0.0000	$0.0000	$0.0000	$0.0000
19	Revenue Deficiency $/kWh	$0.0000	($0.0000)	($0.0000)	($0.0000)
20					
21					
22					
23					
24					
25					
26					
27	**Customer Other**				
28					
29	**Present Rates**				
30					
31	Rate Base	0	0	0	0
32	Net Operating Income (Present Rates)	0	0	0	0
33	Rate of Return (Present Rates)	0.00%	0.00%	0.00%	0.00%
34	Relative Rate of Return	0.00	0.00	0.00	0.00
35	Sales Revenue (Present Rates)	0	(356)	(38)	(38)
36	Revenue Present Rates $/kWh	$0.0000	($0.0000)	($0.0000)	($0.0000)
37	Revenue Required - $/Mo/Customer	$0.00	($1.06)	($1.06)	($1.05)
38					
39					
40	**Proposed Rate of Return**				
41					
42	Proposed Rate of Return	0.00%	0.00%	0.00%	0.00%
43	Return Required Proposed Rate of Return	0	0	0	0
44	Sales Revenue Required Proposed ROR	0	(356)	(38)	(38)
45	Revenue Deficiency Sales Revenue	(0)	(0)	(0)	(0)
46	Percent Increase Required	0.00%	0.00%	0.00%	0.00%
47	Annual Booked kWh Sales	0	79,310,898	10,461,996	2,603,234
48	Sales Revenue Required $/kWh	$0.0000	($0.0000)	($0.0000)	($0.0000)
49	Revenue Deficiency $/kWh	$0.0000	($0.0000)	($0.0000)	($0.0000)

L. Schafer
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (E) – 3

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Allocation Development Table
Rate-Class Level

Line No.	Description	Allocator	Total DC Distribution	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]	[Q]
1	Development of Depreciable Plant Allocators															
2	3602 Easements	NCAPSUBS	273,473	68,079	7,427	20,453	22	72,044	42,626	0	52,306	8,032	0	2,300	147	37
3	Direct Subtransmission	SUBTAED	269,260,369	65,795,785	7,201,342	19,852,133	21,470	69,885,787	41,389,548	4,117,808	50,803,105	7,789,651	0	2,223,459	144,003	36,278
4																
5																
6	Development of Customer Deposits Allocation															
7	Residential	SMXRES	(2,413,820)	(2,413,820)	0	0	0	0	0	0	0	0	0	0	0	0
8	Commercial	SMXCOMM	(6,356,787)	0	(212,569)	(960,316)	(944)	(2,410,821)	(1,346,574)	0	(1,424,705)	0	0	0	0	(858)
9	Total Customer Deposits		(8,770,607)	(2,413,820)	(212,569)	(960,316)	(944)	(2,410,821)	(1,346,574)	0	(1,424,705)	0	0	0	0	(858)
10																
11																
12	Development of Transformers Allocator															
13	Sum of Max (Input to Line Transformers)		3,844,973	1,977,732	79,576	359,503	0	902,497	504,097	0	0	0	0	19,974	1,273	321
14	NCAP (Input to Line Transformers)		1,871,845	601,327	65,741	180,395	0	625,576	377,238	0	0	0	0	19,974	1,273	321
15	Total		5,716,818	2,579,059	145,317	539,898	0	1,528,073	881,335	0	0	0	0	39,948	2,546	642
16	Average		2,858,409	1,289,530	72,659	269,949	0	764,037	440,668	0	0	0	0	19,974	1,273	321
17																
18																
19	Development of Account 903 Allocator															
20	990300 Cust records and collection exp	CUST903	27,587,759	24,809,197	32,917	1,877,014	826	797,980	50,378	67	10,413	4,712	0	3,882	77	298
21	Total		27,587,759	24,809,197	32,917	1,877,014	826	797,980	50,378	67	10,413	4,712	0	3,882	77	298
22																
23																
24	Development of Account 908 Allocator															
25	990800 Customer assistance expenses	CUST908	415,386	323,427	1,445	53,369	35	33,035	2,184	9	1,367	25	0	449	18	24
26	DSM	DSM908	966,826	966,826	0	0	0	0	0	0	0	0	0	0	0	0
31	Total		1,382,212	1,290,254	1,445	53,369	35	33,035	2,184	9	1,367	25	0	449	18	24
32																
33																
34	Development of CRMB Allocator															
35	Total from 903 Allocator Development	CUST903	27,587,759	24,809,197	32,917	1,877,014	826	797,980	50,378	67	10,413	4,712	0	3,882	77	298
36	Total from 908 Allocator Development	CUST908	1,382,212	1,290,254	1,445	53,369	35	33,035	2,184	9	1,367	25	0	449	18	24
37	Total from Customer Information Expense (CUST909)	CUST909	398,755	363,541	420	24,739	2	9,520	270	1	107	74	0	76	1	4
38	Total		29,368,727	26,462,992	34,782	1,955,122	863	840,534	52,832	76	11,886	4,811	0	4,407	95	326

Potomac Electric Power Company
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Line No.	Description	Allocator	Total DC Distribution	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]	[Q]
	Allocation Development Table **Capacity-Distribution Related** **Rate-Class & (Sub)Functional Levels**															
1	Avg & Excess - Subtrans (NCP)	SUBTAED	100,000	24,436	2,674	7,373	8	25,955	15,372	1,529	18,868	2,893	0	826	53	13
2	NCAP (Primary Substations)	NCAPSUBS	2,452,706	610,583	66,614	183,435	198	646,143	382,297	0	469,122	72,039	0	20,629	1,315	331
3	NCAP (Primary Lines)	NCAPPRIM	2,439,456	607,076	66,225	182,390	196	642,911	380,069	0	466,770	71,650	0	20,530	1,308	331
4	Sum of Max (Secondary Lines)	SMX2ND	3,806,508	1,957,945	78,780	355,902	0	893,473	499,053	0	0	0	0	19,777	1,260	318
5	Avg . Max & NCAP (Transf)	SMXNCAP	2,858,409	1,289,530	72,659	269,949	0	764,037	440,668	0	0	0	0	19,974	1,273	321
6	Avg . Max & NCAP (Transf) - Res Only	SMXNCAPR	1,289,530	1,289,530	0	0	0	0	0	0	0	0	0	0	0	0
7	Avg . Max & NCAP (Transf) - Com Only	SMXNCAPC	1,568,880	0	72,659	269,949	0	764,037	440,668	0	0	0	0	19,974	1,273	321
8																
9	Subtransmission Ext Allocator	EXTSUBT	1	1	0	0	0	0	0	0	0	0	0	0	0	0
10	Substation External Allocator	EXTSUBS	1	1	0	0	0	0	0	0	0	0	0	0	0	0
11	Primary Lines External Allocator	EXTPRIM	1	1	0	0	0	0	0	0	0	0	0	0	0	0
12	Secondary Lines External Allocator	EXTSEC	1	1	0	0	0	0	0	0	0	0	0	0	0	0
13	Transformers External Allocator	EXTTRANSF	1	1	0	0	0	0	0	0	0	0	0	0	0	0
14																
15																
16																
17	MD Universal Surcharge	MDUNIV	1	1	0	0	0	0	0	0	0	0	0	0	0	0
18	Delivery Tax	DELIV	84,468,565	15,552,264	2,173,344	6,704,581	9,025	13,427,443	23,123,403	1,460,921	18,758,867	2,576,577	0	580,442	81,711	19,988
19	Montgomery County Fuel & Energy	MCFUEL	1	1	0	0	0	0	0	0	0	0	0	0	0	0
20	Sum of Max Residential Only	SMXRES	1,957,945	1,957,945	0	0	0	0	0	0	0	0	0	0	0	0
21	Sum of Max Commercial Only	SMXCOMM	2,355,885	0	78,780	355,902	350	893,473	499,053	0	528,009	0	0	0	0	318
22																
23																
24	DC PSOS	DCPSOS	23,184,083	4,598,797	642,686	1,802,414	2,426	3,609,713	6,216,302	392,741	5,042,960	692,664	0	156,041	21,967	5,373
25	DC EATF/SETF	DCEASETF	20,321,528	3,765,018	577,197	1,618,834	2,179	3,241,694	5,583,050	217,823	4,528,984	622,063	0	140,136	19,728	4,823
26	DC RETF Revenue	DCRRETF	1	1	0	0	0	0	0	0	0	0	0	0	0	0

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Allocation Development Table
Customer Related
Rate-Class & (Sub)Functional Levels

Line No.	Description	Allocator	Total DC Distribution	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]	[Q]
1	Acct 369 - Sum of Max (Secondary Serv)	CUST369	3,785,153	1,957,945	78,780	355,902	0	893,473	499,053	0	0	0	0	0	0	0
2	Acct 370-Meters	CUST370	7,598,693	827,818	369,680	2,878,716	16,332	1,832,788	541,442	14,182	823,918	290,790	0	3,027	0	0
3	Acct 371 Install on Cust Prem Direct Assign	CUST371	1,367,203	1,205	1,811	94,957	0	0	1,262,621	0	6,610	0	0	0	0	0
4	Acct 373 Street Light & Signal Sys Dir Assign	CUST373	1	0	0	0	0	0	0	0	0	0	1	0	0	0
5																
6	Acct 370.1-AMI Meters	CUST3701	32,511,379	27,937,304	190,451	3,350,386	1,576	757,565	177,700	0	54,158	39,393	0	2,846	0	0
7	Customer Accounts Expense 902	CUST902	1,056,841	357,214	5,397	224,337	509	241,153	96,189	823	127,997	2,543	0	679	0	0
8	Customer Accounts Expense 903	CUST903	76,236,079	68,557,795	90,962	5,186,944	2,283	2,205,139	139,213	185	28,774	13,021	0	10,729	212	822
9	Interval Billing Costs	INTERVBILL	275,557	259,456	863	15,186	0	33	0	0	2	0	0	17	0	0
10	Customer Accounts Expense 904	CUST904	2,666,568	2,164,682	12,375	333,388	2,192	53,586	99,995	0	351	0	0	0	0	0
11	Customer Information Expense 907	CUST907	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Customer Information Expense 908	CUST908	1,473,227	1,147,083	5,125	189,280	124	117,162	7,746	31	4,847	90	0	1,593	62	84
13	Customer Information Expense 908-DSM	DSM908	28,712	28,712	0	0	0	0	0	0	0	0	0	0	0	0
14	Customer Information Expense 909	CUST909	1,164,440	1,061,606	1,226	72,244	7	27,799	790	2	312	217	0	221	4	13
15	Customer Information Expense 910	CUST910	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Sales Expense 913	CUST913	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17																
18	Number of Customers (SL-E number of lights)		377,160	274,706	980	22,735	5	3,246	275	1	156	97	0	74,953	3	3
19	Number of Customers	CUSTS	302,235	274,706	980	22,735	5	3,246	275	1	156	97	0	28	3	3
20	Customers Less Metro and SL	CUSTLMSL	302,110	274,706	980	22,735	5	3,246	275	1	156	0	0	0	3	3
21	Net Energy Metering Number of Customers	CUSTSNEM	4,657	4,196	49	238	0	159	2	0	13	0	0	0	0	0
22	Load Settlement Customers	CUSTSLS	302,235	274,706	980	22,735	5	3,246	275	1	156	97	0	28	3	3
23	Customer Count for AMI Allocator	CUSTSAMI	302,235	274,706	980	22,735	5	3,246	275	1	156	97	0	28	3	3
24	CEO - Online Customers	CEOCUSTS	1	1	0	0	0	0	0	0	0	0	0	0	0	0
25	Billing Services Customers	BILSVC	44,660	37,132	560	5,114	4	496	1,247	1	100	1	0	2	2	1
26	Residential Customers Only - 904	CUSTSRES	274,706	274,706	0	0	0	0	0	0	0	0	0	0	0	0
27	Low Voltage Commercial Customers Only - 904	CUSTSLV	27,236	0	980	22,735	0	3,246	275	0	0	0	0	0	0	0
28	Res and LV Custs Only	CUSTSRESLV	301,942	274,706	980	22,735	0	3,246	275	0	0	0	0	0	0	0
29																
30	[Available Storm] Outages	OUT[storm name 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Riley Outages	OUTRILEY	44,966	41,534	102	3,163	0	81	84	0	2	0	0	0	0	0
32	Toby Outages	OUTTOBY	186	174	2	10	0	0	0	0	0	0	0	0	0	0
33	[Available Storm] Outages	OUT[storm name 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Md Enviro Trust	MDENV	1	1	0	0	0	0	0	0	0	0	0	0	0	0
35																
36	Customer Deposits - Residential	CUSTDEPRES	1,957,945	1,957,945	0	0	0	0	0	0	0	0	0	0	0	0
37	Customer Deposits - Commercial	CUSTDEPCOM	2,355,885	0	78,780	355,902	350	893,473	499,053	0	528,009	0	0	0	0	318

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Internally Developed Allocators
Development Table
Rate-Class Level

Line No.	Description	Allocator	Total DC Distribution	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]	[Q]
1	Plant 360 - 368	PLTDACTS	2,897,134,873	1,019,417,773	73,127,591	240,592,360	132,332	744,972,632	432,938,895	0	314,635,188	48,302,967	0	21,314,017	1,358,173	342,946
2	Plant 361	PLANT361	67,547,024	16,804,121	1,833,523	5,049,170	5,450	17,785,127	10,523,121	37,390	12,913,191	1,982,860	0	567,744	36,212	9,115
3	Acct 3700 Meters	PLANT370	66,033,710	51,489,784	686,427	8,735,850	17,909	3,064,245	821,533	13,067	857,481	339,456	0	7,957	0	0
4	Installations	PLANT371	1,367,203	1,205	1,811	94,957	0	0	1,262,621	0	6,610	0	0	0	0	0
5	Acct 3730 Street Lighting and Signal Systems	PLANT373	10,106,511	0	0	0	0	0	0	0	0	0	10,106,511	0	0	0
6	Plant - Primary Demand	PLTPRIM	1,644,564,546	409,306,003	44,651,932	122,970,123	132,332	433,364,775	256,258,999	0	314,635,188	48,302,967	0	13,837,694	881,769	222,764
7	Plant - Secondary Demand	PLTSEC	1,252,570,327	610,111,770	28,475,659	117,622,236	0	311,607,857	176,679,896	0	0	0	0	7,476,323	476,404	120,182
8	Plant - Demand	PLTDEM	2,897,134,873	1,019,417,773	73,127,591	240,592,360	132,332	744,972,632	432,938,895	0	314,635,188	48,302,967	0	21,314,017	1,358,173	342,946
9	Plant - Customer	PLTCUST	380,038,007	207,980,896	6,984,775	37,276,484	17,909	74,475,601	41,971,260	13,067	864,091	339,456	10,106,511	7,957	0	0
10	Total Distribution Plant	DISTPLT	3,277,172,881	1,227,398,669	80,112,366	277,868,843	150,241	819,448,233	474,910,155	13,067	315,499,278	48,642,423	10,106,511	21,321,975	1,358,173	342,946
11	Subtransmission and Distribution Plant	STDPLT	3,547,219,220	1,293,386,511	87,334,729	297,778,925	171,774	889,538,017	516,420,519	4,142,895	366,450,678	56,454,811	10,106,511	23,551,924	1,502,596	379,330
12	STDPLT less Residential, Street Lighting, and Traffic Signa	STDPLT-LESSRSl	2,218,671,678	**0**	87,334,729	297,778,925	171,774	889,538,017	516,420,519	4,142,895	366,450,678	56,454,811	**0**	**0**	**0**	379,330
13	Subtransmission and Distribution AFUDC	STAFUDC	6,508,276	1,590,346	174,063	479,845	519	1,689,205	1,000,424	99,531	1,227,959	188,283	0	53,743	3,481	877
14	Depreciable Plant - Distribution	DPPLT	3,166,950,078	1,164,908,361	78,225,794	265,828,149	128,765	804,742,747	467,200,999	0	306,189,857	47,005,079	10,106,511	20,942,354	1,334,481	336,982
15	Depreciable Plant for General	DPPLTG	3,502,244,157	1,282,193,929	86,113,562	294,416,132	168,144	877,692,779	509,412,080	4,130,875	357,850,444	55,134,185	10,106,511	23,173,771	1,478,484	373,260
16	CWIP Distribution	CWIPDIST	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	CWIP AFUDC	CWIPAF	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	CWIP ST&D	CWIPSTD	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Deferred Taxes	DEFTAX	(800,844,028)	(292,003,623)	(19,717,275)	(67,228,569)	(38,781)	(200,828,075)	(116,590,564)	(935,328)	(82,732,366)	(12,745,617)	(2,281,714)	(5,317,240)	(339,236)	(85,640)
20	Customer Deposits	CUSTDEP	(8,770,607)	(2,413,820)	(212,569)	(960,316)	(944)	(2,410,821)	(1,346,574)	0	(1,424,705)	0	0	0	0	(858)
21	Sale of Electricity	ELECSAL	528,475,591	101,836,108	13,840,112	56,627,278	65,211	152,329,951	108,126,172	2,491,481	80,121,676	10,631,794	631,344	1,340,533	331,754	102,177
22	O&M LESS A&G	OMLESAG	97,079,178	50,691,662	1,505,690	7,789,245	7,517	15,333,056	12,777,109	26,430	7,358,952	1,138,859	4,196	413,443	26,120	6,897
23	OM Operations	OMOPS	24,139,191	8,524,628	474,697	2,098,544	1,852	4,562,374	5,758,024	6,017	2,220,884	349,357	6,192	126,551	8,040	2,030
24	OM Maintenance	OMMAINT	29,926,083	9,787,744	760,052	2,417,592	1,760	7,632,255	4,449,380	16,754	4,008,884	616,283	(3,991)	221,671	14,133	3,568
25	OM Account 592	OMEXP592	8,553,018	2,125,347	231,946	638,777	690	2,249,934	1,331,324	12,884	1,633,728	250,841	0	71,808	4,585	1,154
26	OM Account 593	OMEXP593	8,297,389	2,808,510	207,183	672,831	442	2,106,014	1,223,569	20	1,051,719	161,441	0	60,806	3,874	980
27	Account 903	ACCT903	27,587,759	24,809,197	32,917	1,877,014	826	797,980	50,378	67	10,413	4,712	0	3,882	77	298
28	Account 908	ACCT908	1,382,212	1,290,254	1,445	53,369	35	33,035	2,184	9	1,367	25	0	449	18	24
29	Cust. Rel. Manag. & Billing (CRMB)	CRMB	29,368,727	26,462,992	34,782	1,955,122	863	840,534	52,832	76	11,886	4,811	0	4,407	95	326
30	Depreciation Exp Less AFUDC	DEPRE	108,181,884	40,177,107	2,641,618	9,139,058	5,173	26,955,400	15,634,091	116,123	10,727,406	1,654,364	379,210	696,675	44,440	11,219
31	MD Prop Tax	MDPTAX	4,994,089	1,870,435	122,083	423,445	229	1,248,758	723,716	20	480,790	74,126	15,401	32,493	2,070	523

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Line No.	Description	Allocator	Total DC Distribution	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]	[Q]
	Allocation Ratios **Capacity-Distribution Related** **Rate-Class & (Sub)Functional Levels**															
1	Avg & Excess - Subtrans (NCP)	SUBTAED	1.000000	0.244357	0.026745	0.073728	0.000080	0.259547	0.153716	0.015293	0.188677	0.028930	0.000000	0.008258	0.000535	0.000135
2	NCAP (Primary Substations)	NCAPSUBS	1.000000	0.248943	0.027159	0.074789	0.000081	0.263441	0.155867	0.000000	0.191267	0.029371	0.000000	0.008411	0.000536	0.000135
3	NCAP (Primary Lines)	NCAPPRIM	1.000000	0.248857	0.027147	0.074767	0.000080	0.263547	0.155801	0.000000	0.191342	0.029371	0.000000	0.008416	0.000536	0.000136
4	Sum of Max (Secondary Lines)	SMX2ND	1.000000	0.514368	0.020696	0.093498	0.000000	0.234722	0.131105	0.000000	0.000000	0.000000	0.000000	0.005196	0.000331	0.000084
5	Avg . Max & NCAP (Transf)	SMXNCAP	1.000000	0.451135	0.025419	0.094440	0.000000	0.267294	0.154165	0.000000	0.000000	0.000000	0.000000	0.006988	0.000445	0.000112
6	Avg . Max & NCAP (Transf) - Res Only	SMXNCAPR	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
7	Avg . Max & NCAP (Transf) - Com Only	SMXNCAPC	1.000000	0.000000	0.046312	0.172065	0.000000	0.486995	0.280880	0.000000	0.000000	0.000000	0.000000	0.012731	0.000811	0.000205
8																
9	Subtransmission Ext Allocator	EXTSUBT	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
10	Substation External Allocator	EXTSUBS	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
11	Primary Lines External Allocator	EXTPRIM	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
12	Secondary Lines External Allocator	EXTSEC	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
13	Transformers External Allocator	EXTTRANSF	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
14																
15																
16																
17	MD Universal Surcharge	MDUNIV	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
18	Delivery Tax	DELIV	1.000000	0.184119	0.025730	0.079374	0.000107	0.158964	0.273752	0.017295	0.222081	0.030503	0.000000	0.006872	0.000967	0.000237
19	Montgomery County Fuel & Energy	MCFUEL	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
20	Sum of Max Residential Only	SMXRES	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
21	Sum of Max Commercial Only	SMXCOMM	1.000000	0.000000	0.033440	0.151069	0.000149	0.379252	0.211832	0.000000	0.224123	0.000000	0.000000	0.000000	0.000000	0.000135
22																
23																
24	DC PSOS	DCPSOS	1.000000	0.198360	0.027721	0.077744	0.000105	0.155698	0.268128	0.016940	0.217518	0.029877	0.000000	0.006731	0.000947	0.000232
25	DC EATF/SETF	DCEASETF	1.000000	0.185272	0.028403	0.079661	0.000107	0.159520	0.274736	0.010719	0.222866	0.030611	0.000000	0.006896	0.000971	0.000237
26	DC RETF Revenue	DCRRETF	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Total DC Distribution	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]	[Q]
	Allocation Ratios **Customer Related** **Rate-Class & (Sub)Functional Levels**															
1	Acct 369 - Sum of Max (Secondary Serv)	CUST369	1.000000	0.517270	0.020813	0.094026	0.000000	0.236047	0.131845	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
2	Acct 370-Meters	CUST370	1.000000	0.108942	0.048651	0.378844	0.002149	0.241198	0.071255	0.001866	0.108429	0.038268	0.000000	0.000398	0.000000	0.000000
3	Acct 371 Install on Cust Prem Direct Assign	CUST371	1.000000	0.000881	0.001324	0.069453	0.000000	0.000000	0.923507	0.000000	0.004835	0.000000	0.000000	0.000000	0.000000	0.000000
4	Acct 373 Street Light & Signal Sys Dir Assign	CUST373	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
5																
6	Acct 370.1-AMI Meters	CUST3701	1.000000	0.859308	0.005858	0.103053	0.000048	0.023302	0.005466	0.000000	0.001666	0.001212	0.000000	0.000088	0.000000	0.000000
7	Customer Accounts Expense 902	CUST902	1.000000	0.338002	0.005106	0.212271	0.000481	0.228183	0.091016	0.000778	0.121113	0.002407	0.000000	0.000643	0.000000	0.000000
8	Customer Accounts Expense 903	CUST903	1.000000	0.899283	0.001193	0.068038	0.000030	0.028925	0.001826	0.000002	0.000377	0.000171	0.000000	0.000141	0.000003	0.000011
9	Interval Billing Costs	INTERVBILL	1.000000	0.941569	0.003132	0.055110	0.000000	0.000120	0.000000	0.000000	0.000007	0.000000	0.000000	0.000062	0.000000	0.000000
10	Customer Accounts Expense 904	CUST904	1.000000	0.811786	0.004641	0.125025	0.000822	0.020095	0.037500	0.000000	0.000132	0.000000	0.000000	0.000000	0.000000	0.000000
11	Customer Information Expense 907	CUST907	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
12	Customer Information Expense 908	CUST908	1.000000	0.778619	0.003479	0.128480	0.000084	0.079528	0.005258	0.000021	0.003290	0.000061	0.000000	0.001081	0.000042	0.000057
13	Customer Information Expense 908-DSM	DSM908	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
14	Customer Information Expense 909	CUST909	1.000000	0.911688	0.001053	0.062042	0.000006	0.023873	0.000678	0.000002	0.000268	0.000186	0.000000	0.000190	0.000003	0.000011
15	Customer Information Expense 910	CUST910	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
16	Sales Expense 913	CUST913	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
17																
18	Number of Customers (SL-E number of lights)		1.000000	0.728355	0.002599	0.060279	0.000014	0.008606	0.000729	0.000003	0.000413	0.000257	0.000000	0.198729	0.000008	0.000008
19	Number of Customers	CUSTS	1.000000	0.908915	0.003243	0.075222	0.000018	0.010740	0.000910	0.000003	0.000515	0.000321	0.000000	0.000093	0.000010	0.000010
20	Customers Less Metro and SL	CUSTLMSL	1.000000	0.909292	0.003245	0.075253	0.000018	0.010744	0.000910	0.000003	0.000515	0.000000	0.000000	0.000000	0.000010	0.000010
21	Net Energy Metering Number of Customers	CUSTSNEM	1.000000	0.901009	0.010522	0.051106	0.000000	0.034142	0.000429	0.000000	0.002791	0.000000	0.000000	0.000000	0.000000	0.000000
22	Load Settlement Customers	CUSTSLS	1.000000	0.908915	0.003243	0.075222	0.000018	0.010740	0.000910	0.000003	0.000515	0.000321	0.000000	0.000093	0.000010	0.000010
23	Customer Count for AMI Allocator	CUSTSAMI	1.000000	0.908915	0.003243	0.075222	0.000018	0.010740	0.000910	0.000003	0.000515	0.000321	0.000000	0.000093	0.000010	0.000010
24	CEO - Online Customers	CEOCUSTS	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
25	Billing Services Customers	BILSVC	1.000000	0.831438	0.012539	0.114510	0.000090	0.011106	0.027922	0.000022	0.002239	0.000022	0.000000	0.000045	0.000045	0.000022
26	Residential Customers Only - 904	CUSTSRES	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
27	Low Voltage Commercial Customers Only - 904	CUSTSLV	1.000000	0.000000	0.035991	0.834731	0.000000	0.119181	0.010097	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
28	Res and LV Custs Only	CUSTSRESLV	1.000000	0.909797	0.003246	0.075295	0.000000	0.010750	0.000911	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
29																
30	[Available Storm] Outages	OUT[storm name 1	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
31	Riley Outages	OUTRILEY	1.000000	0.923676	0.002268	0.070342	0.000000	0.001801	0.001868	0.000000	0.000044	0.000000	0.000000	0.000000	0.000000	0.000000
32	Toby Outages	OUTTOBY	1.000000	0.935484	0.010753	0.053763	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
33	[Available Storm] Outages	OUT[storm name 2	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
34	Md Enviro Trust	MDENV	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
35																
36	Customer Deposits - Residential	CUSTDEPRES	1.000000	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
37	Customer Deposits - Commercial	CUSTDEPCOM	1.000000	0.000000	0.033440	0.151069	0.000149	0.379252	0.211832	0.000000	0.224123	0.000000	0.000000	0.000000	0.000000	0.000135

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Allocator	Total DC Distribution	Residential (R)	Master-Metered Accounts (MMA)	General Service Low Voltage (GS-LV)	General Service High Voltage (GS-HV)	Time-Metered Medium General Service Low Voltage (MGT-LV)	Time-Metered General Service Low Voltage (GT-LV)	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	Metro	Street Lighting S Service	Street Lighting E Service	Traffic Signal	Tele-Communication Network Service
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]	[M]	[N]	[O]	[P]	[Q]
	Allocation Ratios Internally Developed Rate-Class Level															
1	Plant 360 - 368	PLTDACTS	1.000000	0.351871	0.025241	0.083045	0.000046	0.257141	0.149437	0.000000	0.108602	0.016673	0.000000	0.007357	0.000469	0.000118
2	Plant 361	PLANT361	1.000000	0.248777	0.027144	0.074750	0.000081	0.263300	0.155790	0.000554	0.191173	0.029355	0.000000	0.008405	0.000536	0.000135
3	Acct 3700 Meters	PLANT370	1.000000	0.779750	0.010395	0.132294	0.000271	0.046404	0.012441	0.000198	0.012986	0.005141	0.000000	0.000121	0.000000	0.000000
4	Installations	PLANT371	1.000000	0.000881	0.001324	0.069453	0.000000	0.000000	0.923507	0.000000	0.004835	0.000000	0.000000	0.000000	0.000000	0.000000
5	Acct 3730 Street Lighting and Signal Systems	PLANT373	1.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	1.000000	0.000000	0.000000	0.000000
6	Plant - Primary Demand	PLTPRIM	1.000000	0.248884	0.027151	0.074774	0.000080	0.263513	0.155822	0.000000	0.191318	0.029371	0.000000	0.008414	0.000536	0.000135
7	Plant - Secondary Demand	PLTSEC	1.000000	0.487088	0.022734	0.093905	0.000000	0.248775	0.141054	0.000000	0.000000	0.000000	0.000000	0.005969	0.000380	0.000096
8	Plant - Demand	PLTDEM	1.000000	0.351871	0.025241	0.083045	0.000046	0.257141	0.149437	0.000000	0.108602	0.016673	0.000000	0.007357	0.000469	0.000118
9	Plant - Customer	PLTCUST	1.000000	0.547263	0.018379	0.098086	0.000047	0.195969	0.110440	0.000034	0.002274	0.000893	0.026593	0.000021	0.000000	0.000000
10	Total Distribution Plant	DISTPLT	1.000000	0.374530	0.024446	0.084789	0.000046	0.250047	0.144915	0.000004	0.096272	0.014843	0.003084	0.006506	0.000414	0.000105
11	Subtransmission and Distribution Plant	STDPLT	1.000000	0.364620	0.024621	0.083947	0.000048	0.250771	0.145585	0.001168	0.103306	0.015915	0.002849	0.006640	0.000424	0.000107
12	STDPLT less Residential, Street Lighting, and Traffic Signa	STDPLT-LESSRSl	1.000000	0.000000	0.039364	0.134215	0.000077	0.400933	0.232761	0.001867	0.165167	0.025445	0.000000	0.000000	0.000000	0.000171
13	Subtransmission and Distribution AFUDC	STAFUDC	1.000000	0.244357	0.026745	0.073728	0.000080	0.259547	0.153716	0.015293	0.188677	0.028930	0.000000	0.008258	0.000535	0.000135
14	Depreciable Plant - Distribution	DPPLT	1.000000	0.367833	0.024701	0.083938	0.000041	0.254107	0.147524	0.000000	0.096683	0.014842	0.003191	0.006613	0.000421	0.000106
15	Depreciable Plant for General	DPPLTG	1.000000	0.366106	0.024588	0.084065	0.000048	0.250609	0.145453	0.001179	0.102177	0.015743	0.002886	0.006617	0.000422	0.000107
16	CWIP Distribution	CWIPDIST	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
17	CWIP AFUDC	CWIPAF	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
18	CWIP ST&D	CWIPSTD	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
19	Deferred Taxes	DEFTAX	1.000000	0.364620	0.024621	0.083947	0.000048	0.250771	0.145585	0.001168	0.103306	0.015915	0.002849	0.006640	0.000424	0.000107
20	Customer Deposits	CUSTDEP	1.000000	0.275217	0.024236	0.109492	0.000108	0.274875	0.153533	0.000000	0.162441	0.000000	0.000000	0.000000	0.000000	0.000098
21	Sale of Electricity	ELECSAL	1.000000	0.192698	0.026189	0.107152	0.000123	0.288244	0.204600	0.004714	0.151609	0.020118	0.001195	0.002537	0.000628	0.000193
22	O&M LESS A&G	OMLESAG	1.000000	0.522168	0.015510	0.080236	0.000077	0.157944	0.131615	0.000272	0.075804	0.011731	0.000043	0.004259	0.000269	0.000071
23	OM Operations	OMOPS	1.000000	0.353145	0.019665	0.086935	0.000077	0.189003	0.238534	0.000249	0.092003	0.014473	0.000257	0.005243	0.000333	0.000084
24	OM Maintenance	OMMAINT	1.000000	0.327064	0.025398	0.080785	0.000059	0.255037	0.148679	0.000560	0.133960	0.020593	(0.000133)	0.007407	0.000472	0.000119
25	OM Account 592	OMEXP592	1.000000	0.248491	0.027119	0.074684	0.000081	0.263057	0.155655	0.001506	0.191012	0.029328	0.000000	0.008396	0.000536	0.000135
26	OM Account 593	OMEXP593	1.000000	0.338481	0.024970	0.081090	0.000053	0.253817	0.147464	0.000002	0.126753	0.019457	0.000000	0.007328	0.000467	0.000118
27	Account 903	ACCT903	1.000000	0.899283	0.001193	0.068038	0.000030	0.028925	0.001826	0.000002	0.000377	0.000171	0.000000	0.000141	0.000003	0.000011
28	Account 908	ACCT908	1.000000	0.933470	0.001046	0.038611	0.000025	0.023900	0.001580	0.000006	0.000989	0.000018	0.000000	0.000325	0.000013	0.000017
29	Cust. Rel. Manag. & Billing (CRMB)	CRMB	1.000000	0.901060	0.001184	0.066572	0.000029	0.028620	0.001799	0.000003	0.000405	0.000164	0.000000	0.000150	0.000003	0.000011
30	Depreciation Exp Less AFUDC	DEPRE	1.000000	0.371385	0.024418	0.084479	0.000048	0.249167	0.144517	0.001073	0.099161	0.015292	0.003505	0.006440	0.000411	0.000104
31	MD Prop Tax	MDPTAX	1.000000	0.374530	0.024446	0.084789	0.000046	0.250047	0.144915	0.000004	0.096272	0.014843	0.003084	0.006506	0.000414	0.000105

L. Schafer
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (E) – 4

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Rate of Return	Customer Count	Customer Component $/Mo./Cust.	Total DC Distribution	Demand Total	Energy Total	Customer Total
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
	Present Rate Of Return Summary - Revenue							
	Revenue at Present Rates							
1	Total DC Distribution	4.87%	302,235	26.65	528,475,591	431,817,133	(0)	96,658,458
2	Total Residential Service	-4.06%	275,686	17.62	115,676,220	57,374,187	0	58,302,033
3	Total GS	10.84%	22,740	43.20	56,692,489	44,903,472	0	11,789,017
4	Total GT-LV	11.45%	3,521	601.69	260,456,123	235,033,627	0	25,422,496
5	Total GT-HV	11.03%	157	214.29	82,613,157	82,210,511	0	402,646
6	Total GT	11.36%	3,678	585.19	343,069,280	317,244,138	0	25,825,142
7	Total Metro	8.22%	97	86.73	10,631,794	10,530,840	0	100,954
8	Total Street Lighting	-2.20%	31	1,722.15	2,303,631	1,662,990	0	640,641
9	Total TN Service	17.34%	3	18.65	102,177	101,505	0	672
10	Residential (R)	-4.87%	274,706	17.40	101,836,108	44,471,044	0	57,365,064
11	Master-Metered Accounts (MMA)	8.90%	980	79.65	13,840,112	12,903,143	0	936,969
12	General Service Low Voltage (GS-LV)	10.84%	22,735	43.16	56,627,278	44,852,336	0	11,774,942
13	General Service High Voltage (GS-HV)	23.40%	5	216.54	65,211	51,136	0	14,075
14	Time-Metered Medium General Service Low Voltage (MGT-LV)	12.37%	3,246	308.92	152,329,951	140,296,893	0	12,033,059
15	Time-Metered General Service Low Voltage (GT-LV)	9.89%	275	4,057.41	108,126,172	94,736,734	0	13,389,438
16	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	10.51%	1	338.10	2,491,481	2,487,424	0	4,057
17	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	11.03%	156	213.49	80,121,676	79,723,087	0	398,589
18	Metro	8.22%	97	86.73	10,631,794	10,530,840	0	100,954
21	Street Lighting S Service	3.00%	0	0.00	631,344	0	0	631,344
22	Street Lighting E Service	-5.05%	28	27.20	1,340,533	1,331,392	0	9,141
23	Traffic Signal	9.25%	3	4.33	331,754	331,598	0	156
24	Tele-Communication Network Service	17.34%	3	18.65	102,177	101,505	0	672
25								
26								
27	**Proposed Rate Of Return Summary - Revenue**							
28								
29	Revenue Requirement							
30								
31	Total DC Distribution	7.81%	302,235	34.74	617,106,248	491,118,231	(0)	125,988,016
32	Total Residential Service	7.81%	275,686	27.83	261,194,829	169,111,463	0	92,083,366
33	Total GS	7.81%	22,740	38.78	49,029,619	38,447,513	0	10,582,106
34	Total GT-LV	7.81%	3,521	516.57	218,393,882	196,567,920	0	21,825,962
35	Total GT-HV	7.81%	157	198.22	72,815,794	72,443,344	0	372,450
36	Total GT	7.81%	3,678	503.01	291,209,676	269,011,263	0	22,198,412
37	Total Metro	7.81%	97	85.45	10,439,473	10,340,010	0	99,463
38	Total Street Lighting	7.81%	31	2,752.84	5,160,157	4,136,100	0	1,024,057
39	Total TN Service	7.81%	3	17.00	72,494	71,882	0	612
40	Residential (R)	7.81%	274,706	27.67	248,134,727	156,923,904	0	91,210,823
41	Master-Metered Accounts (MMA)	7.81%	980	74.18	13,060,101	12,187,558	0	872,543
42	General Service Low Voltage (GS-LV)	7.81%	22,735	38.75	48,987,474	38,416,022	0	10,571,452
43	General Service High Voltage (GS-HV)	7.81%	5	163.90	42,145	31,492	0	10,654
44	Time-Metered Medium General Service Low Voltage (MGT-LV)	7.81%	3,246	237.00	119,152,942	109,921,439	0	9,231,503
45	Time-Metered General Service Low Voltage (GT-LV)	7.81%	275	3,816.50	99,240,940	86,646,481	0	12,594,460
46	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	7.81%	1	311.66	2,412,393	2,408,653	0	3,740
47	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	7.81%	156	197.49	70,403,400	70,034,690	0	368,710
48	Metro	7.81%	97	85.45	10,439,473	10,340,010	0	99,463
51	Street Lighting S Service	7.81%	0	0.00	1,012,176	0	0	1,012,176
52	Street Lighting E Service	7.81%	28	34.90	3,833,999	3,822,271	0	11,728
53	Traffic Signal	7.81%	3	4.26	313,982	313,829	0	153
54	Tele-Communication Network Service	7.81%	3	17.00	72,494	71,882	0	612

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Demand Distribution Subtransmission	Demand Distribution Substations	Demand Distribution Primary	Demand Distribution Secondary	Demand Distribution Transformers	Demand Distribution Services
[A]	[B]	[J]	[K]	[L]	[M]	[N]	[O]
	Present Rate Of Return Summary - Revenue						
	Revenue at Present Rates						
1	Total DC Distribution	23,553,675	64,637,527	252,567,359	56,927,622	34,130,950	(0)
2	Total Residential Service	1,632,973	6,089,994	37,847,955	10,253,726	1,549,539	0
3	Total GS	2,200,548	6,007,506	21,774,348	9,181,337	5,739,734	0
4	Total GT-LV	12,812,911	34,833,304	123,215,054	37,367,182	26,805,177	0
5	Total GT-HV	6,138,753	15,506,233	60,565,524	0	0	0
6	Total GT	18,951,665	50,339,537	183,780,578	37,367,182	26,805,177	0
7	Total Metro	716,950	2,007,560	7,806,330	0	0	0
8	Total Street Lighting	45,831	178,089	1,298,671	113,942	26,458	0
9	Total TN Service	5,710	14,842	59,476	11,435	10,043	0
10	Residential (R)	936,360	4,152,843	30,701,424	8,459,249	221,167	0
11	Master-Metered Accounts (MMA)	696,613	1,937,151	7,146,531	1,794,476	1,328,372	0
12	General Service Low Voltage (GS-LV)	2,196,220	5,996,348	21,738,697	9,181,337	5,739,734	0
13	General Service High Voltage (GS-HV)	4,328	11,157	35,651	0	0	0
14	Time-Metered Medium General Service Low Voltage (MGT-LV)	8,508,526	22,992,730	65,520,984	25,210,821	18,063,831	0
15	Time-Metered General Service Low Voltage (GT-LV)	4,304,386	11,840,573	57,694,070	12,156,361	8,741,345	0
16	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	447,075	0	2,040,349	0	0	0
17	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	5,691,678	15,506,233	58,525,176	0	0	0
18	Metro	716,950	2,007,560	7,806,330	0	0	0
21	Street Lighting S Service	0	0	0	0	0	0
22	Street Lighting E Service	29,079	134,222	1,089,167	80,526	(1,601)	0
23	Traffic Signal	16,752	43,867	209,504	33,417	28,058	0
24	Tele-Communication Network Service	5,710	14,842	59,476	11,435	10,043	0
25							
26							
27	**Proposed Rate Of Return Summary - Revenue**						
28							
29	Revenue Requirement						
30							
31	Total DC Distribution	25,048,531	68,481,125	260,434,998	85,870,519	51,283,058	(0)
32	Total Residential Service	7,484,689	20,212,450	66,838,518	48,340,971	26,234,835	0
33	Total GS	1,772,613	4,979,216	19,673,228	7,522,569	4,499,887	0
34	Total GT-LV	9,946,963	27,943,867	109,050,140	29,497,448	20,129,502	0
35	Total GT-HV	4,899,868	12,720,346	54,823,130	0	0	0
36	Total GT	14,846,831	40,664,212	163,873,270	29,497,448	20,129,502	0
37	Total Metro	694,273	1,953,021	7,692,716	0	0	0
38	Total Street Lighting	246,864	663,193	2,309,846	502,763	413,433	0
39	Total TN Service	3,261	9,032	47,420	6,768	5,401	0
40	Residential (R)	6,843,559	18,408,768	59,966,714	46,678,461	25,026,402	0
41	Master-Metered Accounts (MMA)	641,130	1,803,682	6,871,804	1,662,511	1,208,432	0
42	General Service Low Voltage (GS-LV)	1,770,656	4,973,746	19,649,164	7,522,569	4,499,887	0
43	General Service High Voltage (GS-HV)	1,957	5,471	24,064	0	0	0
44	Time-Metered Medium General Service Low Voltage (MGT-LV)	6,253,485	17,570,709	54,372,934	18,942,596	12,781,714	0
45	Time-Metered General Service Low Voltage (GT-LV)	3,693,478	10,373,157	54,677,205	10,554,851	7,347,789	0
46	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	368,305	0	2,040,349	0	0	0
47	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	4,531,563	12,720,346	52,782,781	0	0	0
48	Metro	694,273	1,953,021	7,692,716	0	0	0
51	Street Lighting S Service	0	0	0	0	0	0
52	Street Lighting E Service	231,579	622,808	2,107,596	472,136	388,152	0
53	Traffic Signal	15,286	40,385	202,250	30,627	25,281	0
54	Tele-Communication Network Service	3,261	9,032	47,420	6,768	5,401	0

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Customer Services (369)	Customer Meters (370)	Customer Installations (371)	Customer Street Lighting (373)	Customer Meter Reading (902)	Customer Records & Collections (903)	Customer Uncollectibles (904)	Customer Service Expense	Customer Sales Expense	Customer Other
[A]	[B]	[P]	[Q]	[R]	[S]	[T]	[U]	[V]	[W]	[X]	[Y]
	Present Rate Of Return Summary - Revenue										
	Revenue at Present Rates										
1	Total DC Distribution	17,732,701	14,464,549	9,265,586	631,344	1,459,452	49,203,409	4,595,097	3,144,233	(0)	(3,837,914)
2	Total Residential Service	1,342,406	9,453,345	19,535	0	886,188	43,534,961	3,686,362	2,880,365	0	(3,501,128)
3	Total GS	3,217,380	3,327,436	646,242	0	238,028	3,862,070	622,852	163,440	0	(288,430)
4	Total GT-LV	13,172,915	1,349,267	8,554,773	0	241,325	1,767,693	285,231	95,996	0	(44,703)
5	Total GT-HV	0	242,494	45,036	0	91,643	21,593	652	3,213	0	(1,986)
6	Total GT	13,172,915	1,591,761	8,599,809	0	332,968	1,789,286	285,883	99,209	0	(46,689)
7	Total Metro	0	90,715	0	0	1,787	9,487	0	200	0	(1,235)
8	Total Street Lighting	0	1,292	0	631,344	483	6,958	0	958	0	(394)
9	Total TN Service	0	0	0	0	0	648	0	61	0	(38)
10	Residential (R)	727,058	9,233,023	7,360	0	878,225	43,468,341	3,663,631	2,876,107	0	(3,488,681)
11	Master-Metered Accounts (MMA)	615,348	220,322	12,175	0	7,963	66,619	22,731	4,258	0	(12,448)
12	General Service Low Voltage (GS-LV)	3,217,380	3,320,035	646,242	0	237,640	3,860,166	618,487	163,354	0	(288,361)
13	General Service High Voltage (GS-HV)	0	7,400	0	0	388	1,904	4,365	86	0	(69)
14	Time-Metered Medium General Service Low Voltage (MGT-LV)	8,954,722	1,090,137	0	0	173,198	1,664,883	100,359	90,967	0	(41,208)
15	Time-Metered General Service Low Voltage (GT-LV)	4,218,193	259,129	8,554,773	0	68,127	102,809	184,873	5,029	0	(3,495)
16	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	0	3,327	0	0	585	138	0	19	0	(13)
17	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	0	239,167	45,036	0	91,058	21,456	652	3,193	0	(1,973)
18	Metro	0	90,715	0	0	1,787	9,487	0	200	0	(1,235)
21	Street Lighting S Service	0	0	0	631,344	0	0	0	0	0	0
22	Street Lighting E Service	0	1,292	0	0	483	6,802	0	920	0	(356)
23	Traffic Signal	0	0	0	0	0	156	0	38	0	(38)
24	Tele-Communication Network Service	0	0	0	0	0	648	0	61	0	(38)
25											
26											
27	**Proposed Rate Of Return Summary - Revenue**										
28											
29	Revenue Requirement										
30											
31	Total DC Distribution	29,343,722	24,826,607	9,133,833	1,012,176	2,007,336	55,049,095	4,862,373	3,590,788	(0)	(3,837,914)
32	Total Residential Service	16,827,394	20,419,069	20,134	0	1,451,159	49,560,859	3,969,067	3,336,811	0	(3,501,128)
33	Total GS	2,542,981	2,943,492	633,303	0	227,667	3,752,847	612,099	158,147	0	(288,430)
34	Total GT-LV	9,973,347	1,156,357	8,436,318	0	236,170	1,696,492	280,567	91,414	0	(44,703)
35	Total GT-HV	0	215,695	44,077	0	90,004	20,944	640	3,076	0	(1,986)
36	Total GT	9,973,347	1,372,052	8,480,395	0	326,174	1,717,436	281,207	94,490	0	(46,689)
37	Total Metro	0	89,267	0	0	1,782	9,449	0	199	0	(1,235)
38	Total Street Lighting	0	2,727	0	1,012,176	553	7,909	0	1,086	0	(394)
39	Total TN Service	0	0	0	0	0	594	0	56	0	(38)
40	Residential (R)	16,265,699	20,208,317	8,047	0	1,443,376	49,494,938	3,946,475	3,332,651	0	(3,488,681)
41	Master-Metered Accounts (MMA)	561,695	210,752	12,087	0	7,783	65,921	22,592	4,161	0	(12,448)
42	General Service Low Voltage (GS-LV)	2,542,981	2,938,872	633,303	0	227,310	3,751,189	608,086	158,072	0	(288,361)
43	General Service High Voltage (GS-HV)	0	4,620	0	0	357	1,658	4,013	75	0	(69)
44	Time-Metered Medium General Service Low Voltage (MGT-LV)	6,406,274	917,589	0	0	168,835	1,595,684	97,842	86,487	0	(41,208)
45	Time-Metered General Service Low Voltage (GT-LV)	3,567,074	238,767	8,436,318	0	67,335	100,808	182,725	4,927	0	(3,495)
46	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	0	3,023	0	0	577	134	0	19	0	(13)
47	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	0	212,672	44,077	0	89,427	20,810	640	3,057	0	(1,973)
48	Metro	0	89,267	0	0	1,782	9,449	0	199	0	(1,235)
51	Street Lighting S Service	0	0	0	1,012,176	0	0	0	0	0	0
52	Street Lighting E Service	0	2,727	0	0	553	7,755	0	1,048	0	(356)
53	Traffic Signal	0	0	0	0	0	154	0	38	0	(38)
54	Tele-Communication Network Service	0	0	0	0	0	594	0	56	0	(38)

L. Schafer
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (E) – 5

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Total DC Distribution	Demand Total	Energy Total	Customer Total	Demand Distribution Subtransmission	Demand Distribution Substations	Demand Distribution Primary	Demand Distribution Secondary	Demand Distribution Transformers	Demand Distribution Services
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
	Present Rate Of Return Summary - Unit Cost										
	$/kWh										
1	Total DC Distribution	$0.0476	$0.0389	$0.0000	$0.0087	$0.0021	$0.0058	$0.0228	$0.0051	$0.0031	$0.0000
2	Total Residential Service	$0.0466	$0.0231	$0.0000	$0.0235	$0.0007	$0.0025	$0.0152	$0.0041	$0.0006	$0.0000
3	Total GS	$0.0653	$0.0517	$0.0000	$0.0136	$0.0025	$0.0069	$0.0251	$0.0106	$0.0066	$0.0000
4	Total GT-LV	$0.0542	$0.0489	$0.0000	$0.0053	$0.0027	$0.0072	$0.0256	$0.0078	$0.0056	$0.0000
5	Total GT-HV	$0.0329	$0.0327	$0.0000	$0.0002	$0.0024	$0.0062	$0.0241	$0.0000	$0.0000	$0.0000
6	Total GT	$0.0469	$0.0434	$0.0000	$0.0035	$0.0026	$0.0069	$0.0251	$0.0051	$0.0037	$0.0000
7	Total Metro	$0.0319	$0.0316	$0.0000	$0.0003	$0.0022	$0.0060	$0.0234	$0.0000	$0.0000	$0.0000
8	Total Street Lighting	$0.0257	$0.0185	$0.0000	$0.0071	$0.0005	$0.0020	$0.0145	$0.0013	$0.0003	$0.0000
9	Total TN Service	$0.0392	$0.0390	$0.0000	$0.0003	$0.0022	$0.0057	$0.0228	$0.0044	$0.0039	$0.0000
10	Residential (R)	$0.0466	$0.0203	$0.0000	$0.0262	$0.0004	$0.0019	$0.0140	$0.0039	$0.0001	$0.0000
11	Master-Metered Accounts (MMA)	$0.0469	$0.0437	$0.0000	$0.0032	$0.0024	$0.0066	$0.0242	$0.0061	$0.0045	$0.0000
12	General Service Low Voltage (GS-LV)	$0.0653	$0.0517	$0.0000	$0.0136	$0.0025	$0.0069	$0.0251	$0.0106	$0.0066	$0.0000
13	General Service High Voltage (GS-HV)	$0.0573	$0.0450	$0.0000	$0.0124	$0.0038	$0.0098	$0.0314	$0.0000	$0.0000	$0.0000
14	Time-Metered Medium General Service Low Voltage (MGT-LV)	$0.0515	$0.0474	$0.0000	$0.0041	$0.0029	$0.0078	$0.0221	$0.0085	$0.0061	$0.0000
15	Time-Metered General Service Low Voltage (GT-LV)	$0.0586	$0.0513	$0.0000	$0.0073	$0.0023	$0.0064	$0.0313	$0.0066	$0.0047	$0.0000
16	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	$0.0130	$0.0130	$0.0000	$0.0000	$0.0023	$0.0000	$0.0107	$0.0000	$0.0000	$0.0000
17	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	$0.0345	$0.0344	$0.0000	$0.0002	$0.0025	$0.0067	$0.0252	$0.0000	$0.0000	$0.0000
18	Metro	$0.0319	$0.0316	$0.0000	$0.0003	$0.0022	$0.0060	$0.0234	$0.0000	$0.0000	$0.0000
21	Street Lighting S Service	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
22	Street Lighting E Service	$0.0169	$0.0168	$0.0000	$0.0001	$0.0004	$0.0017	$0.0137	$0.0010	$0.0000	$0.0000
23	Traffic Signal	$0.0317	$0.0317	$0.0000	$0.0000	$0.0016	$0.0042	$0.0200	$0.0032	$0.0027	$0.0000
24	Tele-Communication Network Service	$0.0392	$0.0390	$0.0000	$0.0003	$0.0022	$0.0057	$0.0228	$0.0044	$0.0039	$0.0000
25											
26											
27	**Proposed Rate Of Return Summary - Unit Cost**										
28											
29	$/kWh										
30											
31	Total DC Distribution	$0.0556	$0.0443	$0.0000	$0.0114	$0.0023	$0.0062	$0.0235	$0.0077	$0.0046	$0.0000
32	Total Residential Service	$0.1052	$0.0681	$0.0000	$0.0371	$0.0030	$0.0081	$0.0269	$0.0195	$0.0106	$0.0000
33	Total GS	$0.0564	$0.0443	$0.0000	$0.0122	$0.0020	$0.0057	$0.0226	$0.0087	$0.0052	$0.0000
34	Total GT-LV	$0.0454	$0.0409	$0.0000	$0.0045	$0.0021	$0.0058	$0.0227	$0.0061	$0.0042	$0.0000
35	Total GT-HV	$0.0290	$0.0288	$0.0000	$0.0001	$0.0020	$0.0051	$0.0218	$0.0000	$0.0000	$0.0000
36	Total GT	$0.0398	$0.0368	$0.0000	$0.0030	$0.0020	$0.0056	$0.0224	$0.0040	$0.0028	$0.0000
37	Total Metro	$0.0313	$0.0310	$0.0000	$0.0003	$0.0021	$0.0059	$0.0231	$0.0000	$0.0000	$0.0000
38	Total Street Lighting	$0.0575	$0.0461	$0.0000	$0.0114	$0.0027	$0.0074	$0.0257	$0.0056	$0.0046	$0.0000
39	Total TN Service	$0.0278	$0.0276	$0.0000	$0.0002	$0.0013	$0.0035	$0.0182	$0.0026	$0.0021	$0.0000
40	Residential (R)	$0.1134	$0.0717	$0.0000	$0.0417	$0.0031	$0.0084	$0.0274	$0.0213	$0.0114	$0.0000
41	Master-Metered Accounts (MMA)	$0.0443	$0.0413	$0.0000	$0.0030	$0.0022	$0.0061	$0.0233	$0.0056	$0.0041	$0.0000
42	General Service Low Voltage (GS-LV)	$0.0565	$0.0443	$0.0000	$0.0122	$0.0020	$0.0057	$0.0226	$0.0087	$0.0052	$0.0000
43	General Service High Voltage (GS-HV)	$0.0371	$0.0277	$0.0000	$0.0094	$0.0017	$0.0048	$0.0212	$0.0000	$0.0000	$0.0000
44	Time-Metered Medium General Service Low Voltage (MGT-LV)	$0.0402	$0.0371	$0.0000	$0.0031	$0.0021	$0.0059	$0.0184	$0.0064	$0.0043	$0.0000
45	Time-Metered General Service Low Voltage (GT-LV)	$0.0538	$0.0470	$0.0000	$0.0068	$0.0020	$0.0056	$0.0296	$0.0057	$0.0040	$0.0000
46	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	$0.0126	$0.0126	$0.0000	$0.0000	$0.0019	$0.0000	$0.0107	$0.0000	$0.0000	$0.0000
47	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	$0.0303	$0.0302	$0.0000	$0.0002	$0.0020	$0.0055	$0.0227	$0.0000	$0.0000	$0.0000
48	Metro	$0.0313	$0.0310	$0.0000	$0.0003	$0.0021	$0.0059	$0.0231	$0.0000	$0.0000	$0.0000
51	Street Lighting S Service	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
52	Street Lighting E Service	$0.0483	$0.0482	$0.0000	$0.0001	$0.0029	$0.0079	$0.0266	$0.0060	$0.0049	$0.0000
53	Traffic Signal	$0.0300	$0.0300	$0.0000	$0.0000	$0.0015	$0.0039	$0.0193	$0.0029	$0.0024	$0.0000
54	Tele-Communication Network Service	$0.0278	$0.0276	$0.0000	$0.0002	$0.0013	$0.0035	$0.0182	$0.0026	$0.0021	$0.0000

Potomac Electric Power Company
District of Columbia
Class Cost of Service Study
For the Twelve Months Ended June 30, 2019

Line No.	Description	Customer Services (369)	Customer Meters (370)	Customer Installations (371)	Customer Street Lighting (373)	Customer Meter Reading (902)	Customer Records & Collections (903)	Customer Uncollectibles (904)	Customer Service Expense	Customer Sales Expense	Customer Other
[A]	[B]	[M]	[N]	[O]	[P]	[Q]	[R]	[S]	[T]	[U]	[V]
	Present Rate Of Return Summary - Unit Cost										
	$/kWh										
1	Total DC Distribution	$0.0016	$0.0013	$0.0008	$0.0001	$0.0001	$0.0044	$0.0004	$0.0003	$0.0000	-$0.0003
2	Total Residential Service	$0.0005	$0.0038	$0.0000	$0.0000	$0.0004	$0.0175	$0.0015	$0.0012	$0.0000	-$0.0014
3	Total GS	$0.0037	$0.0038	$0.0007	$0.0000	$0.0003	$0.0044	$0.0007	$0.0002	$0.0000	-$0.0003
4	Total GT-LV	$0.0027	$0.0003	$0.0018	$0.0000	$0.0001	$0.0004	$0.0001	$0.0000	$0.0000	$0.0000
5	Total GT-HV	$0.0000	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
6	Total GT	$0.0018	$0.0002	$0.0012	$0.0000	$0.0000	$0.0002	$0.0000	$0.0000	$0.0000	$0.0000
7	Total Metro	$0.0000	$0.0003	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
8	Total Street Lighting	$0.0000	$0.0000	$0.0000	$0.0070	$0.0000	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000
9	Total TN Service	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	$0.0000	$0.0000	$0.0000	$0.0000
10	Residential (R)	$0.0003	$0.0042	$0.0000	$0.0000	$0.0004	$0.0199	$0.0017	$0.0013	$0.0000	-$0.0016
11	Master-Metered Accounts (MMA)	$0.0021	$0.0007	$0.0000	$0.0000	$0.0000	$0.0002	$0.0001	$0.0000	$0.0000	$0.0000
12	General Service Low Voltage (GS-LV)	$0.0037	$0.0038	$0.0007	$0.0000	$0.0003	$0.0044	$0.0007	$0.0002	$0.0000	-$0.0003
13	General Service High Voltage (GS-HV)	$0.0000	$0.0065	$0.0000	$0.0000	$0.0003	$0.0017	$0.0038	$0.0001	$0.0000	-$0.0001
14	Time-Metered Medium General Service Low Voltage (MGT-LV)	$0.0030	$0.0004	$0.0000	$0.0000	$0.0001	$0.0006	$0.0000	$0.0000	$0.0000	$0.0000
15	Time-Metered General Service Low Voltage (GT-LV)	$0.0023	$0.0001	$0.0046	$0.0000	$0.0000	$0.0001	$0.0001	$0.0000	$0.0000	$0.0000
16	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
17	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	$0.0000	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
18	Metro	$0.0000	$0.0003	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
21	Street Lighting S Service	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
22	Street Lighting E Service	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000
23	Traffic Signal	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
24	Tele-Communication Network Service	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	$0.0000	$0.0000	$0.0000	$0.0000
25											
26											
27	**Proposed Rate Of Return Summary - Unit Cost**										
28											
29	$/kWh										
30											
31	Total DC Distribution	$0.0026	$0.0022	$0.0008	$0.0001	$0.0002	$0.0050	$0.0004	$0.0003	$0.0000	-$0.0003
32	Total Residential Service	$0.0068	$0.0082	$0.0000	$0.0000	$0.0006	$0.0200	$0.0016	$0.0013	$0.0000	-$0.0014
33	Total GS	$0.0029	$0.0034	$0.0007	$0.0000	$0.0003	$0.0043	$0.0007	$0.0002	$0.0000	-$0.0003
34	Total GT-LV	$0.0021	$0.0002	$0.0018	$0.0000	$0.0000	$0.0004	$0.0001	$0.0000	$0.0000	$0.0000
35	Total GT-HV	$0.0000	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
36	Total GT	$0.0014	$0.0002	$0.0012	$0.0000	$0.0000	$0.0002	$0.0000	$0.0000	$0.0000	$0.0000
37	Total Metro	$0.0000	$0.0003	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
38	Total Street Lighting	$0.0000	$0.0000	$0.0000	$0.0113	$0.0000	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000
39	Total TN Service	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	$0.0000	$0.0000	$0.0000	$0.0000
40	Residential (R)	$0.0074	$0.0092	$0.0000	$0.0000	$0.0007	$0.0226	$0.0018	$0.0015	$0.0000	-$0.0016
41	Master-Metered Accounts (MMA)	$0.0019	$0.0007	$0.0000	$0.0000	$0.0000	$0.0002	$0.0001	$0.0000	$0.0000	$0.0000
42	General Service Low Voltage (GS-LV)	$0.0029	$0.0034	$0.0007	$0.0000	$0.0003	$0.0043	$0.0007	$0.0002	$0.0000	-$0.0003
43	General Service High Voltage (GS-HV)	$0.0000	$0.0041	$0.0000	$0.0000	$0.0003	$0.0015	$0.0035	$0.0001	$0.0000	-$0.0001
44	Time-Metered Medium General Service Low Voltage (MGT-LV)	$0.0022	$0.0003	$0.0000	$0.0000	$0.0001	$0.0005	$0.0000	$0.0000	$0.0000	$0.0000
45	Time-Metered General Service Low Voltage (GT-LV)	$0.0019	$0.0001	$0.0046	$0.0000	$0.0000	$0.0001	$0.0001	$0.0000	$0.0000	$0.0000
46	Time-Metered General Service High Voltage 69KV (GT-HV-69KV)	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
47	Time-Metered General Service High Voltage Other (GT-HV-OTHER)	$0.0000	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
48	Metro	$0.0000	$0.0003	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
51	Street Lighting S Service	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
52	Street Lighting E Service	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0000	$0.0000	$0.0000	$0.0000
53	Traffic Signal	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
54	Tele-Communication Network Service	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	$0.0000	$0.0000	$0.0000	$0.0000

IN THE MATTER OF THE APPLICATION OF POTOMAC ELECTRIC POWER COMPANY FOR AUTHORITY TO IMPLEMENT A MULTIYEAR RATE PLAN FOR ELECTRIC DISTRIBUTION SERVICE IN THE DISTRICT OF COLUMBIA	**)**	**Formal Case No. 1156**

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

VOLUME III

DIRECT TESTIMONIES AND EXHIBITS OF

Mr. Peter R. Blazunas

P.R. Blazunas
Direct Testimony
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (F)

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EXECUTIVE SUMMARY – PETER R. BLAZUNAS

The purpose of this testimony is to support the Multiyear Rate Plan (MRP) portion of the Potomac Electric Power Company's (Pepco or the Company) Performance Based Rates (PBR) proposal. In particular, this testimony provides the distribution rate design that supports the Company's proposed increases in distribution revenue during the MRP; a summary of the status of the Customer Base Rate Credit (CBRC); a summary of the effect of the proposed rate changes on the major rate schedules and on Residential Aid Discount (RAD) customers; and revised tariff sheets based on the proposed changes to the distribution rates.

In addition, this testimony also provides the following reports and compliance filings: the results of the test year weather-normalization study; the Company's most recent Conditional Demand Analysis (CDA) and appliance saturation study; the results of the Company's most recent Distribution Marginal Cost Study; and the distribution rate design that supports the Traditional Test Period Compliance Filing as set forth in the Direct Testimony of Company Witness Ziminsky (PEPCO (D)).

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF PETER R. BLAZUNAS
FORMAL CASE NO. 1156

I. INTRODUCTION

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

A1. My name is Peter R. Blazunas. I am the Manager of Rate Administration for Pepco in the Regulatory Affairs Department of Pepco Holdings LLC (PHI). I am testifying on behalf of Pepco.

Q2. What are your responsibilities in your role as the Manager of Rate Administration?

A2. I am responsible for the development of electric rates, including tariff surcharges, for Pepco's Maryland and District of Columbia jurisdictions. I also participate in the development of Pepco's policies and practices with respect to rate design and assist with regulatory compliance matters, including tariff administration and periodic filings.

Q3. Please state your educational background and professional experience.

A3. I received a Bachelor of Arts degree in Economics from the University of Dayton and a Master of Arts degree in Economics from the University of Akron. I began my career with FirstEnergy Corp. (FirstEnergy) in 2012 as a State Regulatory Analyst in the Ohio Rates and Regulatory Affairs Department. During my time at FirstEnergy, I was the lead analyst responsible for various riders, such as the First Energy Ohio utilities' Delivery Capital Recovery Rider ("Rider DCR") and uncollectible riders. I also provided support in various regulatory proceedings, including rate proceedings and regulatory audits. Further, I served as Adjunct Faculty

in the Department of Economics at the University of Akron from 2012 to 2017, and from January to May of 2018 served as Adjunct Faculty in the Department of Applied General and Technical Studies at the University of Akron. In July 2017, I joined the Pepco Regulatory Strategy and Revenue Policy team of the Regulatory Affairs Department of PHI as a Senior Rate Analyst. I assumed my current position at PHI in November 2018.

Q4. Have you previously submitted testimony before the Public Service Commission of the District of Columbia (Commission)?

A4. Yes. I submitted testimony with respect to rate design and cost recovery on behalf of Pepco before the Commission in Formal Case No. 1130, Pepco's Application for Approval of its Transportation Electrification Program.

Q5. What is the purpose of your Direct Testimony?

A5. The purpose of my Direct Testimony is to provide the following in support of the Company's proposed Multiyear Rate Plan (MRP):

- A distribution base rate design supporting the Company's proposed increases in distribution revenue as set forth in the Direct Testimony of Company Witness Wolverton (PEPCO (C)). This proposed rate design also incorporates the results from the Class Cost of Service Study (CCOSS), as provided in the Direct Testimony of Company Witness Schafer (PEPCO (E));
- A summary of the status of the CBRC;
- Discussion of the effect of proposed rate changes on the major rate schedules and RAD customers; and
- Revised tariff sheets based on the proposed changes to the distribution rates.

In addition to providing support for the Company's proposed MRP, my testimony also provides the following reports and compliance filings:

- The results of the weather-normalization study of test year sales based on non-RAD customers only and an explanation of the weather-normalization process;
- The Company's most recent CDA and appliance saturation study;
- The results of the Distribution Marginal Cost Study; and
- Support for the Traditional Test Period Compliance Filing, submitted to comply with Order No. 18846[1] as set forth in the Direct Testimony of Company Witness Ziminsky (PEPCO (D)).

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

Q6. Please describe the MRP that the Company is proposing in this filing.

A6. As discussed in the Direct Testimony of Company Witness McGowan (PEPCO (B)), the Company is proposing a three-year MRP for the period of 2020-2022 with an initial rate effective date of May 1, 2020. The MRP includes an adjustment to distribution revenue and base rates for the second and the third years of the MRP based on the Company's projected costs for this timeframe. The rate effective dates for these proposed adjustments are January 1, 2021 and January 1, 2022, respectively.

[1] *See, 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. 1139, Order No. 18846 at ¶594, (July 25, 2017) in which the Commission directed the Company to file a traditional test period filing in addition to any multiyear rate proposal.

Throughout the remainder of this testimony I refer to the period of May 1, 2020 through December 31, 2020 as "Year 1" (or RY1) and the latter two years of the MRP, from 2021 through 2022, as RY2 and RY3, respectively.

Q7. Please describe the Traditional Test Period Compliance Filing that is included in this application.

A7. The Company has included the Traditional Test Period Compliance Filing in this application in order to comply with the Commission's directives in Order No. 18846.[2] The Traditional Test Period Compliance Filing included in this application is based on a test year period beginning July 1, 2018 and ending on June 30, 2019.

Q8. What exhibits are included in your testimony?

A8. The following exhibits are included in my testimony:

[2] *Id.* "The Commission is not averse to allowing Pepco to include in its next rate case a request for a fully forecasted test year and or a multi-year rate proposal, in addition to a traditional test year filing, subject to the following conditions in addition to those stated in Commission Rules 200.1, 200.2, 200.3, and 200.5..."

Table 1
List of Sponsored Exhibits

PEPCO (F)	Description	Associated Filing
PEPCO (F)-1	Four-Step Method Revenue Allocation Results	Multiyear Rate Plan and Traditional Test Period Compliance Filing
PEPCO (F)-2	Approved Allocation of Revenue Increases by Rate Schedule for Formal Case Nos. 1076, 1087, 1103, and 1139	
PEPCO (F)-3	Proposed Rate Schedule Revenue Requirements for the MRP	Multiyear Rate Plan
PEPCO (F)-4	Comparison of Customer Unit Cost and Customer Charges by Rate Schedule	
PEPCO (F)-5	Proposed Rates for Multiyear Rate Plan (2020 – 2022)	
PEPCO (F)-6	Revenue Proofs at Current and Proposed Rates by Rate Schedule	
PEPCO (F)-7	Bill Impacts	
PEPCO (F)-8	Tariff Sheets	
PEPCO (F)-9	Weather Normalization Study	Compliance Filings
PEPCO (F)-10	Conditional Demand Analysis	
PEPCO (F)-11	Distribution Marginal Cost Study	
PEPCO (F)-12	Rate Schedule Revenue Requirements	Traditional Test Period Compliance Filing
PEPCO (F)-13	Proposed Rates for Traditional Test Period Compliance Filing	
PEPCO (F)-14	Revenue Proofs by Rate Schedule	
PEPCO (F)-15	Bill Impacts	
PEPCO (F)-16	Tariff Sheets	

II. DISTRIBUTION REVENUE ALLOCATION METHODOLOGY

A. Introduction to the Four-Step Method

Q9. Please describe the general approach used to allocate the proposed increases in the revenue requirement in this application among the customer rate schedules.

A9. The approach used for the allocation of the proposed increases in the distribution revenue requirement associated with the MRP and Traditional Test Period Compliance Filing sections of my testimony consists of the following analyses:

- Class Rates of Return Analysis: I summarize the class rates of return (ROR) results and corresponding revenue surpluses or deficiencies from the Class Cost of Service Study (CCOSS), as provided in the Direct Testimony of Company Witness Schafer (PEPCO (E)). I then develop a Unitized Rate of Return (UROR) analysis based on this summary which provides an indication, for each rate schedule[3], as to whether it is providing a relative rate of return higher or lower than the system average rate of return, based on its fully allocated cost of service.
- Four-Step Method Revenue Allocation Analysis: I assign responsibility for the Company's proposed revenue requirement increase among the various customer rate schedules using the Four-Step Revenue Allocation Methodology (Four-Step Method), taking into account the results of the Class Rates of Return Analysis and its implications with respect to ratemaking principles I discuss below.

[3] The terms "rate class" and "rate schedule" are used interchangeably throughout this testimony.

- Proposed Rate Schedule Revenue Requirements: Following the Four-Step Method, I then apply the resulting rate schedule-specific allocation percentages to the total dollar increase in the revenue requirement associated with the particular filing (MRP or Traditional Test Period Compliance Filing) in order to determine each rate schedule's allocated share of the revenue requirement increase (in dollar terms).

Q10. Please provide an overview of the proposed Four-Step Method approach for revenue allocation purposes.

A10. The Company's proposed Four-Step Revenue Allocation Methodology (Four-Step Method) is described below and addresses the Commission's stated need in Order Nos. 18846, 17424, 16930, and 15710 in Formal Case Nos. 1139, 1103, 1087 and 1076,[4] respectively, to address disparities in rate class-specific rates of return as part of an approach to allocate revenue requirements while also adhering to the guiding ratemaking principles I discuss below. The method begins by summarizing the rate class-specific distribution revenue, net operating income, net rate base, rate of return, and UROR results from the CCOSS.[5] The UROR results from the CCOSS are used as a benchmark to help determine each class's movement towards cost of service, for use in the allocation of the proposed revenue increase on a rate class-specific basis.[6]

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[4] *See*, Formal Case No. 1139, Order No. 18846; *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. 1103, Order No. 17424 (March 26, 2014); *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. 1087, Order No. 16930 (Sept. 27, 2012) and *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. 1076, Order No. 15710 (Mar. 2, 2010).

[5] The UROR is the ratio of the ROR for the rate class to that of the overall system ROR.

[6] The CCOSS, as provided in the Direct Testimony of Company Witness Schafer (PEPCO (E)), is based on the 12-month period ending June 30, 2019.

Q11. Please list each step of the proposed Four-Step Method.

A11. The Company's proposed Four-Step Method consists of the following 4-step process:

- Step 1: Determine which rate classes, if any, have a relative rate of return significantly higher than the system average rate of return. Any classes that meet this criterion are excluded from any allocation of the distribution rate increase.
- Step 2: Determine which rate classes, if any, have a relative rate of return within a close range of the system average rate of return. Any classes that meet this criterion receive an allocated increase equal to the overall system average increase (in percentage terms).
- Step 3: Determine which rate classes, if any, have a relative rate of return significantly lower than the system average rate of return. Any classes that meet this criterion receive an allocated increase greater than the overall system average increase (in percentage terms).
- Step 4: Any remaining rate classes, if any, that have not been excluded from the increase in Step 1 or allocated an increase in Step 2 or 3 receive an allocated increase of the remaining revenue to be collected in proportion to their current level of annualized distribution revenue.

Q12. What is the UROR Analysis?

A12. The UROR analysis provides a measurement of the contribution of each rate class to the overall system required rate of return, which provides an indication of whether a given rate class is contributing more or less than its fully allocated cost of service. The UROR measures the contribution of each class by relating the relative

return from each rate class to the overall return from the entire system (i.e., all rate classes taken together). A UROR greater than 1.0 means that the rate class provided a greater than average return during a test year period, or that it contributed more than its fully allocated cost of service. A UROR less than 1.0 means that the rate class provided a lower than average return during a test year period, or that it contributed less than its fully allocated cost of service.

Q13. Please explain how the UROR Analysis is used by the Company in its ratemaking process.

A13. The UROR Analysis is used as a tool by the Company to help determine which rate schedules are allocated additional distribution revenues for collection from their customers as a result of contributing more or less to the total cost of the system relative to the cost imposed by a particular rate schedule. The results of the UROR analysis provide guidance based on the Commission-recognized ratemaking principle of cost causation for purposes of conducting the revenue allocation process.

B. Principles and Objectives of the Four-Step Method

Q14. Please describe the Commission's ratemaking principles of cost causation and gradualism that guided the Company's development of its proposed base distribution rates.

A14. In developing the proposed revenue allocation and base distribution rates, the Company relied on the ratemaking principles of cost causation and gradualism that the Commission has recognized in its recent previous decisions. These principles were most recently cited by the Commission in Order No. 18846 in Formal Case No. 1139, as set forth below:

> The Commission has wide discretion in setting class revenue requirements. Traditionally, in setting class revenue requirements for Pepco, we have considered the cost of service for each class, as well as a broad range of other cost and non-cost factors. While the Commission has policy of gradually lessening the disparities between rate classes and moving towards a UROR [Unitized Rate of Return], there is no requirement of uniformity among the rates of return from different customer classes. For example, customer class rates of return may vary based on the risk to Pepco, because the level of risk is a valid factor to be considered in rate design. Differences can be based not only on quantity, but also on the nature, time, and pattern of use, so as to achieve reasonable efficiency and economic operation. Other valid non-cost factors that may be considered in setting both customer class revenue requirements and rate designs, include "equitable considerations" such as value of service and ability to pay, the quality of service delivered, historical rate patterns, the need to conserve energy resources, and other market-place realities, as well as principles of gradualism and rate continuity.[7]

While the Commission has not required equalized rates of return among the rate classes, it has stated its policy of gradually bringing all of the customer classes closer to the overall system rate of return. The Company's proposed rate design is informed by the Commission's actions in prior recent decisions and balances the guiding principle of cost causation with the guiding principle of gradualism.

Q15. How is the size of the allocation performed in each step of the Four-Step Revenue Method determined?

A15. Generally, the size of the allocation in each step is selected in order to achieve the following objectives:

1. Ensure that a rate class with an existing class rate of return within a close range of the system average rate of return does not materially shift to a rate of return further from the system average rate of return.

[7] *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. 1139, Order No. 18846 at ¶453 (July 25, 2017).

2. Ensure that the final proposed rate of return for a rate class with an existing rate of return significantly above the system average rate of return does not increase, nor move to a level significantly below the system average rate of return.
3. Ensure that the final proposed rate of return for a rate class with an existing rate of return significantly below the lower limit of the system average rate of return does not decrease nor move to a level significantly above the system average rate of return.
4. Limit the maximum increase to any individual rate schedule in a manner that reflects consideration of the Commission's guiding ratemaking principles.

These objectives of the Four-Step Method are achieved by assigning values to the following three revenue allocation inputs: the threshold for exclusion from any allocation of the revenue increase (Criteria for Step 1); the defined range of the UROR Steady State (Criteria for Step 2); and the Multiplier to System Average Increase, which is applied to under-earning rate schedules as outlined in Step 3 of the Four-Step Method. These inputs are based on the results of the UROR Analysis from the Class Rates of Return Analysis, movement in the UROR from prior recent cases, and the Commission's approved revenue allocation decisions from prior recent cases, as defined in the following sections.[8]

[8] Commission precedent guided the proposed revenue allocation and rate design, taking into account the Commission's repeated stated intention to move towards greater equity among the rate classes.

Q16. Please explain the concept of the UROR Steady State.

A16. The UROR Steady State represents a defined range set as a plus or minus percentage threshold to a UROR of 1.0 intended to indicate whether any rate class has a rate of return relatively close, though not equal to, the overall return from the entire system. The UROR Steady State serves as a tool to help distinguish rate classes with significantly higher or lower rates of return relative to the overall system from those that are within a close range of the overall return from the entire system, thereby allowing for more targeted revenue allocations.

Q17. Please explain the first step of the Four-Step Revenue Allocation Method.

A17. First, rate classes with URORs that are determined to be significantly outside of the range of the UROR Steady State are excluded from any allocation of the distribution rate increase. This step recognizes rate schedules with greater than average returns that also meaningfully exceed the URORs of other rate schedules also above the UROR Steady State and designates them as outliers.

Q18. Please explain the second step of the Four-Step Revenue Allocation Method.

A18. Second, a portion of the increase is allocated to the rate classes with a current class rate of return within a defined range of the UROR Steady State. The distribution revenue increase allocated to each applicable class in this step is calculated as each applicable class's current annualized distribution revenue multiplied by the proposed total system distribution revenue increase (as expressed in percentage terms).

Q19. Please explain the third step of the Four-Step Revenue Allocation Method.

A19. Third, a portion of the increase is allocated to the rate classes with a UROR below the lower limit of the UROR Steady State. The portion of the distribution revenue increase allocated to the class in this step is calculated as the Multiplier to

System Average Increase times the proposed total system distribution revenue increase (as expressed in percentage terms) multiplied by annualized current distribution revenue for that class. This approach sets an upper limit to the amount by which the under-earning rate schedules will be allocated a revenue increase. This step may also include an adjustment to the amount of revenue allocated to each under-earning class in a manner that reflects consideration of the Commission's guiding ratemaking principles discussed above.

Q20. Please explain the fourth and final step of the Four-Step Revenue Allocation Method.

A20. In the final step, the remainder of the increase is allocated to all remaining rate classes in proportion to their current level of annualized distribution revenue, excluding those classes which either have already been allocated a portion of the increase in Steps 2 and 3 or have been excluded from any allocation of the distribution rate increase, as determined in Step 1.

C. Class Rates of Return and Revenue Allocation Results

Q21. Please describe the results of the Class Rates of Return and UROR Analysis.

A21. The results of the Class Rates of Return and UROR Analysis for the 12-month period ending June 30, 2019 are provided on Table 1 of PEPCO (F)-1. The results show that the URORs for all rate classes are currently above or below 1.0. All of the commercial classes, as well as the MMA, RT, TS and TN rate schedules, have positive RORs with URORs above 1.0, indicating that these rate schedules provided a greater than average return, or contributed more than their fully allocated cost of service. The R and SL-E rate schedules have negative RORs with URORs below zero, indicating these rate schedules provided a below average return, or contributed less than their fully

allocated cost of service. Rate Schedule SL-S has a positive ROR with a UROR above zero but below 1.0, indicating this class also provided a lower than average return.

Q22. How has the Commission approached the issue of disparities in the rate of return among rate schedules?

A22. The Commission detailed its approach to the customer class revenue allocation process in Formal Case No. 1139, Order No. 18846: "To reflect the cost causation from each class, the Commission strives to bring all classes closer to an UROR of 1.0 in each rate case. However, this goal is also tempered with notions of gradualism in order to avoid rate shock to customers of any particular rate class."[9] As I have previously mentioned, the Commission's policy has been that uniformity of rates of return among rate classes is not required.

Q23. Please identify where the results of the Four-Step Method are shown.

A23. The inputs for and the results of each step of the Four-Step Method are provided on Tables 2 through 10 of PEPCO (F)-1. Tables 2 through 5 display the inputs used for the Four-Step Method. Table 6 provides the amount of revenue allocated to each rate schedule as a result of each step of the Four-Step Method, while Tables 7 and 8 summarize the total amounts allocated to each rate schedule. Tables 9 and 10 show the UROR Analysis and resulting class-specific revenue increases based on the revenue allocation as determined in Steps 1 through 4 of the Four-Step Method.

[9] Formal Case No. 1139, Order No. 18846 at ¶456, footnote 763.

Q24. Please explain how the threshold for exclusion from any allocation of the revenue increase was determined, as shown in Table 3 of PEPCO (F)-1.

A24. In recent prior cases, the Commission has generally not excluded any rate schedules from its approved revenue allocation, with few exceptions.[10] However, given that the majority of the rate schedules with URORs above 1.0 fall within a concentrated range, the Company is proposing to exclude Schedules GS-3A and TN from an allocation of a revenue increase since both of these rate schedules are outliers that are well outside this range.

This proposal allows for movement towards a more equalized UROR among the rate classes while taking into consideration the Commission's guiding ratemaking principles of cost causation and gradualism in revenue allocation. Excluding Schedules GS-3A and TN from the revenue increase allocation moves both rate schedules downward in their rate of return and closer towards the overall system rate of return.

Q25. Please explain how the range of the UROR Steady State was determined, as shown in Table 4 of PEPCO (F)-1.

A25. The decision to use a threshold of +/- 10% of the overall system average rate of return as an initial evaluation point for the range of the UROR Steady State was informed by the methodology the Company has recently used in its Maryland jurisdiction. As shown in PEPCO (F)-1, no rate schedules have URORs within the Company's proposed UROR Steady State, defined as having a UROR within +/- 10% of the overall system average rate of return, as shown in Table 4 of PEPCO (F)-1. In

[10] In Formal Rate Case No. 1139, the Commission excluded Schedules SL-E, TS and SL-S from the approved revenue increase. In Formal Case No. 1087, the Commission approved revenue decreases for Schedules RTM and TN. In Formal Case No. 1076, the Commission approved a revenue decrease for Schedule GT-3A. *See,* PEPCO (F)-2.

fact, no rate schedule in either the over-earning or under-earning group has a UROR within even a wider band of +/- 25% (or +/- 0.25) of the system average UROR. Furthermore, excluding Schedule SL-S, no rate schedule in either the over-earning or under-earning group has a UROR within +/- 50% (or +/- 0.5) of the system average UROR.

Given that no rate schedule is currently within any range of a 1.0 UROR contemplated for use by the Company in this step and therefore eligible for inclusion in Step 2 of the Four-Step Method, the Company is proposing to leave the band as being defined by a UROR within +/- 10% of the overall system average rate of return for the present application.

Q26. Please explain how the Multiplier to the System Average Increase value of 1.80 was determined, as shown in Table 5 of PEPCO (F)-1.

A26. The determination of 1.80 as the Multiplier to the System Average Increase for Step 3 of the Four-Step Method is informed by the results of the Class Rates of Return Analysis, an evaluation of recent UROR movements in previous cases for the under-contributing rate schedules mentioned below, and a review of the level of revenue increase the Commission has allocated to these particular rate schedules in the past relative to the total system increase.

Q27. Please explain how the Multiplier to the System Average Increase value of 1.80 reflects the Commission's prior revenue allocations to the classes included in the 3rd Step of the Four-Step Method.

A27. A review of the Commission's approved allocated increases to these under-contributing rate schedules in each recent prior case, relative to the respective system average increase for that particular case, helped inform the determination of 1.80 as the

proposed value of the Multiplier to the System Average Increase. As shown on page 1 of PEPCO (F)-2, the average multiplier value determined based on the Commission's approved allocation[11] to the Rate Schedule R class is 2.09.[12] For Schedule SL-E, the average multiplier value is 6.52 due to a wider variance of calculated multipliers.[13] For SL-S, the average multiplier value is 1.11.

The results of this review, which are provided on page 1 of PEPCO (F)-2, show that the Company's proposal is within a reasonable range of and consistent with the proportion of revenue allocated to these rate schedules in recent prior cases.

Q28. Please explain how the Company's proposed Multiplier to the System Average Increase value of 1.80 is supported by the Class Rates of Return and UROR Analyses.

A28. The Class Rates of Return Analysis shows that the R, SL-E and SL-S rate schedules under-contributed relative to the overall system average ROR. As I have previously mentioned, no class is currently within a close range of a 1.0 UROR. However, the R and SL-E rate schedules in particular had negative URORs of -1.0 and -1.04, respectively, that indicate much lower RORs than the system ROR.

Since Formal Case No. 1076 (including Formal Case Nos. 1087, 1103, 1139, and 1150), the status of the majority of classes as under or over-contributors relative to

[11] In its previous revenue allocation decisions, the Commission has not used the proposed Multiplier to the System Average Increase approach. However, as shown on page 1 of PEPCO (F)-2, the comparable Multiplier to the System Average Increase value for each case can be calculated by dividing the approved class revenue increase (%) by the overall system average increase (%).

[12] As shown on page 1 of PEPCO (F)-2, the average multiplier value determined based on the Commission's approved allocation to this class is 1.84 if Formal Case Nos. 1076 and 1087 are excluded due to the fact that the R and MMA rate schedules were treated jointly for revenue allocation purposes in these cases.

[13] As shown on page 1 of PEPCO (F)-2, the average multiplier value determined based on the Commission's approved allocation to this class is 6.52. This reflects the inclusion of Rate Schedule TS in the SL-E class in Formal Case Nos. 1076 and 1087 as they were treated jointly for revenue allocation purposes in these cases.

the system ROR has remained generally consistent.[14] This is true for Rate Schedules R, SL-E, and SL-S. These schedules have consistently provided lower RORs relative to the system ROR, as shown below in Tables 2 and 3.

The Company's proposed value of 1.80 as the Multiplier to the System Average Increase for Step 3 of the Four-Step Method allows for movement towards a more equalized UROR among the rate classes while taking into consideration both the Commission's guiding ratemaking principles of cost causation and gradualism and its approach to revenue allocation for under-earning rate classes in recent prior decisions.

Table 2
Current URORs for Schedules R, SL-E and SL-S for Formal Case Nos. 1076, 1087, 1103, 1139, and 1150.

Rate Schedule	1150 Current	1139 Current	1103 Current	1087 Current	1076 Current
R		-0.80	-0.62	-0.50	-0.43
RAD			-0.82	-0.91	-0.76
R-AE		-0.72	-0.52	-0.73	-0.55
R-TM		1.65	1.62	1.66	1.54
Residential (Combined)	-0.50				
SL-E	-0.47	-0.74	-0.72	-0.82	-0.72
SL-LED	0.11				
SL-S	-0.31	-0.10	0.59	0.02	0.05

Table 3
Settlement/Approved URORs for Schedules R, SL-E and SL-S for Formal Case Nos. 1076, 1087, 1103, 1139, and 1150.

Rate Schedule	1150 Settlement	1139 Approved	1103 Approved	1087 Approved	1076 Approved
R		-0.54	-0.35	-0.24	-0.23
RAD			-0.56	-0.66	-0.54
R-AE		-0.48	-0.27	-0.42	-0.32
R-TM		1.36	1.44	1.41	1.69
Residential (Combined)	-0.60				
SL-E	-0.54	-0.59	-0.41	-0.47	-0.59
SL-LED	0.10				
SL-S	-0.39	-0.08	0.64	0.13	0.27

[14] Between Formal Case Nos. 1076, 1087, 1103, 1139, and 1150, there are only two instances of a rate schedule changing between having a Current UROR above or below 1.0. In Formal Case No. 1076, Rate Schedule TN had a UROR of 0.94 but has been above 1.0 in every subsequent case. In Formal Case No. 1076, Rate Schedule GT-3B had a UROR of 0.96 but has been above 1.0 in every subsequent case.

Q29. Please describe the allocation results for each rate schedule from the Four-Step Method.

A29. In view of the results of the Class Rates of Return and UROR Analyses, while also taking into account the consideration of the ratemaking principles mentioned above and the Commission's approach to revenue allocation in prior recent rate cases, I propose the following allocation of the proposed distribution revenue requirement pursuant to the Four-Step Method discussed above:

1. First, Rate Schedules GS-3A and TN both have URORs above 3.0. Therefore, I propose no increase for these rate schedules as the current rates for these rate schedules already recover amounts greater than their respective fully allocated cost of service.
2. Second, no rate schedule currently has a class rate of return within the range of the UROR Steady State (equal to +/- 10% of a UROR of 1.0). Therefore, I am not proposing an increase for any rate schedule equal to the system average increase of 22.13%.
3. Third, approximately 36% of the total increase is allocated to Rate Schedules R, SL-E and SL-S. These rate schedules have a UROR less than 0.9, or below the UROR Steady State described above.[15] I am proposing an additional adjustment within this step that consists of reducing the amount allocated to Rate Schedule SL-S by 25% and applying this amount to Schedule R.[16] This proposed adjustment

[15] The amount initially allocated to each rate class in this step is equal to each individual rate class's current annualized distribution revenue times 1.80, multiplied by the proposed total system distribution revenue increase of 22.13%.

[16] This proposed additional adjustment reflects approximately 10% of annualized current distribution revenue for Rate Schedule SL-S but only 0.08% of the annualized current distribution revenue for Rate Schedule R.

reduces the effective Multiplier to System Average Increase for Rate Schedule SL-S from 1.80 to 1.35, which is closer to the increase the Commission has allocated to this class in recent prior cases[17] and reflects the fact that this class has a positive Current UROR only 0.38 below the target 1.0, in contrast to the negative Current URORs of R and SL-E at or exceeding -1.0.

4. In accordance with the final step of the Four-Step Method, the remaining amount of the increase is allocated to the remaining rate classes based on their level of current annualized distribution revenue for the 12-month period ending June 30, 2019 as shown in row 45 of PEPCO (F)-1.

The results of the of the Four-Step Method, as shown in PEPCO (F)-1, are summarized in Table 4.

[17] As shown on page 1 of PEPCO (F)-2, Rate Schedule SL-S has an average multiplier value determined based on the Commission's approved allocation to this class of 1.11, with a range of 0 to 2.21.

Table 4
Summary of Four-Step Method Revenue Allocation Results

	Rate Schedule	Current ROR	Proposed ROR	Current UROR	Proposed UROR	Allocation of Distribution Revenue Increase (%)
Over-Contributing Rate Schedules ***(1.1 < UROR <=3.0)***	**MMA**	8.90%	11.49%	1.83	1.47	**2.10%**
	GS-LV	10.84%	14.11%	2.23	1.81	**9.33%**
	MGT-LV	12.37%	15.57%	2.54	1.99	**26.31%**
	GT-LV	9.89%	12.99%	2.03	1.66	**14.88%**
	GT-3B	10.51%	13.06%	2.16	1.67	**0.08%**
	GT-3A	11.03%	14.09%	2.27	1.80	**10.39%**
	RT	8.22%	10.78%	1.69	1.38	**1.35%**
	TS	9.25%	12.25%	1.90	1.57	**0.04%**
Over-Contributing Rate Schedules Excluded from Increase ***(UROR > 3.0)***	**GS-3A**	23.40%	23.40%	4.81	3.00	**-**
	TN	17.34%	17.34%	3.56	2.22	**-**
Under-Contributing Rate Schedules ***(UROR < 0.9)***	**R**	-4.87%	-2.17%	-1.00	-0.28	**35.09%**
	SL-S	3.00%	5.38%	0.62	0.69	**0.21%**
	SL-E	-5.05%	-4.10%	-1.04	-0.52	**0.21%**
Total		4.87%	7.81%	1.0	1.0	100%

Note: may not add up to 100% due to rounding.

Q30. Do the results of the Company's proposed revenue allocation compare favorably to the aforementioned principles and objectives of the Four-Step Method?

A30. Yes. The proposed revenue allocation provides for movement towards a more equalized UROR among the rate classes while reflecting consideration of the Commission's guiding ratemaking principles and its approach to revenue allocation in prior recent decisions. In particular, the proposed allocation achieves the following:

1. The percentage of revenue to be allocated to each individual rate schedule following the Four-Step Method (as shown above in the

last column of Table 4 and also on row 39 of PEPCO (F)-1) is within a reasonable range of and consistent with the proportion of revenue allocated to these rate schedules in recent prior cases, as shown on page 2 of PEPCO (F)-2.

2. All rate schedules with an existing UROR greater than 1.1, or the upper limit of the UROR Steady State, saw a decrease to their UROR under the proposed revenue allocation while remaining above the lower limit of the UROR Steady State.

3. All rate schedules with an existing UROR greater than 1.1, or the upper limit of the UROR Steady State, received an increase to their annualized current distribution revenue equal to 80% of the System Average Increase (in percentage terms), as shown on row 49 of PEPCO (F)-1. This is within a reasonable range of and consistent with the proportion of revenue allocated to these rate schedules in recent prior cases, as shown on page 1 of PEPCO (F)-2. For Formal Case Nos. 1076, 1087, 1103, and 1139, the average percentage of the approved increase relative to the overall system average increase for the GS and GT classes is 84% and for Schedule RT is 68%.

4. All rate schedules with an existing UROR less than 0.9, or the lower limit of the UROR Steady State, received an increase to their UROR under the proposed revenue allocation while remaining beneath the upper limit of the UROR Steady State. The increases for Schedules R, SL-S and SL-E were calculated using Multiplier to the System Average Increase values of 1.80, 1.35, and 1.80, respectively. The

increases allocated to these classes are within a reasonable range of and consistent with the proportion of revenue allocated to these rate schedules in recent prior cases, as shown on PEPCO (F)-2.

Taken together, the objectives achieved with the Four-Step Method balance the Commission's stated goal of moving the revenue recovered from each rate class to a level more reflective of cost causation with its consideration of gradualism, and do not materially differ from the results achieved by Commission-approved revenue allocation methodologies in recent previous cases. These objectives and results also recognize the Commission's policy that uniformity of rates of return among rate classes is not required.

III. RATE DESIGN FOR MULTIYEAR RATE PLAN

A. Introduction

Q31. What are the increase in distribution revenue requirement targets that the Company's proposed base rates are designed to recover for each year of the MRP?

A31. The following list provides the proposed increase in the revenue requirement for each year of the MRP, as provided in the Direct Testimony of Company Witness Wolverton (PEPCO (C)):

- **January 1 – December 31, 2020 (RY1)**: An increase of approximately $85 million.[18]
- **January 1 – December 31, 2021 (RY2)**: An increase of approximately $40 million.

[18] The RY1 annual revenue requirement as supported by Company Witness Wolverton (PEPCO (C)) is approximately $85 million. The rates designed to recover this increased level of revenue will, however, only be in effect for the period May 1 – December 31, 2020.

- **January 1 – December 31, 2022 (RY3)**: An increase of approximately $37 million.
- **Total**: An increase of approximately $162 million between RY1 and RY3.

The Direct Testimony of Company Witness Wolverton (PEPCO (C)) discusses how these proposed revenue requirement amounts may change over the course of the MRP, including the Company's proposed Annual Reconciliation Filing designed to compare actual Pepco-Distribution-DC adjusted calendar-year results versus the projected Pepco-Distribution-DC adjusted calendar-year data provided in the MRP.

B. Proposed Rate Schedule Revenue Requirements

Q32. What revenue requirement increase is the Company proposing for each rate schedule for each year of the MRP?

A32. The Company's proposed increases in the revenue requirement targets for each rate schedule for each year of the MRP are provided on page 1 of PEPCO (F)-3. Columns (C), (E), and (G) show the amount of the proposed increase in the revenue requirement allocated to each rate schedule based on the revenue allocation results from the Four-Step Method analysis, as shown in Columns (B), (D), and (F).

Q33. Please explain the Company's approach for allocating the proposed revenue increases for each year of the MRP.

A33. The method for allocating the dollar amount increases in the revenue requirement among the rate schedules for each year of the MRP is based on the results of the Four-Step Method, as discussed earlier in my testimony and provided in PEPCO (F)-1. The allocation percentages assigned to each rate schedule in Columns (B), (D) and (F) of PEPCO (F)-3 are identical to the results shown in Table 8 of PEPCO (F)-1. The total revenue increase amount (in dollar terms) allocated to the rate class for each

year of the MRP is calculated by multiplying the assigned allocation percentages from the Four-Step Method by the total revenue requirement increase amount for that particular year of the MRP, as shown on page 1 of PEPCO (F)-3.

Q34. Do the allocation results for each service classification vary for each year of the MRP?

A34. No, they do not. This is because, as I have previously explained, the proposed allocation of the increase in the revenue requirement (in percentage terms) for each year of the MRP is based on the results of the Four-Step Method, as shown in Table 8 of PEPCO (F)-1. The allocation percentages assigned to each rate class as shown in Pepco (F)-1 are applied to the proposed increases in the distribution revenue requirement for RY1, RY2, and RY3 of the MRP.

Q35. What is the total electric revenue requirement the Company is proposing for each rate schedule for each year of the MRP in this filing?

A35. The proposed total revenue requirement for each rate schedule for each year of the MRP is shown on page 2 to 4 of PEPCO (F)-3. The total revenue requirements presented starting on page 2 of PEPCO (F)-3 reflect the sum of the Company's annual projected change in annualized distribution revenue and the allocated amount of the revenue increase for each rate schedule for each year.

Q36. Please explain the Company's projected changes in annualized distribution revenue between each year from current distribution revenue through RY3, as shown in Columns (C), (I) and (O) of PEPCO (F)-3.

A36. The Company's proposed total revenue requirement targets for each rate schedule for each year of the MRP are provided starting on page 2 of PEPCO (F)-3. Columns (D), (J), and (P) provide the Company's projected level of underlying current

annualized revenue for each year of the MRP based on rates put into effect as a result of Formal Case No. 1150.[19] Columns (C), (I), and (O) represent the adjustments between the prior period's ending level of annual distribution revenue and the current period's projected level of underlying current annualized revenues based on rates put into effect as a result of Formal Case No. 1150.

Columns (E), (K), and (Q) present the proposed increases in the revenue requirement for each rate schedule for each year of the MRP. Columns (G), (M), and (S) reflect the total revenue requirement targets for each rate schedule for each year of the MRP, reflecting both the annual projected change in underlying current annualized distribution revenue based on rates put into effect as a result of Formal Case No. 1150 and proposed increases in the revenue requirement.

C. Rate Design Methodology

Q37. What are the standard components of a distribution rate structure for a given rate schedule?

A37. Distribution rate structures are typically made up of a combination of the following three charges: a customer charge, a demand charge, and an energy charge. These are the individual rate components that generally define a given distribution rate structure. A customer charge is a fixed charge assessed every billing period that does not vary with the customer's energy usage. A demand charge, which usually takes the form of a per kilowatt charge, is billed on the basis of the customer's highest usage during a defined period. An energy charge is a per kilowatt-hour rate that is billed on

[19] *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, Formal Case No. 1150, Order No. 19433 (Aug. 9, 2018).

the basis of the customer's volume of energy consumption. Rate structures can vary for different classes based on the number, type, and measurement of these rate components.

Q38. What are the steps used to design rate structures for each customer rate schedule?

A38. The following is a list of the three general steps used to design the Company's proposed base rate structures for each rate schedule, as applicable:

- Determine the level of the customer charge;
- Determine the level of the demand charge; and
- Determine the level of the energy (volumetric) charge.

The guiding principles used in the development of the distribution rate design reflect the directives given by the Commission in Formal Case No. 1139, Formal Case No. 1103, Formal Case No. 1087, and Formal Case No. 1076.[20] With regard to the design of the rate class-specific rate components (customer, demand, and volumetric charges), the Commission has affirmed its policy of placing a greater emphasis on customer charges and demand rates and less emphasis on volumetric (kWh) charges, consistent with its guiding ratemaking principles such as cost causation and gradualism.[21] The Company's approach taken in this proceeding reflects these directives and considerations. In addition, throughout the rate design process, the Company has taken into consideration the Commission's guiding ratemaking principles of cost causation and gradualism previously discussed in my testimony.

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[20] *See*, Formal Case No. 1139, Order No. 18846; Formal Case No. 1103, Order No. 17424; Formal Case No. 1087, Order No. 16930; and Formal Case No. 1076, Order No. 15710.

[21] "This decision continues the Commission's policy of moving the design of residential distribution rates away from volumetric (kWh) rates, and towards rates that are based more on customer and demand charges." *See, 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. 1139, Order No. 18846 at ¶484 (July 25, 2017).

Q39. Please describe the process used to achieve the first objective in the design of distribution rate components, determining the level of customer charges.

A39. The Company utilized one or more of the following four different approaches in order to evaluate the level of customer charges for each of the various rate schedules. The decision of which approach to use for each rate schedule and the amount by which to increase or decrease the existing customer charge is informed by the magnitude of the proposed increase, the current level of the existing customer charge relative to its Customer Unit Cost (Unit Cost),[22] and consideration of prior Commission approved changes to this rate component.

- Percentage of Revenue Requirement Increase: the share of the revenue increase collected through the customer charge is set to equal a target percentage amount of the increase in the revenue requirement.
- Parity with Unit Cost: for rate schedules with an existing customer charge that is reasonably close to the Unit Cost, the customer charge is either increased or decreased so that it is set equal to the Unit Cost.
- Percent Movement to Unit Cost: This approach presents a gradual and moderated percentage-based movement to full cost (equal to the Unit Cost).
- Class Average Increase: This approach applies the same overall revenue percentage increase (relative to the current level of distribution revenue for a particular rate schedule) to the customer charge.

All of these approaches take into consideration the current customer charge in effect for each rate schedule relative to that particular rate schedule's Unit Cost, as

[22] For each class, the customer unit cost is the monthly level of customer-related costs the Company incurs to serve a customer in that class. *See*, the Direct Testimony of Company Witness Schafer (PEPCO (E)).

shown in PEPCO (F)-4. The Unit Costs shown in this exhibit are from the CCOSS, as presented in the Direct Testimony of Company Witness Schafer (PEPCO (E)).

The Company is not proposing a customer charge increase for any rate schedule for any year in the MRP that would exceed that rate schedule's Unit Cost.[23]

Q40. Please describe the process used to achieve the second objective in the rate design process, determining the level of demand charges.

A40. For rate schedules with a three-part rate structure (*i.e.*, with an existing demand charge component), the change to the demand charge is determined by subtracting the amount of the revenue increase collected through the customer charge and then multiplying the remaining amount by the proportion of current revenue collected through the current demand charge relative to the total amount of revenue collected through the current energy and demand charges.[24]

For rate schedules with a two-part rate structure but without an energy charge, the remaining distribution revenue requirement following the determination of the customer charge is recovered through the demand charge.

Q41. Please describe the process used to achieve the third objective in the design of distribution rate components, determining the level of energy charges.

A41. For rate schedules with a two-part rate structure (*i.e.*, without a demand charge component), the remaining distribution revenue requirement following the determination of the customer charge is recovered through an increase in the volumetric

[23] The CCOSS, as provided in the Direct Testimony of Company Witness Schafer (PEPCO (E)), is based on the 12-month period ending June 30, 2019. The Unit Cost shown for each rate schedule in PEPCO (F)-4 is reflective of this same test year period.

[24] If the customer charge is decreased, then the revenue that is now no longer collected via the customer charge is added to the revenue total that is split proportionally between the demand and energy rate components in the manner described above.

rates.[25] The winter and summer volumetric rates are increased in proportion to their respective share of current revenue collected through the volumetric rates.

For rate schedules with a three-part rate structure (*i.e.*, with an existing demand charge component), the change to the energy charge is determined in an identical fashion to the calculation of the demand charge described above. This is done by subtracting the amount of the revenue increase collected through the customer charge and then multiplying the remaining amount by the proportion of current revenue collected through the current energy charge relative to the total amount of revenue collected through the current energy and demand charges.

Q42. How has the Company incorporated the use of AMI data in the development of the proposed rate design?

A42. The Company is not presently proposing any alternative rate designs utilizing AMI data as a part of this filing. Instead, the Company will revisit the possibility of doing so after the conclusion of the MEDSIS "Future Rate Design Working Group" initiative established pursuant to Order No. 19432 in Formal Case No. 1130.

Q43. Did the Company rely on the same general methodology for designing distribution rate components for each year of the MRP?

A43. Yes. The Company relied on the same general steps and ratemaking principles I have previously described for designing distribution rate components for the various rate schedules for each year of the MRP.

[25] For rate schedules with a block kWh structure, the first block is designed so that the winter and summer energy rates are equal.

Q44. Is the Company proposing to make any structural changes to the rate design for any rate schedule?

A44. No. The Company is not proposing any structural changes to the rate design for any rate schedule over the course of the MRP. By the term "structural," I mean any changes to the number or to the type of distribution rate components that currently exist for each rate schedule. While the Company is proposing to leave the basic structure of the rates for each class unmodified, the proposed rate design for the MRP does include adjustments to the level of rates and the total amount of revenue to be recovered from each rate schedule.

Q45. Are forecasted billing determinants utilized in the design of rates for the term of the MRP?

A45. Generally, yes. Forecasted customer counts and kilowatt hours are utilized for the design of rates for the term of the MRP for all rate schedules. As the Company does not forecast demand, kW billing determinants were derived for each applicable rate schedule using load factors calculated for the 12-month period ending June 30, 2019.

Q46. Is the Company proposing to fix rates for the entire term of the MRP?

A46. No. As I have previously discussed, in addition to the proposed increase in the revenue requirement for RY1, the MRP also provides adjustments to the revenue requirement for RY2 and RY3. Rates for each year of the MRP will differ, as they are designed to collect the target revenue requirement for that specific year. Further, beginning in RY3, the revenue requirement will incorporate applicable sharing

amounts in the authorized level of revenue based on the Company's proposed Annual Reconciliation Filing for RY1.[26]

Q47. Is the Company proposing to update the forecasted billing determinants used in the MRP rate design ahead of the rate effective date of each period of the MRP?

A47. Yes. The Company is proposing an Annual Billing Determinant Update to be made approximately 60 days prior to the rate effective date of each period of the MRP.[27] The purpose of this filing is to minimize the variance between the Company's allowed level of revenue and the actual revenues collected by the Company in the applicable MRP period caused by a difference between forecasted and actual billing determinants for the applicable MRP rate effective period.

Q48. Please explain how this adjustment will work for RY1 and RY2.

A48. Approximately 60 days before the rate effective dates for RY1 and RY2, the Company will file its Annual Billing Determinant Update.[28] In the filing, the Company will design rates utilizing the approved level of revenue for the applicable period and will apply the same approved methodology for the design of the rate components for each rate schedule as I have already described above and elaborate on below in the subsections covering the proposed rate design for each rate schedule. The filing would, however, incorporate into the rate design the most up-to-date forecasted billing determinants for the applicable rate effective period.

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[26] For RY2 and RY3, the Company's proposed Annual Billing Determinant Update compliance filing will follow the Company's proposed Annual Reconciliation Filing.

[27] For RY1, this timeline may be shortened such that the update is included in the Company's Compliance Filing for the Order issued in this proceeding. For RY3, this timeline assumes that the Commission would have already issued a decision with respect to the Company's Annual Reconciliation Filing within the procedural timeline proposed by the Company. For a description of the Company's proposed Annual Reconciliation Filing and procedural schedule, *see*, the Direct Testimony of Company Witness Wolverton (PEPCO (C)).

[28] For RY1, this timeline may be shortened such that the update is included in the Company's Compliance Filing for the Order issued in this proceeding.

Q49. Please explain how this adjustment will work for RY3.

A49. In the same manner as that described for RY1 and RY2, except that the approved level of revenue for RY3 will incorporate any sharing amounts resulting from the May 2021 Annual Reconciliation Filing of RY1.

Q50. Why is it necessary for the Company to make annual adjustments to the forecasted billing determinants used to design rates for each period of the MRP?

A50. Rates are generally constructed based on the amount of revenue to be collected and the applicable customer billing determinants (customer counts, billing demand, and kWh usage) specific to a particular rate schedule over a specific period of time. If the forecasted billing determinants used to design the rates to collect a target level of revenue over a specific period of time do not closely match the actual billing determinants for that period of time, the rates may over- or under-collect relative to the target revenue amount. While sales of electricity are included in the Annual Reconciliation Filing, the purpose of these annual adjustments is to minimize the possibility that they drive significant variances within the Annual Reconciliation Filing.

Q51. What is the Bill Stabilization Adjustment (BSA)?

A51. As authorized by the Commission in Order No. 15556 in Formal Case No. 1053, the BSA is a revenue decoupling mechanism that removes the link between electricity use and utility distribution revenue. Before the BSA the more electricity customers used, the more distribution revenues the Company received. This previous rate structure created a disincentive for the Company to encourage customers to conserve energy since it lowered its distribution revenues. The BSA allows the Company to promote energy efficiency programs that will help customers reduce their energy use

and drive down electricity supply costs. It functions as a monthly adjustment that will lower customer rates if the Company is receiving more distribution revenue than the Commission has approved on the basis of a target level of distribution revenue per customer and will increase rates if the Company is receiving less distribution revenue than the Commission has approved on the basis of a target level of distribution revenue per customer. The BSA applies only to the distribution portion of the bill.[29]

Q52. Will the BSA be adjusted over the course of the MRP?

A52. Yes. The average class distribution base revenue per customer targets used in the Company's monthly BSA calculation will be updated annually to reflect authorized adjustments to the revenue requirement over the term of the MRP. Any adjustments made through the Annual Billing Determinant Update filings will also be reflected in the BSA accordingly. This will help ensure that the Company is collecting its target distribution revenue amount per customer and that customers' bills are adjusted as appropriate.

D. Proposed MRP Rate Design for RY1, RY2 and RY3

Q53. Please identify where the proposed rates for each period of the MRP are shown.

A53. A summary of the Company's proposed rates for each rate year of the MRP are provided in PEPCO (F)-5.

[29] The BSA applies to the distribution rates for residential and commercial customers (excluding rate schedules SL, RT, TN and T).

Q54. Has the Company prepared a proof of the revenues that the proposed rates produce?

A54. Yes. Detailed calculations for each rate component of each rate schedule and a proof of proposed revenues by rate schedule are shown on PEPCO (F)-6.

Residential Rate Design and Rate Relief Programs

Q55. Please describe the Company's proposed changes to the rate design for Residential Service (Schedule R).

A55. For Schedule R, the Company proposes to increase the customer charge over the three-year period of the MRP in an effort to make the charge more fully reflective of customer-related costs using the Current Share of Revenue approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule R is equal to $27.67. The Company is proposing to increase the customer charge by $3.47, $1.62, and $1.42 for RY1, RY2, and RY3, respectively. This would result in the customer charge for RY3 being equal to 80% of the 2019 Test Period Unit Cost for Schedule R of $27.67.

The Company's decision to base the proposed customer charge increase using the Percentage of Revenue Requirement Increase approach, which consists of collecting 40% of the revenue increase for each year of the MRP through the customer charge, was informed by principles of cost causation and gradualism. Recovering a larger percentage of the revenue requirement increase from Schedule R customers through the customer charge could be inconsistent with the Commission's expressed principles of gradualism and rate continuity.

The remaining distribution revenue requirement for each year of the MRP is recovered through the summer and winter volumetric rate blocks such that the relative

proportion of proposed revenue recovered by each rate component is approximately equal to the relative proportion of current revenue recovered by each rate component.[30]

Q56. How will the proposed rate changes that result from the implementation of the MRP affect RAD customers?

A56. The Residential Aid Discount Program provides eligible customers a monthly credit for their distribution charges, known as the Residential Aid Credit (RAC). Customers who receive certification of income eligibility from the District of Columbia Department of Energy and the Environment (DOEE) are eligible for participation in the RAD program. Pursuant to Order No. 18059 in Formal Case No. 1120, the RAC offsets the full customer and volumetric energy charges for the distribution portion of a participant's bill. The RAC also offsets the Residential Aid Discount Surcharge, the Sustainable Energy Trust Fund Surcharge, and the Energy Assistance Trust Fund Surcharge. As a result, the proposed changes to Rate Schedule R under the MRP will have no impact on RAD customers since the RAC will be adjusted to reflect the proposed distribution rates for each period of the MRP.

Q57. Is the Company providing any new rate relief program offerings to residential customers?

A57. Yes. Pursuant to Order No. 19741 in Formal Case No. 1149, beginning on or around February 2020, on a two-year experimental basis, the Company will provide a Senior Citizen and Disabled Resident rate credit to eligible District of Columbia residents who are listed in the District of Columbia Office of the Chief Financial Officer's D.C. Homestead Deduction and Senior Citizen/Disabled Resident Property

[30] As I have previously mentioned, for rate schedules such as Schedule R that have a block kWh structure, the first block is designed so that the winter and summer energy rates are equal.

Owner Tax Relief database. This rate credit will not be available to customers enrolled in the RAD program. Eligible customers will be automatically enrolled on an annual basis and will receive a monthly credit of $7.50, which is approximately 50% of the current fixed monthly customer charge for Schedule R service.[31]

Master Metered Apartments

Q58. Please describe the Company's proposed changes to the rate design for Master Metered Apartment Service (Schedule MMA).

A58. For Schedule MMA, the Company proposes to increase the customer charge over the three-year period of the MRP in an effort to make the charge more fully reflective of customer-related costs using the Class Average Increase approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule MMA is equal to $74.18. The Company is proposing to increase the customer charge by $2.07, $0.99, and $0.89 for RY1, RY2, and RY3, respectively.

The Company's use of the Class Average Increase approach, which increases the customer charge by the same overall percentage increase applied to the revenue requirement for that particular class, results in a modest increase relative to the current difference between the existing customer charge and the 2019 Test Period Unit Cost.

The remaining distribution revenue requirement for each year of the MRP is recovered through the summer and winter volumetric rate blocks for both rate schedules such that the relative proportion of proposed revenue recovered by each rate component is

[31] The Company is not proposing any change to the level of the Senior Citizen and Disabled Resident rate credit as a part of this proceeding.

approximately equal to the relative proportion of current revenue recovered by each rate component. [32]

Commercial and Temporary Service Rate Design

Q59. Please describe the Company's proposed changes to the rate design for General Service – Non-Demand (Schedule GS ND).

A59. For Schedule GS ND, the Company proposes to increase the customer charge over the three-year period of the MRP in an effort to make the charge more fully reflective of customer-related costs using the Class Average Increase approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule GS ND is equal to $38.75. The Company is proposing to increase the customer charge by $4.68, $2.23, and $2.00 for RY1, RY2, and RY3, respectively.

The Company's use of the Class Average Increase approach, which increases the customer charge by the same overall percentage increase applied to the revenue requirement for that particular class, results in a modest increase relative to the current difference between the existing customer charge and the 2019 Test Period Unit Cost. The remaining distribution revenue requirement for each year of the MRP is recovered through the summer and winter volumetric charges such that the relative proportion of proposed revenue recovered by each rate component is approximately equal to the relative proportion of current revenue recovered by each rate component.

[32] As I have previously mentioned, for rate schedules such as Schedule MMA that have a block kWh structure, the first block is designed so that the winter and summer energy rates are equal.

Q60. Please describe the Company's proposed changes to the rate design for Temporary Service (Schedule T).

A60. Historically, the customer charges for Schedules GS ND and T have been set at the same level, and this approach is continued in this rate design. For Schedule T, the customer charge has been modified in the same manner as Schedule GS ND for RY1, RY2, and RY3. The volumetric rates have been designed to recover the residual revenue increase allocated to Schedule T for each year of the MRP.

Q61. Please describe the Company's proposed changes to the rate design for General Service – Low Voltage (Schedule GS LV).

A61. Schedule GS LV has a three-part rate structure consisting of a customer charge, a demand charge, and a seasonally differentiated volumetric charge. For this rate schedule, the Company proposes to increase the customer charge in an effort to make the charge more fully reflective of customer-related costs using the Parity with Unit Cost approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule GS LV is equal to $38.75. The Company is proposing to increase the customer charge by $3.58 for RY1. This would result in the customer charge for RY1 being equal to the 2019 Test Period Unit Cost for Schedule GS LV of $38.75.

The Company's use of the Parity with Unit Cost approach, which sets the customer charge equal to the 2019 Test Period Unit Cost, results in a modest increase relative to the current difference between the existing customer charge and the 2019 Test Period Unit Cost. For RY2 and RY3, the Company is proposing to collect the entire proposed revenue increases for each year through the demand and volumetric

rates for this rate schedule. This proposal would keep the customer charge for RY2 and RY3 unmodified from the customer charge proposed for RY1.

The Company proposes that the remaining distribution revenue requirement be recovered through the demand and volumetric charges in proportion to their share of revenue relative to total non-customer-related revenue. The amount of the increase to be collected through the demand charge is calculated by subtracting the amount of the proposed revenue increase collected through the customer charge, then multiplying the remaining amount by the proportion of current revenue collected through the current demand charge relative to the total amount of current revenue collected through the current energy and demand charges.

Q62. Please describe the Company's proposed changes to the rate design for General Service – Primary Service (Schedule GS 3A).

A62. Schedule GS 3A has a three-part rate structure consisting of a customer charge, a demand charge, and a seasonally differentiated volumetric charge. As previously discussed and shown in PEPCO (F)-1 and PEPCO (F)-3, the Company is not proposing to allocate any of the proposed increase in the revenue requirement over the term of the MRP to Schedule GS 3A.

Q63. Please describe the Company's proposed changes to the rate design for Time Metered Medium General Service – Low Voltage (Schedule MGT LV).

A63. Schedule MGT LV has a three-part rate consisting of a customer charge, demand charge, and volumetric charge. This rate schedule was created as part of the Settlement Agreement in Formal Case No. 1150.[33] According to the Settlement Agreement in Formal Case No. 1150, the rates approved and currently in effect for this

[33] Formal Case No. 1150, Order No. 19433 at ¶49.

rate schedule are the same rates approved in that case for Schedule GT LV. The Company is proposing a rate design for Schedule MGT LV that is independent of the rate design for Schedule GT LV and is based on actual and forecasted customer billing determinants recorded for this class.

For this rate schedule, the Company proposes to decrease the customer charge in an effort to make the charge reflective of customer-related costs using the Parity with Unit Cost approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule MGT LV is equal to $237. The Company is proposing to decrease the customer charge by $219.76 for RY1. This would result in the customer charge for RY1 being equal to the 2019 Test Period Unit Cost for Schedule MGT LV of $237.

The Company proposes to collect the entire proposed revenue increases for RY2 and RY3 through the demand and volumetric rates for this rate schedule. This proposal would keep the customer charge for RY2 and RY3 unmodified from the rate proposed for RY1.

The Company proposes that the remaining distribution revenue requirement be recovered through the demand and volumetric charges in proportion to their share of revenue relative to total non-customer-related revenue. The amount of the increase to be collected through the demand charge is calculated by subtracting the amount of the proposed revenue increase collected through the customer charge, then multiplying the remaining amount by the proportion of current revenue collected through the current demand charge relative to the total amount of current revenue collected through the current energy and demand charges. The remaining distribution revenue requirement is recovered through the volumetric charge.

Q64. Please describe the Company's proposed changes to the rate design for Time Metered General Service – Low Voltage (Schedule GT LV).

A64. Schedule GT LV has a three-part rate consisting of a customer charge, demand charge, and volumetric charge. For this rate schedule, the Company proposes to increase the customer charge over the three-year period of the MRP in an effort to make the charge more fully reflective of customer-related costs using the Percent Movement to Unit Cost approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule GT LV is equal to $3,816.50. The Company is proposing to increase the customer charge by $483.84 for each year of the MRP. This would result in the customer charge for RY3 being equal to approximately 50% of the 2019 Test Period Unit Cost for Schedule GT LV of $3,816.50.

The Company's use of the Movement to Unit Cost approach results in a modest increase relative to the current difference between the existing customer charge and the 2019 Test Period Unit Cost.

The Company proposes that the remaining distribution revenue requirement be recovered through the demand and volumetric charges in proportion to their share of revenue relative to total non-customer-related revenue. The amount of the increase to be collected through the demand charge is calculated by subtracting the amount of the proposed revenue increase collected through the customer charge, then multiplying the remaining amount by the proportion of current revenue collected through the customer demand charge relative to the total amount of current revenue collected through the current energy and demand charges. The remaining distribution revenue requirement is recovered through the volumetric charge.

Q65. In Paragraph 16 of the Settlement Agreement reached in Formal Case No. 1150 and approved by the Commission, Pepco agreed to work with OPC, AOBA, and other interested parties to address in Pepco's next rate case certain structural deficiencies in the BSA. Has Pepco complied with this directive?

A65. Yes. As part of the Settlement in Formal Case No. 1150, Pepco created the MGT-LV rate class. The creation of this new rate class was anticipated to keep customers with smaller loads from migrating to the GT-LV class and, over time, decrease and eliminate the deferral balances of the GT-LV class, as well as the new MGT-LV class. While the MGT-LV class has only been in existence since August 13, 2018 (the rate effective period for the Order approving the Settlement in Formal Case No. 1150), the Company currently projects that, based on the rates approved in Formal Case No. 1150, the MGT-LV deferral balance will decline through April 2020 and the GT-LV deferral will slightly increase over that same period.

Further, Pepco currently projects that, with the implementation of the MRP rates informed by the separate costs of service for MGT-LV and GT-LV, the deferral balance for the former will go to zero in July 2020 and the deferral balance for the latter will go to zero in April 2021.

In addition, Pepco looks forward to working with AOBA and any other parties to further refine the operation of the BSA.

Q66. Please describe the Company's proposed changes to the rate design for Time Metered General Service – Primary Service (Schedule GT 3A).

A66. Schedule GT 3A has a three-part rate structure consisting of a customer charge, a demand charge, and a seasonally differentiated volumetric charge. For this rate schedule, the Company proposes to increase the customer charge in an effort to make

the charge more fully reflective of customer-related costs using the Parity with Unit Cost approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule GT 3A is equal to $197.49. The Company is proposing to increase the customer charge by $9.85 for RY1. This would result in the customer charge for RY1 being equal to the 2019 Test Period Unit Cost for Schedule GT 3A of $197.49.

The Company's use of the Parity with Unit Cost approach, which sets the customer charge equal to the 2019 Test Period Unit Cost, results in a modest increase relative to the current difference between the existing customer charge and the 2019 Test Period Unit Cost. For RY2 and RY3, the Company is proposing to collect the entire proposed revenue increases for each year through the demand and volumetric rates for this rate schedule. This proposal would keep the customer charge for RY2 and RY3 unmodified from the customer charge proposed for RY1.

The Company proposes that the remaining distribution revenue requirement be recovered through the demand and volumetric charges in proportion to their share of revenue relative to total non-customer-related revenue. The amount of the increase to be collected through the demand charge is calculated by subtracting the amount of the proposed revenue increase collected through the customer charge, then multiplying the remaining amount by the proportion of current revenue collected through the current demand charge relative to the total amount of current revenue collected through the current energy and demand charges. The remaining distribution revenue requirement is recovered through the volumetric charge.

Q67. Please describe the Company's proposed changes to the rate design for Time Metered General Service – High Voltage (Schedule GT 3B).

A67. Schedule GT 3B has a two-part rate consisting of a customer charge and a demand charge. The Company proposes to modify the rates for this schedule using the same approach the Company proposed and the Commission approved in Order Nos. 17424 and 18846 in Formal Case Nos. 1103 and 1139, respectively. The proposed customer charge is designed to fully reflect the customer-related costs, as developed in the CCOSS. The balance of the allocated revenue requirement is recovered through the demand charge.

As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule GT 3B is equal to $311.66. Therefore, the Company is proposing to decrease the customer charge by $111.72 for RY1. This would result in the customer charge for RY1 being equal to the 2019 Test Period Unit Cost for Schedule GT 3B of $311.66. This proposal would keep the customer charge for RY2 and RY3 unmodified from the customer charge proposed for RY1. The balance of the allocated revenue requirement for RY1, RY2, and RY3 would be recovered through the demand charge for this rate schedule.

Q68. Is the Company proposing any changes to the rate design for Rapid Transit Service (Schedule RT)?

A68. Yes. Schedule RT's sole distribution rate component is a monthly customer charge. The proposed customer charge is designed to recover the entire revenue requirement allocated to the class for RY1, RY2, and RY3.

Street Lighting Service, Traffic Signal Service, Servicing Street Lights, Outdoor Lighting and Telecommunications Network Service Rate Design

Q69. Please describe the Company's proposed changes to the rate design for Street Lighting Service (Schedule SL-E).

A69. Schedule SL-E has a two-part rate consisting of a customer charge and a volumetric charge. For this rate schedule, the Company proposes to increase the customer charge over the three-year period of the MRP in an effort to make the charge more fully reflective of customer-related costs using the Percent Movement to Unit Cost approach discussed above. The balance of the allocated revenue requirement for RY1, RY2, and RY3 is proposed to be recovered through the volumetric charge.

As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule SL-E is equal to $34.90. The Company is proposing to increase the customer charge by $2.66 each year of the MRP. The $2.66 increase was calculated by taking the difference between the 2019 Test Period Unit Cost and the current customer charge for SL-E Metered Account customers and multiplying by 0.15 in order to reflect a 15% movement toward the 2019 Test Period Unit Cost for RY1. This calculation is shown in more detail in PEPCO (F)-4. The Schedule SL-E Unmetered Account customer charge likewise receives the same percentage increase as the Schedule SL-E Metered Account customer charge. The resulting proposed customer charge for SL-E Metered Accounts in RY3 is approximately equal to 72% of the 2019 Test Period Unit Cost for Schedule SL-E of $34.90.

Q70. Please describe the Company's proposed changes to the rate design for Traffic Signal Service (Schedule TS).

A70. Schedule TS has a two-part rate consisting of a customer charge and a volumetric charge. For this rate schedule, the Company proposes to decrease the customer charge in an effort to make the charge reflective of customer-related costs using the Parity with Unit Cost approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule TS is equal to $4.26. The Company is proposing to decrease the customer charge by $3.77 for RY1. This would result in the customer charge for RY1 being equal to the 2019 Test Period Unit Cost for Schedule TS of $4.26.

The Company proposes to collect the entire proposed revenue increases for RY2 and RY3 through the volumetric rate for this rate schedule. This proposal would keep the customer charge for RY2 and RY3 unmodified from the customer charge proposed for RY1.

Q71. Please describe the Company's proposed changes to the rate design for Street Lights Served from Overhead Lines (Schedule SSL-OH) and Street Lights Served from Underground Lines (Schedule SSL-UG).

A71. For RY1, RY2, and RY3, the rate components for Schedules SSL-OH and SSL-UG have been adjusted by the same percentage amount so as to recover the proposed level of revenue.

Q72. Please describe the Company's proposed changes to the rate design for Telecommunications Network Service (Schedule TN)?

A72. Schedule TN has a two-part rate structure consisting of a customer charge and a volumetric charge. As previously discussed and shown in PEPCO (F)-1 and PEPCO

(F)-3, the Company is not proposing to allocate any of the proposed increase in the revenue requirement over the term of the MRP to Schedule TN.

Customer Base Rate Credit (CBRC)

Q73. What is the Customer Base Rate Credit (CBRC)?

A73. The CBRC is the manifestation of a commitment from the Company that resulted from the Commission's approval of the Pepco-Exelon Merger in Formal Case No. 1119. Per Formal Case No. 1119, the Company agreed to provide a CBRC in the amount of $25.6 million for use as a credit to offset rate increases for Pepco customers approved by the Commission in any base rate case filed after the close of the Merger until the CBRC is fully utilized.

Q74. Please provide an update on the current status of the CBRC.

A74. In accordance with Order No. 19433 in Formal Case No. 1150, the current monthly CBRC for Schedule R and MMA customers is equal to the combined revenue adjustments for those two classes in Formal Case Nos. 1139 and 1150 and for Schedule GS LV and GS 3A, the current monthly CBRC offsets the same percent of the combined net increase in Formal Case Nos. 1139 and 1150 as the prior CBRC offset in Formal Case No. 1139. Further, the Settlement in Formal Case No. 1150 provided an additional $3.5 million of funding for the CBRC for Schedule R customers which, in addition to the reduction to the CBRC described above, extends the estimated life of the Residential CBRC. In accordance with the Commission directives in Order No. 18846, the CBRC is being used to offset the current customer charge levels for the classes to which it has been applied. The Company is not proposing that any portion of the CBRC be used to offset the proposed rate increases.

Q75. Please provide an update of the amount of CBRC funding that remains per rate class.

A75. Please refer to Table 5 for the initial balance of allocated CBRC credits per Formal Case Nos. 1139 and 1150, the amounts paid out through March 2019, and the remaining balance available for each rate schedule:

Table 5
Current Status of CBRC Funding ($ millions)

CBRC	R	MMA	GS ND / GS LV	GS 3A	TN	Total
FC 1139	$12.8	$2.20	$2.25	$0.01	$0.02	$17.28
FC 1150	$4.39	$ -	$ -	$ -	$ -	$4.39
Total	$17.19	$2.20	$2.25	$0.01	$0.02	$21.67
CBRC Provided Through March 2019	($8.84)	($1.07)	($1.28)	($0.01)	($0.00)	($11.20)
Balance Available	$8.35	$1.13	$0.96	$0.01	$0.02	$10.47

Please note that this analysis excludes the approximately $8.3 million of CBRC funds allocated for the purpose of providing the Senior Citizen and Disabled Resident rate credit discussed earlier in my testimony.

Q76. How long is the CBRC expected to continue?

A76. Please refer to Table 6 below for the expected expiration dates of the CBRC by rate schedule:

Table 6
Expected CBRC Expiration Dates

Rate Schedule	**Month – Year**
Rate Schedule R	March 2021
Rate Schedule MMA	April 2025
Rate Schedules GS ND and GS LV	September 2021
Rate Schedule GS 3A	August 2021
Rate Schedule TN	-

The Company projected the expiration dates of the CBRC by rate schedule utilizing the current value of the CBRC and forecasted customer counts.

Q77. Please provide the reason why Rate Schedule TN's CBRC balance is not forecasted to expire.

A77. In the course of preparing this testimony the Company discovered that Rate Schedule TN's CBRC had, for the period in which it was in effect (August 2017 to August 2018), been incorrectly applied to customers' bills, resulting in an underpayment of the credit for this period. The Company is currently taking steps to remediate this issue and apply the credits as originally directed. Please note, however, that a residual CBRC balance will likely remain after the billing correction is made, and will remain in place unless the Rate Schedule TN CBRC is reinstated or the funds are reallocated.

E. Bill Impact Analysis

Q78. Please identify where the bill comparisons using the recommended rates that result from the rate designs discussed above are shown.

A78. Bill comparisons for RY1, RY2, and RY3 of the MRP for all the major classes at the proposed rates based on forecasted revenue levels are attached as PEPCO (F)-7.

Q79. Please summarize the residential bill impacts under the proposed rates for the MRP.

A79. Under the proposed rates, a residential Standard Offer Service (SOS) customer using an average of 692 kWh per month[34] will see a total monthly bill increase on average for each year of the MRP as shown in Table 7:

[34] The average usage level was derived by dividing total actual kWh sales by total customers for the Traditional Test Period, as shown on page 1 of PEPCO (F)-6.

Table 7
Residential Bill Impacts

Date	Monthly Increase	% Total Bill
May 1, 2020	$8.57	10.33%
January 1, 2021	$3.69	4.02%
January 1, 2022	$3.19	3.34%

F. Proposed Tariff Changes

Q80. Are you proposing any tariff changes?

A80. Yes. The proposed changes to the distribution rates developed in PEPCO (F)-6 for RY1, RY2 and RY3 of the MRP are incorporated into revised tariff sheets provided as PEPCO (F)-8. Future changes to distribution rates in accordance with the annual adjustment procedure described above and the accompanying tariff changes will be submitted to the Commission on or about 2 months prior to their proposed effective date.

IV. WEATHER-NORMALIZATION STUDY

Q81. What is the purpose of a Weather-Normalization Study?

A81. A Weather-Normalization Study is utilized by the Company in order to design rates that yield the target revenue requirement under the assumption of a normal weather year. Weather normalization helps measure and remove the impact that an unusually warm or cold weather year could have in setting the level of customers' rates.

Q82. Has the Company included a weather-normalization study with this filing?

A82. Yes, as directed by the Commission in Paragraph 172 of Order No. 17424 in Formal Case No. 1103, the Company has designed volumetric rates using weather-normalized billing determinants. The weather-normalization study is attached as PEPCO (F)-9. This exhibit includes an explanation of the process for the weather-normalization of sales. The Company continues to use the same weather-normalization

methodology approved by the Commission in Order Nos. 15710, 16930, and 17424 in Formal Case Nos. 1076, 1087, and 1103, respectively. In addition, as directed by the Commission in Order No. 18846 in Formal Case No. 1139, RAD customers have been excluded from the weather normalization calculation.

V. APPLIANCE SATURATION STUDY

Q83. Has the Company included an appliance saturation study with this filing?

A83. Yes. In its initial Formal Case No. 1150 filing, the Company prepared a new Conditional Demand Analysis (CDA) based on the results of its most recent appliance saturation study. This CDA is provided as PEPCO (F)-10.

Q84. How has the Company utilized the updated CDA?

A84. Since its initial filing in Formal Case No. 1150, the Company has incorporated the results of the CDA as a part of its sales forecasting efforts. Further, results of the CDA reinforce the underlying justification for the existence of the first volumetric rate block of the residential rate structure insofar as it confirms that 400 kWh remains a reasonable approximation of electric usage for basic needs.

VI. DISTRIBUTION MARGINAL COST STUDY

Q85. Why is the Company including a Distribution Marginal Cost Study with this filing?

A85. The Distribution Marginal Cost Study attached as PEPCO (F)-11 is included in this filing to comply with various Commission directives in Formal Case No. 939[35] and earlier rate proceedings. Because this is a distribution-only rate request, the Company has not produced generation or transmission marginal cost studies. In past proceedings,

[35] *In the Matter of the Application of Potomac Electric Power Company for An Increase in Retail Rates for the Sale of Electric Energy*, Formal Case No. 939, Order No. 10646 (June 30, 1995).

the Marginal Cost Study was used to design rates that primarily recovered generation-related costs. Since that time the Company has sold its generation plants. Distribution services are clearly not competitive. Therefore, the Company has not used the results of the attached Marginal Cost Study in any way, but the Company is providing it to comply with the previous Commission directive, most recently in Order No. 15710 in Formal Case No. 1076. While the Company has included this study in this filing out of an abundance of caution, the Company requests that the Commission no longer require that the Company file this study with its rate cases since it is no longer relevant.

VII. TRADITIONAL TEST PERIOD COMPLIANCE FILING

A. Introduction

Q86. What is the increase in distribution revenue that the base rates associated with this filing are designed to recover?

A86. As discussed in the Direct Testimony of Company Witness Ziminsky (PEPCO (D)), the Company's Traditional Test Period Compliance Filing revenue requirement study presents an $88.6 million increase in annual District of Columbia distribution revenues.

Q87. Please provide a summary of how you designed rates structured to recover the revenue target associated with this filing.

A87. I followed the same general rate design approach that I have previously discussed in the MRP section of this testimony for the rate design in this compliance filing.

B. Rate Schedule Revenue Requirements

Q88. Did the Company rely on the Four-Step Method, as described above, to allocate the proposed revenue requirement among the Company's rate classes?

A88. Yes. I followed the same general process that I discuss in the Revenue Allocation section above for the revenue allocation in this compliance filing.

Q89. What is the revenue requirement increase for each rate schedule associated with this filing?

A89. The revenue requirement increase for each rate schedule associated with this filing is provided in PEPCO (F)-12.

C. Rate Design

Q90. Did the Company rely on the same general approach, as described above, for designing distribution rate components for each rate schedule?

A90. Yes. I followed the same general rate design procedure that I discuss in the MRP section above for the design of distribution rate components for each rate schedule in this compliance filing, unless noted otherwise in the sections below.

Q91. Please identify where the proposed rates associated with this filing for each rate schedule are shown.

A91. A summary of the results of the rate design for each rate schedule are shown in PEPCO (F)-13.

Q92. Has the Company prepared a proof of the revenue produced by the rates associated with this filing?

A92. Yes. Detailed calculations for each rate component of each rate schedule and a proof of proposed revenues by rate schedule are shown in PEPCO (F)-14.

Residential Rate Design and Rate Relief Programs

Q93. Please explain the rate design for Residential Service (Schedule R).

A93. For Schedule R, the Company proposes to increase the customer charge in an effort to make the charge more fully reflective of customer-related costs using the Current Share of Revenue approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule R is equal to $27.67. The Company is proposing to increase the customer charge by $3.77. This would result in the customer charge being equal to $18.86, or 68% of its Unit Cost.

The Company's decision to base the proposed customer charge increase using the Percentage of Revenue Requirement Increase approach, which consists of collecting 40% of the revenue increase through the customer charge, was informed by principles of cost causation and gradualism. Recovering a larger amount from Schedule R customers than this percentage of the increase through the customer charge could be inconsistent with the Commission's expressed principles of gradualism and rate continuity.

The remaining distribution revenue requirement is recovered through the summer and winter volumetric rate blocks such that the relative proportion of proposed revenue recovered by each rate component is approximately equal to the relative proportion of current revenue recovered by each rate component.[36]

Q94. How will the proposed rate changes affect RAD customers?

A94. The proposed changes to Rate Schedule R under this compliance filing will have no impact on RAD customers since, as I have discussed above, the RAC will be

[36] As I have previously mentioned, for rate schedules such as Schedule R that have a block kWh structure, the first block is designed so that the winter and summer energy rates are equal.

adjusted to reflect the proposed distribution rates and will therefore offset increases to the distribution customer charge, volumetric rates, and applicable surcharges.

Master Metered Apartments

Q95. Please explain the rate design for Master Metered Apartment Service (Schedule MMA).

A95. For Schedule MMA, the Company proposes to increase the customer charge in an effort to make the charge more fully reflective of customer-related costs using the Class Average Increase approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule MMA is equal to $74.18. The Company is proposing to increase the customer charge by $2.11.

The Company's use of the Class Average Increase approach, which increases the customer charge by the same overall percentage increase applied to the revenue requirement for that particular class, results in a modest proposed increase relative to the current difference between the existing customer charge and the 2019 Test Period Unit Cost.

The remaining distribution revenue requirement is recovered through the summer and winter volumetric rate blocks such that the relative proportion of proposed revenue recovered by each rate component is approximately equal to the relative proportion of current revenue recovered by each rate component. [37]

[37] As I have previously mentioned, for rate schedules such as Schedule MMA that have a block kWh structure, the first block is designed so that the winter and summer energy rates are equal.

Commercial and Temporary Service Rate Design

Q96. Please explain the rate design for General Service – Non-Demand (Schedule GS ND).

A96. For Schedule GS ND, the Company proposes to increase the customer charge in an effort to make the charge more fully reflective of customer-related costs using the Class Average Increase approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule GS ND is equal to $38.75. The Company is proposing to increase the customer charge by $4.88.

The Company's use of the Class Average Increase approach, which increases the customer charge by the same overall percentage increase applied to the revenue requirement for that particular class, results in a modest proposed increase relative to the current difference between the existing customer charge and the 2019 Test Period Unit Cost.

The remaining distribution revenue requirement is recovered through the summer and winter volumetric rate blocks such that the relative proportion of proposed revenue recovered by each rate component is approximately equal to the relative proportion of current revenue recovered by each rate component.

Q97. Please explain the rate design for Temporary Service (Schedule T).

A97. Historically, the customer charges for Schedules GS ND and T have been set at the same level, and this approach is continued in this rate design. For Schedule T, the customer charge has been modified in the same manner as Schedule GS ND. The volumetric rates have been designed to recover the residual revenue increase allocated to Schedule T.

Q98. Please explain the rate design for General Service – Low Voltage (Schedule GS LV).

A98. Schedule GS LV has a three-part rate structure consisting of a customer charge, a demand charge, and a seasonally differentiated volumetric charge. For this rate schedule, the Company proposes to increase the customer charge in an effort to make the charge more fully reflective of customer-related costs using the Parity with Unit Cost approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule GS LV is equal to $38.75. The Company is proposing to increase the customer charge by $3.58. This would result in the customer charge being equal to the 2019 Test Period Unit Cost for Schedule GS LV of $38.75.

The Company's use of the Parity with Unit Cost approach, which sets the customer charge equal to the 2019 Test Period Unit Cost, results in a modest proposed increase relative to the current difference between the existing customer charge and the 2019 Test Period Unit Cost.

The Company proposes that the remaining distribution revenue requirement be recovered through the demand and volumetric charges in proportion to their share of revenue relative to total non-customer-related revenue. The amount of the increase to be collected through the demand charge is calculated by subtracting the amount of the proposed revenue increase collected through the customer charge, then multiplying the remaining amount by the proportion of current revenue collected through the current demand charge relative to the total amount of current revenue collected through the current energy and demand charges. The remaining distribution revenue requirement is recovered through the volumetric charge.

Q99. Please explain the rate design for General Service – Primary Service (Schedule GS 3A).

A99. Schedule GS 3A has a three-part rate structure consisting of a customer charge, a demand charge, and a seasonally differentiated volumetric charge. As previously discussed and shown in PEPCO (F)-1 and PEPCO (F)-12, the Company is not proposing to allocate any of proposed increase in the revenue requirement to Schedule GS 3A.

Q100. Please explain the rate design for Time Metered Medium General Service – Low Voltage (Schedule MGT LV).

A100. Schedule MGT LV has a three-part rate consisting of a customer charge, demand charge, and volumetric charge. For this rate schedule, the Company proposes to decrease the customer charge in an effort to make the charge reflective of customer-related costs using the Parity with Unit Cost approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule MGT LV is equal to $237. The Company is proposing to decrease the customer charge by $219.76. This would result in the customer charge for RY1 being equal to the 2019 Test Period Unit Cost for Schedule MGT LV of $237.

The Company proposes that the remaining distribution revenue requirement be recovered through the demand and volumetric charges in proportion to their share of revenue relative to total non-customer-related revenue. The amount of the increase to be collected through the demand charge is calculated by subtracting the amount of the proposed revenue increase collected through the customer charge, then multiplying the remaining amount by the proportion of current revenue collected through the current demand charge relative to the total amount of current revenue collected through the

current energy and demand charges. The remaining distribution revenue requirement is recovered through the volumetric charge.

Q101. Please explain the rate design for Time Metered General Service – Low Voltage (Schedule GT LV).

A101. Schedule GT LV has a three-part rate consisting of a customer charge, demand charge, and volumetric charge. For this rate schedule, the Company proposes to increase the customer charge in an effort to make the charge more fully reflective of customer-related costs using the Percent Movement to Unit Cost approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule GT LV is equal to $3,816.50. The Company is proposing to increase the customer charge by $483.84, representing an approximately 14% movement toward the 2019 Test Period Unit Cost as shown in PEPCO (F)-4. The Company's use of the Percent Movement to Unit Cost results in a modest proposed increase relative to the current difference between the existing customer charge and the 2019 Test Period Unit Cost.

The Company proposes that the remaining distribution revenue requirement be recovered through the demand and volumetric charges in proportion to their share of revenue relative to total non-customer-related revenue. The amount of the increase to be collected through the demand charge is calculated by subtracting the amount of the proposed revenue increase collected through the customer charge, then multiplying the remaining amount by the proportion of current revenue collected through the current demand charge relative to the total amount of current revenue collected through the current energy and demand charges. The remaining distribution revenue requirement is recovered through the volumetric charge.

Q102. Please explain the rate design for Time Metered General Service – Primary Service (Schedule GT 3A).

A102. Schedule GT 3A has a three-part rate structure consisting of a customer charge, a demand charge, and a seasonally differentiated volumetric charge. For this rate schedule, the Company proposes to increase the customer charge in an effort to make the charge more fully reflective of customer-related costs using the Parity with Unit Cost approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule GT 3A is equal to $197.49. The Company is proposing to increase the customer charge by $9.85. This would result in the customer charge being equal to the 2019 Test Period Unit Cost for Schedule GT 3A of $197.49.

The Company's use of the Parity with Unit Cost approach, which sets the customer charge equal to the 2019 Test Period Unit Cost, results in a modest proposed increase relative to the current difference between the existing customer charge and the 2019 Test Period Unit Cost.

The Company proposes that the remaining distribution revenue requirement be recovered through the demand and volumetric charges in proportion to their share of revenue relative to total non-customer-related revenue. The amount of the increase to be collected through the demand charge is calculated by subtracting the amount of the proposed revenue increase collected through the customer charge, then multiplying the remaining amount by the proportion of current revenue collected through the current demand charge relative to the total amount of current revenue collected through the current energy and demand charges. The remaining distribution revenue requirement is recovered through the volumetric charge.

Q103. Please explain the rate design for Time Metered General Service – High Voltage (Schedule GT 3B).

A103. Schedule GT 3B has a two-part rate consisting of a customer charge and a demand charge. The Company proposes to modify the rates for this schedule using the same approach the Company proposed and the Commission approved in Order Nos. 17424 and 18846 in Formal Case Nos. 1103 and 1139, respectively. The proposed customer charge is designed to fully reflect the customer-related costs, as developed in the CCOSS. The balance of the allocated revenue requirement is recovered through the demand charge.

As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule GT 3B is equal to $311.66. Therefore, the Company is proposing to decrease the customer charge by $111.72. This would result in the customer charge being equal to the 2019 Test Period Unit Cost for Schedule GT 3B of $311.66. The balance of the allocated revenue requirement is recovered through the demand charge for this rate schedule.

Q104. Please explain the rate design for Rapid Transit Service (Schedule RT).

A104. Schedule RT's sole distribution rate component is a monthly customer charge. The proposed customer charge is designed to recover the entire revenue requirement allocated to the class.

<u>Street Lighting Service, Traffic Signal Service, Servicing Street Lights, Outdoor Lighting and Telecommunications Network Service Rate Design</u>

Q105. Please explain the rate design for Street Lighting Service (Schedule SL).

A105. Schedule SL-E has a two-part rate consisting of a customer charge and a volumetric charge. For this rate schedule, the Company proposes to increase the customer charge in an effort to make the charge more fully reflective of customer-

related costs using the Percent Movement to Unit Cost approach discussed above. The balance of the allocated revenue requirement is recovered through the volumetric charge.

As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule SL-E is equal to $34.90. The Company is proposing to increase the customer charge by $2.66. The $2.66 increase was calculated by taking the difference between the 2019 Test Period Unit Cost and the current customer charge for SL-E Metered Account customers and multiplying by 0.15 in order to reflect a 15% movement toward the 2019 Test Period Unit Cost. This calculation is shown in more detail in PEPCO (F)-14. The Schedule SL-E Unmetered Account customer charge likewise receives the same percentage increase as the Schedule SL-E Metered Account customer charge.

Q106. Please explain the rate design for Traffic Signal Service (Schedule TS).

A106. Schedule TS has a two-part rate consisting of a customer charge and a volumetric charge. For this rate schedule, the Company proposes to decrease the customer charge in an effort to make the charge reflective of customer-related costs using the Parity with Unit Cost approach discussed above. As shown in PEPCO (F)-4, the 2019 Test Period Unit Cost for Schedule TS is equal to $4.26. The Company is proposing to decrease the customer charge by $3.77. This would result in the customer charge being equal to the 2019 Test Period Unit Cost for Schedule TS of $4.26.

The Company's use of the Parity with Unit Cost approach would collect the entire proposed revenue increase, as well as the revenue no longer collected via the customer charge, through the volumetric rate for this rate schedule.

Q107. Please explain the rate design for Street Lights Served from Overhead Lines (Schedule SSL-OH) and Street Lights Served from Underground Lines (Schedule SSL-UG).

A107. The rate components for Schedules SSL-OH and SSL-UG have been adjusted by the same percentage amount so as to recover the proposed level of revenue.

Q108. Please explain the rate design for Telecommunications Network Service (Schedule TN).

A108. Schedule TN has a two-part rate structure consisting of a customer charge and a volumetric charge. As previously discussed and shown in PEPCO (F)-1 and PEPCO (F)-12, the Company is not proposing to allocate any of proposed increase in the revenue requirement to Schedule TN.

D. Bill Impact Analysis

Q109. Have you prepared bill comparisons using the rates that result from the rate designs discussed above?

A109. Yes. Bill comparisons for all the major classes are attached as PEPCO (F)-15, which provides the impacts of the proposed distribution rate increase included in this compliance filing.

E. Tariff Changes

Q110. Are you proposing any tariff changes?

A110. Yes. The changes to the distribution rates developed in PEPCO (F)-14 for this compliance filing are incorporated into revised tariff sheets provided as PEPCO (F)-16.

VIII. CONCLUSION

Q111. Does this conclude your Direct Testimony?

A111. Yes, it does.

P.R. Blazunas
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (F) – 1

Pepco - District of Columbia
Development of Proposed Distribution Rates
Rate Schedule Allocation of Distribution Revenue Requirements
Twelve Months Ended June 30, 2019

	(A)	(B)	(C)	(D)	(E)	(F)
	Table 1: Class Rates of Return & Current UROR Analysis	PEPCO DC	R	MMA	GS-LV	GS-3A
(1)	Operating Income	$ 106,314,674	$ (40,709,179)	$ 4,624,380	$ 19,826,198	$ 25,092
(2)	Distribution Rate Base	$ 2,183,820,615	$ 836,513,670	$ 51,971,942	$ 182,953,603	$ 107,218
(3)	ROR	4.87%	-4.87%	8.90%	10.84%	23.40%
(4)	Unitized ROR	1.00	-1.00	1.83	2.23	4.81

	Table 2: Revenue Increase	PEPCO DC
(5)	Revenue Requirement	$ 88,632,000
(6)	Operating Income Deficiency	$ 64,243,000
(7)	Proposed ROR	7.81%

	Table 3: Criteria for Step 1: Exclusion from Revenue Increase	
(8)	Upper Limit of Unitized ROR (Excluded if Greater Than)	3.00

	Table 4: Criteria for Step 2: Definition of UROR Steady State	
(9)	Lower Limit of Unitized ROR	0.90
(10)	Upper Limit of Unitized ROR	1.10

	Table 5: Criteria for Step 3: Increase for Under-Earning Classes	
(11)	Multiplier to System Average Increase	1.80

	Table 6: Revenue Allocation Multi-Step Process	TOTAL	R	MMA	GS-LV	GS-3A
(12)	***Step 1 - Exclusion***					**X**
(13)	Step 1: Allocated Revenue Requirement	$ -	$ -	$ -	$ -	$ -
(14)	*Step 1: Remaining Revenue Requirement*	*$ 88,632,000*				
(15)	***Step 2 - UROR Steady State***					
(16)	Proposed System Average Increase					
(17)	Annualized Current Distribution Revenue					
(18)	Step 2: Allocated Revenue Requirement	$ -				
(19)	*Step 2: Remaining Revenue Requirement*	*$ 88,632,000*				
(20)	***Step 3 - Under-Earning Rate Classes***		**X**			
(21)	Under-Earning Rate Class - Increase (Multiplier)		1.80			
(22)	System Average Increase		22.13%			
(23)	Annualized Current Distribution Revenues		$ 77,912,081			
(24)	Step 3: Allocated Revenue Requirement	$ 31,474,737	$ 31,038,514			
(25)	Step 3: Allocated Revenue Requirement - Additional Adjustment	$ -	$ 62,846			
(26)	*Step 3: Remaining Revenue Requirement*	*$ 57,157,263*				
(27)	***Step 4 - Remaining Rate Classes***			**X**	**X**	
(28)	Step 4: Allocated Revenue Requirement	$ 57,157,263		$ 1,858,030	$ 8,270,398	
(29)	*Step 4: Remaining Revenue Requirement*	*$ -*				

	Table 7: Revenue Allocation Summary ($)	TOTAL	R	MMA	GS-LV	GS-3A
(30)	Step 1	$ -	$ -	$ -	$ -	$ -
(31)	Step 2	$ -	$ -	$ -	$ -	$ -
(32)	Step 3	$ 31,474,737	$ 31,101,360	$ -	$ -	$ -
(33)	Step 4	$ 57,157,263	$ -	$ 1,858,030	$ 8,270,398	$ -
(34)	Total	$ 88,632,000	$ 31,101,360	$ 1,858,030	$ 8,270,398	$ -

	Table 8: Revenue Allocation Summary (%)	TOTAL	R	MMA	GS-LV	GS-3A
(35)	Step 1	0.00%	0.00%	0.00%	0.00%	0.00%
(36)	Step 2	0.00%	0.00%	0.00%	0.00%	0.00%
(37)	Step 3	35.51%	35.09%	0.00%	0.00%	0.00%
(38)	Step 4	64.49%	0.00%	2.10%	9.33%	0.00%
(39)	Total	100.00%	35.09%	2.10%	9.33%	0.00%

	Table 9: Proposed Allocation - Proposed UROR Analysis	PEPCO DC	R	MMA	GS-LV	GS-3A
(40)	ROR	7.81%	-2.17%	11.49%	14.11%	23.40%
(41)	Incremental Income	$ 64,243,000	$ 22,543,153	$ 1,346,753	$ 5,994,621	$ -
(42)	Revenue Conversion Factor	1.3796	1.3796	1.3796	1.3796	1.3796
(43)	Revenue Requirement	$ 88,632,000	$ 31,101,360	$ 1,858,030	$ 8,270,398	$ -
(44)	Final Unitized ROR	1.00	-0.28	1.47	1.81	3.00

	Table 10: Rate Schedule Revenue Increase Allocation	PEPCO DC	R	MMA	GS-LV	GS-3A
(45)	Annualized Current Distribution Revenue	$ 400,467,188	$ 77,912,081	$ 10,445,791	$ 46,495,952	$ 51,577
(46)	Revenue Change	$ 88,632,000	$ 31,101,360	$ 1,858,030	$ 8,270,398	$ -
(47)	Proposed Revenue	$ 489,099,188	$ 109,013,441	$ 12,303,821	$ 54,766,351	$ 51,577
(48)	Revenue Change based on Annualized Current Revenue (%)	22.13%	39.92%	17.79%	17.79%	0.00%
(49)	Ratio of Service Classification Distribution Revenue Change (%) to Overall Distribution Revenue Change (%)		1.80	0.80	0.80	-

Notes:
- For the purposes of cost of service and revenue allocation, Schedule "GS-LV" shown above is inclusive of Schedules "GS-ND," "T", and "GS-LV" (or "GS-DLV").
- Schedule "OL-LED" is not shown since there are no active customers on this Schedule as of the time of this filing.
- Schedule "GS-3A" is also referred to as Schedule "GS-HV."
- Schedule "GT-3B" is also referred to as Schedule "GS-HV-69kV."
- Schedule "GT-3A" is also referred to as Schedule "GS-HV-Other."

Pepco - District of Columbia
Development of Proposed Distribution Rates
Rate Schedule Allocation of Distribution Revenue Requirements
Twelve Months Ended June 30, 2019

	(A)	(B)	(G)	(H)	(I)	(J)
	Table 1: Class Rates of Return & Current UROR Analysis	PEPCO DC	MGT-LV	GT-LV	GT-3B	GT-3A
(1)	Operating Income	$ 106,314,674	$ 65,270,488	$ 30,575,446	$ 223,085	$ 24,106,678
(2)	Distribution Rate Base	$ 2,183,820,615	$ 527,822,823	$ 309,029,550	$ 2,122,406	$ 218,471,556
(3)	ROR	4.87%	12.37%	9.89%	10.51%	11.03%
(4)	Unitized ROR	1.00	2.54	2.03	2.16	2.27

	Table 2: Revenue Increase	PEPCO DC
(5)	Revenue Requirement	$ 88,632,000
(6)	Operating Income Deficiency	$ 64,243,000
(7)	Proposed ROR	7.81%

	Table 3: Criteria for Step 1: Exclusion from Revenue Increase	
(8)	Upper Limit of Unitized ROR (Excluded if Greater Than)	3.00

	Table 4: Criteria for Step 2: Definition of UROR Steady State	
(9)	Lower Limit of Unitized ROR	0.90
(10)	Upper Limit of Unitized ROR	1.10

	Table 5: Criteria for Step 3: Increase for Under-Earning Classes	
(11)	Multiplier to System Average Increase	1.80

	Table 6: Revenue Allocation Multi-Step Process	TOTAL	MGT-LV	GT-LV	GT-3B	GT-3A
(12)	***Step 1 - Exclusion***					
(13)	Step 1: Allocated Revenue Requirement	$ -	$ -	$ -	$ -	$ -
(14)	*Step 1: Remaining Revenue Requirement*	*$ 88,632,000*				
(15)	***Step 2 - UROR Steady State***					
(16)	Proposed System Average Increase					
(17)	Annualized Current Distribution Revenue					
(18)	Step 2: Allocated Revenue Requirement	$ -				
(19)	*Step 2: Remaining Revenue Requirement*	*$ 88,632,000*				
(20)	***Step 3 - Under-Earning Rate Classes***					
(21)	Under-Earning Rate Class - Increase (Multiplier)					
(22)	System Average Increase					
(23)	Annualized Current Distribution Revenues					
(24)	Step 3: Allocated Revenue Requirement	$ 31,474,737				
(25)	Step 3: Allocated Revenue Requirement - Additional Adjustment	$ -				
(26)	*Step 3: Remaining Revenue Requirement*	*$ 57,157,263*				
(27)	***Step 4 - Remaining Rate Classes***		**X**	**X**	**X**	**X**
(28)	Step 4: Allocated Revenue Requirement	$ 57,157,263	$ 23,320,423	$ 13,186,229	$ 74,699	$ 9,211,676
(29)	*Step 4: Remaining Revenue Requirement*	*$ -*				

	Table 7: Revenue Allocation Summary ($)	TOTAL	MGT-LV	GT-LV	GT-3B	GT-3A
(30)	Step 1	$ -	$ -	$ -	$ -	$ -
(31)	Step 2	$ -	$ -	$ -	$ -	$ -
(32)	Step 3	$ 31,474,737	$ -	$ -	$ -	$ -
(33)	Step 4	$ 57,157,263	$ 23,320,423	$ 13,186,229	$ 74,699	$ 9,211,676
(34)	Total	$ 88,632,000	$ 23,320,423	$ 13,186,229	$ 74,699	$ 9,211,676

	Table 8: Revenue Allocation Summary (%)	TOTAL	MGT-LV	GT-LV	GT-3B	GT-3A
(35)	Step 1	0.00%	0.00%	0.00%	0.00%	0.00%
(36)	Step 2	0.00%	0.00%	0.00%	0.00%	0.00%
(37)	Step 3	35.51%	0.00%	0.00%	0.00%	0.00%
(38)	Step 4	64.49%	26.31%	14.88%	0.08%	10.39%
(39)	Total	100.00%	26.31%	14.88%	0.08%	10.39%

	Table 9: Proposed Allocation - Proposed UROR Analysis	PEPCO DC	MGT-LV	GT-LV	GT-3B	GT-3A
(40)	ROR	7.81%	15.57%	12.99%	13.06%	14.09%
(41)	Incremental Income	$ 64,243,000	$ 16,903,308	$ 9,557,755	$ 54,144	$ 6,676,885
(42)	Revenue Conversion Factor	1.3796	1.3796	1.3796	1.3796	1.3796
(43)	Revenue Requirement	$ 88,632,000	$ 23,320,423	$ 13,186,229	$ 74,699	$ 9,211,676
(44)	Final Unitized ROR	1.00	1.99	1.66	1.67	1.80

	Table 10: Rate Schedule Revenue Increase Allocation	PEPCO DC	MGT-LV	GT-LV	GT-3B	GT-3A
(45)	Annualized Current Distribution Revenue	$ 400,467,188	$ 131,106,778	$ 74,132,619	$ 419,955	$ 51,787,789
(46)	Revenue Change	$ 88,632,000	$ 23,320,423	$ 13,186,229	$ 74,699	$ 9,211,676
(47)	Proposed Revenue	$ 489,099,188	$ 154,427,202	$ 87,318,848	$ 494,653	$ 60,999,465
(48)	Revenue Change based on Annualized Current Revenue (%)	22.13%	17.79%	17.79%	17.79%	17.79%
(49)	Ratio of Service Classification Distribution Revenue Change (%) to Overall Distribution Revenue Change (%)		0.80	0.80	0.80	0.80

Notes:
- For the purposes of cost of service and revenue allocation, Schedule "GS-LV" shown above is inclusive of Schedules "GS-ND," "T", and "GS-LV" (or "GS-DLV").
- Schedule "OL-LED" is not shown since there are no active customers on this Schedule as of the time of this filing.
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- Schedule "GT-3A" is also referred to as Schedule "GS-HV-Other."

Pepco - District of Columbia
Development of Proposed Distribution Rates
Rate Schedule Allocation of Distribution Revenue Requirements
Twelve Months Ended June 30, 2019

	(A)	(B)	(K)	(L)	(M)	(N)	(O)
	Table 1: Class Rates of Return & Current UROR Analysis	PEPCO DC	RT	SL-S	SL-E	TS	TN
(1)	Operating Income	$ 106,314,674	$ 2,788,043	$ 172,087	$ (709,649)	$ 82,859	$ 39,146
(2)	Distribution Rate Base	$ 2,183,820,615	$ 33,913,495	$ 5,737,819	$ 14,054,777	$ 895,998	$ 225,758
(3)	ROR	4.87%	8.22%	3.00%	-5.05%	9.25%	17.34%
(4)	Unitized ROR	1.00	1.69	0.62	-1.04	1.90	3.56

	Table 2: Revenue Increase	PEPCO DC
(5)	Revenue Requirement	$ 88,632,000
(6)	Operating Income Deficiency	$ 64,243,000
(7)	Proposed ROR	7.81%

	Table 3: Criteria for Step 1: Exclusion from Revenue Increase	
(8)	Upper Limit of Unitized ROR (Excluded if Greater Than)	3.00

	Table 4: Criteria for Step 2: Definition of UROR Steady State	
(9)	Lower Limit of Unitized ROR	0.90
(10)	Upper Limit of Unitized ROR	1.10

	Table 5: Criteria for Step 3: Increase for Under-Earning Classes	
(11)	Multiplier to System Average Increase	1.80

	Table 6: Revenue Allocation Multi-Step Process	TOTAL	RT	SL-S	SL-E	TS	TN
(12)	***Step 1 - Exclusion***						**X**
(13)	Step 1: Allocated Revenue Requirement	$ -	$ -	$ -	$ -	$ -	$ -
(14)	*Step 1: Remaining Revenue Requirement*	*$ 88,632,000*					
(15)	***Step 2 - UROR Steady State***						
(16)	Proposed System Average Increase						
(17)	Annualized Current Distribution Revenue						
(18)	Step 2: Allocated Revenue Requirement	$ -					
(19)	*Step 2: Remaining Revenue Requirement*	*$ 88,632,000*					
(20)	***Step 3 - Under-Earning Rate Classes***			**X**	**X**		
(21)	Under-Earning Rate Class - Increase (Multiplier)			1.80	1.80		
(22)	System Average Increase			22.13%	22.13%		
(23)	Annualized Current Distribution Revenues			$ 631,022	$ 463,974		
(24)	Step 3: Allocated Revenue Requirement	$ 31,474,737		$ 251,386	$ 184,838		
(25)	Step 3: Allocated Revenue Requirement - Additional Adjustment	$ -		$ (62,846)	$ -		
(26)	*Step 3: Remaining Revenue Requirement*	*$ 57,157,263*					
(27)	***Step 4 - Remaining Rate Classes***		**X**			**X**	
(28)	Step 4: Allocated Revenue Requirement	$ 57,157,263	$ 1,198,752			$ 37,055	
(29)	*Step 4: Remaining Revenue Requirement*	*$ -*					

	Table 7: Revenue Allocation Summary ($)	TOTAL	RT	SL-S	SL-E	TS	TN
(30)	Step 1	$ -	$ -	$ -	$ -	$ -	$ -
(31)	Step 2	$ -	$ -	$ -	$ -	$ -	$ -
(32)	Step 3	$ 31,474,737	$ -	$ 188,539	$ 184,838	$ -	$ -
(33)	Step 4	$ 57,157,263	$ 1,198,752	$ -	$ -	$ 37,055	$ -
(34)	Total	$ 88,632,000	$ 1,198,752	$ 188,539	$ 184,838	$ 37,055	$ -

	Table 8: Revenue Allocation Summary (%)	TOTAL	RT	SL-S	SL-E	TS	TN
(35)	Step 1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(36)	Step 2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(37)	Step 3	35.51%	0.00%	0.21%	0.21%	0.00%	0.00%
(38)	Step 4	64.49%	1.35%	0.00%	0.00%	0.04%	0.00%
(39)	Total	100.00%	1.35%	0.21%	0.21%	0.04%	0.00%

	Table 9: Proposed Allocation - Proposed UROR Analysis	PEPCO DC	RT	SL-S	SL-E	TS	TN
(40)	ROR	7.81%	10.78%	5.38%	-4.10%	12.25%	17.34%
(41)	Incremental Income	$ 64,243,000	$ 868,889	$ 136,659	$ 133,976	$ 26,859	$ -
(42)	Revenue Conversion Factor	1.3796	1.3796	1.3796	1.3796	1.3796	1.3796
(43)	Revenue Requirement	$ 88,632,000	$ 1,198,752	$ 188,539	$ 184,838	$ 37,055	$ -
(44)	Final Unitized ROR	1.00	1.38	0.69	-0.52	1.57	2.22

	Table 10: Rate Schedule Revenue Increase Allocation	PEPCO DC	RT	SL-S	SL-E	TS	TN
(45)	Annualized Current Distribution Revenue	$ 400,467,188	$ 6,739,348	$ 631,022	$ 463,974	$ 208,323	$ 71,978
(46)	Revenue Change	$ 88,632,000	$ 1,198,752	$ 188,539	$ 184,838	$ 37,055	$ -
(47)	Proposed Revenue	$ 489,099,188	$ 7,938,100	$ 819,562	$ 648,812	$ 245,379	$ 71,978
(48)	Revenue Change based on Annualized Current Revenue (%)	22.13%	17.79%	29.88%	39.84%	17.79%	0.00%
(49)	Ratio of Service Classification Distribution Revenue Change (%) to Overall Distribution Revenue Change (%)		0.80	1.35	1.80	0.80	-

Notes:
- For the purposes of cost of service and revenue allocation, Schedule "GS-LV" shown above is inclusive of Schedules "GS-ND," "T", and "GS-LV" (or "GS-DLV").
- Schedule "OL-LED" is not shown since there are no active customers on this Schedule as of the time of this filing.
- Schedule "GS-3A" is also referred to as Schedule "GS-HV."
- Schedule "GT-3B" is also referred to as Schedule "GS-HV-69kV."
- Schedule "GT-3A" is also referred to as Schedule "GS-HV-Other."

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Introduced as:
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Pepco - District of Columbia
Development of Proposed Distribution Rates
Summary of Formal Case Nos. 1076 , 1087, 1103, and 1139
Commission Approved Allocation of Revenue Increase, by Rate Schedule

Summary of Calculated Multiplier to System Average Increase per Approved Revenue Allocations, by Rate Schedule

	Formal Case No. 1139[1]	**R**	**MMA**	**GS**	**GT-LV**	**GT-3B**	**GT-3A**	**RT**	**SL-S**	**SL-E**	**TS**	**TN**
(A)	Current Distribution Revenue ($ millions)	$ 65.91	$ 14.63	$ 46.95	$ 175.43	$ 0.57	$ 50.08	$ 6.44	$ 0.66	$ 0.49	$ 0.23	$ 0.12
(B)	Approved Class Revenue Increase ($ millions)	$ 6.39	$ 1.06	$ 4.52	$ 18.92	$ 0.06	$ 5.23	$ 0.71	$ -	$ -	$ -	$ 0.01
(C)	Approved Class Revenue Increase (%)	9.70%	7.25%	9.63%	10.78%	10.53%	10.44%	11.02%	0.00%	0.00%	0.00%	8.33%
(D)	Approved System Average Increase (%)	10.21%	10.21%	10.21%	10.21%	10.21%	10.21%	10.21%	10.21%	10.21%	10.21%	10.21%
(E)	**Calculated Multiplier - Ratio of (C) to (D)**	**0.95**	**0.71**	**0.94**	**1.06**	**1.03**	**1.02**	**1.08**	**-**	**-**	**-**	**0.82**

	Formal Case No. 1103[2]	**R**	**MMA**	**GS**	**GT-LV**	**GT-3B**	**GT-3A**	**RT**	**SL-S**	**SL-E**	**TS**	**TN**
(F)	Current Distribution Revenue ($ millions)	$ 51.01	$ 12.28	$ 45.32	$ 152.60	$ 0.43	$ 44.65	$ 6.12	$ 0.60	$ 0.27	$ 0.12	$ 0.08
(G)	Approved Class Revenue Increase ($ millions)	$ 10.42	$ 0.69	$ 1.81	$ 7.92	$ 0.02	$ 1.98	$ 0.32	$ 0.06	$ 0.22	$ 0.01	$ 0.00
(H)	Approved Class Revenue Increase (%)	20.43%	5.63%	3.98%	5.19%	3.72%	4.44%	5.30%	9.25%	82.03%	8.98%	1.06%
(I)	Approved System Average Increase (%)	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%	7.48%
(J)	**Calculated Multiplier - Ratio of (H) to (I)**	**2.73**	**0.75**	**0.53**	**0.69**	**0.50**	**0.59**	**0.71**	**1.24**	**10.97**	**1.20**	**0.14**

	Formal Case No. 1087[3]	**R / MMA**	**GS**	**GT-LV**	**GT-3B**	**GT-3A**	**RT**	**SL-S**	**SL-E / TS**	**TN**
(K)	Current Distribution Revenue ($ millions)	$ 51.55	$ 43.09	$ 136.16	$ 0.40	$ 44.12	$ 5.84	$ 0.52	$ 0.20	$ 0.10
(L)	Approved Class Revenue Increase ($ millions)	$ 11.03	$ 1.94	$ 10.72	$ 0.03	$ 0.13	$ 0.28	$ 0.05	$ 0.22	$ (0.02)
(M)	Approved Class Revenue Increase (%)	21.40%	4.51%	7.88%	6.52%	0.29%	4.77%	8.67%	111.72%	-19.94%
(N)	Approved System Average Increase (%)	8.64%	8.64%	8.64%	8.64%	8.64%	8.64%	8.64%	8.64%	8.64%
(O)	**Calculated Multiplier - Ratio of (M) to (N)**	**2.48**	**0.52**	**0.91**	**0.75**	**0.03**	**0.55**	**1.00**	**12.92**	**(2.31)**

	Formal Case No. 1076[4]	**R / MMA**	**GS**	**GT-LV**	**GT-3B**	**GT-3A**	**RT**	**SL-S**	**SL-E / TS**	**TN**
(P)	Current Distribution Revenue ($ millions)	$ 41.57	$ 41.08	$ 116.42	$ 0.35	$ 43.65	$ 5.67	$ 0.48	$ 0.15	$ 0.32
(Q)	Approved Class Revenue Increase ($ millions)	$ 7.47	$ 2.08	$ 10.59	$ 0.09	$ (0.20)	$ 0.17	$ 0.09	$ 0.03	$ 0.02
(R)	Approved Class Revenue Increase (%)	17.98%	5.06%	9.10%	26.07%	-0.45%	3.04%	17.98%	17.98%	6.89%
(S)	Approved System Average Increase (%)	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%
(T)	**Calculated Multiplier - Ratio of (R) to (S)**	**2.21**	**0.62**	**1.12**	**3.20**	**(0.05)**	**0.37**	**2.21**	**2.21**	**0.85**

	Averages - Formal Case Nos. 1076, 1087, 1103, 1139	**R**	**MMA**	**GS**	**GT-LV**	**GT-3B**	**GT-3A**	**RT**	**SL-S**	**SL-E**	**TS**	**TN**
(U)	Calculated Multiplier	**2.09**	**1.54**	**0.65**	**0.94**	**1.37**	**0.40**	**0.68**	**1.11**	**6.52**	**4.08**	**(0.13)**

(V)	**Average of Calculated Multiplier - GS and GT Classes Only**	**0.84**
(W)	**Average of Calculated Multiplier - R Only (excluding Formal Case Nos. 1076 & 1087)**	**1.84**
(X)	**Average of Calculated Multiplier - MMA Only (excluding Formal Case Nos. 1076 & 1087)**	**0.73**

Notes:

- Schedule "R" in the tables for Formal Case Nos. 1076, 1087, and 1103 reflects all of the residential rate schedule subgroups RAD, AE, and RTM. In Formal Case No. 1139, the Commission directed that all of these residential subgroups be merged under Rate Schedule "R."
- For revenue allocation purposes, Rate Schedules "R" and "MMA" were treated as one class in Formal Case Nos. 1076 & 1087.
- For revenue allocation purposes, Rate Schedules "SL-E" and "TS" were treated as one class were treated as one class in Formal Case Nos. 1076 & 1087.

Sources:

1 *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. 1139, Order No. 18846 at Page 148 (July 25, 2017).*

2 *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. 1103, Revised Rate Schedules at Attachment B, Page 1 (April 15, 2014).*

3 *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. 1087, Rate Schedules at Attachment B, Pag (October 12, 2012).*

4 *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. 1076, Rate Schedules at Attachment B, Pag 30, 2010).*

Pepco - District of Columbia
Development of Proposed Distribution Rates
Summary of Formal Case Nos. 1076 , 1087, 1103, and 1139
Commission Approved Allocation of Revenue Increase, by Rate Schedule

Summary of Percentage of Total D.C. Revenue Increase, by Rate Schedule

	Formal Case No. 1139[1]	**Total D.C.**	**R**	**MMA**	**GS**	**GT-LV**	**GT-3B**	**GT-3A**	**RT**	**SL-S**	**SL-E**	**TS**	**TN**
(A)	Current Distribution Revenue ($ millions)	$ 361.51	$ 65.91	$ 14.63	$ 46.95	$ 175.43	$ 0.57	$ 50.08	$ 6.44	$ 0.66	$ 0.49	$ 0.23	$ 0.12
(B)	Approved Class Revenue Increase ($ millions)	$ 36.90	$ 6.39	$ 1.06	$ 4.52	$ 18.92	$ 0.06	$ 5.23	$ 0.71	$ -	$ -	$ -	$ 0.01
(E)	**Percentage of Total D.C. Approved Revenue Increase (%)**	**100.00%**	**17.32%**	**2.87%**	**12.25%**	**51.27%**	**0.16%**	**14.17%**	**1.92%**	**0.00%**	**0.00%**	**0.00%**	**0.03%**

	Formal Case No. 1103[2]	**Total D.C.**	**R**	**MMA**	**GS**	**GT-LV**	**GT-3B**	**GT-3A**	**RT**	**SL-S**	**SL-E**	**TS**	**TN**
(F)	Current Distribution Revenue ($ millions)	$ 313.48	$ 51.01	$ 12.28	$ 45.32	$ 152.60	$ 0.43	$ 44.65	$ 6.12	$ 0.60	$ 0.27	$ 0.12	$ 0.08
(G)	Approved Class Revenue Increase ($ millions)	$ 23.45	$ 10.42	$ 0.69	$ 1.81	$ 7.92	$ 0.02	$ 1.98	$ 0.32	$ 0.06	$ 0.22	$ 0.01	$ 0.00
(J)	**Percentage of Total D.C. Approved Revenue Increase (%)**	**100.00%**	**44.44%**	**2.95%**	**7.70%**	**33.79%**	**0.07%**	**8.45%**	**1.38%**	**0.24%**	**0.94%**	**0.04%**	**0.00%**

	Formal Case No. 1087[3]	**Total D.C.**	**R / MMA**	**GS**	**GT-LV**	**GT-3B**	**GT-3A**	**RT**	**SL-S**	**SL-E / TS**	**TN**
(K)	Current Distribution Revenue ($ millions)	$ 281.98	$ 51.55	$ 43.09	$ 136.16	$ 0.40	$ 44.12	$ 5.84	$ 0.52	$ 0.20	$ 0.10
(L)	Approved Class Revenue Increase ($ millions)	$ 24.38	$ 11.03	$ 1.94	$ 10.72	$ 0.03	$ 0.13	$ 0.28	$ 0.05	$ 0.22	$ (0.02)
(O)	**Percentage of Total D.C. Approved Revenue Increase (%)**	**100.00%**	**45.25%**	**7.97%**	**44.00%**	**0.11%**	**0.53%**	**1.14%**	**0.19%**	**0.90%**	**-0.08%**

	Formal Case No. 1076[4]	**Total D.C.**	**R / MMA**	**GS**	**GT-LV**	**GT-3B**	**GT-3A**	**RT**	**SL-S**	**SL-E / TS**	**TN**
(P)	Current Distribution Revenue ($ millions)	$ 249.69	$ 41.57	$ 41.08	$ 116.42	$ 0.35	$ 43.65	$ 5.67	$ 0.48	$ 0.15	$ 0.32
(Q)	Approved Class Revenue Increase ($ millions)	$ 20.35	$ 7.47	$ 2.08	$ 10.59	$ 0.09	$ (0.20)	$ 0.17	$ 0.09	$ 0.03	$ 0.02
(R)	**Percentage of Total D.C. Approved Revenue Increase (%)**	**100.00%**	**36.73%**	**10.23%**	**52.05%**	**0.44%**	**-0.96%**	**0.85%**	**0.42%**	**0.14%**	**0.11%**

	Summary - Formal Case Nos. 1076, 1087, 1103, 1139	**Total D.C.**	**R**	**MMA**	**GS**	**GT-LV**	**GT-3B**	**GT-3A**	**RT**	**SL-S**	**SL-E**	**TS**	**TN**
(S)	Minimum Percentage of Total D.C. Approved Revenue Increase (%)		17.32%	2.87%	7.70%	33.79%	0.07%	-0.96%	0.85%	0.00%	0.00%	0.00%	-0.08%
(T)	Maximum Percentage of Total D.C. Approved Revenue Increase (%)		45.25%	2.95%	12.25%	52.05%	0.44%	14.17%	1.92%	0.42%	0.94%	0.04%	0.11%
(U)	**Avg. Percentage of Total D.C. Approved Revenue Increase (%)**		**35.93%**	**21.95%**	**9.53%**	**45.28%**	**0.20%**	**5.55%**	**1.32%**	**0.21%**	**0.49%**	**0.02%**	**0.02%**

(V)	**Avg. Percentage of Total D.C. Approved Revenue Increase (%)-R Only (excluding Formal Case Nos. 1076 & 1087)**	30.88%
(W)	**Avg. Percentage of Total D.C. Approved Revenue Increase (%)-MMA Only (excluding Formal Case Nos. 1076 & 1087)**	2.91%

Notes:

- Schedule "R" in the tables for Formal Case Nos. 1076, 1087, and 1103 reflects all of the residential rate schedule subgroups RAD, AE, and RTM. In Formal Case No. 1139, the Commission directed that all of these residential subgroups be merged under Rate Schedule "R."
- For revenue allocation purposes, Rate Schedules "R" and "MMA" were treated as one class in Formal Case Nos. 1076 & 1087.
- For revenue allocation purposes, Rate Schedules "SL-E" and "TS" were treated as one class were treated as one class in Formal Case Nos. 1076 & 1087.

Sources:

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3 *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. 1087, Rate Schedules at Attachment B, Page 2 (October 12, 2012).*

4 *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. 1076, Rate Schedules at Attachment B, Page 2 (June 30, 2010).*

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Pepco - District of Columbia
Development of Proposed Distribution Rates

Revenue Allocation of Distribution Revenue Requirements Results for Multiyear Rate Plan

MRP Rate Year	RY1	RY2	RY3
Proposed Increase in Revenue Requirement ($ Millions)	**$84.938**	**$40.447**	**$36.402**

(A)	(B)	(C) = $84.938 * B	(D)	(E) = $40.447 * D	(F)	(G) = $36.402 * F
	RY1		RY2		RY3	
Rate Class	Allocation of Proposed Revenue Requirement Increase (%)	Allocation of Proposed Revenue Requirement Increase ($ Millions)	Allocation of Proposed Revenue Requirement Increase (%)	Allocation of Proposed Revenue Requirement Increase ($ Millions)	Allocation of Proposed Revenue Requirement Increase (%)	Allocation of Proposed Revenue Requirement Increase ($ Millions)
Overall System Increase	**100.00%**	**$ 84.938**	**100.00%**	**$ 40.447**	**100.00%**	**$ 36.402**
R	35.09%	$ 29.805	35.09%	$ 14.193	35.09%	$ 12.774
MMA	2.10%	$ 1.781	2.10%	$ 0.848	2.10%	$ 0.763
GS-LV	9.33%	$ 7.926	9.33%	$ 3.774	9.33%	$ 3.397
GS-3A	0.00%	$ -	0.00%	$ -	0.00%	$ -
MGT-LV	26.31%	$ 22.349	26.31%	$ 10.642	26.31%	$ 9.578
GT-LV	14.88%	$ 12.637	14.88%	$ 6.017	14.88%	$ 5.416
GT-3B	0.08%	$ 0.072	0.08%	$ 0.034	0.08%	$ 0.031
GT-3A	10.39%	$ 8.828	10.39%	$ 4.204	10.39%	$ 3.783
RT	1.35%	$ 1.149	1.35%	$ 0.547	1.35%	$ 0.492
SL-S	0.21%	$ 0.181	0.21%	$ 0.086	0.21%	$ 0.077
SL-E	0.21%	$ 0.177	0.21%	$ 0.084	0.21%	$ 0.076
TS	0.04%	$ 0.036	0.04%	$ 0.017	0.04%	$ 0.015
TN	0.00%	$ -	0.00%	$ -	0.00%	$ -

Notes:
- For the purposes of cost of service and revenue allocation, Schedule "GS-LV" shown above is inclusive of Schedules "GS-ND," "T", and "GS-DLV."
- Schedule "OL-LED" is not shown since there are no active customers on this Schedule as of the time of this filing.

Pepco - District of Columbia
Development of Proposed Distribution Rates
Rate Class Allocation of Distribution Revenue Requirements Results for Multiyear Rate Plan

Current Annualized Revenue and Allocation of Proposed Increase in Distribution Revenues by Rate Schedule

(A)	(B)	(C)	(D) = B + C	(E)	(F) = E / D	(G) = D + E
	12 Months Ending June 30, 2019[1]	**Projected Change in Distribution Revenue[2]**	**RY1**			
Rate Schedule	Current Revenue ($)	Increase / (Decrease) ($)	Current Revenue ($)	Allocated Revenue Requirement Increase ($)	Overall Class Increase to Current Revenue (%)	Total Revenue Requirement ($)
R	$ 77,912,081	$ 2,708,163	$ 80,620,244	$ 29,805,172	36.97%	$ 110,425,416
MMA	$ 10,445,791	$ (285,643)	$ 10,160,149	$ 1,780,594	17.53%	$ 11,940,743
GS-ND	$ 13,427,430	$ (17,737)	$ 13,409,693	$ 2,288,845	17.07%	$ 15,698,538
T	$ 1,268,963	$ (1,676)	$ 1,267,287	$ 216,308	17.07%	$ 1,483,595
GS-DLV	$ 31,799,559	$ (42,005)	$ 31,757,554	$ 5,420,566	17.07%	$ 37,178,120
GS-3A	$ 51,577	$ (143)	$ 51,433	$ -	0.00%	$ 51,433
MGT-LV	$ 131,106,778	$ (1,912,063)	$ 129,194,716	$ 22,348,516	17.30%	$ 151,543,231
GT-LV	$ 74,132,619	$ (1,081,151)	$ 73,051,468	$ 12,636,677	17.30%	$ 85,688,144
GT-3B	$ 419,955	$ (999)	$ 418,956	$ 71,586	17.09%	$ 490,541
GT-3A	$ 51,787,789	$ (139,120)	$ 51,648,669	$ 8,827,768	17.09%	$ 60,476,437
RT	$ 6,739,348	$ (2)	$ 6,739,346	$ 1,148,792	17.05%	$ 7,888,138
SL-S	$ 631,022	$ -	$ 631,022	$ 180,682	28.63%	$ 811,704
SL-E	$ 463,974	$ 45,030	$ 509,004	$ 177,134	34.80%	$ 686,138
TS	$ 208,323	$ 20,218	$ 228,542	$ 35,511	15.54%	$ 264,052
TN	$ 71,978	$ (893)	$ 71,085	$ -	0.00%	$ 71,085
Total	**$ 400,467,188**	**$ (708,021)**	**$ 399,759,167**	**$ 84,938,150**		**$ 484,697,318**

Notes:
1. This column shows current annualized distribution revenue by rate schedule for the test year period of July 1, 2018 through June 30, 2019.
2. This column represents forecasted incremental base distribution revenue for calendar year 2020 based on rates established in Formal Case No. 1150. These incremental base distribution revenues provide the bridge between annualized base distribution revenues for the 12 months ending June 30, 2019 to annualized base distribution revenues for the 12 months ending December 31, 2020.

Pepco - District of Columbia
Development of Proposed Distribution Rates
Rate Class Allocation of Distribution Revenue Requirements Results for Multiyear Rate Plan

Current Annualized Revenue and Allocation of Proposed Increase in Distribution Revenues by Rate Schedule

(A)	(H)	(I)	(J) = H + I	(K)	(L) = K / J	(M) = J + K
	RY1	**Projected Change in Distribution Revenue[3]**	**RY2**			
Rate Schedule	Total Revenue Requirement ($)	Increase / (Decrease) ($)	Current Revenue ($)	Allocated Revenue Requirement Increase ($)	Overall Class Increase to Current Revenue (%)	Total Revenue Requirement ($)
R	$ 110,425,416	$ 1,842,752	$ 112,268,169	$ 14,192,939	12.64%	$ 126,461,108
MMA	$ 11,940,743	$ (795)	$ 11,939,948	$ 847,902	7.10%	$ 12,787,850
GS-ND	$ 15,698,538	$ 8,317	$ 15,706,855	$ 1,089,926	6.94%	$ 16,796,781
T	$ 1,483,595	$ 786	$ 1,484,381	$ 103,004	6.94%	$ 1,587,385
GS-DLV	$ 37,178,120	$ 19,696	$ 37,197,816	$ 2,581,222	6.94%	$ 39,779,038
GS-3A	$ 51,433	$ 57	$ 51,491	$ -	0.00%	$ 51,491
MGT-LV	$ 151,543,231	$ 141,737	$ 151,684,968	$ 10,642,150	7.02%	$ 162,327,118
GT-LV	$ 85,688,144	$ 80,143	$ 85,768,288	$ 6,017,465	7.02%	$ 91,785,753
GT-3B	$ 490,541	$ 455	$ 490,996	$ 34,088	6.94%	$ 525,085
GT-3A	$ 60,476,437	$ 56,546	$ 60,532,983	$ 4,203,699	6.94%	$ 64,736,681
RT	$ 7,888,138	$ -	$ 7,888,138	$ 547,044	6.94%	$ 8,435,182
SL-S	$ 811,704	$ -	$ 811,704	$ 86,039	10.60%	$ 897,743
SL-E	$ 686,138	$ 105	$ 686,243	$ 84,350	12.29%	$ 770,593
TS	$ 264,052	$ 47	$ 264,099	$ 16,910	6.40%	$ 281,009
TN	$ 71,085	$ (1,123)	$ 69,962	$ -	0.00%	$ 69,962
Total	**$ 484,697,318**	**$ 2,148,723**	**$ 486,846,040**	**$ 40,446,738**		**$ 527,292,778**

Notes:
3. This column represents forecasted incremental base distribution revenue for calendar year 2020 based on rates established in Formal Case No. 1150. These incremental base distribution revenues provide the bridge between annualized base distribution revenues for the 12 months ending June 30, 2019 to annualized base distribution revenues for the 12 months ending December 31, 2020.

Pepco - District of Columbia
Development of Proposed Distribution Rates
Rate Class Allocation of Distribution Revenue Requirements Results for Multiyear Rate Plan

Current Annualized Revenue and Allocation of Proposed Increase in Distribution Revenues by Rate Schedule

(A)	(N)	(O)	(P) = N + O	(Q)	(R) = Q / P	(S) = P + Q
	RY2	Projected Change in Distribution Revenue[4]	RY3			
Rate Schedule	Total Revenue Requirement ($)	Increase / (Decrease) ($)	Current Revenue ($)	Allocated Revenue Requirement Increase ($)	Overall Class Increase to Current Revenue (%)	Total Revenue Requirement ($)
R	$ 126,461,108	$ 1,939,509	$ 128,400,617	$ 12,773,645	9.95%	$ 141,174,262
MMA	$ 12,787,850	$ (754)	$ 12,787,096	$ 763,112	5.97%	$ 13,550,208
GS-ND	$ 16,796,781	$ 10,544	$ 16,807,325	$ 980,934	5.84%	$ 17,788,259
T	$ 1,587,385	$ 996	$ 1,588,381	$ 92,703	5.84%	$ 1,681,084
GS-DLV	$ 39,779,038	$ 24,971	$ 39,804,009	$ 2,323,100	5.84%	$ 42,127,109
GS-3A	$ 51,491	$ 64	$ 51,554	$ -	0.00%	$ 51,554
MGT-LV	$ 162,327,118	$ 159,568	$ 162,486,687	$ 9,577,935	5.89%	$ 172,064,622
GT-LV	$ 91,785,753	$ 90,226	$ 91,875,979	$ 5,415,719	5.89%	$ 97,291,697
GT-3B	$ 525,085	$ 517	$ 525,602	$ 30,680	5.84%	$ 556,281
GT-3A	$ 64,736,681	$ 63,573	$ 64,800,254	$ 3,783,329	5.84%	$ 68,583,583
RT	$ 8,435,182	$ -	$ 8,435,182	$ 492,339	5.84%	$ 8,927,521
SL-S	$ 897,743	$ -	$ 897,743	$ 77,435	8.63%	$ 975,178
SL-E	$ 770,593	$ (258)	$ 770,334	$ 75,915	9.85%	$ 846,249
TS	$ 281,009	$ (116)	$ 280,893	$ 15,219	5.42%	$ 296,112
TN	$ 69,962	$ (1,026)	$ 68,936	$ -	0.00%	$ 68,936
Total	**$ 527,292,778**	**$ 2,287,814**	**$ 529,580,592**	**$ 36,402,064**		**$ 565,982,657**

Notes:

4. This column represents forecasted incremental base distribution revenue for calendar year 2020 based on rates established in Formal Case No. 1150. These incremental base distribution revenues provide the bridge between annualized base distribution revenues for the 12 months ending June 30, 2019 to annualized base distribution revenues for the 12 months ending December 31, 2020.

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Pepco - District of Columbia
Development of Proposed Distribution Rates
Comparison of Current and MRP RY1 Proposed Customer Charge to Unit Cost by Rate Schedule

	R	MMA	GS-ND	GS-DLV	GS-3A	MGT-LV	GT-LV	GT-3B	GT-3A	SL-E	TS	TN
Current Customer Charge	$ 15.09	$ 11.84	$ 27.42	$ 35.17	$ 89.41	$ 456.76	$ 456.76	$ 423.38	$ 187.64	$ 17.19	$ 8.03	$ 15.43
Unit Cost from CCOSS[1]	$ 27.67	$ 74.18	$ 38.75	$ 38.75	$ 163.90	$ 237.00	$ 3,816.50	$ 311.66	$ 197.49	$ 34.90	$ 4.26	$ 17.00
Difference ($)	$ (12.58)	$ (62.34)	$ (11.33)	$ (3.58)	$ (74.49)	$ 219.76	$ (3,359.74)	$ 111.72	$ (9.85)	$ (17.71)	$ 3.77	$ (1.57)
RY1 Proposed Customer Charge	$ 18.56	$ 13.91	$ 32.10	$ 38.75	$ 89.41	$ 237.00	$ 940.60	$ 311.66	$ 197.49	$ 19.85	$ 4.26	$ 15.43
Difference from Unit Cost ($)	$ (9.11)	$ (60.27)	$ (6.65)	$ -	$ (74.49)	$ -	$ (2,875.90)	$ -	$ -	$ (15.05)	$ -	$ (1.57)
Percent of Unit Cost (%)	67.08%	18.75%	82.84%	100.00%	54.55%	100.00%	24.65%	100.00%	100.00%	56.87%	100.00%	90.74%
Movement to Unit Cost (%)	27.59%	3.32%	41.31%	100.00%	0.00%	100.00%	14.40%	100.00%	100.00%	15.02%	100.00%	0.00%

Notes:
1. From the Class Cost of Service Model (CCOSS). *See* the Direct Testimony of Company Witness Schafer, at page 17.

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Pepco - District of Columbia
Proposed Rates for Multiyear Rate Plan (2020-2022)

	Present	Proposed RY1	Proposed RY2	Proposed RY3
Residential				
Customer	$ 15.09	$ 18.56	$ 20.18	$ 21.60
	$ 15.09	$ 18.56	$ 20.18	$ 21.60
Winter				
1st 400 kwh	$ 0.00800	$ 0.01288	$ 0.01495	$ 0.01691
Excess of 400 kwh	$ 0.01594	$ 0.02630	$ 0.03064	$ 0.03471
Summer				
1st 400 kwh	$ 0.00800	$ 0.01288	$ 0.01495	$ 0.01691
Excess of 400 kwh	$ 0.02283	$ 0.03541	$ 0.04094	$ 0.04612
MMA				
Customer	$ 11.84	$ 13.91	$ 14.90	$ 15.79
	$ 11.84	$ 13.91	$ 14.90	$ 15.79
Winter				
1st 400 kwh	$ 0.00891	$ 0.00912	$ 0.00988	$ 0.01050
Excess of 400 kwh	$ 0.01774	$ 0.01654	$ 0.01782	$ 0.01884
Summer				
1st 400 kwh	$ 0.00891	$ 0.00912	$ 0.00988	$ 0.01050
Excess of 400 kwh	$ 0.02542	$ 0.03003	$ 0.03282	$ 0.03523
GSLV ND				
Customer	$ 27.42	$ 32.10	$ 34.33	$ 36.33
Summer kWh	$ 0.04173	$ 0.04851	$ 0.05237	$ 0.05594
Winter kWh	$ 0.03266	$ 0.04231	$ 0.04564	$ 0.04878
T				
Customer	$ 27.42	$ 32.10	$ 34.33	$ 36.33
Summer kWh	$ 0.06223	$ 0.05741	$ 0.06209	$ 0.06642
Winter kWh	$ 0.04853	$ 0.06308	$ 0.06824	$ 0.07309
GS LV D				
Customer	$ 35.17	$ 38.75	$ 38.75	$ 38.75
kW	$ 8.06	$ 9.43	$ 10.10	$ 10.66
Summer kWh	$ 0.02807	$ 0.03460	$ 0.03819	$ 0.04174
Winter kWh	$ 0.02127	$ 0.02595	$ 0.02859	$ 0.03124
GS 3A (GS HV)				
Customer	$ 89.41	$ 89.41	$ 89.41	$ 89.41
kW	$ 10.82	$ 10.82	$ 10.82	$ 10.82
Summer kWh	$ 0.02054	$ 0.01907	$ 0.01987	$ 0.02063
Winter kWh	$ 0.01476	$ 0.01240	$ 0.01289	$ 0.01338
MGT LV				
Customer	$ 456.76	$ 237.00	$ 237.00	$ 237.00
Summer kWh	$ 0.00958	$ 0.01482	$ 0.01675	$ 0.01865
Winter kWh	$ 0.00958	$ 0.01482	$ 0.01673	$ 0.01863
kW	$ 11.88	$ 15.17	$ 16.26	$ 17.24
GT LV				
Customer	$ 456.76	$ 940.60	$ 1,424.44	$ 1,908.28
Summer kWh	$ 0.00958	$ 0.01449	$ 0.01601	$ 0.01747
Winter kWh	$ 0.00958	$ 0.01550	$ 0.01711	$ 0.01867
kW	$ 11.88	$ 13.77	$ 14.47	$ 15.07
GT 3A (GS HV Other)				
Customer	$ 187.64	$ 197.49	$ 197.49	$ 197.49
Summer kWh	$ 0.00454	$ 0.00526	$ 0.00606	$ 0.00685
Winter kWh	$ 0.00453	$ 0.00486	$ 0.00558	$ 0.00631
kW	$ 8.86	$ 10.27	$ 10.96	$ 11.58
GT 3B (GS HV 69kV)				
Customer	$ 423.38	$ 311.66	$ 311.66	$ 311.66
kWh				
kW Summer	$ 1.79	$ 1.84	$ 1.95	$ 2.05
kW Winter	$ 1.92	$ 2.23	$ 2.37	$ 2.50

Pepco - District of Columbia
Proposed Rates for Multiyear Rate Plan (2020-2022)

	Present	Proposed RY1	Proposed RY2	Proposed RY3
RT (Metro)				
Customer	$ 6,216.22	$ 7,203.15	$ 7,673.12	$ 8,096.09
SL-E				
Customer - Metered Accounts	$ 17.19	$ 19.85	$ 22.51	$ 25.17
Customer - Unmetered Accounts	$ 14.70	$ 16.97	$ 19.25	$ 21.52
kWh	$ 0.00615	$ 0.00867	$ 0.00972	$ 0.01065
TS				
Customer	$ 8.03	$ 4.26	$ 4.26	$ 4.26
kWh	$ 0.02203	$ 0.02775	$ 0.02934	$ 0.03077
SL-S				
Fixed - OVERHEAD INCANDESCENT Without GLOBE	$ 2.492	$ 3.128	$ 3.453	$ 3.745
Fixed - OVERHEAD INCANDESCENT With GLOBE	$ 3.639	$ 4.568	$ 5.042	$ 5.468
Fixed - OVERHEAD MERCURY VAPOR 175 WATT	$ 7.756	$ 9.735	$ 10.746	$ 11.655
Fixed - OVERHEAD MERCURY VAPOR 250 WATT	$ 8.861	$ 11.122	$ 12.277	$ 13.316
Fixed - OVERHEAD METAL HALIDE 400 WATT	$ 29.990	$ 37.643	$ 41.550	$ 45.067
Fixed - UNDERGROUND INCANDESCENT With GLOBE	$ 34.870	$ 43.768	$ 48.311	$ 52.400
Fixed - UNDERGROUND MERCURY VAPOR 250 WATT	$ 35.171	$ 44.146	$ 48.728	$ 52.852
Fixed - UNDERGROUND MERCURY VAPOR 400 WATT	$ 41.242	$ 51.766	$ 57.139	$ 61.975
Fixed - UNDERGROUND HIGH PRESSURE SODIUM 150 WATT	$ 30.843	$ 38.714	$ 42.732	$ 46.348
Fixed - UNDERGROUND METAL HALIDE 100 WATT	$ 26.578	$ 33.360	$ 36.823	$ 39.939
Fixed - UNDERGROUND METAL HALIDE 175 WATT	$ 29.990	$ 37.643	$ 41.550	$ 45.067
Fixed - UNDERGROUND METAL HALIDE 400 WATT	$ 29.990	$ 37.643	$ 41.550	$ 45.067
O&M - OVERHEAD INCANDESCENT Without GLOBE	$ 0.039	$ 0.049	$ 0.054	$ 0.059
O&M - OVERHEAD INCANDESCENT With GLOBE	$ 0.860	$ 1.079	$ 1.192	$ 1.292
O&M - OVERHEAD MERCURY VAPOR 175 WATT	$ 0.767	$ 0.963	$ 1.063	$ 1.153
O&M - OVERHEAD MERCURY VAPOR 250 WATT	$ 0.777	$ 0.975	$ 1.077	$ 1.168
O&M - OVERHEAD METAL HALIDE 400 WATT	$ 1.253	$ 1.573	$ 1.736	$ 1.883
O&M - UNDERGROUND INCANDESCENT With GLOBE	$ 1.576	$ 1.978	$ 2.183	$ 2.368
O&M - UNDERGROUND MERCURY VAPOR 250 WATT	$ 1.416	$ 1.777	$ 1.962	$ 2.128
O&M - UNDERGROUND MERCURY VAPOR 400 WATT	$ 1.759	$ 2.208	$ 2.437	$ 2.643
O&M - UNDERGROUND HIGH PRESSURE SODIUM 150 WATT	$ 1.155	$ 1.450	$ 1.600	$ 1.736
O&M - UNDERGROUND METAL HALIDE 100 WATT	$ 1.039	$ 1.304	$ 1.440	$ 1.561
O&M - UNDERGROUND METAL HALIDE 175 WATT	$ 1.253	$ 1.573	$ 1.736	$ 1.883
O&M - UNDERGROUND METAL HALIDE 400 WATT	$ 1.253	$ 1.573	$ 1.736	$ 1.883
TN				
Customer	$ 15.43	$ 15.43	$ 15.43	$ 15.43
Summer kWh	$ 0.01288	$ 0.01200	$ 0.01165	$ 0.01132
Winter kWh	$ 0.01288	$ 0.01200	$ 0.01165	$ 0.01132
OL LED				
Customer	$ 8.76	$ 8.76	$ 8.76	$ 8.76
kWh	$ 0.00895	$ 0.00895	$ 0.00895	$ 0.00895

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Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule Residential ("R")	**Current**	**RY1**	**RY2**	**RY3**
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 29,805,172	$ 14,192,939	$ 12,773,645
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		36.97%	12.64%	9.95%
Customer Charge Recovery ($)		$ 63,758,516	$ 70,907,902	$ 77,682,407
Volumetric Charge Recovery ($)		$ 46,666,901	$ 55,553,206	$ 63,491,855
Customer Charge Recovery (%)	64%	58%	56%	55%
Volumetric Charge Recovery (%)	36%	42%	44%	45%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)	(G) = H - A	(H)	(I) = H * (B+C+D)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**	**Weather Normalization**	**Weather Normalized Billing Determinants**	**Weather Normalized Revenue**
Residential Monthly Customer Charge	3,296,472	$ 15.09			$ 49,743,762		-	3,296,472	49,743,762
Kilowatt-hour charge									
First 400 kWh									
Summer	479,754,157	$ 0.00800	$ (0.00014)	$ (0.00047)	$ 3,545,383	1	(32,560,075)	447,194,082	$ 3,304,764
Winter	619,095,009	$ 0.00800	$ (0.00014)	$ (0.00047)	$ 4,575,112	2	(13,514,448)	605,580,561	$ 4,475,240
Over 400 kWh									
Summer	548,551,090	$ 0.02283	$ (0.00039)	$ (0.00133)	$ 11,579,914	3	(34,207,720)	514,343,370	$ 10,857,789
Winter	634,720,170	$ 0.01594	$ (0.00027)	$ (0.00093)	$ 9,355,775	4	(14,219,547)	620,500,623	$ 9,146,179
Total kWh Charge	2,282,120,426				$ 29,056,184		(94,501,790)	2,187,618,636	27,783,972
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization									
Total Distribution					$ 78,799,947				$ 77,527,735
Percent Change									
BSA/Revenue Annualization					$ 1,820,297				
Total Distribution including BSA/Revenue Annualization					$ 80,620,244				
Proposed Total Dist. Revenue Increase/Decrease									
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Target Recovery of Proposed Change to Revenue Requirement through Customer Charge (%)									
Target Recovery of Proposed Change to Revenue Requirement through Customer Charge ($)									
Customer Charge based on 40% Recovery of Proposed Change to Revenue Requirement through Customer Charge									
Proposed Customer Charge									
Average Billing Period Energy Use (kWh)	692								

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule Residential ("R")	**RY1**
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 29,805,172
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	36.97%
Customer Charge Recovery ($)	$ 63,758,516
Volumetric Charge Recovery ($)	$ 46,666,901
Customer Charge Recovery (%)	58%
Volumetric Charge Recovery (%)	42%

	(J)	(K) = ($18.56 / B) -1 = [(P-((N+O)*J))) - (B*J)] / (B*J)	(L) = B * K	(M) = B + L	(N)	(O)	(P) = J * M = [SUM(First 400 kWh $ in Col. I) / Total kWh $ in Col. I] * (Total kWh $ in Col. P) *[Col. J / (SUM(First 400 kWh $ in Col. J)] = J * (M + N + O)
				RY1			
Delivery Service	**2020 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Residential Monthly Customer Charge	3,435,265	23.00%	$ 3.47	$ 18.56			$ 63,758,516
Kilowatt-hour charge							
First 400 kWh							
Summer	470,494,641	61.01%	$0.00488	$ 0.01288	($0.00014)	($0.00047)	$ 5,773,201
Winter	594,463,364	61.01%	$0.00488	$ 0.01288	($0.00014)	($0.00047)	$ 7,294,358
Over 400 kWh							
Summer	541,308,709	55.11%	$0.01258	$ 0.03541	($0.00039)	($0.00133)	$ 18,237,109
Winter	611,996,518	65.01%	$0.01036	$ 0.02630	($0.00027)	($0.00093)	$ 15,362,232
Total kWh Charge	2,218,263,232						$ 46,666,901
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 29,805,172
Total Distribution							$ 110,425,416
Percent Change							36.97%
BSA/Revenue Annualization							$ 1,842,752
Total Distribution including BSA/Revenue Annualization							$ 112,268,169
Proposed Total Dist. Revenue Increase/Decrease							**$ 31,647,925**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 112,268,169**
Percent Change							**39.26%**

Customer Charge Rate Design		
Full Customer Cost from CCOSS	**$ 27.67**	
Present Customer Charge	**$ 15.09**	
Target Recovery of Proposed Change to Revenue Requirement through Customer Charge (%)	40%	
Target Recovery of Proposed Change to Revenue Requirement through Customer Charge ($)	$ 3.47	= 40% * $29,805,172 / 3,435,265
Customer Charge based on 40% Recovery of Proposed Change to Revenue Requirement through Customer Charge	$ 18.56	
Proposed Customer Charge	**$ 18.56**	

Average Billing Period Energy Use (kWh) **646**

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule Residential ("R")	
	RY2
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 14,192,939
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	12.64%
Customer Charge Recovery ($)	$ 70,907,902
Volumetric Charge Recovery ($)	$ 55,553,206
Customer Charge Recovery (%)	56%
Volumetric Charge Recovery (%)	44%

	(Q)	(R) = ($20.18 / M) -1 = [(W-((U+V)*Q))) - (M*Q)] / (M*Q)	(S) = M * R	(T) = M + S	(U)	(V)	(W) = Q * T = [SUM(First 400 kWh $ in Col. P) / Total kWh $ in Col. P] * (Total kWh $ in Col. W) *[Col. Q / (SUM(First 400 kWh $ in Col. Q)] = Q * (T+U+V)
				RY2			
Delivery Service	**2021 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Residential Monthly Customer Charge	3,513,771	8.73%	$ 1.62	$ 20.18			$ 70,907,902
Kilowatt-hour charge							
First 400 kWh							
Summer	480,985,360	16.09%	$0.00207	$ 0.01495	($0.00014)	($0.00047)	$ 6,898,927
Winter	603,553,051	16.09%	$0.00207	$ 0.01495	($0.00014)	($0.00047)	$ 8,656,955
Over 400 kWh							
Summer	553,536,304	15.62%	$0.00553	$ 0.04094	($0.00039)	($0.00133)	$ 21,709,817
Winter	621,244,549	16.48%	$0.00434	$ 0.03064	($0.00027)	($0.00093)	$ 18,287,507
Total kWh Charge	2,259,319,264						$ 55,553,206
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 14,192,939
Total Distribution							$ 126,461,108
Percent Change							12.64%
BSA/Revenue Annualization							$ 1,939,509
Total Distribution including BSA/Revenue Annualization							$ 128,400,617
Proposed Total Dist. Revenue Increase/Decrease							**$ 16,132,449**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 128,400,617**
Percent Change							**14.37%**

Customer Charge Rate Design			
Full Customer Cost from CCOSS			
Present Customer Charge	**$ 18.56**		
Target Recovery of Proposed Change to Revenue Requirement through Customer Charge (%)	40%		
Target Recovery of Proposed Change to Revenue Requirement through Customer Charge ($)	$ 1.62	= 40% * $14,192,939 / 3,513,771	
Customer Charge based on 40% Recovery of Proposed Change to Revenue Requirement through Customer Charge	$ 20.18		
Proposed Customer Charge	**$ 20.18**		
Average Billing Period Energy Use (kWh)	**643**		

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule Residential ("R")	
	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 12,773,645
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	9.95%
Customer Charge Recovery ($)	$ 77,682,407
Volumetric Charge Recovery ($)	$ 63,491,855
Customer Charge Recovery (%)	55%
Volumetric Charge Recovery (%)	45%

	(X)	(Y) = ($21.6 / T) -1 = [(AD-((AB+AC)*X))) - (T*X)] / (T*X)	(Z) = T * Y	(AA) = T + Z	(AB)	(AC)	(AD) = X * AA = [SUM(First 400 kWh $ in Col. W) / Total kWh $ in Col. W] * (Total kWh $ in Col. AD) *[Col. X / (SUM(First 400 kWh $ in Col. X)] = X * (AA+AB+AC)
				RY3			
Delivery Service	**2022 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Residential Monthly Customer Charge	3,596,408	7.04%	$ 1.42	$ 21.60			$ 77,682,407
Kilowatt-hour charge							
First 400 kWh							
Summer	485,360,607	13.05%	$0.00195	$ 0.01691	($0.00014)	($0.00047)	$ 7,909,042
Winter	605,688,210	13.05%	$0.00195	$ 0.01691	($0.00014)	($0.00047)	$ 9,869,803
Over 400 kWh							
Summer	558,889,885	12.64%	$0.00518	$ 0.04612	($0.00039)	($0.00133)	$ 24,812,188
Winter	623,714,997	13.30%	$0.00407	$ 0.03471	($0.00027)	($0.00093)	$ 20,900,823
Total kWh Charge	2,273,653,700						$ 63,491,855
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 12,773,645
Total Distribution							$ 141,174,262
Percent Change							9.95%
BSA/Revenue Annualization							$ -
Total Distribution including BSA/Revenue Annualization							$ 141,174,262
Proposed Total Dist. Revenue Increase/Decrease							**$ 12,773,645**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 141,174,262**
Percent Change							**9.95%**
Customer Charge Rate Design							
Full Customer Cost from CCOSS							
Present Customer Charge			**$ 20.18**				
Target Recovery of Proposed Change to Revenue Requirement through Customer Charge (%)			40%				
Target Recovery of Proposed Change to Revenue Requirement through Customer Charge ($)			$ 1.42	= 40% * $12,773,645 / 3,596,408			
Customer Charge based on 40% Recovery of Proposed Change to Revenue Requirement through Customer Charge			$ 21.60				
Proposed Customer Charge			**$ 21.60**				
Average Billing Period Energy Use (kWh)	**632**						

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Schedule Master Metered Apartments ("MMA")

	Current	RY1	RY2	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 1,780,594	$ 847,902	$ 763,112
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		17.53%	7.10%	5.97%
Customer Charge Recovery ($)		$ 9,083,105	$ 9,729,566	$ 10,310,728
Volumetric Charge Recovery ($)		$ 2,857,638	$ 3,058,284	$ 3,239,480
Customer Charge Recovery (%)	72%	76%	76%	76%
Volumetric Charge Recovery (%)	28%	24%	24%	24%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)	(G) = H - A	(H)	(I) = H * (B+C+D)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**	**Weather Normalization**	**Weather Normalized Billing Determinants**	**Weather Normalized Revenue**
Residential Monthly Customer Charge	652,991	$ 11.84			$ 7,731,413		-	652,991	$ 7,731,413
Kilowatt-hour charge									
First 400 kWh									
Summer	95,304,051	$ 0.00891	$ (0.00049)	$ (0.00167)	$ 643,302	5	(3,737,915)	91,566,135	$ 618,071
Winter	116,074,987	$ 0.00891	$ (0.00049)	$ (0.00167)	$ 783,506	6	(1,124,427)	114,950,560	$ 775,916
Over 400 kWh									
Summer	64,101,150	$ 0.02542	$ (0.00140)	$ (0.00477)	$ 1,233,947	7	(2,403,644)	61,697,507	$ 1,187,677
Winter	27,170,302	$ 0.01774	$ (0.00098)	$ (0.00333)	$ 364,897	8	(352,959)	26,817,343	$ 360,157
Total kWh Charge	302,650,490				$ 3,025,653		(7,618,945)	295,031,545	$ 2,941,822
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization									
Total Distribution					$ 10,757,066				$ 10,673,235
Percent Change									
BSA/Revenue Annualization					$ (596,917)				
Total Distribution including BSA/Revenue Annualization					$ 10,160,149				
Proposed Total Dist. Revenue Increase/Decrease									
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Ratio of Class Increase to System Average Increase									
Change based on Overall Class Increase ($)									
Proposed Customer Charge based on Overall Class Increase ($)									
Proposed Customer Charge									

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Schedule Master Metered Apartments ("MMA")

	RY1
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 1,780,594
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	17.53%
Customer Charge Recovery ($)	$ 9,083,105
Volumetric Charge Recovery ($)	$ 2,857,638
Customer Charge Recovery (%)	76%
Volumetric Charge Recovery (%)	24%

	(J)	(K) = ($13.91 / B) -1 = [(P-((N+O)*J))) - (B*J)] / (B*J)	(L) = B * K	(M) = B + L	(N)	(O)	(P) = J * M = [SUM(First 400 kWh $ in Col. I) / Total kWh $ in Col. I] * (Total kWh $ in Col. P) *[Col. J / (SUM(First 400 kWh $ in Col. J)] = J * (M + N + O)
				RY1			
Delivery Service	**2020 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Residential Monthly Customer Charge	652,991	17.48%	$ 2.07	$ 13.91			$ 9,083,105
Kilowatt-hour charge							
First 400 kWh							
Summer	72,331,526	2.34%	$0.00021	$ 0.00912	($0.00049)	($0.00167)	$ 503,296
Winter	122,273,612	2.34%	$0.00021	$ 0.00912	($0.00049)	($0.00167)	$ 850,801
Over 400 kWh							
Summer	48,347,534	18.14%	$0.00461	$ 0.03003	($0.00140)	($0.00477)	$ 1,153,690
Winter	28,612,018	-6.78%	($0.00120)	$ 0.01654	($0.00098)	($0.00333)	$ 349,851
Total kWh Charge	271,564,690						$ 2,857,638
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 1,780,594
Total Distribution							$ 11,940,743
Percent Change							17.53%
BSA/Revenue Annualization							$ (795)
Total Distribution including BSA/Revenue Annualization							$ 11,939,948
Proposed Total Dist. Revenue Increase/Decrease							**$ 1,779,799**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 11,939,948**
Percent Change							**17.52%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$ 74.18**	
Present Customer Charge	**$ 11.84**	
Ratio of Class Increase to System Average Increase	1.00	
Change based on Overall Class Increase ($)	$ 2.07	= 17.53% * $11.84
Proposed Customer Charge based on Overall Class Increase ($)	$ 13.91	
Proposed Customer Charge	**$ 13.91**	

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Schedule Master Metered Apartments ("MMA")

	RY2
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 847,902
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	7.10%
Customer Charge Recovery ($)	$ 9,729,566
Volumetric Charge Recovery ($)	$ 3,058,284
Customer Charge Recovery (%)	76%
Volumetric Charge Recovery (%)	24%

	(Q)	(R) = ($14.9 / M) -1 = [(W-((U+V)*Q))) - (M*Q)] / (M*Q)	(S) = M * R	(T) = M + S	(U)	(V)	(W) = Q * T = [SUM(First 400 kWh $ in Col. P) / Total kWh $ in Col. P] * (Total kWh $ in Col. W) *[Col. Q / (SUM(First 400 kWh $ in Col. Q)] = Q * (T+U+V)
				RY2			
Delivery Service	**2021 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Residential Monthly Customer Charge	652,991	7.12%	$ 0.99	$ 14.90			$ 9,729,566
Kilowatt-hour charge							
First 400 kWh							
Summer	69,373,423	8.33%	$0.00076	$ 0.00988	($0.00049)	($0.00167)	$ 535,431
Winter	118,389,416	8.33%	$0.00076	$ 0.00988	($0.00049)	($0.00167)	$ 913,742
Over 400 kWh							
Summer	46,326,892	9.29%	$0.00279	$ 0.03282	($0.00140)	($0.00477)	$ 1,234,695
Winter	27,711,404	7.76%	$0.00128	$ 0.01782	($0.00098)	($0.00333)	$ 374,415
Total kWh Charge	261,801,135						$ 3,058,284
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 847,902
Total Distribution							$ 12,787,850
Percent Change							7.10%
BSA/Revenue Annualization							$ (754)
Total Distribution including BSA/Revenue Annualization							$ 12,787,096
Proposed Total Dist. Revenue Increase/Decrease							**$ 847,148**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 12,787,096**
Percent Change							**7.10%**

Customer Charge Rate Design

Full Customer Cost from CCOSS		
Present Customer Charge	**$ 13.91**	
Ratio of Class Increase to System Average Increase	1.00	
Change based on Overall Class Increase ($)	$ 0.99	= 7.1% * $13.91
Proposed Customer Charge based on Overall Class Increase ($)	$ 14.90	
Proposed Customer Charge	**$ 14.90**	

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Schedule Master Metered Apartments ("MMA")

		RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$	763,112
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		5.97%
Customer Charge Recovery ($)	$	10,310,728
Volumetric Charge Recovery ($)	$	3,239,480
Customer Charge Recovery (%)		76%
Volumetric Charge Recovery (%)		24%

	(X)	(Y) = ($15.79 / T) -1 = [(AD-((AB+AC)*X))) - (T*X)] / (T*X)	(Z) = T * Y	(AA) = T + Z	(AB)	(AC)	(AD) = X * AA = [SUM(First 400 kWh $ in Col. W) / Total kWh $ in Col. W] * (Total kWh $ in Col. AD) *[Col. X / (SUM(First 400 kWh $ in Col. X)] = X * (AA+AB+AC)
				RY3			
Delivery Service	**2022 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Residential Monthly Customer Charge	652,991	5.97%	$ 0.89	$ 15.79			$ 10,310,728
Kilowatt-hour charge							
First 400 kWh							
Summer	67,464,022	6.29%	$0.00062	$ 0.01050	($0.00049)	($0.00167)	$ 562,622
Winter	116,601,923	6.29%	$0.00062	$ 0.01050	($0.00049)	($0.00167)	$ 972,412
Over 400 kWh							
Summer	45,007,229	7.33%	$0.00241	$ 0.03523	($0.00140)	($0.00477)	$ 1,307,848
Winter	27,296,468	5.71%	$0.00102	$ 0.01884	($0.00098)	($0.00333)	$ 396,598
Total kWh Charge	256,369,642						$ 3,239,480
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 763,112
Total Distribution							$ 13,550,208
Percent Change							5.97%
BSA/Revenue Annualization							$ -
Total Distribution including BSA/Revenue Annualization							$ 13,550,208
Proposed Total Dist. Revenue Increase/Decrease							**$ 763,112**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 13,550,208**
Percent Change							**5.97%**

Customer Charge Rate Design

Full Customer Cost from CCOSS			
Present Customer Charge	**$**	**14.90**	
Ratio of Class Increase to System Average Increase		1.00	
Change based on Overall Class Increase ($)	$	0.89	= 5.97% * $14.9
Proposed Customer Charge based on Overall Class Increase ($)	$	15.79	
Proposed Customer Charge	**$**	**15.79**	

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Schedule General Service Non Demand ("GS-ND")

	Current	RY1	RY2	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 2,288,845	$ 1,089,926	$ 980,934
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		17.07%	6.94%	5.84%
Customer Charge Recovery ($)		$ 6,636,090	$ 7,104,839	$ 7,528,020
Volumetric Charge Recovery ($)		$ 9,062,448	$ 9,691,942	$ 10,260,239
Customer Charge Recovery (%)	44%	42%	42%	42%
Volumetric Charge Recovery (%)	56%	58%	58%	58%

Delivery Service	(A) Billing Determinants	(B) Current Rate	(C) 5 Year EDIT Credit	(D) 10 Year EDIT Credit	(E) = A * (B+C+D) Present Revenue	(F) Billing Determinant Adjustment No.	(G) = H - A Weather Normalization	(H) Weather Normalized Billing Determinants	(I) = H * (B+C+D) Weather Normalized Revenue
Monthly Customer Charge	207,939	$ 27.42			$ 5,701,687		-	207,939	$ 5,701,687
Distribution									
Kilowatt-hour Charge									
Summer	96,056,555	$ 0.04173	$ (0.00100)	$ (0.00342)	$ 3,583,870	9	(2,841,486)	93,215,069	$ 3,477,854
Winter	133,410,324	$ 0.03266	$ (0.00078)	$ (0.00267)	$ 3,896,916	10	(1,555,167)	131,855,157	$ 3,851,489
Total kWh Charge	229,466,879				$ 7,480,786		(4,396,653)	225,070,226	$ 7,329,343
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization									
Total Distribution					$ 13,182,473				$ 13,031,031
Percent Change									
BSA/Revenue Annualization					$ 227,220				
Total Distribution including BSA/Revenue Annualization					$ 13,409,693				
Proposed Total Dist. Revenue Increase/Decrease									
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Ratio of Class Increase to System Average Increase									
Change based on Overall Class Increase ($)									
Proposed Customer Charge based on Overall Class Increase ($)									
Proposed Customer Charge									

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Schedule General Service Non Demand ("GS-ND")		
		RY1
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$	2,288,845
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		17.07%
Customer Charge Recovery ($)	$	6,636,090
Volumetric Charge Recovery ($)	$	9,062,448
Customer Charge Recovery (%)		42%
Volumetric Charge Recovery (%)		58%

	(J)	(K) = ($32.1 / B) -1 = [(P-((N+O)*J))) - (B*J)] / (B*J)	(L) = B * K	(M) = B + L	(N)	(O)	(P) = J * (M + N + O)
				RY1			
Delivery Service	**2020 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	206,732	17.07%	$ 4.68	$ 32.10			$ 6,636,090
Distribution							
Kilowatt-hour Charge							
Summer	97,530,355	16.25%	$0.00678	$ 0.04851	($0.00100)	($0.00342)	$ 4,300,232
Winter	122,557,015	29.54%	$0.00965	$ 0.04231	($0.00078)	($0.00267)	$ 4,762,217
Total kWh Charge	220,087,370						$ 9,062,448
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 2,288,845
Total Distribution							$ 15,698,538
Percent Change							17.07%
BSA/Revenue Annualization							$ 8,317
Total Distribution including BSA/Revenue Annualization							$ 15,706,855
Proposed Total Dist. Revenue Increase/Decrease							**$ 2,297,162**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 15,706,855**
Percent Change							**17.13%**

Customer Charge Rate Design			
Full Customer Cost from CCOSS	**$ 38.75**		
Present Customer Charge	**$ 27.42**		
Ratio of Class Increase to System Average Increase	1.00		
Change based on Overall Class Increase ($)	$ 4.68	= 17.07% * $27.42	
Proposed Customer Charge based on Overall Class Increase ($)	$ 32.10		
Proposed Customer Charge	**$ 32.10**		

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Schedule General Service Non Demand ("GS-ND")

	RY2
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 1,089,926
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	6.94%
Customer Charge Recovery ($)	$ 7,104,839
Volumetric Charge Recovery ($)	$ 9,691,942
Customer Charge Recovery (%)	42%
Volumetric Charge Recovery (%)	58%

	(Q)	(R) = ($34.33 / M) -1 = [(W-((U+V)*Q))) - (M*Q)] / (M*Q)	(S) = M * R	(T) = M + S	(U)	(V)	(W) = Q * (T+U+V)
	RY2						
Delivery Service	**2021 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	206,957	6.95%	$ 2.23	$ 34.33			$ 7,104,839
Distribution							
Kilowatt-hour Charge							
Summer	95,906,807	7.96%	$0.00386	$ 0.05237	($0.00100)	($0.00342)	$ 4,598,933
Winter	120,703,026	7.89%	$0.00334	$ 0.04564	($0.00078)	($0.00267)	$ 5,093,009
Total kWh Charge	216,609,833						$ 9,691,942
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 1,089,926
Total Distribution							$ 16,796,781
Percent Change							6.94%
BSA/Revenue Annualization							$ 10,544
Total Distribution including BSA/Revenue Annualization							$ 16,807,325
Proposed Total Dist. Revenue Increase/Decrease							**$ 1,100,470**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 16,807,325**
Percent Change							**7.01%**

Customer Charge Rate Design

Full Customer Cost from CCOSS		
Present Customer Charge	**$ 32.10**	
Ratio of Class Increase to System Average Increase	1.00	
Change based on Overall Class Increase ($)	$ 2.23	= 6.94% * $32.1
Proposed Customer Charge based on Overall Class Increase ($)	$ 34.33	
Proposed Customer Charge	**$ 34.33**	

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Schedule General Service Non Demand ("GS-ND")		
		RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$	980,934
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		5.84%
Customer Charge Recovery ($)	$	7,528,020
Volumetric Charge Recovery ($)	$	10,260,239
Customer Charge Recovery (%)		42%
Volumetric Charge Recovery (%)		58%

	(X)	(Y) = ($36.33 / T) -1 = [(AD-((AB+AC)*X))) - (T*X)] / (T*X)	(Z) = T * Y	(AA) = T + Z	(AB)	(AC)	(AD) = X * (AA+AB+AC)
				RY3			
Delivery Service	**2022 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	207,212	5.83%	$ 2.00	$ 36.33			$ 7,528,020
Distribution							
Kilowatt-hour Charge							
Summer	94,492,281	6.82%	$0.00357	$ 0.05594	($0.00100)	($0.00342)	$ 4,868,596
Winter	118,941,674	6.87%	$0.00314	$ 0.04878	($0.00078)	($0.00267)	$ 5,391,642
Total kWh Charge	213,433,955						$ 10,260,239
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 980,934
Total Distribution							$ 17,788,259
Percent Change							5.84%
BSA/Revenue Annualization							$ -
Total Distribution including BSA/Revenue Annualization							$ 17,788,259
Proposed Total Dist. Revenue Increase/Decrease							**$ 980,934**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 17,788,259**
Percent Change							**5.84%**

Customer Charge Rate Design			
Full Customer Cost from CCOSS			
Present Customer Charge	**$ 34.33**		
Ratio of Class Increase to System Average Increase	1.00		
Change based on Overall Class Increase ($)	$ 2.00	= 5.84% * $34.33	
Proposed Customer Charge based on Overall Class Increase ($)	$ 36.33		
Proposed Customer Charge	**$ 36.33**		

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Schedule Temporary Service ("T")

	Current	RY1	RY2	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 216,308	$ 103,004	$ 92,703
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		17.07%	6.94%	5.84%
Customer Charge Recovery ($)		$ 109,102	$ 116,809	$ 123,766
Volumetric Charge Recovery ($)		$ 1,374,493	$ 1,470,576	$ 1,557,318
Customer Charge Recovery (%)	8%	7%	7%	7%
Volumetric Charge Recovery (%)	92%	93%	93%	93%

Delivery Service	(A) Billing Determinants	(B) Current Rate	(C) 5 Year EDIT Credit	(D) 10 Year EDIT Credit	(E) = A * (B+C+D) Present Revenue	(F) Billing Determinant Adjustment No.	(G) = H - A Weather Normalization	(H) Weather Normalized Billing Determinants	(I) = H * (B+C+D) Weather Normalized Revenue
Monthly Customer Charge	3,601	$ 27.42			$ 98,739		-	3,601	$ 98,739.42
Distribution									
Summer Energy Rate	9,307,308	$ 0.06223	$ (0.00097)	$ (0.00331)	$ 539,358	11	(284,000)	9,023,308	$ 522,901
Winter Energy Rate	16,531,688	$ 0.04853	$ (0.00076)	$ (0.00258)	$ 747,067	12	(182,552)	16,349,136	$ 738,817
Total kWh Charge	25,838,996				$ 1,286,425		(466,552)	25,372,444	$ 1,261,718
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization									
Total Distribution					$ 1,385,165				$ 1,261,718
Percent Change									
BSA/Revenue Annualization					$ (117,878)				
Total Distribution including BSA/Revenue Annualization					$ 1,267,287				
Proposed Total Dist. Revenue Increase/Decrease									
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization									
Percent Change									
Customer Charge Rate Design									
Present Customer Charge									
Proposed GS-ND Customer Charge									
Proposed Customer Charge									

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Schedule Temporary Service ("T")

		RY1
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$	216,308
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		17.07%
Customer Charge Recovery ($)	$	109,102
Volumetric Charge Recovery ($)	$	1,374,493
Customer Charge Recovery (%)		7%
Volumetric Charge Recovery (%)		93%

	(J)	(K) = ($32.1 / B) -1 = [(P-((N+O)*J))) - (B*J)] / (B*J)	(L) = B * K	(M) = B + L	(N)	(O)	(P) = J * (M + N + O)
				RY1			
Delivery Service	**2020 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	3,399	17.07%	$ 4.68	$ 32.10			$ 109,102
Distribution							
Summer Energy Rate	10,720,722	-7.74%	($0.00482)	$ 0.05741	($0.00097)	($0.00331)	$ 569,638
Winter Energy Rate	13,471,701	29.99%	$0.01455	$ 0.06308	($0.00076)	($0.00258)	$ 804,854
Total kWh Charge	24,192,423						$ 1,374,493
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 216,308
Total Distribution							$ 1,483,595
Percent Change							17.07%
BSA/Revenue Annualization							$ 786
Total Distribution including BSA/Revenue Annualization							$ 1,484,381
Proposed Total Dist. Revenue Increase/Decrease							**$ 217,094**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 1,484,381**
Percent Change							**17.13%**

Customer Charge Rate Design

Present Customer Charge	**$ 27.42**
Proposed GS-ND Customer Charge	$ 32.10
Proposed Customer Charge	**$ 32.10**

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Schedule Temporary Service ("T")		
		RY2
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$	103,004
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		6.94%
Customer Charge Recovery ($)	$	116,809
Volumetric Charge Recovery ($)	$	1,470,576
Customer Charge Recovery (%)		7%
Volumetric Charge Recovery (%)		93%

	(Q)	(R) = ($34.33 / M) -1 = [(W-((U+V)*Q))) - (M*Q)] / (M*Q)	(S) = M * R	(T) = M + S	(U)	(V)	(W) = Q * (T+U+V)
				RY2			
Delivery Service	**2021 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	3,403	6.95%	$ 2.23	$ 34.33			$ 116,809
Distribution							
Summer Energy Rate	10,542,259	8.15%	$0.00468	$ 0.06209	($0.00097)	($0.00331)	$ 609,459
Winter Energy Rate	13,267,906	8.18%	$0.00516	$ 0.06824	($0.00076)	($0.00258)	$ 861,117
Total kWh Charge	23,810,165						$ 1,470,576
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 103,004
Total Distribution							$ 1,587,385
Percent Change							6.94%
BSA/Revenue Annualization							$ 996
Total Distribution including BSA/Revenue Annualization							$ 1,588,381
Proposed Total Dist. Revenue Increase/Decrease							**$ 104,000**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 1,588,381**
Percent Change							**7.01%**

Customer Charge Rate Design

Present Customer Charge	**$**	**32.10**
Proposed GS-ND Customer Charge	$	34.33
Proposed Customer Charge	**$**	**34.33**

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Schedule Temporary Service ("T")	**RY3**
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 92,703
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	5.84%
Customer Charge Recovery ($)	$ 123,766
Volumetric Charge Recovery ($)	$ 1,557,318
Customer Charge Recovery (%)	7%
Volumetric Charge Recovery (%)	93%

	(X)	(Y) = ($36.33 / T) -1 = [(AD-((AB+AC)*X))) - (T*X)] / (T*X)	(Z) = T * Y	(AA) = T + Z	(AB)	(AC)	(AD) = X * (AA+AB+AC)
				RY3			
Delivery Service	**2022 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	3,407	5.83%	$ 2.00	$ 36.33			$ 123,766
Distribution							
Summer Energy Rate	10,386,772	6.97%	$0.00433	$ 0.06642	($0.00097)	($0.00331)	$ 645,408
Winter Energy Rate	13,074,295	7.10%	$0.00485	$ 0.07309	($0.00076)	($0.00258)	$ 911,910
Total kWh Charge	23,461,067						$ 1,557,318
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 92,703
Total Distribution							$ 1,681,084
Percent Change							5.84%
BSA/Revenue Annualization							$ -
Total Distribution including BSA/Revenue Annualization							$ 1,681,084
Proposed Total Dist. Revenue Increase/Decrease							**$ 92,703**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 1,681,084**
Percent Change							**5.84%**

Customer Charge Rate Design

Present Customer Charge	**$ 34.33**
Proposed GS-ND Customer Charge	$ 36.33
Proposed Customer Charge	**$ 36.33**

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Schedule General Service Low Voltage ("GSD-LV")

	Current	RY1	RY2	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 5,420,566	$ 2,581,222	$ 2,323,100
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		17.07%	6.94%	5.84%
Customer Charge Recovery ($)		$ 2,363,246	$ 2,365,822	$ 2,368,738
Demand Charge Recovery ($)		$ 17,559,358	$ 18,585,681	$ 19,392,289
Volumetric Charge Recovery ($)		$ 17,255,516	$ 18,827,535	$ 20,366,081
Customer Charge Recovery (%)	7%	6%	6%	6%
Demand Charge Recovery (%)	48%	47%	47%	46%
Volumetric Charge Recovery (%)	45%	46%	47%	48%

Delivery Service	(A) Billing Determinants	(B) Current Rate	(C) 5 Year EDIT Credit	(D) 10 Year EDIT Credit	(E) = A * (B+C+D) Present Revenue	(F) Billing Determinant Adjustment No.	(G) = H - A Weather Normalization	(H) Weather Normalized Billing Determinants	(I) = H * (B+C+D) Weather Normalized Revenue
Monthly Customer Charge	61,276	$ 35.17			$ 2,155,077		-	61,276	$ 2,155,077
Distribution									
Kilowatt-hour Charge									
Summer	283,446,851	$ 0.02807	$ (0.00043)	$ (0.00148)	$ 7,414,970	13	(8,300,075)	275,146,776	$ 7,197,840
Winter	345,267,257	$ 0.02127	$ (0.00033)	$ (0.00112)	$ 6,843,197	14	(3,303,176)	341,964,081	$ 6,777,728
Total kWh Charge	628,714,108				$ 14,258,167		(11,603,251)	617,110,857	$ 13,975,568
Demand Charge (Total kW)									
Summer	945,037	$ 8.06	$ (0.12)	$ (0.43)	$ 7,097,228		-	945,037	$ 7,097,228
Winter	1,064,387	$ 8.06	$ (0.12)	$ (0.43)	$ 7,993,546		-	1,064,387	$ 7,993,546
Total KW Charge	2,009,424				$ 15,090,774		-	2,009,424	$ 15,090,774
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization									
Total Distribution					$ 31,504,018				$ 31,221,419
Percent Change									
BSA/Revenue Annualization					$ 253,536				
Total Distribution including BSA/Revenue Annualization					$ 31,757,554				
Proposed Total Dist. Revenue Increase/Decrease									
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Proposed Customer Charge									
Demand Charge Rate Design									
Present Demand Charge									
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)									
Calculated Demand Charge Increase									
Calculated Demand Charge									
Proposed Demand Charge									

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Schedule General Service Low Voltage ("GSD-LV")

		RY1
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$	5,420,566
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		17.07%
Customer Charge Recovery ($)	$	2,363,246
Demand Charge Recovery ($)	$	17,559,358
Volumetric Charge Recovery ($)	$	17,255,516
Customer Charge Recovery (%)		6%
Demand Charge Recovery (%)		47%
Volumetric Charge Recovery (%)		46%

	(J)	(K) = ($38.75 / B) -1 = [(P-((N+O)*J))) - (B*J)] / (B*J) = ($9.43 / B) -1	(L) = B * K	(M) = B + L	(N)	(O)	(P) = J * M = ($17,255,516 / $13,975,568) * I = (M+N+O) * J
				RY1			
Delivery Service	**2020 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	60,988	10.18%	$ 3.58	$ 38.75			$ 2,363,246
Distribution							
Kilowatt-hour Charge							
Summer	271,834,969	23.27%	$0.00653	$ 0.03460	($0.00043)	($0.00148)	$ 8,887,112
Winter	341,588,857	22.00%	$0.00468	$ 0.02595	($0.00033)	($0.00112)	$ 8,368,404
Total kWh Charge	613,423,827						$ 17,255,516
Demand Charge (Total kW)							
Summer	920,462	17.00%	$ 1.37	$ 9.43	($0.12)	($0.43)	$ 8,173,701
Winter	1,056,943	17.00%	$ 1.37	$ 9.43	($0.12)	($0.43)	$ 9,385,657
Total KW Charge	1,977,405						$ 17,559,358
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 5,420,566
Total Distribution							$ 37,178,120
Percent Change							17.07%
BSA/Revenue Annualization							$ 19,696
Total Distribution including BSA/Revenue Annualization							$ 37,197,816
Proposed Total Dist. Revenue Increase/Decrease							**$ 5,440,262**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 37,197,816**
Percent Change							**17.13%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$**	**38.75**
Present Customer Charge	**$**	**35.17**
Proposed Customer Charge	**$**	**38.75**

Demand Charge Rate Design

Present Demand Charge	**$**	**8.06**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)		50%	= [$5,420,566 - ($2,363,246 - $2,155,077)] * ($15,090,774 / ($15,090,774 + $13,975,568)) / $5,420,566
Calculated Demand Charge Increase	$	1.37	= (49.92% * $5,420,566) / 1,977,405
Calculated Demand Charge	$	9.43	
Proposed Demand Charge	**$**	**9.43**	

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Schedule General Service Low Voltage ("GSD-LV")

		RY2
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$	2,581,222
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		6.94%
Customer Charge Recovery ($)	$	2,365,822
Demand Charge Recovery ($)	$	18,585,681
Volumetric Charge Recovery ($)	$	18,827,535
Customer Charge Recovery (%)		6%
Demand Charge Recovery (%)		47%
Volumetric Charge Recovery (%)		47%

	(Q)	(R) = ($38.75 / M) -1 = [(W-((U+V)*Q))) - (M*Q)] / (M*Q) = ($10.1 / M) -1	(S) = M * R	(T) = M + S	(U)	(V)	(W) = Q * T = ($18,827,535 / $17,255,516) * P = (T+U+V) * Q
				RY2			
Delivery Service	**2021 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	61,054	0.00%	$ -	$ 38.75			$ 2,365,822
Distribution							
Kilowatt-hour Charge							
Summer	267,309,844	10.35%	$0.00358	$ 0.03819	($0.00043)	($0.00148)	$ 9,696,749
Winter	336,421,450	10.18%	$0.00264	$ 0.02859	($0.00033)	($0.00112)	$ 9,130,786
Total kWh Charge	603,731,294						$ 18,827,535
Demand Charge (Total kW)							
Summer	905,372	7.09%	$ 0.67	$ 10.10	($0.12)	($0.43)	$ 8,645,279
Winter	1,041,003	7.09%	$ 0.67	$ 10.10	($0.12)	($0.43)	$ 9,940,402
Total KW Charge	1,946,375						$ 18,585,681
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 2,581,222
Total Distribution							$ 39,779,038
Percent Change							6.94%
BSA/Revenue Annualization							$ 24,971
Total Distribution including BSA/Revenue Annualization							$ 39,804,009
Proposed Total Dist. Revenue Increase/Decrease							**$ 2,606,192**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 39,804,009**
Percent Change							**7.01%**

Customer Charge Rate Design

Full Customer Cost from CCOSS		
Present Customer Charge	**$ 38.75**	
Proposed Customer Charge	**$ 38.75**	

Demand Charge Rate Design

Present Demand Charge	**$ 9.43**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)	50%	= [$2,581,222 - ($2,365,822 - $2,363,246)] * ($17,559,358 / ($17,559,358 + $17,255,516)) / $2,581,222
Calculated Demand Charge Increase	$ 0.67	= (50.44% * $2,581,222) / 1,946,375
Calculated Demand Charge	$ 10.10	
Proposed Demand Charge	**$ 10.10**	

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Schedule General Service Low Voltage ("GSD-LV")

		RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$	2,323,100
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		5.84%
Customer Charge Recovery ($)	$	2,368,738
Demand Charge Recovery ($)	$	19,392,289
Volumetric Charge Recovery ($)	$	20,366,081
Customer Charge Recovery (%)		6%
Demand Charge Recovery (%)		46%
Volumetric Charge Recovery (%)		48%

	(X)	(Y) = ($38.75 / T) -1 = [(AD-((AB+AC)*X))) - (T*X)] / (T*X) = ($10.7 / T) -1	(Z) = T * Y	(AA) = T + Z	(AB)	(AC)	(AD) = X * AA = ($20,366,081 / $18,827,535) * W = (AA+AB+AC) * X
				RY3			
Delivery Service	**2022 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	61,130	0.00%	$ -	$ 38.75			$ 2,368,738
Distribution							
Kilowatt-hour Charge							
Summer	263,367,302	9.30%	$0.00355	$ 0.04174	($0.00043)	($0.00148)	$ 10,489,147
Winter	331,512,239	9.28%	$0.00265	$ 0.03124	($0.00033)	($0.00112)	$ 9,876,934
Total kWh Charge	594,879,541						$ 20,366,081
Demand Charge (Total kW)							
Summer	892,358	5.94%	$ 0.56	$ 10.66	($0.12)	($0.43)	$ 9,020,961
Winter	1,025,936	5.94%	$ 0.56	$ 10.66	($0.12)	($0.43)	$ 10,371,327
Total KW Charge	1,918,294						$ 19,392,289
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 2,323,100
Total Distribution							$ 42,127,109
Percent Change							5.84%
BSA/Revenue Annualization							$ -
Total Distribution including BSA/Revenue Annualization							$ 42,127,109
Proposed Total Dist. Revenue Increase/Decrease							**$ 2,323,100**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 42,127,109**
Percent Change							**5.84%**

Customer Charge Rate Design

Full Customer Cost from CCOSS		
Present Customer Charge	**$ 38.75**	
Proposed Customer Charge	**$ 38.75**	

Demand Charge Rate Design

Present Demand Charge	**$ 10.10**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)	50%	= [$2,323,100 - ($2,368,738 - $2,365,822)] * ($18,585,681 / ($18,585,681 + $18,827,535)) / $2,323,100
Calculated Demand Charge Increase	$ 0.60	= (49.68% * $2,323,100) / 1,918,294
Calculated Demand Charge	$ 10.70	
Proposed Demand Charge	**$ 10.70**	

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Schedule General Service Primary Service - General Service ("GS 3A")

	Current	RY1	RY2	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ -	$ -	$ -
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		0.00%	0.00%	0.00%
Customer Charge Recovery ($)		$ 5,331	$ 5,337	$ 5,337
Demand Charge Recovery ($)		$ 28,434	$ 27,987	$ 27,577
Volumetric Charge Recovery ($)		$ 17,668	$ 18,166	$ 18,640
Customer Charge Recovery (%)	12%	10%	10%	10%
Demand Charge Recovery (%)	52%	55%	54%	53%
Volumetric Charge Recovery (%)	37%	34%	35%	36%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)	(G) = H - A	(H)	(I) = H * (B+C+D)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**	**Weather Normalization**	**Weather Normalized Billing Determinants**	**Weather Normalized Revenue**
Monthly Customer Charge	65	$ 89.41			$ 5,812		-	65	$ 5,812
Distribution									
Kilowatt-hour Charge									
Summer	551,065	$ 0.02054	$ (0.00035)	$ (0.00118)	$ 10,476	15	(16,212)	534,853	$ 10,168
Winter	609,202	$ 0.01476	$ (0.00025)	$ (0.00085)	$ 8,322	16	(6,961)	602,241	$ 8,227
Total kWh Charge	1,160,267				$ 18,797		(23,172)	1,137,095	$ 18,394
Demand Charge (Total kW)									
Summer	1,216	$ 10.82	$ (0.18)	$ (0.62)	$ 12,184		-	1,216	$ 12,184
Winter	1,367	$ 10.82	$ (0.18)	$ (0.62)	$ 13,697		-	1,367	$ 13,697
Total KW Charge	2,583				$ 25,882		-	2,583	$ 25,882
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization									
Total Distribution					$ 50,491				$ 50,087
Percent Change									
BSA/Revenue Annualization					$ 943				
Total Distribution including BSA/Revenue Annualization					$ 51,433				
Proposed Total Dist. Revenue Increase/Decrease									
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Proposed Customer Charge									
Demand Charge Rate Design									
Present Demand Charge									
Proposed Demand Charge									

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Schedule General Service Primary Service - General Service ("GS 3A")

	RY1
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ -
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	0.00%
Customer Charge Recovery ($)	$ 5,331
Demand Charge Recovery ($)	$ 28,434
Volumetric Charge Recovery ($)	$ 17,668
Customer Charge Recovery (%)	10%
Demand Charge Recovery (%)	55%
Volumetric Charge Recovery (%)	34%

	(J)	(K) = ($89.41 / B) -1 = [(P-((N+O)*J))) - (B*J)] / (B*J) = ($10.82 / B) -1	(L) = B * K	(M) = B + L	(N)	(O)	(P) = J * M = ($17,668 / $18,394) * I = (M+N+O) * J
				RY1			
Delivery Service	**2020 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	60	0.00%	$ -	$ 89.41			$ 5,331
Distribution							
Kilowatt-hour Charge							
Summer	556,705	-7.14%	($0.00147)	$ 0.01907	($0.00035)	($0.00118)	$ 9,766
Winter	699,557	-16.02%	($0.00236)	$ 0.01240	($0.00025)	($0.00085)	$ 7,902
Total kWh Charge	1,256,262						$ 17,668
Demand Charge (Total kW)							
Summer	1,265	0.00%	$ -	$ 10.82	($0.18)	($0.62)	$ 12,680
Winter	1,572	0.00%	$ -	$ 10.82	($0.18)	($0.62)	$ 15,754
Total KW Charge	2,838						$ 28,434
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ -
Total Distribution							$ 51,433
Percent Change							0.00%
BSA/Revenue Annualization							$ 57
Total Distribution including BSA/Revenue Annualization							$ 51,491
Proposed Total Dist. Revenue Increase/Decrease							**$ 57**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 51,491**
Percent Change							**0.11%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$ 163.90**
Present Customer Charge	**$ 89.41**
Proposed Customer Charge	**$ 89.41**

Demand Charge Rate Design

Present Demand Charge	**$ 10.82**
Proposed Demand Charge	**$ 10.82**

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Schedule General Service Primary Service - General Service ("GS 3A")

	RY2
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ -
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	0.00%
Customer Charge Recovery ($)	$ 5,337
Demand Charge Recovery ($)	$ 27,987
Volumetric Charge Recovery ($)	$ 18,166
Customer Charge Recovery (%)	10%
Demand Charge Recovery (%)	54%
Volumetric Charge Recovery (%)	35%

	(Q)	(R) = ($89.41 / M) -1 = [(W-((U+V)*Q))) - (M*Q)] / (M*Q) = ($10.82 / M) -1	(S) = M * R	(T) = M + S	(U)	(V)	(W) = Q * T = ($18,166 / $17,668) * P = (T+U+V) * Q
				RY2			
Delivery Service	**2021 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	60	0.00%	$ -	$ 89.41			$ 5,337
Distribution							
Kilowatt-hour Charge							
Summer	547,438	4.20%	$0.00080	$0.01987	($0.00035)	($0.00118)	10,042
Winter	688,975	4.01%	$0.00050	$0.01289	($0.00025)	($0.00085)	$ 8,125
Total kWh Charge	1,236,412						$ 18,166
Demand Charge (Total kW)							
Summer	1,245	0.00%	$ -	$ 10.82	($0.18)	($0.62)	$ 12,474
Winter	1,548	0.00%	$ -	$ 10.82	($0.18)	($0.62)	$ 15,513
Total KW Charge	2,793						$ 27,987
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ -
Total Distribution							$ 51,491
Percent Change							0.00%
BSA/Revenue Annualization							$ 64
Total Distribution including BSA/Revenue Annualization							$ 51,554
Proposed Total Dist. Revenue Increase/Decrease							**$ 64**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 51,554**
Percent Change							**0.12%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	
Present Customer Charge	**$ 89.41**
Proposed Customer Charge	**$ 89.41**

Demand Charge Rate Design

Present Demand Charge	**$ 10.82**
Proposed Demand Charge	**$ 10.82**

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Schedule General Service Primary Service - General Service ("GS 3A")

	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ -
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	0.00%
Customer Charge Recovery ($)	$ 5,337
Demand Charge Recovery ($)	$ 27,577
Volumetric Charge Recovery ($)	$ 18,640
Customer Charge Recovery (%)	10%
Demand Charge Recovery (%)	53%
Volumetric Charge Recovery (%)	36%

	(X)	(Y) = ($89.41 / T) -1 = [(AD-((AB+AC)*X))) - (T*X)] / (T*X) = ($10.82 / T) -1	(Z) = T * Y	(AA) = T + Z	(AB)	(AC)	(AD) = X * AA = ($18,640 / $18,166) * W = (AA+AB+AC) * X
				RY3			
Delivery Service	**2022 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	60	0.00%	$ -	$ 89.41			$ 5,337
Distribution							
Kilowatt-hour Charge							
Summer	539,363	3.82%	$0.00076	$0.02063	($0.00035)	($0.00118)	$ 10,303
Winter	678,921	3.77%	$0.00049	$0.01338	($0.00025)	($0.00085)	$ 8,336.50
Total kWh Charge	1,218,284						$ 18,640
Demand Charge (Total kW)							
Summer	1,227	0.00%	$ -	$ 10.82	($0.18)	($0.62)	$ 12,295
Winter	1,525	0.00%	$ -	$ 10.82	($0.18)	($0.62)	$ 15,282
Total KW Charge	2,752						$ 27,577
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ -
Total Distribution							$ 51,554
Percent Change							0.00%
BSA/Revenue Annualization							$ -
Total Distribution including BSA/Revenue Annualization							$ 51,554
Proposed Total Dist. Revenue Increase/Decrease							**$ -**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 51,554**
Percent Change							**0.00%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	
Present Customer Charge	**$ 89.41**
Proposed Customer Charge	**$ 89.41**

Demand Charge Rate Design

Present Demand Charge	**$ 10.82**
Proposed Demand Charge	**$ 10.82**

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Schedule Time Metered Medium General Service - Low Voltage ("MGT-LV")

	Current	RY1	RY2	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 22,348,516	$ 10,642,150	$ 9,577,935
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		17.30%	7.02%	5.89%
Customer Charge Recovery ($)		$ 9,240,035	$ 9,288,619	$ 9,292,411
Demand Charge Recovery ($)		$ 102,445,766	$ 108,493,147	$ 113,697,346
Volumetric Charge Recovery ($)		$ 39,857,431	$ 44,545,353	$ 49,074,865
Customer Charge Recovery (%)	14%	6%	6%	5%
Demand Charge Recovery (%)	66%	68%	67%	66%
Volumetric Charge Recovery (%)	21%	26%	27%	29%

Delivery Service	(A) Billing Determinants	(B) Current Rate	(C) 5 Year EDIT Credit	(D) 10 Year EDIT Credit	(E) = A * (B+C+D) Present Revenue	(F) Billing Determinant Adjustment No.	(G) = H - A Weather Normalization	(H) Weather Normalized Billing Determinants	(I) = H * (B+C+D) Weather Normalized Revenue
Monthly Customer Charge	38,952	$ 456.76			$ 17,791,716		-	38,952	$ 17,791,716
Distribution									
Kilowatt-hour Charge									
Summer	1,341,961,511	$ 0.00958	$ (0.00015)	$ (0.00051)	$ 11,970,297	17	(32,312,944)	1,309,648,566	$ 11,682,065
Winter	1,661,804,977	$ 0.00958	$ (0.00015)	$ (0.00051)	$ 14,823,300	18	(11,111,326)	1,650,693,651	$ 14,724,187
Total kWh Charge	3,003,766,488				$ 26,793,597		(43,424,270)	2,960,342,217	$ 26,406,253
Demand Charge (Total kW)									
Summer	3,402,217	$ 11.88	$ (0.19)	$ (0.64)	$ 37,594,502		-	3,402,217	$ 37,594,502
Winter	4,196,062	$ 11.88	$ (0.19)	$ (0.64)	$ 46,366,481		-	4,196,062	$ 46,366,481
Total KW Charge	7,598,279				$ 83,960,982		-	7,598,279	$ 83,960,982
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization									
Total Distribution					$ 128,546,295				$ 128,158,950
Percent Change									
BSA/Revenue Annualization					$ 648,421				
Total Distribution including BSA/Revenue Annualization					$ 129,194,716				
Proposed Total Dist. Revenue Increase/Decrease									
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Proposed Customer Charge									
Demand Charge Rate Design									
Present Demand Charge									
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)									
Calculated Demand Charge Increase									
Calculated Demand Charge									
Proposed Demand Charge									

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Schedule Time Metered Medium General Service - Low Voltage ("MGT-LV")

	RY1
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 22,348,516
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	17.30%
Customer Charge Recovery ($)	$ 9,240,035
Demand Charge Recovery ($)	$ 102,445,766
Volumetric Charge Recovery ($)	$ 39,857,431
Customer Charge Recovery (%)	6%
Demand Charge Recovery (%)	68%
Volumetric Charge Recovery (%)	26%

	(J)	(K) = ($237. / B) -1 = [(P-((N+O)*J))) - (B*J)] / (B*J) = ($15.17 / B) -1	(L) = B * K	(M) = B + L	(N)	(O)	(P) = J * M = ($39,857,431 / $26,406,253) * I = (M+N+O) * J
				RY1			
Delivery Service	**2020 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	38,988	-48.11%	$ (219.76)	$ 237.00			$ 9,240,035
Distribution							
Kilowatt-hour Charge							
Summer	1,245,474,880	54.67%	$0.00524	$ 0.01482	($0.00015)	($0.00051)	$ 17,632,836
Winter	1,569,141,226	54.73%	$0.00524	$ 0.01482	($0.00015)	($0.00051)	$ 22,224,596
Total kWh Charge	2,814,616,106						$ 39,857,431
Demand Charge (Total kW)							
Summer	3,170,165	27.69%	$ 3.29	$ 15.17	($0.19)	($0.64)	$ 45,460,169
Winter	3,973,891	27.69%	$ 3.29	$ 15.17	($0.19)	($0.64)	$ 56,985,597
Total KW Charge	7,144,056						$ 102,445,766
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 22,348,516
Total Distribution							$ 151,543,231
Percent Change							17.30%
BSA/Revenue Annualization							$ 141,737
Total Distribution including BSA/Revenue Annualization							$ 151,684,968
Proposed Total Dist. Revenue Increase/Decrease							**$ 22,490,252**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 151,684,968**
Percent Change							**17.41%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$ 237.00**	
Present Customer Charge	**$ 456.76**	
Proposed Customer Charge	**$ 237.00**	

Demand Charge Rate Design

Present Demand Charge	**$ 11.88**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)	105%	= [$22,348,516 - ($9,240,035 - $17,791,716)] * ($83,960,982 / ($83,960,982 + $26,406,253)) / $22,348,516
Calculated Demand Charge Increase	$ 3.29	= (105.18% * $22,348,516) / 7,144,056
Calculated Demand Charge	$ 15.17	
Proposed Demand Charge	**$ 15.17**	

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Schedule Time Metered Medium General Service - Low Voltage ("MGT-LV")

	RY2
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 10,642,150
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	7.02%
Customer Charge Recovery ($)	$ 9,288,619
Demand Charge Recovery ($)	$ 108,493,147
Volumetric Charge Recovery ($)	$ 44,545,353
Customer Charge Recovery (%)	6%
Demand Charge Recovery (%)	67%
Volumetric Charge Recovery (%)	27%

	(Q)	(R) = ($237. / M) -1 = [(W-((U+V)*Q))) - (M*Q)] / (M*Q) = ($16.26 / M) -1	(S) = M * R	(T) = M + S	(U)	(V)	(W) = Q * T = ($44,545,353 / $39,857,431) * P = (T+U+V) * Q
				RY2			
Delivery Service	**2021 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	39,193	0.00%	$ -	$ 237.00			$ 9,288,619
Distribution							
Kilowatt-hour Charge							
Summer	1,224,739,138	13.05%	$0.00193	$ 0.01675	($0.00015)	($0.00051)	$ 19,706,761
Winter	1,545,390,251	12.88%	$0.00191	$ 0.01673	($0.00015)	($0.00051)	$ 24,838,591
Total kWh Charge	2,770,129,389						$ 44,545,353
Demand Charge (Total kW)							
Summer	3,117,621	7.19%	$ 1.09	$ 16.26	($0.19)	($0.64)	$ 48,104,884
Winter	3,913,692	7.19%	$ 1.09	$ 16.26	($0.19)	($0.64)	$ 60,388,262
Total KW Charge	7,031,312						$ 108,493,147
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 10,642,150
Total Distribution							$ 162,327,118
Percent Change							7.02%
BSA/Revenue Annualization							$ 159,568
Total Distribution including BSA/Revenue Annualization							$ 162,486,687
Proposed Total Dist. Revenue Increase/Decrease							**$ 10,801,719**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 162,486,687**
Percent Change							**7.12%**

Customer Charge Rate Design

Full Customer Cost from CCOSS		
Present Customer Charge	**$ 237.00**	
Proposed Customer Charge	**$ 237.00**	

Demand Charge Rate Design

Present Demand Charge	**$ 15.17**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)	72%	= [$10,642,150 - ($9,288,619 - $9,240,035)] * ($102,445,766 / ($102,445,766 + $39,857,431)) / $10,642,150
Calculated Demand Charge Increase	$ 1.09	= (71.99% * $10,642,150) / 7,031,312
Calculated Demand Charge	$ 16.26	
Proposed Demand Charge	**$ 16.26**	

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Schedule Time Metered Medium General Service - Low Voltage ("MGT-LV")

	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 9,577,935
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	5.89%
Customer Charge Recovery ($)	$ 9,292,411
Demand Charge Recovery ($)	$ 113,697,346
Volumetric Charge Recovery ($)	$ 49,074,865
Customer Charge Recovery (%)	5%
Demand Charge Recovery (%)	66%
Volumetric Charge Recovery (%)	29%

	(X)	(Y) = ($237. / T) -1 = [(AD-((AB+AC)*X))) - (T*X)] / (T*X) = ($17.24 / T) -1	(Z) = T * Y	(AA) = T + Z	(AB)	(AC)	(AD) = X * AA = ($49,074,865 / $44,545,353) * W = (AA+AB+AC) * X
				RY3			
Delivery Service	**2022 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	39,209	0.00%	$ -	$ 237.00			$ 9,292,411
Distribution							
Kilowatt-hour Charge							
Summer	1,206,644,345	11.35%	$0.00190	$ 0.01865	($0.00015)	($0.00051)	$ 21,710,607
Winter	1,522,813,683	11.34%	$0.00190	$ 0.01863	($0.00015)	($0.00051)	$ 27,364,258
Total kWh Charge	2,729,458,028						$ 49,074,865
Demand Charge (Total kW)							
Summer	3,072,018	6.03%	$ 0.98	$ 17.24	($0.19)	($0.64)	$ 50,411,822
Winter	3,856,522	6.03%	$ 0.98	$ 17.24	($0.19)	($0.64)	$ 63,285,524
Total KW Charge	6,928,540						$ 113,697,346
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 9,577,935
Total Distribution							$ 172,064,622
Percent Change							5.89%
BSA/Revenue Annualization							$ -
Total Distribution including BSA/Revenue Annualization							$ 172,064,622
Proposed Total Dist. Revenue Increase/Decrease							**$ 9,577,935**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 172,064,622**
Percent Change							**5.89%**

Customer Charge Rate Design

Full Customer Cost from CCOSS		
Present Customer Charge	**$ 237.00**	
Proposed Customer Charge	**$ 237.00**	

Demand Charge Rate Design

Present Demand Charge	**$ 16.26**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)	71%	= [$9,577,935 - ($9,292,411 - $9,288,619)] * ($108,493,147 / ($108,493,147 + $44,545,353)) / $9,577,935
Calculated Demand Charge Increase	$ 0.98	= (70.89% * $9,577,935) / 6,928,540
Calculated Demand Charge	$ 17.24	
Proposed Demand Charge	**$ 17.24**	

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Schedule Time Metered General Service Low Voltage - General Service ("GT-LV")

	Current	RY1	RY2	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 12,636,677	$ 6,017,465	$ 5,415,719
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		17.30%	7.02%	5.89%
Customer Charge Recovery ($)		$ 3,110,568	$ 4,743,394	$ 6,356,493
Demand Charge Recovery ($)		$ 57,260,976	$ 59,405,183	$ 61,113,237
Volumetric Charge Recovery ($)		$ 25,316,600	$ 27,637,176	$ 29,821,967
Customer Charge Recovery (%)	2%	4%	5%	7%
Demand Charge Recovery (%)	74%	67%	65%	63%
Volumetric Charge Recovery (%)	24%	30%	30%	31%

Delivery Service	(A) Billing Determinants	(B) Current Rate	(C) 5 Year EDIT Credit	(D) 10 Year EDIT Credit	(E) = A * (B+C+D) Present Revenue	(F) Billing Determinant Adjustment No.	(G) = H - A Weather Normalization	(H) Weather Normalized Billing Determinants	(I) = H * (B+C+D) Weather Normalized Revenue
Monthly Customer Charge	3,300	$ 456.76			$ 1,507,308		-	3,300	$ 1,507,308
Distribution									
Kilowatt-hour Charge									
Summer	807,006,951	$ 0.00958	$ (0.00015)	$ (0.00051)	$ 7,198,502	19	(19,462,726)	787,544,226	$ 7,024,894
Winter	1,064,884,594	$ 0.00958	$ (0.00015)	$ (0.00051)	$ 9,498,771	20	(7,180,183)	1,057,704,411	$ 9,434,723
Total kWh Charge	1,871,891,545				$ 16,697,273		(26,642,909)	1,845,248,637	$ 16,459,618
Demand Charge (Total kW)									
Summer	2,034,014	$ 11.88	$ (0.19)	$ (0.64)	$ 22,475,851		-	2,034,014	$ 22,475,851
Winter	2,656,134	$ 11.88	$ (0.19)	$ (0.64)	$ 29,350,285		-	2,656,134	$ 29,350,285
Total KW Charge	4,690,148				$ 51,826,136		-	4,690,148	$ 51,826,136
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization									
Total Distribution					$ 70,030,717				$ 69,793,062
Percent Change									
BSA/Revenue Annualization					$ 3,020,751				
Total Distribution including BSA/Revenue Annualization					$ 73,051,468				
Proposed Total Dist. Revenue Increase/Decrease									
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Target Movement Toward Full Cost (%)									
Target Movement Toward Full Cost ($)									
Change to Present based on Target Movement Toward Full Cost									
Proposed Customer Charge									
Demand Charge Rate Design									
Present Demand Charge									
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)									
Calculated Demand Charge Increase									
Calculated Demand Charge									
Proposed Demand Charge									

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Schedule Time Metered General Service Low Voltage - General Service ("GT-LV")

	RY1
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 12,636,677
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	17.30%
Customer Charge Recovery ($)	$ 3,110,568
Demand Charge Recovery ($)	$ 57,260,976
Volumetric Charge Recovery ($)	$ 25,316,600
Customer Charge Recovery (%)	4%
Demand Charge Recovery (%)	67%
Volumetric Charge Recovery (%)	30%

	(J)	(K) = ($940.6 / B) -1 = [(P-((N+O)*J))) - (B*J)] / (B*J) = ($13.77 / B) -1	(L) = B * K	(M) = B + L	(N)	(O)	(P) = J * M = ($25,316,600 / $16,459,618) * I = (M+N+O) * J
				RY1			
Delivery Service	**2020 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	3,307	105.93%	$ 483.84	$ 940.60			$ 3,110,568
Distribution							
Kilowatt-hour Charge							
Summer	781,415,497	51.23%	$0.00491	$ 0.01449	($0.00015)	($0.00051)	$ 10,805,016
Winter	977,856,938	61.80%	$0.00592	$ 0.01550	($0.00015)	($0.00051)	$ 14,511,583
Total kWh Charge	1,759,272,435						$ 25,316,600
Demand Charge (Total kW)							
Summer	1,983,972	15.91%	$ 1.89	$ 13.77	($0.19)	($0.64)	$ 25,672,602
Winter	2,441,142	15.91%	$ 1.89	$ 13.77	($0.19)	($0.64)	$ 31,588,375
Total KW Charge	4,425,114						$ 57,260,976
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 12,636,677
Total Distribution							$ 85,688,144
Percent Change							17.30%
BSA/Revenue Annualization							$ 80,143
Total Distribution including BSA/Revenue Annualization							$ 85,768,288
Proposed Total Dist. Revenue Increase/Decrease							**$ 12,716,820**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 85,768,288**
Percent Change							**17.41%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$ 3,816.50**	
Present Customer Charge	**$ 456.76**	
Target Movement Toward Full Cost (%)	14%	
Target Movement Toward Full Cost ($)	$ 483.84	= 14.4% * ($3816.5 - $456.76)
Change to Present based on Target Movement Toward Full Cost	$ 940.60	
Proposed Customer Charge	**$ 940.60**	

Demand Charge Rate Design

Present Demand Charge	**$ 11.88**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)	66%	= [$12,636,677 - ($3,110,568 - $1,507,308)] * ($51,826,136 / ($51,826,136 + $16,459,618)) / $12,636,677
Calculated Demand Charge Increase	$ 1.89	= (66.27% * $12,636,677) / 4,425,114
Calculated Demand Charge	$ 13.77	
Proposed Demand Charge	**$ 13.77**	

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Schedule Time Metered General Service Low Voltage - General Service ("GT-LV")

	RY2
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 6,017,465
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	7.02%
Customer Charge Recovery ($)	$ 4,743,394
Demand Charge Recovery ($)	$ 59,405,183
Volumetric Charge Recovery ($)	$ 27,637,176
Customer Charge Recovery (%)	5%
Demand Charge Recovery (%)	65%
Volumetric Charge Recovery (%)	30%

	(Q)	(R) = ($1424.44 / M) -1 = [(W-((U+V)*Q))) - (M*Q)] / (M*Q) = ($14.47 / M) -1	(S) = M * R	(T) = M + S	(U)	(V)	(W) = Q * T = ($27,637,176 / $25,316,600) * P = (T+U+V) * Q
				RY2			
Delivery Service	**2021 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	3,330	51.44%	$ 483.84	$ 1,424.44			$ 4,743,394
Distribution							
Kilowatt-hour Charge							
Summer	768,410,423	10.51%	$0.00152	$ 0.01601	($0.00015)	($0.00051)	$ 11,795,428
Winter	963,078,034	10.38%	$0.00161	$ 0.01711	($0.00015)	($0.00051)	$ 15,841,747
Total kWh Charge	1,731,488,458						$ 27,637,176
Demand Charge (Total kW)							
Summer	1,951,130	5.08%	$ 0.70	$ 14.47	($0.19)	($0.64)	$ 26,613,415
Winter	2,404,089	5.08%	$ 0.70	$ 14.47	($0.19)	($0.64)	$ 32,791,769
Total KW Charge	4,355,219						$ 59,405,183
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 6,017,465
Total Distribution							$ 91,785,753
Percent Change							7.02%
BSA/Revenue Annualization							$ 90,226
Total Distribution including BSA/Revenue Annualization							$ 91,875,979
Proposed Total Dist. Revenue Increase/Decrease							**$ 6,107,691**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 91,875,979**
Percent Change							**7.12%**

Customer Charge Rate Design

Full Customer Cost from CCOSS		
Present Customer Charge	**$ 940.60**	
Target Movement Toward Full Cost (%)		
Target Movement Toward Full Cost ($)	$ 483.84	
Change to Present based on Target Movement Toward Full Cost	$ 1,424.44	
Proposed Customer Charge	**$ 1,424.44**	

Demand Charge Rate Design

Present Demand Charge	**$ 13.77**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)	51%	= [$6,017,465 - ($4,743,394 - $3,110,568)] * ($57,260,976 / ($57,260,976 + $25,316,600)) / $6,017,465
Calculated Demand Charge Increase	$ 0.70	= (50.53% * $6,017,465) / 4,355,219
Calculated Demand Charge	$ 14.47	
Proposed Demand Charge	**$ 14.47**	

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Schedule Time Metered General Service Low Voltage - General Service ("GT-LV")

	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 5,415,719
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	5.89%
Customer Charge Recovery ($)	$ 6,356,493
Demand Charge Recovery ($)	$ 61,113,237
Volumetric Charge Recovery ($)	$ 29,821,967
Customer Charge Recovery (%)	7%
Demand Charge Recovery (%)	63%
Volumetric Charge Recovery (%)	31%

	(X)	(Y) = ($1908.28 / T) -1 = [(AD-((AB+AC)*X))) - (T*X)] / (T*X) = ($15.07 / T) -1	(Z) = T * Y	(AA) = T + Z	(AB)	(AC)	(AD) = X * AA = ($29,821,967 / $27,637,176) * W = (AA+AB+AC) * X
				RY3			
Delivery Service	**2022 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	3,331	33.97%	$ 483.84	$ 1,908.28			$ 6,356,493
Distribution							
Kilowatt-hour Charge							
Summer	757,108,340	9.12%	$0.00146	$ 0.01747	($0.00015)	($0.00051)	$ 12,727,888
Winter	949,049,922	9.13%	$0.00156	$ 0.01867	($0.00015)	($0.00051)	$ 17,094,079
Total kWh Charge	1,706,158,263						$ 29,821,967
Demand Charge (Total kW)							
Summer	1,922,744	4.15%	$ 0.60	$ 15.07	($0.19)	($0.64)	$ 27,379,876
Winter	2,368,916	4.15%	$ 0.60	$ 15.07	($0.19)	($0.64)	$ 33,733,361
Total KW Charge	4,291,660						$ 61,113,237
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 5,415,719
Total Distribution							$ 97,291,697
Percent Change							5.89%
BSA/Revenue Annualization							$ -
Total Distribution including BSA/Revenue Annualization							$ 97,291,697
Proposed Total Dist. Revenue Increase/Decrease							**$ 5,415,719**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 97,291,697**
Percent Change							**5.89%**

Customer Charge Rate Design

Full Customer Cost from CCOSS		
Present Customer Charge	**$ 1,424.44**	
Target Movement Toward Full Cost (%)		
Target Movement Toward Full Cost ($)	$ 483.84	
Change to Present based on Target Movement Toward Full Cost	$ 1,908.28	
Proposed Customer Charge	**$ 1,908.28**	

Demand Charge Rate Design

Present Demand Charge	**$ 14.47**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)	48%	= [$5,415,719 - ($6,356,493 - $4,743,394)] * ($59,405,183 / ($59,405,183 + $27,637,176)) / $5,415,719
Calculated Demand Charge Increase	$ 0.60	= (47.92% * $5,415,719) / 4,291,660
Calculated Demand Charge	$ 15.07	
Proposed Demand Charge	**$ 15.07**	

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Schedule Time Metered General Service - High Voltage ("GT-3B")	**Current**	**RY1**	**RY2**	**RY3**
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 71,586	$ 34,088	$ 30,680
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		17.09%	6.94%	5.84%
Customer Charge Recovery ($)		$ 3,717	$ 3,721	$ 3,725
Demand Charge Recovery ($)		$ 486,824	$ 521,364	$ 552,556
Customer Charge Recovery (%)	1%	1%	1%	1%
Demand Charge Recovery (%)	99%	99%	99%	99%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)	(G) = H - A	(H)	(I) = H * (B+C+D)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**	**Weather Normalization**	**Weather Normalized Billing Determinants**	**Weather Normalized Revenue**
Monthly Customer Charge	12	$ 423.38			$ 5,081		-	12	$ 5,081
Demand Charge (Total kW)									
Summer	170,489	$ 1.79	$ (0.14)	$ (0.47)	$ 201,177		-	170,489	$ 201,177
Winter	216,073	$ 1.92	$ (0.15)	$ (0.51)	$ 272,252		-	216,073	$ 272,252
Total KW Charge	386,562				$ 473,429		-	386,562	$ 473,429
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization									
Total Distribution					$ 478,510				$ 478,510
Percent Change									
BSA/Revenue Annualization					$ (59,554)				
Total Distribution including BSA/Revenue Annualization					$ 418,956				
Proposed Total Dist. Revenue Increase/Decrease									
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Proposed Customer Charge									

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Schedule Time Metered General Service - High Voltage ("GT-3B")	**RY1**
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 71,586
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	17.09%
Customer Charge Recovery ($)	$ 3,717
Demand Charge Recovery ($)	$ 486,824
Customer Charge Recovery (%)	1%
Demand Charge Recovery (%)	99%

	(J)	(K) = ($311.66 / B) -1 = [(P-((N+O)*J))) - (B*J)] / (B*J)	(L) = B * K	(M) = B + L	(N)	(O)	(P) = J * (M + N + O)
				RY1			
Delivery Service	**2020 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	12	-26.39%	$ (111.72)	$ 311.66			$ 3,717
Demand Charge (Total kW)							
Summer	168,488	2.67%	$0.04779	$ 1.84	$ (0.14)	$ (0.47)	$ 206,869
Winter	178,072	16.26%	$0.31215	$ 2.23	$ (0.15)	$ (0.51)	$ 279,955
Total KW Charge	346,560						$ 486,824
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 71,586
Total Distribution							$ 490,541
Percent Change							17.09%
BSA/Revenue Annualization							$ 455
Total Distribution including BSA/Revenue Annualization							$ 490,996
Proposed Total Dist. Revenue Increase/Decrease							**$ 72,041**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 490,996**
Percent Change							**17.20%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$ 311.66**
Present Customer Charge	**$ 423.38**
Proposed Customer Charge	**$ 311.66**

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Schedule Time Metered General Service - High Voltage ("GT-3B")	**RY2**
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 34,088
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	6.94%
Customer Charge Recovery ($)	$ 3,721
Demand Charge Recovery ($)	$ 521,364
Customer Charge Recovery (%)	1%
Demand Charge Recovery (%)	99%

	(Q)	(R) = ($311.66 / M) -1 = [(W-((U+V)*Q))) - (M*Q)] / (M*Q)	(S) = M * R	(T) = M + S	(U)	(V)	(W) = Q * (T+U+V)
				RY2			
Delivery Service	**2021 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	12	0.00%	$ -	$ 311.66			$ 3,721
Demand Charge (Total kW)							
Summer	165,664	5.96%	$0.10953	$ 1.95	$ (0.14)	$ (0.47)	$ 221,546
Winter	175,191	6.24%	$0.13922	$ 2.37	$ (0.15)	$ (0.51)	$ 299,818
Total KW Charge	340,855						$ 521,364
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 34,088
Total Distribution							$ 525,085
Percent Change							6.94%
BSA/Revenue Annualization							$ 517
Total Distribution including BSA/Revenue Annualization							$ 525,602
Proposed Total Dist. Revenue Increase/Decrease							**$ 34,605**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 525,602**
Percent Change							**7.05%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	
Present Customer Charge	**$ 311.66**
Proposed Customer Charge	**$ 311.66**

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Schedule Time Metered General Service - High Voltage ("GT-3B")	**RY3**
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 30,680
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	5.84%
Customer Charge Recovery ($)	$ 3,725
Demand Charge Recovery ($)	$ 552,556
Customer Charge Recovery (%)	1%
Demand Charge Recovery (%)	99%

	(X)	(Y) = ($311.66 / T) -1 = [(AD-((AB+AC)*X))) - (T*X)] / (T*X)	(Z) = T * Y	(AA) = T + Z	(AB)	(AC)	(AD) = X * (AA+AB+AC)
	RY3						
Delivery Service	**2022 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	12	0.00%	$ -	$ 311.66			$ 3,725
Demand Charge (Total kW)							
Summer	163,222	5.20%	$0.10121	$ 2.05	$ (0.14)	$ (0.47)	$ 234,801
Winter	172,366	5.57%	$0.13212	$ 2.50	$ (0.15)	$ (0.51)	$ 317,755
Total KW Charge	335,588						$ 552,556
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 30,680
Total Distribution							$ 556,281
Percent Change							5.84%
BSA/Revenue Annualization							$ -
Total Distribution including BSA/Revenue Annualization							$ 556,281
Proposed Total Dist. Revenue Increase/Decrease							**$ 30,680**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 556,281**
Percent Change							**5.84%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	
Present Customer Charge	**$ 311.66**
Proposed Customer Charge	**$ 311.66**

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Schedule Time Metered General Service - Primary Service ("GT 3A")

	Current	RY1	RY2	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 8,827,768	$ 4,203,699	$ 3,783,329
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		17.09%	6.94%	5.84%
Customer Charge Recovery ($)		$ 367,408	$ 367,809	$ 368,262
Demand Charge Recovery ($)		$ 48,838,745	$ 51,499,037	$ 53,784,044
Volumetric Charge Recovery ($)		$ 11,270,284	$ 12,869,836	$ 14,431,278
Customer Charge Recovery (%)	1%	1%	1%	1%
Demand Charge Recovery (%)	80%	81%	80%	78%
Volumetric Charge Recovery (%)	19%	19%	20%	21%

Delivery Service	(A) Billing Determinants	(B) Current Rate	(C) 5 Year EDIT Credit	(D) 10 Year EDIT Credit	(E) = A * (B+C+D) Present Revenue	(F) Billing Determinant Adjustment No.	(G) = H - A Weather Normalization	(H) Weather Normalized Billing Determinants	(I) = H * (B+C+D) Weather Normalized Revenue
Monthly Customer Charge	1,867	$ 187.64			$ 350,324		-	1,867	$ 350,324
Distribution									
Kilowatt-hour Charge									
Summer	1,102,431,669	$ 0.00454	$ (0.00007)	$ (0.00024)	$ 4,663,286	21	(26,326,034)	1,076,105,635	$ 4,551,927
Winter	1,244,208,828	$ 0.00453	$ (0.00007)	$ (0.00024)	$ 5,250,561	22	-	1,244,208,828	$ 5,250,561
Total kWh Charge	2,346,640,497				$ 9,913,847		(26,326,034)	2,320,314,463	$ 9,802,488
Demand Charge (Total kW)									
Summer	2,335,482	$ 8.86	$ (0.14)	$ (0.47)	$ 19,267,727		-	2,335,482	$ 19,267,727
Winter	2,644,583	$ 8.86	$ (0.14)	$ (0.47)	$ 21,817,810		-	2,644,583	$ 21,817,810
Total KW Charge	4,980,065				$ 41,085,536		-	4,980,065	$ 41,085,536
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization									
Total Distribution					$ 51,349,707				$ 51,238,348
Percent Change									
BSA/Revenue Annualization					$ 298,961				
Total Distribution including BSA/Revenue Annualization					$ 51,648,669				
Proposed Total Dist. Revenue Increase/Decrease									
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Proposed Customer Charge									
Demand Charge Rate Design									
Present Demand Charge									
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)									
Calculated Demand Charge Increase									
Calculated Demand Charge									
Proposed Demand Charge									

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Schedule Time Metered General Service - Primary Service ("GT 3A")

	RY1
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 8,827,768
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	17.09%
Customer Charge Recovery ($)	$ 367,408
Demand Charge Recovery ($)	$ 48,838,745
Volumetric Charge Recovery ($)	$ 11,270,284
Customer Charge Recovery (%)	1%
Demand Charge Recovery (%)	81%
Volumetric Charge Recovery (%)	19%

	(J)	(K) = ($197.49 / B) -1 = [(P-((N+O)*J))) - (B*J)] / (B*J) = ($10.27 / B) -1	(L) = B * K	(M) = B + L	(N)	(O)	(P) = J * M = ($11,270,284 / $9,802,488) * I = (M+N+O) * J
				RY1			
Delivery Service	**2020 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	1,860	5.25%	$ 9.85	$ 197.49			$ 367,408
Distribution							
Kilowatt-hour Charge							
Summer	1,056,842,969	15.90%	$0.00072	$ 0.00526	($0.00007)	($0.00024)	$ 5,233,519
Winter	1,328,032,898	7.19%	$0.00033	$ 0.00486	($0.00007)	($0.00024)	$ 6,036,765
Total kWh Charge	2,384,875,867						$ 11,270,284
Demand Charge (Total kW)							
Summer	2,241,350	15.91%	$ 1.41	$ 10.27	($0.14)	($0.47)	$ 21,651,437
Winter	2,814,421	15.91%	$ 1.41	$ 10.27	($0.14)	($0.47)	$ 27,187,308
Total KW Charge	5,055,771						$ 48,838,745
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 8,827,768
Total Distribution							$ 60,476,437
Percent Change							17.09%
BSA/Revenue Annualization							$ 56,546
Total Distribution including BSA/Revenue Annualization							$ 60,532,983
Proposed Total Dist. Revenue Increase/Decrease							**$ 8,884,314**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 60,532,983**
Percent Change							**17.20%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$ 197.49**	
Present Customer Charge	**$ 187.64**	
Proposed Customer Charge	**$ 197.49**	

Demand Charge Rate Design

Present Demand Charge	**$ 8.86**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)	81%	= [$8,827,768 - ($367,408 - $350,324)] * ($41,085,536 / ($41,085,536 + $9,802,488)) / $8,827,768
Calculated Demand Charge Increase	$ 1.41	= (80.58% * $8,827,768) / 5,055,771
Calculated Demand Charge	$ 10.27	
Proposed Demand Charge	**$ 10.27**	

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Schedule Time Metered General Service - Primary Service ("GT 3A")

	RY2
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 4,203,699
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	6.94%
Customer Charge Recovery ($)	$ 367,809
Demand Charge Recovery ($)	$ 51,499,037
Volumetric Charge Recovery ($)	$ 12,869,836
Customer Charge Recovery (%)	1%
Demand Charge Recovery (%)	80%
Volumetric Charge Recovery (%)	20%

	(Q)	(R) = ($197.49 / M) -1 = [(W-((U+V)*Q))) - (M*Q)] / (M*Q) = ($10.96 / M) -1	(S) = M * R	(T) = M + S	(U)	(V)	(W) = Q * T = ($12,869,836 / $11,270,284) * P = (T+U+V) * Q
				RY2			
Delivery Service	**2021 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	1,862	0.00%	$ -	$ 197.49			$ 367,809
Distribution							
Kilowatt-hour Charge							
Summer	1,039,250,136	15.18%	$0.00080	$ 0.00606	($0.00007)	($0.00024)	$ 5,976,294
Winter	1,307,942,995	14.93%	$0.00072	$ 0.00558	($0.00007)	($0.00024)	$ 6,893,542
Total kWh Charge	2,347,193,131						$ 12,869,836
Demand Charge (Total kW)							
Summer	2,203,935	6.72%	$ 0.69	$ 10.96	($0.14)	($0.47)	$ 22,810,727
Winter	2,771,817	6.72%	$ 0.69	$ 10.96	($0.14)	($0.47)	$ 28,688,310
Total KW Charge	4,975,752						$ 51,499,037
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 4,203,699
Total Distribution							$ 64,736,681
Percent Change							6.94%
BSA/Revenue Annualization							$ 63,573
Total Distribution including BSA/Revenue Annualization							$ 64,800,254
Proposed Total Dist. Revenue Increase/Decrease							**$ 4,267,272**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 64,800,254**
Percent Change							**7.05%**

Customer Charge Rate Design

Full Customer Cost from CCOSS		
Present Customer Charge	**$ 197.49**	
Proposed Customer Charge	**$ 197.49**	

Demand Charge Rate Design

Present Demand Charge	**$ 10.27**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)	81%	= [$4,203,699 - ($367,809 - $367,408)] * ($48,838,745 / ($48,838,745 + $11,270,284)) / $4,203,699
Calculated Demand Charge Increase	$ 0.69	= (81.25% * $4,203,699) / 4,975,752
Calculated Demand Charge	$ 10.96	
Proposed Demand Charge	**$ 10.96**	

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Schedule Time Metered General Service - Primary Service ("GT 3A")

		RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$	3,783,329
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		5.84%
Customer Charge Recovery ($)	$	368,262
Demand Charge Recovery ($)	$	53,784,044
Volumetric Charge Recovery ($)	$	14,431,278
Customer Charge Recovery (%)		1%
Demand Charge Recovery (%)		78%
Volumetric Charge Recovery (%)		21%

	(X)	(Y) = ($197.49 / T) -1 = [(AD-((AB+AC)*X))) - (T*X)] / (T*X) = ($11.58 / T) -1	(Z) = T * Y	(AA) = T + Z	(AB)	(AC)	(AD) = X * AA = ($14,431,278 / $12,869,836) * W = (AA+AB+AC) * X
				RY3			
Delivery Service	**2022 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	1,865	0.00%	$ -	$ 197.49			$ 368,262
Distribution							
Kilowatt-hour Charge							
Summer	1,023,922,281	13.10%	$0.00079	$ 0.00685	($0.00007)	($0.00024)	$ 6,701,372
Winter	1,288,856,912	13.03%	$0.00073	$ 0.00631	($0.00007)	($0.00024)	$ 7,729,906
Total kWh Charge	2,312,779,193						$ 14,431,278
Demand Charge (Total kW)							
Summer	2,171,412	5.66%	$ 0.62	$ 11.58	($0.14)	($0.47)	$ 23,820,386
Winter	2,731,418	5.66%	$ 0.62	$ 11.58	($0.14)	($0.47)	$ 29,963,657
Total KW Charge	4,902,830						$ 53,784,044
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 3,783,329
Total Distribution							$ 68,583,583
Percent Change							5.84%
BSA/Revenue Annualization							$ -
Total Distribution including BSA/Revenue Annualization							$ 68,583,583
Proposed Total Dist. Revenue Increase/Decrease							**$ 3,783,329**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 68,583,583**
Percent Change							**5.84%**

Customer Charge Rate Design

Full Customer Cost from CCOSS		
Present Customer Charge	**$**	**197.49**
Proposed Customer Charge	**$**	**197.49**

Demand Charge Rate Design

Present Demand Charge	**$**	**10.96**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)		80%	= [$3,783,329 - ($368,262 - $367,809)] * ($51,499,037 / ($51,499,037 + $12,869,836)) / $3,783,329
Calculated Demand Charge Increase	$	0.62	= (80.01% * $3,783,329) / 4,902,830
Calculated Demand Charge	$	11.58	
Proposed Demand Charge	**$**	**11.58**	

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Schedule- Rapid Transit Service ("RT")

	Current	RY1	RY2	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 1,148,792	$ 547,044	$ 492,339
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		17.05%	6.94%	5.84%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Annualized Authorized Revenue**
Monthly Customer Charge	1,164	$ 6,216.22	$ (96.57)	$ (329.83)	$ 6,739,350	$ 6,739,350
Total Distribution					$ 6,739,350	$ 6,739,350
BSA/Revenue Annualization						$ (5)
Total Distribution including BSA/Revenue Annualization						$ 6,739,346
Proposed Total Dist. Revenue Increase/Decrease						
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization						
Percent Change						

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Schedule- Rapid Transit Service ("RT")

	RY1
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 1,148,792
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	17.05%

	(G)	(H)	(I)	(J)	(K)	(L)	(M)
		= I / B	= J - B	= [M - ((K+L)*G))] / G			= $7,888,138
	RY1						
Delivery Service	**2020 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	1,164	15.88%	$ 986.93	$ 7,203.15	$ (96.57)	$ (329.83)	$ 7,888,138
Total Distribution							$ 7,888,138
BSA/Revenue Annualization							
Total Distribution including BSA/Revenue Annualization							
Proposed Total Dist. Revenue Increase/Decrease							**$ 1,148,792**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 7,888,138**
Percent Change							**17.05%**

Pepco - District of Columbia
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Schedule- Rapid Transit Service ("RT")

	RY2
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 547,044
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	6.94%

	(N)	(O)	(P)	(Q)	(R)	(S)	(T)
		= P / J	= Q - J	= [T - ((R+S)*N))] / N			= $8,435,182
	RY2						
Delivery Service	**2021 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	1,164	6.52%	$ 469.97	$ 7,673.12	$ (96.57)	$ (329.83)	$ 8,435,182
Total Distribution							$ 8,435,182
BSA/Revenue Annualization							
Total Distribution including BSA/Revenue Annualization							
Proposed Total Dist. Revenue Increase/Decrease							**$ 547,044**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 8,435,182**
Percent Change							**6.94%**

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Schedule- Rapid Transit Service ("RT")

	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 492,339
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	5.84%

	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
		= W / Q	= X - Q	= [AA - ((Y+Z)*U))] / U			= $8,927,521
	RY3						
Delivery Service	**2022 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	1,164	5.51%	$ 422.97	$ 8,096.09	$ (96.57)	$ (329.83)	$ 8,927,521
Total Distribution							$ 8,927,521
BSA/Revenue Annualization							
Total Distribution including BSA/Revenue Annualization							
Proposed Total Dist. Revenue Increase/Decrease							**$ 492,339**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 8,927,521**
Percent Change							**5.84%**

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Servicing Street Lights -Schedules ("SSL-OH") & ("SSL-UG")

	Current	RY1	RY2	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 180,682	$ 86,039	$ 77,435
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		28.63%	10.60%	8.63%

	(A)	(B)	(C)	(D) = A * B	(E) = A * C	(F)	(G)	(H) = A *(B+C+F+G)
	Billing Determinants	CURRENT RATE FIXED	CURRENT RATE O & M	ANNUALIZED REVENUE FIXED	ANNUALIZED REVENUE O & M	5 Year EDIT Credit	10 Year EDIT Credit	TOTAL REVENUE
OVERHEAD								
INCANDESCENT								
Without GLOBE	144	$ 2.492	$ 0.039	$ 359	$ 6	$ (0.189)	$ (0.646)	$ 244
With GLOBE	12	$ 3.639	$ 0.860	$ 43.668	$ 10.320	$ (0.189)	$ (0.646)	$ 44
TOTAL INCANDESCENT	156							$ 288
MERCURY VAPOR								
175 WATT	0	$ 7.756	$ 0.767	$ -	$ -	$ (0.189)	$ (0.646)	$ -
250 WATT	0	$ 8.861	$ 0.777	$ -	$ -	$ (0.189)	$ (0.646)	$ -
TOTAL MERCURY VAPOR	0							$ -
METAL HALIDE								
400 WATT	12	$ 29.990	$ 1.253	$ 359.880	$ 15.036	$ (0.189)	$ (0.646)	$ 365
TOTAL METAL HALIDE	12							$ 365
TOTAL OVERHEAD	168							$ 653
UNDERGROUND								
INCANDESCENT								
With GLOBE	2,076	$ 34.870	$ 1.576	$ 72,390.120	$ 3,271.776	$ (0.189)	$ (0.646)	$ 73,928
TOTAL INCANDESCENT	2,076							$ 73,928
MERCURY VAPOR								
250 WATT	2,796	$ 35.171	$ 1.416	$ 98,338.116	$ 3,959.136	$ (0.189)	$ (0.646)	$ 99,963
400 WATT	336	$ 41.242	$ 1.759	$ 13,857.312	$ 591.024	$ (0.189)	$ (0.646)	$ 14,168
TOTAL MERCURY VAPOR	3,132							$ 114,130
HIGH PRESSURE SODIUM								
150 WATT	0	$ 30.843	$ 1.155	$ -	$ -	$ (0.189)	$ (0.646)	$ -
TOTAL HIGH PRESURE SODIUM	0							$ -
METAL HALIDE								
100 WATT	2,772	$ 26.578	$ 1.039	$ 73,674.216	$ 2,880.108	$ (0.189)	$ (0.646)	$ 74,240
175 WATT	12,504	$ 29.990	$ 1.253	$ 374,994.960	$ 15,667.512	$ (0.189)	$ (0.646)	$ 380,222
400 WATT	0	$ 29.990	$ 1.253	$ -	$ -	$ (0.189)	$ (0.646)	$ -
TOTAL METAL HALIDE	15,276							$ 454,461
TOTAL UNDERGROUND	20,484							$ 642,520
TOTAL OH & UG	**20,652**							**$ 643,173**

Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization	
Total Distribution	$ 643,173
Percent Change	
BSA/Revenue Annualization	$ (12,151)
Total Distribution including BSA/Revenue Annualization	**$ 631,022**
Proposed Total Dist. Revenue Increase/Decrease	
Rate Change	
Rate Component Change (%)	

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Servicing Street Lights -Schedules ("SSL-OH") & ("SSL-UG")

	Current	RY1
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 180,682
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		28.63%

	(A)	(I) = B * 125.52%	(J) = C * 125.52%	(K)	(L)	(M) = A *(I+J+K+L)
		RY1				
	Billing Determinants	PROPOSED RATE FIXED	PROPOSED RATE O & M	5 Year EDIT Credit	10 Year EDIT Credit	ANNUALIZED REVENUE
OVERHEAD						
INCANDESCENT						
Without GLOBE	144	$ 3.128	$ 0.049	$ (0.189)	$ (0.646)	$ 337
With GLOBE	12	$ 4.568	$ 1.079	$ (0.189)	$ (0.646)	$ 58
TOTAL INCANDESCENT	156					$ 395
MERCURY VAPOR						
175 WATT	0	$ 9.735	$ 0.963	$ (0.189)	$ (0.646)	$ -
250 WATT	0	$ 11.122	$ 0.975	$ (0.189)	$ (0.646)	$ -
TOTAL MERCURY VAPOR	0					$ -
METAL HALIDE						
400 WATT	12	$ 37.643	$ 1.573	$ (0.189)	$ (0.646)	$ 461
TOTAL METAL HALIDE	12					$ 461
TOTAL OVERHEAD	168					$ 856
UNDERGROUND						
INCANDESCENT						
With GLOBE	2,076	$ 43.768	$ 1.978	$ (0.189)	$ (0.646)	$ 93,236
TOTAL INCANDESCENT	2,076					$ 93,236
MERCURY VAPOR						
250 WATT	2,796	$ 44.146	$ 1.777	$ (0.189)	$ (0.646)	$ 126,068
400 WATT	336	$ 51.766	$ 2.208	$ (0.189)	$ (0.646)	$ 17,855
TOTAL MERCURY VAPOR	3,132					$ 143,923
HIGH PRESSURE SODIUM						
150 WATT	0	$ 38.714	$ 1.450	$ (0.189)	$ (0.646)	$ -
TOTAL HIGH PRESURE SODIUM	0					$ -
METAL HALIDE						
100 WATT	2,772	$ 33.360	$ 1.304	$ (0.189)	$ (0.646)	$ 93,775
175 WATT	12,504	$ 37.643	$ 1.573	$ (0.189)	$ (0.646)	$ 479,914
400 WATT	0	$ 37.643	$ 1.573	$ (0.189)	$ (0.646)	$ -
TOTAL METAL HALIDE	15,276					$ 573,690
TOTAL UNDERGROUND	20,484					$ 810,849
TOTAL OH & UG	**20,652**					**$ 811,704**

	$ -
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization	$ 180,682
Total Distribution	$ 811,704
Percent Change	28.63%
BSA/Revenue Annualization	$ -
Total Distribution including BSA/Revenue Annualization	**$ 811,704**
Proposed Total Dist. Revenue Increase/Decrease	**$ 180,682**
Rate Change	28.63%
Rate Component Change (%)	25.52%

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Servicing Street Lights -Schedules ("SSL-OH") & ("SSL-UG")

	Current	RY2
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 86,039
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		10.60%

	(A)	(N) = I * 110.38%	(O) = J * 110.38%	(P)	(Q)	(R) = A *(N+O+P+Q)
		RY2				
	Billing Determinants	PROPOSED RATE FIXED	PROPOSED RATE O & M	5 Year EDIT Credit	10 Year EDIT Credit	ANNUALIZED REVENUE
OVERHEAD						
INCANDESCENT						
Without GLOBE	144	$ 3.453	$ 0.054	$ (0.189)	$ (0.646)	$ 385
With GLOBE	12	$ 5.042	$ 1.192	$ (0.189)	$ (0.646)	$ 65
TOTAL INCANDESCENT	156					$ 449
MERCURY VAPOR						
175 WATT	0	$ 10.746	$ 1.063	$ (0.189)	$ (0.646)	$ -
250 WATT	0	$ 12.277	$ 1.077	$ (0.189)	$ (0.646)	$ -
TOTAL MERCURY VAPOR	0					$ -
METAL HALIDE						
400 WATT	12	$ 41.550	$ 1.736	$ (0.189)	$ (0.646)	$ 509
TOTAL METAL HALIDE	12					$ 509
TOTAL OVERHEAD	168					$ 959
UNDERGROUND						
INCANDESCENT						
With GLOBE	2,076	$ 48.311	$ 2.183	$ (0.189)	$ (0.646)	$ 103,094
TOTAL INCANDESCENT	2,076					$ 103,094
MERCURY VAPOR						
250 WATT	2,796	$ 48.728	$ 1.962	$ (0.189)	$ (0.646)	$ 139,395
400 WATT	336	$ 57.139	$ 2.437	$ (0.189)	$ (0.646)	$ 19,737
TOTAL MERCURY VAPOR	3,132					$ 159,132
HIGH PRESSURE SODIUM						
150 WATT	0	$ 42.732	$ 1.600	$ (0.189)	$ (0.646)	$ -
TOTAL HIGH PRESURE SODIUM	0					$ -
METAL HALIDE						
100 WATT	2,772	$ 36.823	$ 1.440	$ (0.189)	$ (0.646)	$ 103,749
175 WATT	12,504	$ 41.550	$ 1.736	$ (0.189)	$ (0.646)	$ 530,810
400 WATT	0	$ 41.550	$ 1.736	$ (0.189)	$ (0.646)	$ -
TOTAL METAL HALIDE	15,276					$ 634,559
TOTAL UNDERGROUND	20,484					$ 896,784
TOTAL OH & UG	**20,652**					**$ 897,743**

	$ -
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization	$ 86,039
Total Distribution	$ 897,743
Percent Change	10.60%
BSA/Revenue Annualization	$ -
Total Distribution including BSA/Revenue Annualization	**$ 897,743**
Proposed Total Dist. Revenue Increase/Decrease	**$ 86,039**
Rate Change	10.60%
Rate Component Change (%)	10.38%

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Servicing Street Lights -Schedules ("SSL-OH") & ("SSL-UG")

	Current	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 77,435
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		8.63%

	(A)	(S) = N * 108.46%	(T) = O * 108.46%	(U)	(V)	(W) = A *(S+T+U+V)
		RY3				
	Billing Determinants	PROPOSED RATE FIXED	PROPOSED RATE O & M	5 Year EDIT Credit	10 Year EDIT Credit	ANNUALIZED REVENUE
OVERHEAD						
INCANDESCENT						
Without GLOBE	144	$ 3.745	$ 0.059	$ (0.189)	$ (0.646)	$ 427
With GLOBE	12	$ 5.468	$ 1.292	$ (0.189)	$ (0.646)	$ 71
TOTAL INCANDESCENT	156					$ 499
MERCURY VAPOR						
175 WATT	0	$ 11.655	$ 1.153	$ (0.189)	$ (0.646)	$ -
250 WATT	0	$ 13.316	$ 1.168	$ (0.189)	$ (0.646)	$ -
TOTAL MERCURY VAPOR	0					$ -
METAL HALIDE						
400 WATT	12	$ 45.067	$ 1.883	$ (0.189)	$ (0.646)	$ 553
TOTAL METAL HALIDE	12					$ 553
TOTAL OVERHEAD	168					$ 1,052
UNDERGROUND						
INCANDESCENT						
With GLOBE	2,076	$ 52.400	$ 2.368	$ (0.189)	$ (0.646)	$ 111,965
TOTAL INCANDESCENT	2,076					$ 111,965
MERCURY VAPOR						
250 WATT	2,796	$ 52.852	$ 2.128	$ (0.189)	$ (0.646)	$ 151,389
400 WATT	336	$ 61.975	$ 2.643	$ (0.189)	$ (0.646)	$ 21,431
TOTAL MERCURY VAPOR	3,132					$ 172,821
HIGH PRESSURE SODIUM						
150 WATT	0	$ 46.348	$ 1.736	$ (0.189)	$ (0.646)	$ -
TOTAL HIGH PRESURE SODIUM	0					$ -
METAL HALIDE						
100 WATT	2,772	$ 39.939	$ 1.561	$ (0.189)	$ (0.646)	$ 112,725
175 WATT	12,504	$ 45.067	$ 1.883	$ (0.189)	$ (0.646)	$ 576,615
400 WATT	0	$ 45.067	$ 1.883	$ (0.189)	$ (0.646)	$ -
TOTAL METAL HALIDE	15,276					$ 689,341
TOTAL UNDERGROUND	20,484					$ 974,126
TOTAL OH & UG	**20,652**					**$ 975,178**

	$ -
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization	$ 77,435
Total Distribution	$ 975,178
Percent Change	8.63%
BSA/Revenue Annualization	$ -
Total Distribution including BSA/Revenue Annualization	**$ 975,178**
Proposed Total Dist. Revenue Increase/Decrease	**$ 77,435**
Rate Change	8.63%
Rate Component Change (%)	8.46%

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Schedule-Street Lighting Service Energy ("SL-E")	Current	RY1	RY2	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 177,134	$ 84,350	$ 75,915
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		34.80%	12.29%	9.85%
Customer Charge Recovery ($)	$ 5,597	$ 6,463	$ 7,329	$ 8,195
Volumetric Charge Recovery ($)	$ 503,408	$ 679,676	$ 763,264	$ 838,054
Customer Charge Recovery (%)	1%	1%	1%	1%
Volumetric Charge Recovery (%)	99%	99%	99%	99%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)
	Billing Determinants	Current Rate	EDIT Credit	10 Year EDIT Credit	Present Revenue	Billing Determinant Adjustment No.
Delivery Service						
Monthly Customer Charge						
Metered Accounts	264	$ 17.19			$ 4,538	
Unmetered Accounts	72	$ 14.70			$ 1,058	
Kilowatt-hour Charge	79,310,898	$ 0.00615	$ (0.00004)	$ (0.00015)	$ 472,693	
	79,310,898					
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization						
Total Distribution					$ 478,290	
Percent Change						
BSA/Revenue Annualization					$ 30,715	
Total Distribution including BSA/Revenue Annualization					$ 509,004	
Proposed Total Dist. Revenue Increase/Decrease						
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization						
Percent Change						
Customer Charge Rate Design						
Full Customer Cost from CCOSS						
Present Customer Charge						
Target Movement Toward Full Cost (%)						
Target Movement Toward Full Cost ($)						
Change to Present based on Target Movement Toward Full Cost						
Proposed Customer Charge (as % of Present)						

Pepco - District of Columbia
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Schedule-Street Lighting Service Energy ("SL-E")

		RY1
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$	177,134
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		34.80%
Customer Charge Recovery ($)	$	6,463
Volumetric Charge Recovery ($)	$	679,676
Customer Charge Recovery (%)		1%
Volumetric Charge Recovery (%)		99%

	(G)	(H)	(I)	(J)	(K)	(L)	(M)
		= (J / B) - 1 = [(M-((K+L)*G))) - (B*G)] / (B*G)	= (115% * B) - B = B * H	= B + H			= G * (J+K+L)
			RY1				
	2020 Forecasted Billing Determinants	Proposed Rate Increase (%)	Proposed Rate Increase ($)	Proposed Rate	5 Year EDIT Credit	10 Year EDIT Credit	Proposed Revenue
Delivery Service							
Monthly Customer Charge							
Metered Accounts	264	15.47%	$ 2.66	$ 19.85			$ 5,240
Unmetered Accounts	72	15.47%	$ 2.27	$ 16.97			$ 1,222
Kilowatt-hour Charge	80,122,601	41.02%	$0.00252	$0.00867	$ (0.00004)	$ (0.00015)	$ 679,676
							$ 679,676
	80,122,601						
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 177,134
Total Distribution							$ 686,138
Percent Change							34.80%
BSA/Revenue Annualization							$ 105
Total Distribution including BSA/Revenue Annualization							$ 686,243
Proposed Total Dist. Revenue Increase/Decrease							**$ 177,239**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 686,243**
Percent Change							**34.82%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$**	**34.90**	
Present Customer Charge	**$**	**17.19**	
Target Movement Toward Full Cost (%)		15%	
Target Movement Toward Full Cost ($)	$	2.66	= 15% * ($34.9 - $17.19)
Change to Present based on Target Movement Toward Full Cost	$	19.85	
Proposed Customer Charge (as % of Present)		**115%**	= $19.85 / $17.19)

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Schedule-Street Lighting Service Energy ("SL-E")

	RY2
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ 84,350
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	12.29%
Customer Charge Recovery ($)	$ 7,329
Volumetric Charge Recovery ($)	$ 763,264
Customer Charge Recovery (%)	1%
Volumetric Charge Recovery (%)	99%

	(N)	(O) = (Q / J) - 1 = [(T-((R+S)*N))) - (J*N)] / (J*N)	(P) = (113% * J) - J = J * O	(Q) = J + P	(R)	(S)	(T) = N * (Q+R+S)
			RY2				
	2021 Forecasted Billing Determinants	Proposed Rate Increase (%)	Proposed Rate Increase ($)	Proposed Rate	5 Year EDIT Credit	10 Year EDIT Credit	Proposed Revenue
Delivery Service							
Monthly Customer Charge							
Metered Accounts	264	13.40%	$ 2.66	$ 22.51			$ 5,943
Unmetered Accounts	72	13.40%	$ 2.27	$ 19.25			$ 1,386
Kilowatt-hour Charge	80,131,779	12.02%	$0.00104	$0.00972	$ (0.00004)	$ (0.00015)	$ 763,264
							$ 763,264
	80,131,779						
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 84,350
Total Distribution							$ 770,593
Percent Change							12.29%
BSA/Revenue Annualization							$ (258)
Total Distribution including BSA/Revenue Annualization							$ 770,334
Proposed Total Dist. Revenue Increase/Decrease							**$ 84,091**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 770,334**
Percent Change							**12.25%**

Customer Charge Rate Design

Full Customer Cost from CCOSS		
Present Customer Charge	**$ 19.85**	
Target Movement Toward Full Cost (%)		
Target Movement Toward Full Cost ($)	$ 2.66	
Change to Present based on Target Movement Toward Full Cost	$ 22.51	
Proposed Customer Charge (as % of Present)	**113%**	= $22.51 / $19.85)

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Schedule-Street Lighting Service Energy ("SL-E")

		RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$	75,915
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		9.85%
Customer Charge Recovery ($)	$	8,195
Volumetric Charge Recovery ($)	$	838,054
Customer Charge Recovery (%)		1%
Volumetric Charge Recovery (%)		99%

	(U)	(V) = (X / Q) - 1 = [(AA-((Y+Z)*U))) - (Q*U)] / (Q*U)	(W) = (112% * Q) - Q = Q * V	(X) = Q + W	(Y)	(Z)	(AA) = U * (X+Y+Z)
			RY3				
	2022 Forecasted Billing Determinants	Proposed Rate Increase (%)	Proposed Rate Increase ($)	Proposed Rate	5 Year EDIT Credit	10 Year EDIT Credit	Proposed Revenue
Delivery Service							
Monthly Customer Charge							
Metered Accounts	264	11.82%	$ 2.66	$ 25.17			$ 6,645
Unmetered Accounts	72	11.82%	$ 2.27	$ 21.52			$ 1,550
Kilowatt-hour Charge	80,109,956	9.64%	$0.00094	$0.01065	$ (0.00004)	$ (0.00015)	$ 838,054
							$ 838,054
	80,109,956						
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 75,915
Total Distribution							$ 846,249
Percent Change							9.85%
BSA/Revenue Annualization							$ -
Total Distribution including BSA/Revenue Annualization							$ 846,249
Proposed Total Dist. Revenue Increase/Decrease							**$ 75,915**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 846,249**
Percent Change							**9.85%**

Customer Charge Rate Design

Full Customer Cost from CCOSS		
Present Customer Charge	**$ 22.51**	
Target Movement Toward Full Cost (%)		
Target Movement Toward Full Cost ($)	$ 2.66	
Change to Present based on Target Movement Toward Full Cost	$ 25.17	
Proposed Customer Charge (as % of Present)	**112%**	= $25.17 / $22.51)

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Schedule-Traffic Signal Service ("TS")

	Current	RY1	RY2	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ 35,511	$ 16,910	$ 15,219
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		15.54%	6.40%	5.42%
Customer Charge Recovery ($)	$ 289	$ 153	$ 153	$ 153
Volumetric Charge Recovery ($)	$ 228,253	$ 263,899	$ 280,856	$ 295,959
Customer Charge Recovery (%)	0%	0%	0%	0%
Volumetric Charge Recovery (%)	100%	100%	100%	100%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)
	Billing Determinants	Current Rate	5 Year EDIT Credit	10 Year EDIT Credit	Present Revenue	Billing Determinant Adjustment No.
Delivery Service						
Monthly Customer Charge	36	$ 8.03			$ 289	
Kilowatt-hour Charge	10,461,996	$ 0.02203	$ (0.00066)	$ (0.00226)	$ 199,929	
	10,461,996					
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization						
Total Distribution					$ 200,218	
Percent Change						
BSA/Revenue Annualization					$ 28,324	
Total Distribution including BSA/Revenue Annualization					$ 228,542	
Proposed Total Dist. Revenue Increase/Decrease						
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization						
Percent Change						
Customer Charge Rate Design						
Full Customer Cost from CCOSS						
Present Customer Charge						
Proposed Customer Charge						

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-Traffic Signal Service ("TS")

		RY1
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$	35,511
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		15.54%
Customer Charge Recovery ($)	$	153
Volumetric Charge Recovery ($)	$	263,899
Customer Charge Recovery (%)		0%
Volumetric Charge Recovery (%)		100%

	(G)	(H) = ($4.26 / B) -1 = [(M-((K+L)*G))) - (B*G)] / (B*A)	(I) = B * H	(J) = B + I	(K)	(L)	(M) = G * (J+K+L)
			RY1				
	2020 Forecasted Billing Determinants	Proposed Rate Increase (%)	Proposed Rate Increase ($)	Proposed Rate	5 Year EDIT Credit	10 Year EDIT Credit	Proposed Revenue
Delivery Service							
Monthly Customer Charge	36	-46.97%	$ (3.77)	$ 4.26			$ 153
Kilowatt-hour Charge	10,630,328	25.94%	$0.00572	$0.02775	$ (0.00066)	$ (0.00226)	$ 263,899
							$ 263,899
	10,630,328						
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 35,511
Total Distribution							$ 264,052
Percent Change							15.54%
BSA/Revenue Annualization							$ 47
Total Distribution including BSA/Revenue Annualization							$ 264,099
Proposed Total Dist. Revenue Increase/Decrease							**$ 35,558**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 264,099**
Percent Change							**15.56%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$**	**4.26**
Present Customer Charge	**$**	**8.03**
Proposed Customer Charge	**$**	**4.26**

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-Traffic Signal Service ("TS")

		RY2
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$	16,910
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		6.40%
Customer Charge Recovery ($)	$	153
Volumetric Charge Recovery ($)	$	280,856
Customer Charge Recovery (%)		0%
Volumetric Charge Recovery (%)		100%

	(N)	(O) = ($4.26 / J) -1 = [(T-((R+S)*N))) - (J*N)] / (I*A)	(P) = J * O	(Q) = J + P	(R)	(S)	(T) = N * (Q+R+S)
			RY2				
	2021 Forecasted Billing Determinants	Proposed Rate Increase (%)	Proposed Rate Increase ($)	Proposed Rate	5 Year EDIT Credit	10 Year EDIT Credit	Proposed Revenue
Delivery Service							
Monthly Customer Charge	36	0.00%	$ -	$ 4.26			$ 153
Kilowatt-hour Charge	10,631,199	5.74%	$0.00159	$0.02934	$ (0.00066)	$ (0.00226)	$ 280,856
							$ 280,856
	10,631,199						
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 16,910
Total Distribution							$ 281,009
Percent Change							6.40%
BSA/Revenue Annualization							$ (116)
Total Distribution including BSA/Revenue Annualization							$ 280,893
Proposed Total Dist. Revenue Increase/Decrease							**$ 16,794**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 280,893**
Percent Change							**6.36%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	
Present Customer Charge	**$ 4.26**
Proposed Customer Charge	**$ 4.26**

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-Traffic Signal Service ("TS")

		RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$	15,219
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		5.42%
Customer Charge Recovery ($)	$	153
Volumetric Charge Recovery ($)	$	295,959
Customer Charge Recovery (%)		0%
Volumetric Charge Recovery (%)		100%

	(U)	(V) = ($4.26 / Q) -1 = [(AA-((Y+Z)*U))) - (Q*U)] / (Q*U)	(W) = Q * V	(X) = Q + W	(Y)	(Z)	(AA) = U * (X+Y+Z)
			RY3				
	2022 Forecasted Billing Determinants	Proposed Rate Increase (%)	Proposed Rate Increase ($)	Proposed Rate	5 Year EDIT Credit	10 Year EDIT Credit	Proposed Revenue
Delivery Service							
Monthly Customer Charge	36	0.00%	$ -	$ 4.26			$ 153
Kilowatt-hour Charge	10,628,194	4.87%	$0.00143	$0.03077	$ (0.00066)	$ (0.00226)	$ 295,959
	10,628,194						$ 295,959
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ 15,219
Total Distribution							$ 296,112
Percent Change							5.42%
BSA/Revenue Annualization							$ -
Total Distribution including BSA/Revenue Annualization							$ 296,112
Proposed Total Dist. Revenue Increase/Decrease							**$ 15,219**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 296,112**
Percent Change							**5.42%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	
Present Customer Charge	**$ 4.26**
Proposed Customer Charge	**$ 4.26**

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-Telecommunications Network Service ("TN")	**Current**	**RY1**	**RY2**	**RY3**
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		$ -	$ -	$ -
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		0.00%	0.00%	0.00%
Customer Charge Recovery ($)		$ 56,116	$ 56,116	$ 56,116
Volumetric Charge Recovery ($)		$ 14,968	$ 13,845	$ 12,819
Customer Charge Recovery (%)	76%	79%	80%	81%
Volumetric Charge Recovery (%)	24%	21%	20%	19%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)	(G) = H - A	(H)	(I) = H * (B+C+D)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**	**Weather Normalization**	**Weather Normalized Billing Determinants**	**Weather Normalized Revenue**
Monthly Customer Charge	6,372	$ 15.43	$ (1.50001)	$ (5.12327)	$ 56,116		-	6,372	56,116
Distribution									
Summer Energy	1,111,220	$ 0.01288	$ (0.00140)	$ (0.00478)	$ 7,445	23	(33,585)	1,077,635	7,220
Winter Energy	1,539,728	$ 0.01288	$ (0.00140)	$ (0.00478)	$ 10,316	24	(14,129)	1,525,599	10,222
Total kWh Charge	2,650,948				$ 17,761		(47,714)	2,603,234	17,442
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization									
Total Distribution					$ 73,878				$ 73,558
Percent Change									
BSA/Revenue Annualization					$ (2,793)				
Total Distribution including BSA/Revenue Annualization					$ 71,085				
Proposed Total Dist. Revenue Increase/Decrease									
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Proposed Customer Charge									

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-Telecommunications Network Service ("TN")	**RY1**
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ -
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	0.00%
Customer Charge Recovery ($)	$ 56,116
Volumetric Charge Recovery ($)	$ 14,968
Customer Charge Recovery (%)	79%
Volumetric Charge Recovery (%)	21%

	(J)	(K) = ($15.43 / B) -1 = [(P-((N+O)*J))) - (B*J)] / (B*J)	(L) = B * K	(M) = B + L	(N)	(O)	(P) = J * (M + N + O)
	RY1						
Delivery Service	**2020 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	6,372	0.00%	$ -	$ 15.43	$ (1.50001)	$ (5.12327)	56,116
Distribution							
Summer Energy	1,139,621	-6.83%	($0.00088)	$ 0.01200	($0.00140)	($0.00478)	$ 6,633
Winter Energy	1,432,052	-6.83%	($0.00088)	$ 0.01200	($0.00140)	($0.00478)	$ 8,335
Total kWh Charge	2,571,674						$ 14,968
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ -
Total Distribution							$ 71,085
Percent Change							0.00%
BSA/Revenue Annualization							$ (1,123)
Total Distribution including BSA/Revenue Annualization							$ 69,962
Proposed Total Dist. Revenue Increase/Decrease							**$ (1,123)**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 69,962**
Percent Change							**-1.58%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$ 17.00**
Present Customer Charge	**$ 15.43**
Proposed Customer Charge	**$ 15.43**

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-Telecommunications Network Service ("TN")	**RY2**
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ -
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	0.00%
Customer Charge Recovery ($)	$ 56,116
Volumetric Charge Recovery ($)	$ 13,845
Customer Charge Recovery (%)	80%
Volumetric Charge Recovery (%)	20%

	(Q)	(R) = ($15.43 / M) -1 = [(W-((U+V)*Q))) - (M*Q)] / (M*Q)	(S) = M * R	(T) = M + S	(U)	(V)	(W) = Q * (T+U+V) = ($13,845 / $14,968) * P
	RY2						
Delivery Service	**2021 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	6,372	0.00%	$ -	$ 15.43	$ (1.50001)	$ (5.12327)	56,116
Distribution							
Summer Energy	1,120,651	-2.92%	($0.00035)	$ 0.01165	($0.00140)	($0.00478)	$ 6,130
Winter Energy	1,410,389	-2.92%	($0.00035)	$ 0.01165	($0.00140)	($0.00478)	$ 7,715
Total kWh Charge	2,531,040						$ 13,845
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ -
Total Distribution							$ 69,962
Percent Change							0.00%
BSA/Revenue Annualization							$ (1,026)
Total Distribution including BSA/Revenue Annualization							$ 68,936
Proposed Total Dist. Revenue Increase/Decrease							**$ (1,026)**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 68,936**
Percent Change							**-1.47%**

Customer Charge Rate Design
Full Customer Cost from CCOSS
Present Customer Charge **$ 15.43**

Proposed Customer Charge **$ 15.43**

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-Telecommunications Network Service ("TN")	**RY3**
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	$ -
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	0.00%
Customer Charge Recovery ($)	$ 56,116
Volumetric Charge Recovery ($)	$ 12,819
Customer Charge Recovery (%)	81%
Volumetric Charge Recovery (%)	19%

	(X)	(Y) = ($15.43 / T) -1 = [(AD-((AB+AC)*X))) - (T*X)] / (T*X)	(Z) = T * Y	(AA) = T + Z	(AB)	(AC)	(AD) = X * (AA+AB+AC) = ($12,819 / $13,845) * W
				RY3			
Delivery Service	**2022 Forecasted Billing Determinants**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	6,372	0.00%	$ -	$ 15.43	$ (1.50001)	$ (5.12327)	56,116
Distribution							
Summer Energy	1,104,122	-2.83%	($0.00033)	$ 0.01132	($0.00140)	($0.00478)	$ 5,675
Winter Energy	1,389,808	-2.83%	($0.00033)	$ 0.01132	($0.00140)	($0.00478)	$ 7,144
Total kWh Charge	2,493,930						$ 12,819
Difference from Prior Total Dist. Revenue incl. BSA/Revenue Annualization							$ -
Total Distribution							$ 68,936
Percent Change							0.00%
BSA/Revenue Annualization							$ -
Total Distribution including BSA/Revenue Annualization							$ 68,936
Proposed Total Dist. Revenue Increase/Decrease							**$ -**
Proposed Total Dist. Revenue incl. BSA/Revenue Annualization							**$ 68,936**
Percent Change							**0.00%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	
Present Customer Charge	**$ 15.43**
Proposed Customer Charge	**$ 15.43**

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-LED Outdoor Lighting Service ("OL LED")	Current	RY1	RY2	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)		-	-	-
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)		-	-	-

	(A)	(B)	(C)	(D)	(E)	(F)
	Billing Determinants	Current Rate	5 Year EDIT Credit	10 Year EDIT Credit	Present Revenue	Billing Determinant Adjustment No.
Delivery Service						
Monthly Customer Charge	-	$ 8.76			$ -	
Kilowatt-hour Charge	-	$ 0.00895	$ -	$ -	$ -	
	-				$ -	
Total					**$ -**	
Proposed Distribution Revenue Increase/Decrease						
Proposed Distribution Revenue						
Percent Change						

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-LED Outdoor Lighting Service ("OL LED")

	RY1
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	-
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	-

	(G)	(H)	(I)	(J)	(K)	(L)	(M)
				RY1			
	2020 Forecasted Billing Determinants	Proposed Rate Increase (%)	Proposed Rate Increase ($)	Proposed Rate	5 Year EDIT Credit	10 Year EDIT Credit	Proposed Revenue
Delivery Service							
Monthly Customer Charge		0.00%	$ -	$ 8.76			$ -
Kilowatt-hour Charge		0.00%	$0.00000	$ 0.00895	$ -	$ -	$ -
							$ -
Total							
Proposed Distribution Revenue Increase/Decrease							**$ -**
Proposed Distribution Revenue							**$ -**
Percent Change							**0.00%**

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-LED Outdoor Lighting Service ("OL LED")

	RY2
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	-
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	-

	(N)	(O)	(P)	(Q)	(R)	(S)	(T)
				RY2			
	2021 Forecasted Billing Determinants	Proposed Rate Increase (%)	Proposed Rate Increase ($)	Proposed Rate	5 Year EDIT Credit	10 Year EDIT Credit	Proposed Revenue
Delivery Service							
Monthly Customer Charge		0.00%	$ -	$ 8.76			$ -
Kilowatt-hour Charge		0.00%	$0.00000	$0.00895	$ -	$ -	$ -
							$ -
Total							
Proposed Distribution Revenue Increase/Decrease							**$ -**
Proposed Distribution Revenue							**$ -**
Percent Change							**0.00%**

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-LED Outdoor Lighting Service ("OL LED")

	RY3
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - ($)	-
Proposed Increase to Rev. Requirement (excl. BSA/Rev. Annualization) - (%)	-

	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
				RY3			
	2022 Forecasted Billing Determinants	Proposed Rate Increase (%)	Proposed Rate Increase ($)	Proposed Rate	5 Year EDIT Credit	10 Year EDIT Credit	Proposed Revenue
Delivery Service							
Monthly Customer Charge		0.00%	$ -	$ 8.76			$ -
Kilowatt-hour Charge		0.00%	$0.00000	$0.00895	$ -	$ -	$ -
							$ -
Total							
Proposed Distribution Revenue Increase/Decrease							**$ -**
Proposed Distribution Revenue							**$ -**
Percent Change							**0.00%**

P.R. Blazunas
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (F) – 7

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED MRP RY1 RATES
SCHEDULE "R"
DISTRICT OF COLUMBIA

	CURRENT RATES				MRP RY1 RATES				INCREASE					
KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)	($)	(%)
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	ANNUAL	ANNUAL
0	17.03	17.11	-	-	20.50	20.58	-	-	3.47	3.47	20.38%	20.28%	3.47	20.32%
10	17.30	17.38	1.72987	1.73787	20.82	20.90	2.08155	2.08955	3.52	3.52	20.35%	20.25%	3.52	20.29%
20	17.57	17.65	0.87837	0.88237	21.13	21.21	1.05655	1.06055	3.56	3.56	20.26%	20.17%	3.56	20.21%
30	17.84	17.92	0.59454	0.59721	21.45	21.53	0.71488	0.71755	3.61	3.61	20.24%	20.15%	3.61	20.19%
40	18.76	18.87	0.46899	0.47165	22.42	22.52	0.56041	0.56307	3.66	3.66	19.51%	19.40%	3.66	19.45%
50	19.68	19.82	0.39366	0.39631	23.39	23.52	0.46773	0.47039	3.70	3.70	18.80%	18.67%	3.70	18.72%
100	24.30	24.56	0.24300	0.24564	28.24	28.50	0.28238	0.28502	3.94	3.94	16.21%	16.04%	3.94	16.11%
200	33.53	34.06	0.16767	0.17031	37.94	38.47	0.18970	0.19233	4.40	4.40	13.12%	12.92%	4.40	13.00%
300	42.77	43.56	0.14256	0.14520	47.64	48.43	0.15880	0.16144	4.87	4.87	11.39%	11.18%	4.87	11.27%
400	52.00	53.06	0.13001	0.13264	57.34	58.40	0.14336	0.14599	5.34	5.34	10.27%	10.06%	5.34	10.15%
500	62.61	63.29	0.12522	0.12658	69.19	69.64	0.13837	0.13929	6.58	6.35	10.51%	10.03%	6.45	10.23%
692	**82.97**	**82.94**	**0.11991**	**0.11985**	**91.93**	**91.24**	**0.13284**	**0.13185**	**8.95**	**8.30**	**10.79%**	**10.01%**	**8.57**	**10.33%**
700	83.82	83.75	0.11975	0.11965	92.87	92.14	0.13268	0.13163	9.05	8.38	10.80%	10.01%	8.66	10.34%
750	89.13	88.87	0.11884	0.11849	98.80	97.76	0.13173	0.13035	9.67	8.89	10.85%	10.00%	9.22	10.36%
800	94.43	93.99	0.11804	0.11748	104.72	103.39	0.13090	0.12923	10.29	9.40	10.90%	10.00%	9.77	10.38%
850	99.73	99.10	0.11733	0.11659	110.64	109.01	0.13016	0.12825	10.91	9.91	10.94%	10.00%	10.33	10.39%
900	105.04	104.22	0.11671	0.11580	116.56	114.63	0.12951	0.12737	11.52	10.41	10.97%	9.99%	10.87	10.40%
950	110.34	109.34	0.11615	0.11509	122.48	120.26	0.12893	0.12659	12.14	10.92	11.00%	9.99%	11.43	10.41%
1,000	115.64	114.45	0.11564	0.11445	128.40	125.88	0.12840	0.12588	12.76	11.43	11.03%	9.99%	11.98	10.43%
1,250	142.16	140.03	0.11373	0.11203	158.01	154.00	0.12641	0.12320	15.85	13.97	11.15%	9.98%	14.75	10.47%
1,500	168.68	165.61	0.11245	0.11041	187.62	182.12	0.12508	0.12141	18.95	16.51	11.23%	9.97%	17.53	10.50%
1,750	195.19	191.20	0.11154	0.10925	217.23	210.24	0.12413	0.12014	22.04	19.04	11.29%	9.96%	20.29	10.52%
2,000	221.71	216.78	0.11085	0.10839	246.84	238.36	0.12342	0.11918	25.13	21.58	11.33%	9.95%	23.06	10.54%
2,250	248.22	242.36	0.11032	0.10771	276.45	266.48	0.12287	0.11844	28.23	24.12	11.37%	9.95%	25.83	10.55%
2,500	274.74	267.94	0.10990	0.10718	306.06	294.60	0.12242	0.11784	31.32	26.66	11.40%	9.95%	28.60	10.56%
3,000	327.77	319.10	0.10926	0.10637	365.28	350.84	0.12176	0.11695	37.50	31.74	11.44%	9.95%	34.14	10.58%
3,500	380.81	370.26	0.10880	0.10579	424.50	407.08	0.12128	0.11631	43.69	36.81	11.47%	9.94%	39.68	10.59%
4,000	433.84	421.43	0.10846	0.10536	483.71	463.31	0.12093	0.11583	49.88	41.89	11.50%	9.94%	45.22	10.60%
5,000	539.90	523.75	0.10798	0.10475	602.15	575.79	0.12043	0.11516	62.25	52.04	11.53%	9.94%	56.29	10.61%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED MRP RY1 RATES
SCHEDULE "MMA"
DISTRICT OF COLUMBIA

	CURRENT RATES				MRP RY1 RATES				INCREASE					
KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)	($)	(%)
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	ANNUAL	ANNUAL
0	13.57	13.99	-	-	15.64	16.06	-	-	2.07	2.07	15.25%	14.80%	2.07	14.98%
100	20.13	21.51	0.20127	0.21511	22.29	23.68	0.22291	0.23676	2.16	2.16	10.73%	10.04%	2.16	10.32%
200	28.42	31.18	0.14210	0.15591	30.68	33.44	0.15339	0.16720	2.26	2.26	7.95%	7.25%	2.26	7.53%
300	36.71	40.85	0.12238	0.13618	39.07	43.21	0.13022	0.14402	2.35	2.35	6.40%	5.75%	2.35	6.01%
400	45.01	50.52	0.11251	0.12631	47.45	52.97	0.11863	0.13243	2.45	2.45	5.44%	4.85%	2.45	5.08%
500	54.55	60.86	0.10910	0.12173	57.53	63.26	0.11506	0.12653	2.98	2.40	5.46%	3.94%	2.64	4.54%
1000	102.26	112.56	0.10226	0.11256	107.92	114.73	0.10792	0.11473	5.66	2.17	5.53%	1.93%	3.62	3.35%
2000	197.69	215.95	0.09885	0.10797	208.70	217.65	0.10435	0.10882	11.00	1.70	5.56%	0.79%	5.58	2.68%
3000	293.12	319.34	0.09771	0.10645	309.48	320.57	0.10316	0.10686	16.35	1.23	5.58%	0.39%	7.53	2.44%
4000	388.55	422.73	0.09714	0.10568	410.25	423.49	0.10256	0.10587	21.70	0.77	5.58%	0.18%	9.49	2.32%
5000	483.98	526.12	0.09680	0.10522	511.03	526.42	0.10221	0.10528	27.05	0.30	5.59%	0.06%	11.45	2.25%
6000	579.41	629.51	0.09657	0.10492	611.81	629.34	0.10197	0.10489	32.40	-0.17	5.59%	-0.03%	13.40	2.20%
7000	674.84	732.90	0.09641	0.10470	712.59	732.26	0.10180	0.10461	37.75	-0.63	5.59%	-0.09%	15.36	2.17%
7500	722.56	784.59	0.09634	0.10461	762.98	783.73	0.10173	0.10450	40.42	-0.87	5.59%	-0.11%	16.33	2.15%
8000	770.27	836.29	0.09628	0.10454	813.37	835.19	0.10167	0.10440	43.09	-1.10	5.59%	-0.13%	17.31	2.14%
8500	817.99	887.98	0.09623	0.10447	863.76	886.65	0.10162	0.10431	45.77	-1.33	5.60%	-0.15%	18.30	2.13%
9000	865.70	939.68	0.09619	0.10441	914.15	938.11	0.10157	0.10423	48.44	-1.57	5.60%	-0.17%	19.27	2.12%
9500	913.42	991.37	0.09615	0.10436	964.53	989.57	0.10153	0.10417	51.12	-1.80	5.60%	-0.18%	20.25	2.11%
10000	961.13	1,043.07	0.09611	0.10431	1,014.92	1,041.03	0.10149	0.10410	53.79	-2.03	5.60%	-0.19%	21.23	2.10%
12500	1,199.71	1,301.54	0.09598	0.10412	1,266.87	1,298.34	0.10135	0.10387	67.16	-3.20	5.60%	-0.25%	26.12	2.07%
15000	1,438.28	1,560.02	0.09589	0.10400	1,518.81	1,555.65	0.10125	0.10371	80.53	-4.37	5.60%	-0.28%	31.01	2.05%
17500	1,676.86	1,818.49	0.09582	0.10391	1,770.76	1,812.96	0.10119	0.10360	93.90	-5.54	5.60%	-0.30%	35.89	2.04%
20000	1,915.43	2,076.97	0.09577	0.10385	2,022.70	2,070.26	0.10114	0.10351	107.27	-6.70	5.60%	-0.32%	40.79	2.03%
22500	2,154.01	2,335.44	0.09573	0.10380	2,274.65	2,327.57	0.10110	0.10345	120.64	-7.87	5.60%	-0.34%	45.68	2.02%
25000	2,392.58	2,593.92	0.09570	0.10376	2,526.60	2,584.88	0.10106	0.10340	134.01	-9.04	5.60%	-0.35%	50.56	2.01%
30000	2,869.73	3,110.87	0.09566	0.10370	3,030.49	3,099.50	0.10102	0.10332	160.75	-11.37	5.60%	-0.37%	60.35	2.00%
35000	3,346.88	3,627.82	0.09563	0.10365	3,534.38	3,614.11	0.10098	0.10326	187.49	-13.71	5.60%	-0.38%	70.12	2.00%
40000	3,824.03	4,144.77	0.09560	0.10362	4,038.27	4,128.73	0.10096	0.10322	214.24	-16.04	5.60%	-0.39%	79.91	1.99%
50000	4,778.33	5,178.67	0.09557	0.10357	5,046.05	5,157.96	0.10092	0.10316	267.72	-20.71	5.60%	-0.40%	99.47	1.98%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY

EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED MRP RY1 RATES
SCHEDULE "GS ND"
DISTRICT OF COLUMBIA

	CURRENT RATES				MRP RY1 RATES				INCREASE					
KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)	($)	(%)
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	ANNUAL	ANNUAL
0	27.42	27.42	-	-	32.10	32.10	-	-	4.68	4.68	17.07%	17.07%	4.68	17.07%
10	28.65	28.58	2.86503	2.85841	33.37	33.34	3.33744	3.33368	4.72	4.75	16.47%	16.62%	4.74	16.56%
20	29.88	29.75	1.49403	1.48741	34.65	34.57	1.73244	1.72868	4.77	4.83	15.96%	16.24%	4.81	16.12%
30	31.11	30.91	1.03703	1.03041	35.92	35.81	1.19744	1.19368	4.81	4.90	15.46%	15.85%	4.86	15.69%
40	32.34	32.08	0.80853	0.80191	37.20	37.05	0.92994	0.92618	4.86	4.97	15.03%	15.49%	4.92	15.30%
50	33.57	33.24	0.67143	0.66481	38.47	38.28	0.76944	0.76568	4.90	5.04	14.60%	15.16%	4.98	14.92%
100	39.72	39.06	0.39723	0.39061	44.84	44.47	0.44844	0.44468	5.12	5.41	12.89%	13.85%	5.29	13.45%
150	45.87	44.88	0.30583	0.29921	51.22	50.65	0.34144	0.33768	5.34	5.77	11.64%	12.86%	5.59	12.34%
200	52.03	50.70	0.26013	0.25351	57.59	56.84	0.28794	0.28418	5.56	6.13	10.69%	12.09%	5.89	11.50%
250	58.18	56.52	0.23271	0.22609	63.96	63.02	0.25584	0.25208	5.78	6.50	9.94%	11.50%	6.20	10.84%
300	64.33	62.34	0.21443	0.20781	70.33	69.21	0.23444	0.23068	6.00	6.86	9.33%	11.00%	6.50	10.29%
400	76.63	73.98	0.19158	0.18496	83.07	81.57	0.20769	0.20393	6.44	7.59	8.40%	10.26%	7.11	9.47%
500	88.93	85.62	0.17787	0.17125	95.82	93.94	0.19164	0.18788	6.88	8.32	7.74%	9.72%	7.72	8.87%
600	101.24	97.27	0.16873	0.16211	108.56	106.31	0.18094	0.17718	7.32	9.04	7.23%	9.29%	8.32	8.41%
700	113.54	108.91	0.16220	0.15558	121.31	118.68	0.17329	0.16954	7.77	9.77	6.84%	8.97%	8.94	8.06%
800	125.84	120.55	0.15730	0.15068	134.05	131.05	0.16756	0.16381	8.21	10.50	6.52%	8.71%	9.55	7.78%
900	138.15	132.19	0.15350	0.14688	146.79	143.42	0.16310	0.15935	8.65	11.23	6.26%	8.50%	10.16	7.54%
1,000	150.45	143.83	0.15045	0.14383	159.54	155.78	0.15954	0.15578	9.09	11.95	6.04%	8.31%	10.76	7.34%
1,250	181.21	172.93	0.14497	0.13835	191.40	186.70	0.15312	0.14936	10.19	13.77	5.62%	7.96%	12.28	6.96%
1,500	211.96	202.03	0.14131	0.13469	223.26	217.63	0.14884	0.14508	11.29	15.59	5.33%	7.72%	13.80	6.69%
1,750	242.72	231.14	0.13870	0.13208	255.12	248.55	0.14578	0.14203	12.39	17.41	5.10%	7.53%	15.32	6.49%
2,000	273.48	260.24	0.13674	0.13012	286.97	279.47	0.14349	0.13973	13.50	19.23	4.94%	7.39%	16.84	6.34%
2,500	334.99	318.44	0.13400	0.12738	350.69	341.31	0.14028	0.13652	15.70	22.86	4.69%	7.18%	19.88	6.11%
3,000	396.51	376.65	0.13217	0.12555	414.41	403.15	0.13814	0.13438	17.90	26.50	4.51%	7.04%	22.92	5.95%
3,500	458.02	434.85	0.13086	0.12424	478.13	464.99	0.13661	0.13285	20.11	30.14	4.39%	6.93%	25.96	5.84%
4,000	519.54	493.06	0.12988	0.12326	541.85	526.83	0.13546	0.13171	22.31	33.77	4.29%	6.85%	29.00	5.75%
5,000	642.57	609.47	0.12851	0.12189	669.29	650.52	0.13386	0.13010	26.72	41.05	4.16%	6.74%	35.08	5.63%
6,000	765.60	725.88	0.12760	0.12098	796.72	774.20	0.13279	0.12903	31.13	48.32	4.07%	6.66%	41.16	5.54%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY

EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED MRP RY1 RATES
SCHEDULE "GS D LV"
DISTRICT OF COLUMBIA

			CURRENT RATES				MRP RY1 RATES				INCREASE			
KW	Hours	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
			SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
10	100	1000	220.28	227.20	0.22028	0.22720	244.09	249.15	0.24409	0.24915	23.81	21.96	10.81%	9.67%
	200	2000	330.28	344.12	0.16514	0.17206	360.63	370.76	0.18031	0.18538	30.35	26.64	9.19%	7.74%
	300	3000	440.29	461.05	0.14676	0.15368	477.17	492.36	0.15906	0.16412	36.88	31.31	8.38%	6.79%
	400	4000	550.30	577.98	0.13757	0.14449	593.71	613.97	0.14843	0.15349	43.41	35.99	7.89%	6.23%
	500	5000	660.30	694.90	0.13206	0.13898	710.25	735.57	0.14205	0.14711	49.94	40.67	7.56%	5.85%
	600	6000	770.31	811.83	0.12838	0.13530	826.79	857.18	0.13780	0.14286	56.48	45.35	7.33%	5.59%
25	100	2,500	497.94	515.24	0.19917	0.20609	552.10	564.76	0.22084	0.22590	54.16	49.53	10.88%	9.61%
	200	5,000	772.95	807.55	0.15459	0.16151	843.45	868.77	0.16869	0.17375	70.49	61.22	9.12%	7.58%
	300	7,500	1,047.97	1,099.87	0.13973	0.14665	1,134.79	1,172.79	0.15131	0.15637	86.83	72.92	8.29%	6.63%
	400	10,000	1,322.98	1,392.18	0.13230	0.13922	1,426.14	1,476.80	0.14261	0.14768	103.16	84.61	7.80%	6.08%
	500	12,500	1,598.00	1,684.50	0.12784	0.13476	1,717.49	1,780.81	0.13740	0.14246	119.49	96.31	7.48%	5.72%
	600	15,000	1,873.01	1,976.81	0.12487	0.13179	2,008.84	2,084.82	0.13392	0.13899	135.83	108.01	7.25%	5.46%
50	100	5,000	960.70	995.30	0.19214	0.19906	1,065.45	1,090.77	0.21309	0.21815	104.74	95.47	10.90%	9.59%
	200	10,000	1,510.73	1,579.93	0.15107	0.15799	1,648.14	1,698.80	0.16481	0.16988	137.41	118.86	9.10%	7.52%
	300	15,000	2,060.76	2,164.56	0.13738	0.14430	2,230.84	2,306.82	0.14872	0.15379	170.08	142.26	8.25%	6.57%
	400	20,000	2,610.80	2,749.20	0.13054	0.13746	2,813.54	2,914.84	0.14068	0.14574	202.74	165.65	7.77%	6.03%
	500	25,000	3,160.83	3,333.83	0.12643	0.13335	3,396.23	3,522.87	0.13585	0.14091	235.41	189.04	7.45%	5.67%
	600	30,000	3,710.86	3,918.46	0.12370	0.13062	3,978.93	4,130.89	0.13263	0.13770	268.07	212.43	7.22%	5.42%
75	100	7,500	1,423.47	1,475.37	0.18980	0.19672	1,578.79	1,616.79	0.21051	0.21557	155.33	141.42	10.91%	9.59%
	200	15,000	2,248.51	2,352.31	0.14990	0.15682	2,452.84	2,528.82	0.16352	0.16859	204.33	176.51	9.09%	7.50%
	300	22,500	3,073.56	3,229.26	0.13660	0.14352	3,326.88	3,440.86	0.14786	0.15293	253.32	211.59	8.24%	6.55%
	400	30,000	3,898.61	4,106.21	0.12995	0.13687	4,200.93	4,352.89	0.14003	0.14510	302.32	246.68	7.75%	6.01%
	500	37,500	4,723.66	4,983.16	0.12596	0.13288	5,074.97	5,264.93	0.13533	0.14040	351.32	281.77	7.44%	5.65%
	600	45,000	5,548.70	5,860.10	0.12330	0.13022	5,949.02	6,176.96	0.13220	0.13727	400.32	316.86	7.21%	5.41%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED MRP RY1 RATES - DELIVERY ONLY
SCHEDULE "MGT LV "
DISTRICT OF COLUMBIA

HOURS		CURRENT RATES				MRP RY1 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**25 KW**				
200	5,000	872.54	872.54	0.17451	0.17451	748.18	748.21	0.14964	0.14964	(124.36)	(124.33)	-14.25%	-14.25%
300	7,500	942.31	942.31	0.12564	0.12564	824.52	824.57	0.10994	0.10994	(117.79)	(117.74)	-12.50%	-12.49%
400	10,000	1,012.07	1,012.07	0.10121	0.10121	900.86	900.92	0.09009	0.09009	(111.21)	(111.15)	-10.99%	-10.98%
500	12,500	1,081.84	1,081.84	0.08655	0.08655	977.21	977.28	0.07818	0.07818	(104.63)	(104.56)	-9.67%	-9.67%
600	15,000	1,151.61	1,151.61	0.07677	0.07677	1,053.55	1,053.64	0.07024	0.07024	(98.06)	(97.97)	-8.52%	-8.51%
									50 KW				
200	10,000	1,288.32	1,288.32	0.12883	0.12883	1,259.36	1,259.42	0.12594	0.12594	(28.96)	(28.90)	-2.25%	-2.24%
300	15,000	1,427.86	1,427.86	0.09519	0.09519	1,412.05	1,412.14	0.09414	0.09414	(15.81)	(15.72)	-1.11%	-1.10%
400	20,000	1,567.39	1,567.39	0.07837	0.07837	1,564.73	1,564.85	0.07824	0.07824	(2.66)	(2.54)	-0.17%	-0.16%
500	25,000	1,706.92	1,706.92	0.06828	0.06828	1,717.41	1,717.57	0.06870	0.06870	10.49	10.64	0.61%	0.62%
600	30,000	1,846.45	1,846.45	0.06155	0.06155	1,870.10	1,870.28	0.06234	0.06234	23.65	23.83	1.28%	1.29%
									75 KW				
200	15,000	1,704.11	1,704.11	0.11361	0.11361	1,770.55	1,770.64	0.11804	0.11804	66.44	66.53	3.90%	3.90%
300	22,500	1,913.40	1,913.40	0.08504	0.08504	1,999.57	1,999.71	0.08887	0.08888	86.17	86.30	4.50%	4.51%
400	30,000	2,122.70	2,122.70	0.07076	0.07076	2,228.60	2,228.78	0.07429	0.07429	105.90	106.08	4.99%	5.00%
500	37,500	2,332.00	2,332.00	0.06219	0.06219	2,457.62	2,457.85	0.06554	0.06554	125.62	125.85	5.39%	5.40%
600	45,000	2,541.30	2,541.30	0.05647	0.05647	2,686.65	2,686.92	0.05970	0.05971	145.35	145.62	5.72%	5.73%
									100 KW				
200	20,000	2,119.89	2,119.89	0.10599	0.10599	2,281.73	2,281.85	0.11409	0.11409	161.84	161.96	7.63%	7.64%
300	30,000	2,398.95	2,398.95	0.07997	0.07997	2,587.10	2,587.28	0.08624	0.08624	188.15	188.33	7.84%	7.85%
400	40,000	2,678.02	2,678.02	0.06695	0.06695	2,892.47	2,892.71	0.07231	0.07232	214.45	214.69	8.01%	8.02%
500	50,000	2,957.08	2,957.08	0.05914	0.05914	3,197.83	3,198.13	0.06396	0.06396	240.75	241.05	8.14%	8.15%
600	60,000	3,236.15	3,236.15	0.05394	0.05394	3,503.20	3,503.56	0.05839	0.05839	267.05	267.42	8.25%	8.26%

KWH DISTRIBUTION

		ON PK	INT	OFF PK
200	HOURS USE =	31%	29%	40%
300	HOURS USE =	33%	27%	40%
400	HOURS USE =	30%	26%	44%
500	HOURS USE =	27%	25%	48%
600	HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED MRP RY1 RATES - DELIVERY ONLY
SCHEDULE "MGT LV "
DISTRICT OF COLUMBIA

HOURS		CURRENT RATES				MRP RY1 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**200 KW**				
200	40,000	3,783.02	3,783.02	0.09458	0.09458	4,326.47	4,326.71	0.10816	0.10817	543.45	543.69	14.37%	14.37%
300	60,000	4,341.15	4,341.15	0.07235	0.07235	4,937.20	4,937.56	0.08229	0.08229	596.05	596.42	13.73%	13.74%
400	80,000	4,899.27	4,899.27	0.06124	0.06124	5,547.93	5,548.42	0.06935	0.06936	648.66	649.14	13.24%	13.25%
500	100,000	5,457.40	5,457.40	0.05457	0.05457	6,158.67	6,159.27	0.06159	0.06159	701.27	701.87	12.85%	12.86%
600	120,000	6,015.53	6,015.53	0.05013	0.05013	6,769.40	6,770.13	0.05641	0.05642	753.87	754.59	12.53%	12.54%
									400 KW				
200	80,000	7,109.27	7,109.27	0.08887	0.08887	8,415.93	8,416.42	0.10520	0.10521	1,306.66	1,307.14	18.38%	18.39%
300	120,000	8,225.53	8,225.53	0.06855	0.06855	9,637.40	9,638.13	0.08031	0.08032	1,411.87	1,412.59	17.16%	17.17%
400	160,000	9,341.79	9,341.79	0.05839	0.05839	10,858.87	10,859.84	0.06787	0.06787	1,517.08	1,518.05	16.24%	16.25%
500	200,000	10,458.05	10,458.05	0.05229	0.05229	12,080.34	12,081.55	0.06040	0.06041	1,622.29	1,623.50	15.51%	15.52%
600	240,000	11,574.30	11,574.30	0.04823	0.04823	13,301.81	13,303.25	0.05542	0.05543	1,727.51	1,728.95	14.93%	14.94%
									600 KW				
200	120,000	10,435.53	10,435.53	0.08696	0.08696	12,505.40	12,506.13	0.10421	0.10422	2,069.87	2,070.59	19.83%	19.84%
300	180,000	12,109.92	12,109.92	0.06728	0.06728	14,337.61	14,338.69	0.07965	0.07966	2,227.69	2,228.77	18.40%	18.40%
400	240,000	13,784.30	13,784.30	0.05743	0.05743	16,169.81	16,171.25	0.06737	0.06738	2,385.51	2,386.95	17.31%	17.32%
500	300,000	15,458.69	15,458.69	0.05153	0.05153	18,002.01	18,003.82	0.06001	0.06001	2,543.32	2,545.13	16.45%	16.46%
600	360,000	17,133.08	17,133.08	0.04759	0.04759	19,834.22	19,836.38	0.05510	0.05510	2,701.14	2,703.31	15.77%	15.78%
									800 KW				
200	160,000	13,761.79	13,761.79	0.08601	0.08601	16,594.87	16,595.84	0.10372	0.10372	2,833.08	2,834.05	20.59%	20.59%
300	240,000	15,994.30	15,994.30	0.06664	0.06664	19,037.81	19,039.25	0.07932	0.07933	3,043.51	3,044.95	19.03%	19.04%
400	320,000	18,226.82	18,226.82	0.05696	0.05696	21,480.75	21,482.67	0.06713	0.06713	3,253.93	3,255.86	17.85%	17.86%
500	400,000	20,459.33	20,459.33	0.05115	0.05115	23,923.68	23,926.09	0.05981	0.05982	3,464.35	3,466.76	16.93%	16.94%
600	480,000	22,691.85	22,691.85	0.04727	0.04727	26,366.62	26,369.51	0.05493	0.05494	3,674.77	3,677.66	16.19%	16.21%

KWH DISTRIBUTION

		ON PK	INT	OFF PK
200	HOURS USE =	31%	29%	40%
300	HOURS USE =	33%	27%	40%
400	HOURS USE =	30%	26%	44%
500	HOURS USE =	27%	25%	48%
600	HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY

EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED MRP RY1 RATES - DELIVERY ONLY
SCHEDULE "GT LV "
DISTRICT OF COLUMBIA

HOURS		CURRENT RATES				MRP RY1 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**100 KW**				
200	20,000	2,146.76	2,146.76	0.10734	0.10734	2,838.74	2,858.99	0.14194	0.14295	691.97	712.23	32.23%	33.18%
300	30,000	2,439.26	2,439.26	0.08131	0.08131	3,140.80	3,171.18	0.10469	0.10571	701.54	731.92	28.76%	30.01%
400	40,000	2,731.76	2,731.76	0.06829	0.06829	3,442.87	3,483.38	0.08607	0.08708	711.10	751.61	26.03%	27.51%
500	50,000	3,024.27	3,024.27	0.06049	0.06049	3,744.94	3,795.57	0.07490	0.07591	720.67	771.30	23.83%	25.50%
600	60,000	3,316.77	3,316.77	0.05528	0.05528	4,047.00	4,107.76	0.06745	0.06846	730.24	791.00	22.02%	23.85%
									300 KW				
200	60,000	5,526.77	5,526.77	0.09211	0.09211	6,635.00	6,695.76	0.11058	0.11160	1,108.24	1,169.00	20.05%	21.15%
300	90,000	6,404.27	6,404.27	0.07116	0.07116	7,541.20	7,632.35	0.08379	0.08480	1,136.93	1,228.08	17.75%	19.18%
400	120,000	7,281.77	7,281.77	0.06068	0.06068	8,447.40	8,568.93	0.07040	0.07141	1,165.63	1,287.15	16.01%	17.68%
500	150,000	8,159.28	8,159.28	0.05440	0.05440	9,353.61	9,505.51	0.06236	0.06337	1,194.33	1,346.23	14.64%	16.50%
600	180,000	9,036.78	9,036.78	0.05020	0.05020	10,259.81	10,442.09	0.05700	0.05801	1,223.02	1,405.31	13.53%	15.55%
									500 KW				
200	100,000	8,906.77	8,906.77	0.08907	0.08907	10,431.27	10,532.54	0.10431	0.10533	1,524.50	1,625.77	17.12%	18.25%
300	150,000	10,369.28	10,369.28	0.06913	0.06913	11,941.61	12,093.51	0.07961	0.08062	1,572.33	1,724.23	15.16%	16.63%
400	200,000	11,831.78	11,831.78	0.05916	0.05916	13,451.94	13,654.48	0.06726	0.06827	1,620.16	1,822.70	13.69%	15.41%
500	250,000	13,294.29	13,294.29	0.05318	0.05318	14,962.27	15,215.45	0.05985	0.06086	1,667.98	1,921.16	12.55%	14.45%
600	300,000	14,756.80	14,756.80	0.04919	0.04919	16,472.61	16,776.42	0.05491	0.05592	1,715.81	2,019.62	11.63%	13.69%
									1,000 KW				
200	200,000	17,356.78	17,356.78	0.08678	0.08678	19,921.94	20,124.48	0.09961	0.10062	2,565.16	2,767.70	14.78%	15.95%
300	300,000	20,281.80	20,281.80	0.06761	0.06761	22,942.61	23,246.42	0.07648	0.07749	2,660.81	2,964.62	13.12%	14.62%
400	400,000	23,206.81	23,206.81	0.05802	0.05802	25,963.28	26,368.36	0.06491	0.06592	2,756.47	3,161.55	11.88%	13.62%
500	500,000	26,131.82	26,131.82	0.05226	0.05226	28,983.95	29,490.30	0.05797	0.05898	2,852.13	3,358.48	10.91%	12.85%
600	600,000	29,056.83	29,056.83	0.04843	0.04843	32,004.62	32,612.24	0.05334	0.05435	2,947.79	3,555.40	10.14%	12.24%

KWH DISTRIBUTION

	ON PK	INT	OFF PK
200 HOURS USE =	31%	29%	40%
300 HOURS USE =	33%	27%	40%
400 HOURS USE =	30%	26%	44%
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POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED MRP RY1 RATES - DELIVERY ONLY
SCHEDULE "GT LV "
DISTRICT OF COLUMBIA

HOURS		CURRENT RATES				MRP RY1 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**2,000 KW**				
200	400,000	34,256.81	34,256.81	0.08564	0.08564	38,903.28	39,308.36	0.09726	0.09827	4,646.47	5,051.55	13.56%	14.75%
300	600,000	40,106.83	40,106.83	0.06684	0.06684	44,944.62	45,552.24	0.07491	0.07592	4,837.79	5,445.40	12.06%	13.58%
400	800,000	45,956.85	45,956.85	0.05745	0.05745	50,985.95	51,796.11	0.06373	0.06475	5,029.10	5,839.26	10.94%	12.71%
500	1,000,000	51,806.88	51,806.88	0.05181	0.05181	57,027.29	58,039.99	0.05703	0.05804	5,220.41	6,233.11	10.08%	12.03%
600	1,200,000	57,656.90	57,656.90	0.04805	0.04805	63,068.63	64,283.87	0.05256	0.05357	5,411.73	6,626.97	9.39%	11.49%
									4,000 KW				
200	800,000	68,056.85	68,056.85	0.08507	0.08507	76,865.95	77,676.11	0.09608	0.09710	8,809.10	9,619.26	12.94%	14.13%
300	1,200,000	79,756.90	79,756.90	0.06646	0.06646	88,948.63	90,163.87	0.07412	0.07514	9,191.73	10,406.97	11.52%	13.05%
400	1,600,000	91,456.95	91,456.95	0.05716	0.05716	101,031.31	102,651.63	0.06314	0.06416	9,574.36	11,194.68	10.47%	12.24%
500	2,000,000	103,157.00	103,157.00	0.05158	0.05158	113,113.98	115,139.38	0.05656	0.05757	9,956.99	11,982.39	9.65%	11.62%
600	2,400,000	114,857.04	114,857.04	0.04786	0.04786	125,196.66	127,627.14	0.05217	0.05318	10,339.62	12,770.09	9.00%	11.12%
									6,000 KW				
200	1,200,000	101,856.90	101,856.90	0.08488	0.08488	114,828.63	116,043.87	0.09569	0.09670	12,971.73	14,186.97	12.74%	13.93%
300	1,800,000	119,406.97	119,406.97	0.06634	0.06634	132,952.65	134,775.50	0.07386	0.07488	13,545.67	15,368.53	11.34%	12.87%
400	2,400,000	136,957.04	136,957.04	0.05707	0.05707	151,076.66	153,507.14	0.06295	0.06396	14,119.62	16,550.09	10.31%	12.08%
500	3,000,000	154,507.11	154,507.11	0.05150	0.05150	169,200.68	172,238.77	0.05640	0.05741	14,693.56	17,731.66	9.51%	11.48%
600	3,600,000	172,057.19	172,057.19	0.04779	0.04779	187,324.69	190,970.41	0.05203	0.05305	15,267.51	18,913.22	8.87%	10.99%
									8,000 KW				
200	1,600,000	135,656.95	135,656.95	0.08479	0.08479	152,791.31	154,411.63	0.09549	0.09651	17,134.36	18,754.68	12.63%	13.83%
300	2,400,000	159,057.04	159,057.04	0.06627	0.06627	176,956.66	179,387.14	0.07373	0.07474	17,899.62	20,330.09	11.25%	12.78%
400	3,200,000	182,457.14	182,457.14	0.05702	0.05702	201,122.02	204,362.65	0.06285	0.06386	18,664.88	21,905.51	10.23%	12.01%
500	4,000,000	205,857.23	205,857.23	0.05146	0.05146	225,287.37	229,338.16	0.05632	0.05733	19,430.14	23,480.93	9.44%	11.41%
600	4,800,000	229,257.33	229,257.33	0.04776	0.04776	249,452.72	254,313.68	0.05197	0.05298	20,195.39	25,056.35	8.81%	10.93%

KWH DISTRIBUTION

		ON PK	INT	OFF PK
200	HOURS USE =	31%	29%	40%
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POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED MRP RY1 RATES - DELIVERY ONLY
SCHEDULE "GT 3A "
DISTRICT OF COLUMBIA

HOURS		CURRENT RATES				MRP RY1 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**1,000 KW**				
200	200,000	12,190.78	12,188.78	0.06095	0.06094	13,795.73	13,714.46	0.06898	0.06857	1,604.95	1,525.67	13.17%	12.52%
300	300,000	14,067.36	14,064.36	0.04689	0.04688	15,764.86	15,642.94	0.05255	0.05214	1,697.50	1,578.58	12.07%	11.22%
400	400,000	15,943.93	15,939.93	0.03986	0.03985	17,733.98	17,571.43	0.04433	0.04393	1,790.05	1,631.50	11.23%	10.24%
500	500,000	17,820.50	17,815.50	0.03564	0.03563	19,703.10	19,499.91	0.03941	0.03900	1,882.60	1,684.41	10.56%	9.45%
600	600,000	19,697.07	19,691.07	0.03283	0.03282	21,672.23	21,428.39	0.03612	0.03571	1,975.15	1,737.32	10.03%	8.82%
									2,000 KW				
200	400,000	24,193.93	24,189.93	0.06048	0.06047	27,393.98	27,231.43	0.06848	0.06808	3,200.05	3,041.50	13.23%	12.57%
300	600,000	27,947.07	27,941.07	0.04658	0.04657	31,332.23	31,088.39	0.05222	0.05181	3,385.15	3,147.32	12.11%	11.26%
400	800,000	31,700.22	31,692.22	0.03963	0.03962	35,270.47	34,945.36	0.04409	0.04368	3,570.26	3,253.15	11.26%	10.26%
500	1,000,000	35,453.36	35,443.36	0.03545	0.03544	39,208.72	38,802.33	0.03921	0.03880	3,755.36	3,358.97	10.59%	9.48%
600	1,200,000	39,206.51	39,194.51	0.03267	0.03266	43,146.96	42,659.30	0.03596	0.03555	3,940.46	3,464.79	10.05%	8.84%
									5,000 KW				
200	1,000,000	60,203.36	60,193.36	0.06020	0.06019	68,188.72	67,782.33	0.06819	0.06778	7,985.36	7,588.97	13.26%	12.61%
300	1,500,000	69,586.22	69,571.22	0.04639	0.04638	78,034.33	77,424.75	0.05202	0.05162	8,448.11	7,853.53	12.14%	11.29%
400	2,000,000	78,969.08	78,949.08	0.03948	0.03947	87,879.95	87,067.18	0.04394	0.04353	8,910.87	8,118.09	11.28%	10.28%
500	2,500,000	88,351.94	88,326.94	0.03534	0.03533	97,725.56	96,709.60	0.03909	0.03868	9,373.62	8,382.65	10.61%	9.49%
600	3,000,000	97,734.80	97,704.80	0.03258	0.03257	107,571.18	106,352.02	0.03586	0.03545	9,836.38	8,647.22	10.06%	8.85%
									7,500 KW				
200	1,500,000	90,211.22	90,196.22	0.06014	0.06013	102,184.33	101,574.75	0.06812	0.06772	11,973.11	11,378.53	13.27%	12.62%
300	2,250,000	104,285.51	104,263.01	0.04635	0.04634	116,952.76	116,038.39	0.05198	0.05157	12,667.24	11,775.37	12.15%	11.29%
400	3,000,000	118,359.80	118,329.80	0.03945	0.03944	131,721.18	130,502.02	0.04391	0.04350	13,361.38	12,172.22	11.29%	10.29%
500	3,750,000	132,434.10	132,396.60	0.03532	0.03531	146,489.60	144,965.65	0.03906	0.03866	14,055.51	12,569.06	10.61%	9.49%
600	4,500,000	146,508.39	146,463.39	0.03256	0.03255	161,258.03	159,429.29	0.03584	0.03543	14,749.64	12,965.90	10.07%	8.85%

KWH DISTRIBUTION

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POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED MRP RY1 RATES - DELIVERY ONLY
SCHEDULE "GT 3A "
DISTRICT OF COLUMBIA

HOURS		CURRENT RATES				MRP RY1 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**10,000 KW**				
200	2,000,000	120,219.08	120,199.08	0.06011	0.06010	136,179.95	135,367.18	0.06809	0.06768	15,960.87	15,168.09	13.28%	12.62%
300	3,000,000	138,984.80	138,954.80	0.04633	0.04632	155,871.18	154,652.02	0.05196	0.05155	16,886.38	15,697.22	12.15%	11.30%
400	4,000,000	157,750.53	157,710.53	0.03944	0.03943	175,562.41	173,936.86	0.04389	0.04348	17,811.88	16,226.34	11.29%	10.29%
500	5,000,000	176,516.25	176,466.25	0.03530	0.03529	195,253.64	193,221.71	0.03905	0.03864	18,737.39	16,755.46	10.62%	9.49%
600	6,000,000	195,281.97	195,221.97	0.03255	0.03254	214,944.87	212,506.55	0.03582	0.03542	19,662.90	17,284.58	10.07%	8.85%
									20,000 KW				
200	4,000,000	240,250.53	240,210.53	0.06006	0.06005	272,162.41	270,536.86	0.06804	0.06763	31,911.88	30,326.34	13.28%	12.62%
300	6,000,000	277,781.97	277,721.97	0.04630	0.04629	311,544.87	309,106.55	0.05192	0.05152	33,762.90	31,384.58	12.15%	11.30%
400	8,000,000	315,313.41	315,233.41	0.03941	0.03940	350,927.33	347,676.24	0.04387	0.04346	35,613.92	32,442.83	11.29%	10.29%
500	10,000,000	352,844.86	352,744.86	0.03528	0.03527	390,309.80	386,245.93	0.03903	0.03862	37,464.94	33,501.07	10.62%	9.50%
600	12,000,000	390,376.30	390,256.30	0.03253	0.03252	429,692.26	424,815.62	0.03581	0.03540	39,315.96	34,559.32	10.07%	8.86%
									30,000 KW				
200	6,000,000	360,281.97	360,221.97	0.06005	0.06004	408,144.87	405,706.55	0.06802	0.06762	47,862.90	45,484.58	13.28%	12.63%
300	9,000,000	416,579.13	416,489.13	0.04629	0.04628	467,218.56	463,561.08	0.05191	0.05151	50,639.43	47,071.95	12.16%	11.30%
400	12,000,000	472,876.30	472,756.30	0.03941	0.03940	526,292.26	521,415.62	0.04386	0.04345	53,415.96	48,659.32	11.30%	10.29%
500	15,000,000	529,173.46	529,023.46	0.03528	0.03527	585,365.95	579,270.15	0.03902	0.03862	56,192.49	50,246.68	10.62%	9.50%
600	18,000,000	585,470.63	585,290.63	0.03253	0.03252	644,439.64	637,124.68	0.03580	0.03540	58,969.01	51,834.05	10.07%	8.86%
									40,000 KW				
200	8,000,000	480,313.41	480,233.41	0.06004	0.06003	544,127.33	540,876.24	0.06802	0.06761	63,813.92	60,642.83	13.29%	12.63%
300	12,000,000	555,376.30	555,256.30	0.04628	0.04627	622,892.26	618,015.62	0.05191	0.05150	67,515.96	62,759.32	12.16%	11.30%
400	16,000,000	630,439.19	630,279.19	0.03940	0.03939	701,657.18	695,154.99	0.04385	0.04345	71,217.99	64,875.81	11.30%	10.29%
500	20,000,000	705,502.07	705,302.07	0.03528	0.03527	780,422.10	772,294.37	0.03902	0.03861	74,920.03	66,992.30	10.62%	9.50%
600	24,000,000	780,564.96	780,324.96	0.03252	0.03251	859,187.03	849,433.74	0.03580	0.03539	78,622.07	69,108.78	10.07%	8.86%

KWH DISTRIBUTION

	ON PK	INT	OFF PK
200 HOURS USE =	31%	29%	40%
300 HOURS USE =	33%	27%	40%
400 HOURS USE =	30%	26%	44%
500 HOURS USE =	27%	25%	48%
600 HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED MRP RY1 RATES - DELIVERY ONLY
SCHEDULE "GT 3B "
DISTRICT OF COLUMBIA

HOURS		CURRENT RATES				MRP RY1 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**10,000 KW**				
200	2,000,000	37,595.79	38,395.79	0.01880	0.01920	38,068.00	41,511.55	0.01903	0.02076	472.21	3,115.76	1.26%	8.11%
300	3,000,000	50,282.00	51,082.00	0.01676	0.01703	50,807.20	54,250.75	0.01694	0.01808	525.21	3,168.75	1.04%	6.20%
400	4,000,000	62,968.20	63,768.20	0.01574	0.01594	63,546.40	66,989.95	0.01589	0.01675	578.20	3,221.75	0.92%	5.05%
500	5,000,000	75,654.41	76,454.41	0.01513	0.01529	76,285.60	79,729.15	0.01526	0.01595	631.20	3,274.74	0.83%	4.28%
600	6,000,000	88,340.61	89,140.61	0.01472	0.01486	89,024.80	92,468.35	0.01484	0.01541	684.19	3,327.73	0.77%	3.73%
									20,000 KW				
200	4,000,000	74,768.20	76,368.20	0.01869	0.01909	75,824.35	82,711.44	0.01896	0.02068	1,056.15	6,343.24	1.41%	8.31%
300	6,000,000	100,140.61	101,740.61	0.01669	0.01696	101,302.75	108,189.84	0.01688	0.01803	1,162.14	6,449.23	1.16%	6.34%
400	8,000,000	125,513.03	127,113.03	0.01569	0.01589	126,781.15	133,668.24	0.01585	0.01671	1,268.13	6,555.22	1.01%	5.16%
500	10,000,000	150,885.44	152,485.44	0.01509	0.01525	152,259.55	159,146.64	0.01523	0.01591	1,374.12	6,661.20	0.91%	4.37%
600	12,000,000	176,257.85	177,857.85	0.01469	0.01482	177,737.95	184,625.04	0.01481	0.01539	1,480.10	6,767.19	0.84%	3.80%
									30,000 KW				
200	6,000,000	111,940.61	114,340.61	0.01866	0.01906	113,580.70	123,911.33	0.01893	0.02065	1,640.09	9,570.72	1.47%	8.37%
300	9,000,000	149,999.23	152,399.23	0.01667	0.01693	151,798.30	162,128.93	0.01687	0.01801	1,799.07	9,729.70	1.20%	6.38%
400	12,000,000	188,057.85	190,457.85	0.01567	0.01587	190,015.90	200,346.53	0.01583	0.01670	1,958.05	9,888.68	1.04%	5.19%
500	15,000,000	226,116.46	228,516.46	0.01507	0.01523	228,233.50	238,564.13	0.01522	0.01590	2,117.04	10,047.67	0.94%	4.40%
600	18,000,000	264,175.08	266,575.08	0.01468	0.01481	266,451.10	276,781.73	0.01480	0.01538	2,276.02	10,206.65	0.86%	3.83%
									40,000 KW				
200	8,000,000	149,113.03	152,313.03	0.01864	0.01904	151,337.05	165,111.22	0.01892	0.02064	2,224.02	12,798.20	1.49%	8.40%
300	12,000,000	199,857.85	203,057.85	0.01665	0.01692	202,293.85	216,068.02	0.01686	0.01801	2,436.00	13,010.18	1.22%	6.41%
400	16,000,000	250,602.67	253,802.67	0.01566	0.01586	253,250.65	267,024.82	0.01583	0.01669	2,647.98	13,222.15	1.06%	5.21%
500	20,000,000	301,347.49	304,547.49	0.01507	0.01523	304,207.45	317,981.62	0.01521	0.01590	2,859.95	13,434.13	0.95%	4.41%
600	24,000,000	352,092.32	355,292.32	0.01467	0.01480	355,164.25	368,938.42	0.01480	0.01537	3,071.93	13,646.11	0.87%	3.84%

KWH DISTRIBUTION

	ON PK	INT	OFF PK
200 HOURS USE =	31%	29%	40%
300 HOURS USE =	33%	27%	40%
400 HOURS USE =	30%	26%	44%
500 HOURS USE =	27%	25%	48%
600 HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY1 RATES AND PROPOSED MRP RY2 RATES
SCHEDULE "R"
DISTRICT OF COLUMBIA

	MRP RY1 RATES				MRP RY2 RATES				INCREASE					
KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)	($)	(%)
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	ANNUAL	ANNUAL
0	20.50	20.58	-	-	22.12	22.20	-	-	1.62	1.62	7.90%	7.87%	1.62	7.88%
10	20.82	20.90	2.08180	2.08980	22.46	22.54	2.24562	2.25362	1.64	1.64	7.88%	7.85%	1.64	7.86%
20	21.14	21.22	1.05680	1.06080	22.79	22.87	1.13962	1.14362	1.66	1.66	7.85%	7.82%	1.66	7.84%
30	21.45	21.53	0.71514	0.71780	23.13	23.21	0.77095	0.77362	1.67	1.67	7.78%	7.76%	1.67	7.77%
40	22.43	22.53	0.56067	0.56333	24.12	24.23	0.60299	0.60564	1.69	1.69	7.54%	7.50%	1.69	7.51%
50	23.40	23.53	0.46799	0.47064	25.11	25.24	0.50221	0.50486	1.71	1.71	7.31%	7.27%	1.71	7.28%
100	28.26	28.53	0.28263	0.28527	30.06	30.33	0.30065	0.30329	1.80	1.80	6.37%	6.31%	1.80	6.33%
200	37.99	38.52	0.18995	0.19259	39.97	40.50	0.19987	0.20250	1.98	1.98	5.21%	5.14%	1.98	5.17%
300	47.72	48.51	0.15906	0.16169	49.88	50.67	0.16628	0.16891	2.16	2.16	4.53%	4.45%	2.16	4.48%
400	57.45	58.50	0.14361	0.14625	59.79	60.84	0.14948	0.15211	2.35	2.35	4.09%	4.02%	2.35	4.05%
500	69.32	69.77	0.13863	0.13954	72.19	72.53	0.14438	0.14505	2.87	2.75	4.14%	3.94%	2.80	4.02%
692	**92.10**	**91.42**	**0.13310**	**0.13211**	**95.99**	**94.95**	**0.13871**	**0.13722**	**3.89**	**3.54**	**4.22%**	**3.87%**	**3.69**	**4.02%**
700	93.05	92.32	0.13293	0.13188	96.98	95.89	0.13854	0.13698	3.93	3.57	4.22%	3.87%	3.72	4.02%
750	98.99	97.96	0.13198	0.13061	103.18	101.73	0.13757	0.13564	4.19	3.77	4.23%	3.85%	3.95	4.01%
800	104.92	103.59	0.13115	0.12949	109.38	107.57	0.13672	0.13446	4.45	3.98	4.24%	3.84%	4.18	4.01%
850	110.86	109.23	0.13042	0.12851	115.58	113.41	0.13597	0.13342	4.72	4.18	4.26%	3.83%	4.41	4.01%
900	116.79	114.87	0.12977	0.12763	121.77	119.25	0.13530	0.13250	4.98	4.38	4.26%	3.81%	4.63	4.00%
950	122.73	120.50	0.12919	0.12685	127.97	125.09	0.13471	0.13168	5.25	4.59	4.28%	3.81%	4.87	4.01%
1,000	128.66	126.14	0.12866	0.12614	134.17	130.93	0.13417	0.13093	5.51	4.79	4.28%	3.80%	5.09	4.00%
1,250	158.34	154.32	0.12667	0.12346	165.16	160.14	0.13213	0.12811	6.83	5.81	4.31%	3.76%	6.24	4.00%
1,500	188.01	182.51	0.12534	0.12167	196.15	189.34	0.13077	0.12623	8.14	6.83	4.33%	3.74%	7.38	3.99%
1,750	217.68	210.69	0.12439	0.12040	227.15	218.54	0.12980	0.12488	9.46	7.85	4.35%	3.73%	8.52	3.99%
2,000	247.36	238.88	0.12368	0.11944	258.14	247.74	0.12907	0.12387	10.78	8.87	4.36%	3.71%	9.67	3.99%
2,250	277.03	267.06	0.12312	0.11869	289.13	276.95	0.12850	0.12309	12.10	9.89	4.37%	3.70%	10.81	3.99%
2,500	306.70	295.24	0.12268	0.11810	320.12	306.15	0.12805	0.12246	13.42	10.91	4.38%	3.70%	11.96	3.99%
3,000	366.05	351.61	0.12202	0.11720	382.10	364.56	0.12737	0.12152	16.05	12.95	4.38%	3.68%	14.24	3.98%
3,500	425.40	407.98	0.12154	0.11657	444.09	422.96	0.12688	0.12085	18.69	14.98	4.39%	3.67%	16.53	3.98%
4,000	484.75	464.35	0.12119	0.11609	506.07	481.37	0.12652	0.12034	21.32	17.02	4.40%	3.67%	18.81	3.98%
5,000	603.44	577.08	0.12069	0.11542	630.03	598.18	0.12601	0.11964	26.59	21.10	4.41%	3.66%	23.39	3.98%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY1 RATES AND PROPOSED MRP RY2 RATES
SCHEDULE "MMA"
DISTRICT OF COLUMBIA

	MRP RY1 RATES				MRP RY2 RATES				INCREASE					
KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)	($)	(%)
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	ANNUAL	ANNUAL
0	15.64	16.06	-	-	16.63	17.05	-	-	0.99	0.99	6.33%	6.16%	0.99	6.23%
100	22.25	23.64	0.22251	0.23636	23.36	24.74	0.23357	0.24742	1.11	1.11	4.99%	4.70%	1.11	4.81%
200	30.60	33.36	0.15300	0.16681	31.82	34.58	0.15910	0.17291	1.22	1.22	3.99%	3.66%	1.22	3.79%
300	38.95	43.09	0.12982	0.14363	40.28	44.42	0.13428	0.14808	1.34	1.34	3.44%	3.11%	1.34	3.24%
400	47.30	52.81	0.11824	0.13203	48.75	54.27	0.12187	0.13566	1.45	1.45	3.07%	2.75%	1.45	2.87%
500	57.33	63.07	0.11467	0.12613	59.10	64.69	0.11821	0.12937	1.77	1.62	3.09%	2.57%	1.68	2.77%
1000	107.53	114.33	0.10753	0.11433	110.89	116.79	0.11089	0.11679	3.36	2.46	3.12%	2.15%	2.84	2.54%
2000	207.91	216.86	0.10395	0.10843	214.46	221.00	0.10723	0.11050	6.55	4.14	3.15%	1.91%	5.14	2.41%
3000	308.29	319.39	0.10276	0.10646	318.02	325.20	0.10601	0.10840	9.73	5.82	3.16%	1.82%	7.45	2.37%
4000	408.67	421.91	0.10217	0.10548	421.59	429.41	0.10540	0.10735	12.92	7.50	3.16%	1.78%	9.76	2.34%
5000	509.06	524.44	0.10181	0.10489	525.16	533.62	0.10503	0.10672	16.10	9.17	3.16%	1.75%	12.06	2.33%
6000	609.44	626.97	0.10157	0.10450	628.73	637.82	0.10479	0.10630	19.28	10.85	3.16%	1.73%	14.36	2.32%
7000	709.82	729.50	0.10140	0.10421	732.29	742.03	0.10461	0.10600	22.47	12.53	3.17%	1.72%	16.67	2.31%
7500	760.02	780.76	0.10134	0.10410	784.08	794.13	0.10454	0.10588	24.06	13.37	3.17%	1.71%	17.82	2.31%
8000	810.21	832.03	0.10128	0.10400	835.86	846.24	0.10448	0.10578	25.65	14.21	3.17%	1.71%	18.98	2.31%
8500	860.40	883.29	0.10122	0.10392	887.64	898.34	0.10443	0.10569	27.25	15.05	3.17%	1.70%	20.13	2.30%
9000	910.59	934.56	0.10118	0.10384	939.43	950.45	0.10438	0.10561	28.84	15.89	3.17%	1.70%	21.29	2.30%
9500	960.78	985.82	0.10113	0.10377	991.21	1,002.55	0.10434	0.10553	30.43	16.73	3.17%	1.70%	22.44	2.30%
10000	1,010.97	1,037.08	0.10110	0.10371	1,043.00	1,054.65	0.10430	0.10547	32.02	17.57	3.17%	1.69%	23.59	2.30%
12500	1,261.93	1,293.40	0.10095	0.10347	1,301.91	1,315.17	0.10415	0.10521	39.98	21.77	3.17%	1.68%	29.36	2.29%
15000	1,512.89	1,549.72	0.10086	0.10331	1,560.83	1,575.69	0.10406	0.10505	47.94	25.96	3.17%	1.68%	35.12	2.29%
17500	1,763.85	1,806.04	0.10079	0.10320	1,819.75	1,836.20	0.10399	0.10493	55.90	30.16	3.17%	1.67%	40.89	2.29%
20000	2,014.80	2,062.36	0.10074	0.10312	2,078.67	2,096.72	0.10393	0.10484	63.87	34.36	3.17%	1.67%	46.66	2.28%
22500	2,265.76	2,318.68	0.10070	0.10305	2,337.59	2,357.24	0.10389	0.10477	71.83	38.55	3.17%	1.66%	52.42	2.28%
25000	2,516.72	2,575.00	0.10067	0.10300	2,596.51	2,617.76	0.10386	0.10471	79.79	42.75	3.17%	1.66%	58.18	2.28%
30000	3,018.64	3,087.65	0.10062	0.10292	3,114.35	3,138.79	0.10381	0.10463	95.71	51.15	3.17%	1.66%	69.72	2.28%
35000	3,520.55	3,600.29	0.10059	0.10287	3,632.18	3,659.83	0.10378	0.10457	111.63	59.54	3.17%	1.65%	81.24	2.28%
40000	4,022.47	4,112.93	0.10056	0.10282	4,150.02	4,180.86	0.10375	0.10452	127.55	67.93	3.17%	1.65%	92.77	2.28%
50000	5,026.30	5,138.21	0.10053	0.10276	5,185.70	5,222.93	0.10371	0.10446	159.40	84.72	3.17%	1.65%	115.84	2.28%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY

EXAMPLES COMPARING BILLS UNDER MRP RY1 RATES AND PROPOSED MRP RY2 RATES
SCHEDULE "GS ND"
DISTRICT OF COLUMBIA

	MRP RY1 RATES				MRP RY2 RATES				INCREASE					
KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)	($)	(%)
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	ANNUAL	ANNUAL
0	32.10	32.10	-	-	34.33	34.33	-	-	2.23	2.23	6.95%	6.95%	2.23	6.95%
10	33.40	33.37	3.34039	3.33663	35.64	35.60	3.56430	3.56002	2.24	2.23	6.71%	6.68%	2.23	6.69%
20	34.71	34.63	1.73539	1.73163	36.96	36.87	1.84780	1.84352	2.25	2.24	6.48%	6.47%	2.24	6.47%
30	36.01	35.90	1.20039	1.19663	38.27	38.14	1.27563	1.27135	2.26	2.24	6.28%	6.24%	2.25	6.25%
40	37.32	37.17	0.93289	0.92913	39.58	39.41	0.98955	0.98527	2.27	2.25	6.08%	6.05%	2.26	6.07%
50	38.62	38.43	0.77239	0.76863	40.89	40.68	0.81790	0.81362	2.28	2.25	5.90%	5.85%	2.26	5.88%
100	45.14	44.76	0.45139	0.44763	47.46	47.03	0.47460	0.47032	2.32	2.27	5.14%	5.07%	2.29	5.10%
150	51.66	51.10	0.34439	0.34063	54.02	53.38	0.36016	0.35589	2.37	2.29	4.59%	4.48%	2.32	4.53%
200	58.18	57.43	0.29089	0.28713	60.59	59.73	0.30295	0.29867	2.41	2.31	4.14%	4.02%	2.35	4.07%
250	64.70	63.76	0.25879	0.25503	67.15	66.09	0.26862	0.26434	2.46	2.33	3.80%	3.65%	2.38	3.72%
300	71.22	70.09	0.23739	0.23363	73.72	72.44	0.24573	0.24145	2.50	2.35	3.51%	3.35%	2.41	3.42%
400	84.26	82.75	0.21064	0.20688	86.85	85.14	0.21712	0.21285	2.59	2.38	3.07%	2.88%	2.47	2.96%
500	97.29	95.42	0.19459	0.19083	99.98	97.84	0.19996	0.19568	2.68	2.42	2.75%	2.54%	2.53	2.63%
600	110.33	108.08	0.18389	0.18013	113.11	110.54	0.18851	0.18424	2.78	2.46	2.52%	2.28%	2.59	2.38%
700	123.37	120.74	0.17625	0.17249	126.24	123.24	0.18034	0.17606	2.87	2.50	2.33%	2.07%	2.65	2.18%
800	136.41	133.41	0.17051	0.16676	139.37	135.95	0.17421	0.16993	2.96	2.54	2.17%	1.90%	2.72	2.02%
900	149.45	146.07	0.16606	0.16230	152.50	148.65	0.16944	0.16517	3.05	2.58	2.04%	1.77%	2.78	1.88%
1,000	162.49	158.73	0.16249	0.15873	165.63	161.35	0.16563	0.16135	3.14	2.62	1.93%	1.65%	2.84	1.77%
1,250	195.09	190.39	0.15607	0.15231	198.45	193.11	0.15876	0.15448	3.37	2.71	1.73%	1.42%	2.99	1.55%
1,500	227.68	222.05	0.15179	0.14803	231.28	224.86	0.15418	0.14991	3.59	2.81	1.58%	1.27%	3.14	1.40%
1,750	260.28	253.71	0.14873	0.14498	264.10	256.62	0.15092	0.14664	3.82	2.91	1.47%	1.15%	3.29	1.28%
2,000	292.88	285.37	0.14644	0.14268	296.93	288.37	0.14846	0.14419	4.05	3.00	1.38%	1.05%	3.44	1.19%
2,500	358.07	348.69	0.14323	0.13947	362.58	351.88	0.14503	0.14075	4.50	3.20	1.26%	0.92%	3.74	1.06%
3,000	423.27	412.00	0.14109	0.13733	428.22	415.39	0.14274	0.13846	4.96	3.39	1.17%	0.82%	4.04	0.97%
3,500	488.46	475.32	0.13956	0.13581	493.87	478.90	0.14111	0.13683	5.41	3.58	1.11%	0.75%	4.34	0.90%
4,000	553.65	538.64	0.13841	0.13466	559.52	542.41	0.13988	0.13560	5.87	3.78	1.06%	0.70%	4.65	0.85%
5,000	684.04	665.27	0.13681	0.13305	690.82	669.43	0.13816	0.13389	6.78	4.16	0.99%	0.63%	5.25	0.78%
6,000	814.43	791.91	0.13574	0.13198	822.12	796.45	0.13702	0.13274	7.69	4.55	0.94%	0.57%	5.86	0.73%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY

EXAMPLES COMPARING BILLS UNDER MRP RY1 RATES AND PROPOSED MRP RY2 RATES
SCHEDULE "GS D LV"
DISTRICT OF COLUMBIA

			MRP RY1 RATES				MRP RY2 RATES				INCREASE			
KW	Hours	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
			SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
10	100	1000	244.09	249.15	0.24409	0.24915	254.36	258.49	0.25436	0.25849	10.27	9.33	4.21%	3.74%
	200	2000	360.63	370.76	0.18031	0.18538	374.48	382.73	0.18724	0.19137	13.85	11.97	3.84%	3.23%
	300	3000	477.17	492.36	0.15906	0.16412	494.60	506.98	0.16487	0.16899	17.44	14.62	3.65%	2.97%
	400	4000	593.71	613.97	0.14843	0.15349	614.72	631.23	0.15368	0.15781	21.02	17.26	3.54%	2.81%
	500	5000	710.25	735.57	0.14205	0.14711	734.85	755.47	0.14697	0.15109	24.60	19.90	3.46%	2.71%
	600	6000	826.79	857.18	0.13780	0.14286	854.97	879.72	0.14249	0.14662	28.18	22.54	3.41%	2.63%
25	100	2,500	552.10	564.76	0.22084	0.22590	577.78	588.09	0.23111	0.23524	25.68	23.33	4.65%	4.13%
	200	5,000	843.45	868.77	0.16869	0.17375	878.08	898.71	0.17562	0.17974	34.63	29.93	4.11%	3.45%
	300	7,500	1,134.79	1,172.79	0.15131	0.15637	1,178.38	1,209.33	0.15712	0.16124	43.59	36.54	3.84%	3.12%
	400	10,000	1,426.14	1,476.80	0.14261	0.14768	1,478.69	1,519.94	0.14787	0.15199	52.54	43.15	3.68%	2.92%
	500	12,500	1,717.49	1,780.81	0.13740	0.14246	1,778.99	1,830.56	0.14232	0.14644	61.50	49.75	3.58%	2.79%
	600	15,000	2,008.84	2,084.82	0.13392	0.13899	2,079.30	2,141.18	0.13862	0.14275	70.46	56.36	3.51%	2.70%
50	100	5,000	1,065.45	1,090.77	0.21309	0.21815	1,116.80	1,137.43	0.22336	0.22749	51.35	46.66	4.82%	4.28%
	200	10,000	1,648.14	1,698.80	0.16481	0.16988	1,717.41	1,758.67	0.17174	0.17587	69.27	59.87	4.20%	3.52%
	300	15,000	2,230.84	2,306.82	0.14872	0.15379	2,318.02	2,379.90	0.15453	0.15866	87.18	73.08	3.91%	3.17%
	400	20,000	2,813.54	2,914.84	0.14068	0.14574	2,918.63	3,001.14	0.14593	0.15006	105.09	86.29	3.74%	2.96%
	500	25,000	3,396.23	3,522.87	0.13585	0.14091	3,519.23	3,622.37	0.14077	0.14489	123.00	99.50	3.62%	2.82%
	600	30,000	3,978.93	4,130.89	0.13263	0.13770	4,119.84	4,243.61	0.13733	0.14145	140.91	112.72	3.54%	2.73%
75	100	7,500	1,578.79	1,616.79	0.21051	0.21557	1,655.83	1,686.77	0.22078	0.22490	77.03	69.98	4.88%	4.33%
	200	15,000	2,452.84	2,528.82	0.16352	0.16859	2,556.74	2,618.62	0.17045	0.17457	103.90	89.80	4.24%	3.55%
	300	22,500	3,326.88	3,440.86	0.14786	0.15293	3,457.65	3,550.48	0.15367	0.15780	130.77	109.62	3.93%	3.19%
	400	30,000	4,200.93	4,352.89	0.14003	0.14510	4,358.56	4,482.33	0.14529	0.14941	157.63	129.44	3.75%	2.97%
	500	37,500	5,074.97	5,264.93	0.13533	0.14040	5,259.48	5,414.19	0.14025	0.14438	184.50	149.26	3.64%	2.83%
	600	45,000	5,949.02	6,176.96	0.13220	0.13727	6,160.39	6,346.04	0.13690	0.14102	211.37	169.08	3.55%	2.74%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY1 RATES AND PROPOSED MRP RY2 RATES - DELIVERY ONLY
SCHEDULE "MGT LV "
DISTRICT OF COLUMBIA

HOURS		MRP RY1 RATES				MRP RY2 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**25 KW**				
200	5,000	764.48	764.51	0.15290	0.15290	785.10	785.01	0.15702	0.15700	20.62	20.50	2.70%	2.68%
300	7,500	848.97	849.01	0.11320	0.11320	866.27	866.14	0.11550	0.11548	17.30	17.12	2.04%	2.02%
400	10,000	933.46	933.52	0.09335	0.09335	947.44	947.27	0.09474	0.09473	13.99	13.75	1.50%	1.47%
500	12,500	1,017.95	1,018.02	0.08144	0.08144	1,028.62	1,028.40	0.08229	0.08227	10.67	10.37	1.05%	1.02%
600	15,000	1,102.44	1,102.53	0.07350	0.07350	1,109.79	1,109.53	0.07399	0.07397	7.35	7.00	0.67%	0.63%
									50 KW				
200	10,000	1,291.96	1,292.02	0.12920	0.12920	1,333.19	1,333.02	0.13332	0.13330	41.24	41.00	3.19%	3.17%
300	15,000	1,460.94	1,461.03	0.09740	0.09740	1,495.54	1,495.28	0.09970	0.09969	34.60	34.25	2.37%	2.34%
400	20,000	1,629.92	1,630.04	0.08150	0.08150	1,657.89	1,657.53	0.08289	0.08288	27.97	27.49	1.72%	1.69%
500	25,000	1,798.90	1,799.05	0.07196	0.07196	1,820.24	1,819.79	0.07281	0.07279	21.34	20.74	1.19%	1.15%
600	30,000	1,967.88	1,968.06	0.06560	0.06560	1,982.59	1,982.05	0.06609	0.06607	14.71	13.99	0.75%	0.71%
									75 KW				
200	15,000	1,819.44	1,819.53	0.12130	0.12130	1,881.29	1,881.03	0.12542	0.12540	61.85	61.50	3.40%	3.38%
300	22,500	2,072.91	2,073.05	0.09213	0.09214	2,124.82	2,124.41	0.09444	0.09442	51.91	51.37	2.50%	2.48%
400	30,000	2,326.38	2,326.56	0.07755	0.07755	2,368.34	2,367.80	0.07894	0.07893	41.96	41.24	1.80%	1.77%
500	37,500	2,579.85	2,580.08	0.06880	0.06880	2,611.86	2,611.19	0.06965	0.06963	32.01	31.11	1.24%	1.21%
600	45,000	2,833.32	2,833.60	0.06296	0.06297	2,855.39	2,854.58	0.06345	0.06344	22.06	20.99	0.78%	0.74%
									100 KW				
200	20,000	2,346.92	2,347.04	0.11735	0.11735	2,429.39	2,429.03	0.12147	0.12145	82.47	81.99	3.51%	3.49%
300	30,000	2,684.88	2,685.06	0.08950	0.08950	2,754.09	2,753.55	0.09180	0.09179	69.21	68.49	2.58%	2.55%
400	40,000	3,022.84	3,023.08	0.07557	0.07558	3,078.79	3,078.07	0.07697	0.07695	55.94	54.99	1.85%	1.82%
500	50,000	3,360.81	3,361.11	0.06722	0.06722	3,403.49	3,402.59	0.06807	0.06805	42.68	41.49	1.27%	1.23%
600	60,000	3,698.77	3,699.13	0.06165	0.06165	3,728.18	3,727.11	0.06214	0.06212	29.42	27.98	0.80%	0.76%

KWH DISTRIBUTION

		ON PK	INT	OFF PK
200	HOURS USE =	31%	29%	40%
300	HOURS USE =	33%	27%	40%
400	HOURS USE =	30%	26%	44%
500	HOURS USE =	27%	25%	48%
600	HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY1 RATES AND PROPOSED MRP RY2 RATES - DELIVERY ONLY
SCHEDULE "MGT LV "
DISTRICT OF COLUMBIA

HOURS		MRP RY1 RATES				MRP RY2 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**200 KW**				
200	40,000	4,456.84	4,457.08	0.11142	0.11143	4,621.79	4,621.07	0.11554	0.11553	164.94	163.99	3.70%	3.68%
300	60,000	5,132.77	5,133.13	0.08555	0.08555	5,271.18	5,270.11	0.08785	0.08784	138.42	136.98	2.70%	2.67%
400	80,000	5,808.69	5,809.17	0.07261	0.07261	5,920.58	5,919.15	0.07401	0.07399	111.89	109.98	1.93%	1.89%
500	100,000	6,484.61	6,485.22	0.06485	0.06485	6,569.97	6,568.19	0.06570	0.06568	85.36	82.97	1.32%	1.28%
600	120,000	7,160.54	7,161.26	0.05967	0.05968	7,219.37	7,217.22	0.06016	0.06014	58.83	55.96	0.82%	0.78%
									400 KW				
200	80,000	8,676.69	8,677.17	0.10846	0.10846	9,006.58	9,005.15	0.11258	0.11256	329.89	327.98	3.80%	3.78%
300	120,000	10,028.54	10,029.26	0.08357	0.08358	10,305.37	10,303.22	0.08588	0.08586	276.83	273.96	2.76%	2.73%
400	160,000	11,380.38	11,381.35	0.07113	0.07113	11,604.16	11,601.30	0.07253	0.07251	223.78	219.95	1.97%	1.93%
500	200,000	12,732.23	12,733.44	0.06366	0.06367	12,902.95	12,899.38	0.06451	0.06450	170.72	165.94	1.34%	1.30%
600	240,000	14,084.08	14,085.52	0.05868	0.05869	14,201.74	14,197.45	0.05917	0.05916	117.67	111.93	0.84%	0.79%
									600 KW				
200	120,000	12,896.54	12,897.26	0.10747	0.10748	13,391.37	13,389.22	0.11159	0.11158	494.83	491.96	3.84%	3.81%
300	180,000	14,924.31	14,925.39	0.08291	0.08292	15,339.56	15,336.34	0.08522	0.08520	415.25	410.95	2.78%	2.75%
400	240,000	16,952.08	16,953.52	0.07063	0.07064	17,287.74	17,283.45	0.07203	0.07201	335.67	329.93	1.98%	1.95%
500	300,000	18,979.85	18,981.65	0.06327	0.06327	19,235.93	19,230.57	0.06412	0.06410	256.08	248.91	1.35%	1.31%
600	360,000	21,007.62	21,009.79	0.05835	0.05836	21,184.12	21,177.68	0.05884	0.05883	176.50	167.89	0.84%	0.80%
									800 KW				
200	160,000	17,116.38	17,117.35	0.10698	0.10698	17,776.16	17,773.30	0.11110	0.11108	659.78	655.95	3.85%	3.83%
300	240,000	19,820.08	19,821.52	0.08258	0.08259	20,373.74	20,369.45	0.08489	0.08487	553.67	547.93	2.79%	2.76%
400	320,000	22,523.77	22,525.70	0.07039	0.07039	22,971.33	22,965.60	0.07179	0.07177	447.55	439.91	1.99%	1.95%
500	400,000	25,227.47	25,229.87	0.06307	0.06307	25,568.91	25,561.76	0.06392	0.06390	341.44	331.88	1.35%	1.32%
600	480,000	27,931.16	27,934.05	0.05819	0.05820	28,166.49	28,157.91	0.05868	0.05866	235.33	223.86	0.84%	0.80%

KWH DISTRIBUTION

		ON PK	INT	OFF PK
200	HOURS USE =	31%	29%	40%
300	HOURS USE =	33%	27%	40%
400	HOURS USE =	30%	26%	44%
500	HOURS USE =	27%	25%	48%
600	HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY

EXAMPLES COMPARING BILLS UNDER MRP RY1 RATES AND PROPOSED MRP RY2 RATES - DELIVERY ONLY
SCHEDULE "GT LV "
DISTRICT OF COLUMBIA

HOURS		MRP RY1 RATES				MRP RY2 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**100 KW**				
200	20,000	2,931.61	2,951.86	0.14658	0.14759	3,423.04	3,445.01	0.17115	0.17225	491.43	493.14	16.76%	16.71%
300	30,000	3,280.11	3,310.49	0.10934	0.11035	3,740.33	3,773.29	0.12468	0.12578	460.22	462.80	14.03%	13.98%
400	40,000	3,628.62	3,669.13	0.09072	0.09173	4,057.63	4,101.57	0.10144	0.10254	429.01	432.45	11.82%	11.79%
500	50,000	3,977.12	4,027.76	0.07954	0.08056	4,374.92	4,429.86	0.08750	0.08860	397.80	402.10	10.00%	9.98%
600	60,000	4,325.63	4,386.39	0.07209	0.07311	4,692.22	4,758.14	0.07820	0.07930	366.59	371.75	8.47%	8.48%
									300 KW				
200	60,000	6,913.63	6,974.39	0.11523	0.11624	7,420.22	7,486.14	0.12367	0.12477	506.59	511.75	7.33%	7.34%
300	90,000	7,959.14	8,050.28	0.08843	0.08945	8,372.11	8,470.99	0.09302	0.09412	412.97	420.71	5.19%	5.23%
400	120,000	9,004.65	9,126.18	0.07504	0.07605	9,324.00	9,455.84	0.07770	0.07880	319.35	329.66	3.55%	3.61%
500	150,000	10,050.16	10,202.07	0.06700	0.06801	10,275.89	10,440.68	0.06851	0.06960	225.72	238.62	2.25%	2.34%
600	180,000	11,095.68	11,277.96	0.06164	0.06266	11,227.78	11,425.53	0.06238	0.06348	132.10	147.57	1.19%	1.31%
									500 KW				
200	100,000	10,895.64	10,996.91	0.10896	0.10997	11,417.41	11,527.27	0.11417	0.11527	521.76	530.36	4.79%	4.82%
300	150,000	12,638.16	12,790.07	0.08425	0.08527	13,003.89	13,168.68	0.08669	0.08779	365.72	378.62	2.89%	2.96%
400	200,000	14,380.68	14,583.22	0.07190	0.07292	14,590.37	14,810.10	0.07295	0.07405	209.68	226.87	1.46%	1.56%
500	250,000	16,123.21	16,376.38	0.06449	0.06551	16,176.85	16,451.51	0.06471	0.06581	53.64	75.13	0.33%	0.46%
600	300,000	17,865.73	18,169.54	0.05955	0.06057	17,763.33	18,092.93	0.05921	0.06031	(102.40)	(76.61)	-0.57%	-0.42%
									1,000 KW				
200	200,000	20,850.68	21,053.22	0.10425	0.10527	21,410.37	21,630.10	0.10705	0.10815	559.68	576.87	2.68%	2.74%
300	300,000	24,335.73	24,639.54	0.08112	0.08213	24,583.33	24,912.93	0.08194	0.08304	247.60	273.39	1.02%	1.11%
400	400,000	27,820.77	28,225.85	0.06955	0.07056	27,756.29	28,195.75	0.06939	0.07049	(64.47)	(30.09)	-0.23%	-0.11%
500	500,000	31,305.81	31,812.16	0.06261	0.06362	30,929.26	31,478.58	0.06186	0.06296	(376.55)	(333.58)	-1.20%	-1.05%
600	600,000	34,790.85	35,398.47	0.05798	0.05900	34,102.22	34,761.41	0.05684	0.05794	(688.63)	(637.06)	-1.98%	-1.80%

KWH DISTRIBUTION

		ON PK	INT	OFF PK
200	HOURS USE =	31%	29%	40%
300	HOURS USE =	33%	27%	40%
400	HOURS USE =	30%	26%	44%
500	HOURS USE =	27%	25%	48%
600	HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY1 RATES AND PROPOSED MRP RY2 RATES - DELIVERY ONLY
SCHEDULE "GT LV "
DISTRICT OF COLUMBIA

HOURS		MRP RY1 RATES				MRP RY2 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**2,000 KW**				
200	400,000	40,760.77	41,165.85	0.10190	0.10291	41,396.29	41,835.75	0.10349	0.10459	635.53	669.91	1.56%	1.63%
300	600,000	47,730.85	48,338.47	0.07955	0.08056	47,742.22	48,401.41	0.07957	0.08067	11.37	62.94	0.02%	0.13%
400	800,000	54,700.93	55,511.09	0.06838	0.06939	54,088.14	54,967.07	0.06761	0.06871	(612.79)	(544.03)	-1.12%	-0.98%
500	1,000,000	61,671.02	62,683.72	0.06167	0.06268	60,434.07	61,532.72	0.06043	0.06153	(1,236.95)	(1,150.99)	-2.01%	-1.84%
600	1,200,000	68,641.10	69,856.34	0.05720	0.05821	66,780.00	68,098.38	0.05565	0.05675	(1,861.11)	(1,757.96)	-2.71%	-2.52%
									4,000 KW				
200	800,000	80,580.93	81,391.09	0.10073	0.10174	81,368.14	82,247.07	0.10171	0.10281	787.21	855.97	0.98%	1.05%
300	1,200,000	94,521.10	95,736.34	0.07877	0.07978	94,060.00	95,378.38	0.07838	0.07948	(461.11)	(357.96)	-0.49%	-0.37%
400	1,600,000	108,461.27	110,081.59	0.06779	0.06880	106,751.85	108,509.69	0.06672	0.06782	(1,709.42)	(1,571.90)	-1.58%	-1.43%
500	2,000,000	122,401.43	124,426.83	0.06120	0.06221	119,443.70	121,641.00	0.05972	0.06082	(2,957.74)	(2,785.83)	-2.42%	-2.24%
600	2,400,000	136,341.60	138,772.08	0.05681	0.05782	132,135.55	134,772.31	0.05506	0.05616	(4,206.05)	(3,999.76)	-3.08%	-2.88%
									6,000 KW				
200	1,200,000	120,401.10	121,616.34	0.10033	0.10135	121,340.00	122,658.38	0.10112	0.10222	938.89	1,042.04	0.78%	0.86%
300	1,800,000	141,311.35	143,134.21	0.07851	0.07952	140,377.77	142,355.35	0.07799	0.07909	(933.58)	(778.86)	-0.66%	-0.54%
400	2,400,000	162,221.60	164,652.08	0.06759	0.06861	159,415.55	162,052.31	0.06642	0.06752	(2,806.05)	(2,599.76)	-1.73%	-1.58%
500	3,000,000	183,131.85	186,169.95	0.06104	0.06206	178,453.32	181,749.28	0.05948	0.06058	(4,678.53)	(4,420.67)	-2.55%	-2.37%
600	3,600,000	204,042.10	207,687.82	0.05668	0.05769	197,491.10	201,446.25	0.05486	0.05596	(6,551.00)	(6,241.57)	-3.21%	-3.01%
									8,000 KW				
200	1,600,000	160,221.27	161,841.59	0.10014	0.10115	161,311.85	163,069.69	0.10082	0.10192	1,090.58	1,228.10	0.68%	0.76%
300	2,400,000	188,101.60	190,532.08	0.07838	0.07939	186,695.55	189,332.31	0.07779	0.07889	(1,406.05)	(1,199.76)	-0.75%	-0.63%
400	3,200,000	215,981.93	219,222.57	0.06749	0.06851	212,079.25	215,594.94	0.06627	0.06737	(3,902.68)	(3,627.63)	-1.81%	-1.65%
500	4,000,000	243,862.27	247,913.06	0.06097	0.06198	237,462.95	241,857.56	0.05937	0.06046	(6,399.32)	(6,055.50)	-2.62%	-2.44%
600	4,800,000	271,742.60	276,603.55	0.05661	0.05763	262,846.65	268,120.18	0.05476	0.05586	(8,895.95)	(8,483.37)	-3.27%	-3.07%

KWH DISTRIBUTION

		ON PK	INT	OFF PK
200	HOURS USE =	31%	29%	40%
300	HOURS USE =	33%	27%	40%
400	HOURS USE =	30%	26%	44%
500	HOURS USE =	27%	25%	48%
600	HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY1 RATES AND PROPOSED MRP RY2 RATES - DELIVERY ONLY
SCHEDULE "GT 3A "
DISTRICT OF COLUMBIA

HOURS		MRP RY1 RATES				MRP RY2 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**1,000 KW**				
200	200,000	13,828.99	13,747.71	0.06914	0.06874	14,645.44	14,549.43	0.07323	0.07275	816.46	801.72	5.90%	5.83%
300	300,000	15,814.74	15,692.82	0.05272	0.05231	16,694.42	16,550.40	0.05565	0.05517	879.69	857.59	5.56%	5.46%
400	400,000	17,800.48	17,637.93	0.04450	0.04409	18,743.40	18,551.38	0.04686	0.04638	942.92	913.45	5.30%	5.18%
500	500,000	19,786.23	19,583.04	0.03957	0.03917	20,792.38	20,552.35	0.04158	0.04110	1,006.15	969.31	5.09%	4.95%
600	600,000	21,771.98	21,528.15	0.03629	0.03588	22,841.36	22,553.32	0.03807	0.03759	1,069.38	1,025.17	4.91%	4.76%
									2,000 KW				
200	400,000	27,460.48	27,297.93	0.06865	0.06824	29,093.40	28,901.38	0.07273	0.07225	1,632.92	1,603.45	5.95%	5.87%
300	600,000	31,431.98	31,188.15	0.05239	0.05198	33,191.36	32,903.32	0.05532	0.05484	1,759.38	1,715.17	5.60%	5.50%
400	800,000	35,403.48	35,078.37	0.04425	0.04385	37,289.31	36,905.27	0.04661	0.04613	1,885.83	1,826.89	5.33%	5.21%
500	1,000,000	39,374.98	38,968.59	0.03937	0.03897	41,387.27	40,907.21	0.04139	0.04091	2,012.29	1,938.62	5.11%	4.97%
600	1,200,000	43,346.48	42,858.81	0.03612	0.03572	45,485.23	44,909.15	0.03790	0.03742	2,138.75	2,050.34	4.93%	4.78%
									5,000 KW				
200	1,000,000	68,354.98	67,948.59	0.06835	0.06795	72,437.27	71,957.21	0.07244	0.07196	4,082.29	4,008.62	5.97%	5.90%
300	1,500,000	78,283.72	77,674.14	0.05219	0.05178	82,682.16	81,962.07	0.05512	0.05464	4,398.44	4,287.93	5.62%	5.52%
400	2,000,000	88,212.47	87,399.69	0.04411	0.04370	92,927.05	91,966.93	0.04646	0.04598	4,714.59	4,567.24	5.34%	5.23%
500	2,500,000	98,141.21	97,125.25	0.03926	0.03885	103,171.94	101,971.79	0.04127	0.04079	5,030.73	4,846.55	5.13%	4.99%
600	3,000,000	108,069.96	106,850.80	0.03602	0.03562	113,416.84	111,976.65	0.03781	0.03733	5,346.88	5,125.85	4.95%	4.80%
									7,500 KW				
200	1,500,000	102,433.72	101,824.14	0.06829	0.06788	108,557.16	107,837.07	0.07237	0.07189	6,123.44	6,012.93	5.98%	5.91%
300	2,250,000	117,326.84	116,412.47	0.05215	0.05174	123,924.50	122,844.36	0.05508	0.05460	6,597.66	6,431.89	5.62%	5.53%
400	3,000,000	132,219.96	131,000.80	0.04407	0.04367	139,291.84	137,851.65	0.04643	0.04595	7,071.88	6,850.85	5.35%	5.23%
500	3,750,000	147,113.08	145,589.13	0.03923	0.03882	154,659.17	152,858.94	0.04124	0.04076	7,546.10	7,269.82	5.13%	4.99%
600	4,500,000	162,006.19	160,177.45	0.03600	0.03559	170,026.51	167,866.23	0.03778	0.03730	8,020.32	7,688.78	4.95%	4.80%

KWH DISTRIBUTION

	ON PK	INT	OFF PK
200 HOURS USE =	31%	29%	40%
300 HOURS USE =	33%	27%	40%
400 HOURS USE =	30%	26%	44%
500 HOURS USE =	27%	25%	48%
600 HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY1 RATES AND PROPOSED MRP RY2 RATES - DELIVERY ONLY
SCHEDULE "GT 3A "
DISTRICT OF COLUMBIA

HOURS		MRP RY1 RATES				MRP RY2 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**10,000 KW**				
200	2,000,000	136,512.47	135,699.69	0.06826	0.06785	144,677.05	143,716.93	0.07234	0.07186	8,164.59	8,017.24	5.98%	5.91%
300	3,000,000	156,369.96	155,150.80	0.05212	0.05172	165,166.84	163,726.65	0.05506	0.05458	8,796.88	8,575.85	5.63%	5.53%
400	4,000,000	176,227.45	174,601.90	0.04406	0.04365	185,656.62	183,736.37	0.04641	0.04593	9,429.17	9,134.47	5.35%	5.23%
500	5,000,000	196,084.94	194,053.00	0.03922	0.03881	206,146.40	203,746.10	0.04123	0.04075	10,061.46	9,693.09	5.13%	5.00%
600	6,000,000	215,942.43	213,504.11	0.03599	0.03558	226,636.18	223,755.82	0.03777	0.03729	10,693.76	10,251.71	4.95%	4.80%
									20,000 KW				
200	4,000,000	272,827.45	271,201.90	0.06821	0.06780	289,156.62	287,236.37	0.07229	0.07181	16,329.17	16,034.47	5.99%	5.91%
300	6,000,000	312,542.43	310,104.11	0.05209	0.05168	330,136.18	327,255.82	0.05502	0.05454	17,593.76	17,151.71	5.63%	5.53%
400	8,000,000	352,257.41	349,006.31	0.04403	0.04363	371,115.75	367,275.26	0.04639	0.04591	18,858.34	18,268.95	5.35%	5.23%
500	10,000,000	391,972.39	387,908.52	0.03920	0.03879	412,095.32	407,294.70	0.04121	0.04073	20,122.93	19,386.18	5.13%	5.00%
600	12,000,000	431,687.37	426,810.73	0.03597	0.03557	453,074.88	447,314.15	0.03776	0.03728	21,387.51	20,503.42	4.95%	4.80%
									30,000 KW				
200	6,000,000	409,142.43	406,704.11	0.06819	0.06778	433,636.18	430,755.82	0.07227	0.07179	24,493.76	24,051.71	5.99%	5.91%
300	9,000,000	468,714.90	465,057.42	0.05208	0.05167	495,105.53	490,784.98	0.05501	0.05453	26,390.63	25,727.56	5.63%	5.53%
400	12,000,000	528,287.37	523,410.73	0.04402	0.04362	556,574.88	550,814.15	0.04638	0.04590	28,287.51	27,403.42	5.35%	5.24%
500	15,000,000	587,859.84	581,764.04	0.03919	0.03878	618,044.23	610,843.31	0.04120	0.04072	30,184.39	29,079.27	5.13%	5.00%
600	18,000,000	647,432.31	640,117.35	0.03597	0.03556	679,513.58	670,872.47	0.03775	0.03727	32,081.27	30,755.13	4.96%	4.80%
									40,000 KW				
200	8,000,000	545,457.41	542,206.31	0.06818	0.06778	578,115.75	574,275.26	0.07226	0.07178	32,658.34	32,068.95	5.99%	5.91%
300	12,000,000	624,887.37	620,010.73	0.05207	0.05167	660,074.88	654,314.15	0.05501	0.05453	35,187.51	34,303.42	5.63%	5.53%
400	16,000,000	704,317.33	697,815.14	0.04402	0.04361	742,034.01	734,353.03	0.04638	0.04590	37,716.68	36,537.89	5.36%	5.24%
500	20,000,000	783,747.29	775,619.55	0.03919	0.03878	823,993.14	814,391.92	0.04120	0.04072	40,245.85	38,772.36	5.14%	5.00%
600	24,000,000	863,177.25	853,423.97	0.03597	0.03556	905,952.27	894,430.80	0.03775	0.03727	42,775.02	41,006.84	4.96%	4.80%

KWH DISTRIBUTION

	ON PK	INT	OFF PK
200 HOURS USE =	31%	29%	40%
300 HOURS USE =	33%	27%	40%
400 HOURS USE =	30%	26%	44%
500 HOURS USE =	27%	25%	48%
600 HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY1 RATES AND PROPOSED MRP RY2 RATES - DELIVERY ONLY
SCHEDULE "GT 3B "
DISTRICT OF COLUMBIA

HOURS		MRP RY1 RATES				MRP RY2 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**10,000 KW**				
200	2,000,000	38,046.32	41,489.86	0.01902	0.02074	39,163.30	42,903.77	0.01958	0.02145	1,116.98	1,413.90	2.94%	3.41%
300	3,000,000	50,774.68	54,218.22	0.01692	0.01807	51,902.50	55,642.97	0.01730	0.01855	1,127.82	1,424.74	2.22%	2.63%
400	4,000,000	63,503.04	66,946.58	0.01588	0.01674	64,641.70	68,382.17	0.01616	0.01710	1,138.66	1,435.59	1.79%	2.14%
500	5,000,000	76,231.40	79,674.94	0.01525	0.01593	77,380.90	81,121.37	0.01548	0.01622	1,149.50	1,446.43	1.51%	1.82%
600	6,000,000	88,959.75	92,403.30	0.01483	0.01540	90,120.10	93,860.57	0.01502	0.01564	1,160.34	1,457.27	1.30%	1.58%
									20,000 KW				
200	4,000,000	75,780.99	82,668.07	0.01895	0.02067	78,014.94	85,495.88	0.01950	0.02137	2,233.95	2,827.81	2.95%	3.42%
300	6,000,000	101,237.70	108,124.79	0.01687	0.01802	103,493.34	110,974.28	0.01725	0.01850	2,255.64	2,849.49	2.23%	2.64%
400	8,000,000	126,694.42	133,581.51	0.01584	0.01670	128,971.74	136,452.68	0.01612	0.01706	2,277.32	2,871.17	1.80%	2.15%
500	10,000,000	152,151.14	159,038.22	0.01522	0.01590	154,450.14	161,931.08	0.01545	0.01619	2,299.00	2,892.86	1.51%	1.82%
600	12,000,000	177,607.85	184,494.94	0.01480	0.01537	179,928.54	187,409.48	0.01499	0.01562	2,320.69	2,914.54	1.31%	1.58%
									30,000 KW				
200	6,000,000	113,515.65	123,846.28	0.01892	0.02064	116,866.58	128,087.99	0.01948	0.02135	3,350.93	4,241.71	2.95%	3.42%
300	9,000,000	151,700.73	162,031.36	0.01686	0.01800	155,084.18	166,305.59	0.01723	0.01848	3,383.46	4,274.23	2.23%	2.64%
400	12,000,000	189,885.80	200,216.43	0.01582	0.01668	193,301.78	204,523.19	0.01611	0.01704	3,415.98	4,306.76	1.80%	2.15%
500	15,000,000	228,070.88	238,401.51	0.01520	0.01589	231,519.38	242,740.79	0.01543	0.01618	3,448.51	4,339.28	1.51%	1.82%
600	18,000,000	266,255.95	276,586.58	0.01479	0.01537	269,736.98	280,958.39	0.01499	0.01561	3,481.03	4,371.81	1.31%	1.58%
									40,000 KW				
200	8,000,000	151,250.31	165,024.49	0.01891	0.02063	155,718.22	170,680.10	0.01946	0.02134	4,467.91	5,655.61	2.95%	3.43%
300	12,000,000	202,163.75	215,937.93	0.01685	0.01799	206,675.02	221,636.90	0.01722	0.01847	4,511.28	5,698.98	2.23%	2.64%
400	16,000,000	253,077.18	266,851.36	0.01582	0.01668	257,631.82	272,593.70	0.01610	0.01704	4,554.64	5,742.34	1.80%	2.15%
500	20,000,000	303,990.62	317,764.79	0.01520	0.01589	308,588.62	323,550.50	0.01543	0.01618	4,598.01	5,785.71	1.51%	1.82%
600	24,000,000	354,904.05	368,678.23	0.01479	0.01536	359,545.42	374,507.30	0.01498	0.01560	4,641.38	5,829.08	1.31%	1.58%

KWH DISTRIBUTION

	ON PK	INT	OFF PK
200 HOURS USE =	31%	29%	40%
300 HOURS USE =	33%	27%	40%
400 HOURS USE =	30%	26%	44%
500 HOURS USE =	27%	25%	48%
600 HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY2 RATES AND PROPOSED MRP RY3 RATES
SCHEDULE "R"
DISTRICT OF COLUMBIA

	MRP RY2 RATES				MRP RY3 RATES				INCREASE					
KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)	($)	(%)
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	ANNUAL	ANNUAL
0	22.12	22.20	-	-	23.54	23.62	-	-	1.42	1.42	6.42%	6.40%	1.42	6.41%
10	22.46	22.54	2.24609	2.25409	23.90	23.98	2.38957	2.39757	1.43	1.43	6.37%	6.34%	1.43	6.35%
20	22.80	22.88	1.14009	1.14409	24.25	24.33	1.21257	1.21657	1.45	1.45	6.36%	6.34%	1.45	6.35%
30	23.14	23.22	0.77143	0.77409	24.61	24.69	0.82024	0.82290	1.46	1.46	6.31%	6.29%	1.46	6.30%
40	24.14	24.24	0.60346	0.60612	25.62	25.72	0.64044	0.64310	1.48	1.48	6.13%	6.10%	1.48	6.12%
50	25.13	25.27	0.50268	0.50533	26.63	26.76	0.53256	0.53521	1.49	1.49	5.93%	5.90%	1.49	5.91%
100	30.11	30.38	0.30112	0.30376	31.68	31.94	0.31680	0.31944	1.57	1.57	5.21%	5.17%	1.57	5.19%
200	40.07	40.60	0.20034	0.20298	41.78	42.31	0.20892	0.21156	1.72	1.72	4.29%	4.24%	1.72	4.26%
300	50.02	50.81	0.16675	0.16938	51.89	52.68	0.17296	0.17559	1.86	1.86	3.72%	3.66%	1.86	3.68%
400	59.98	61.03	0.14995	0.15259	61.99	63.05	0.15498	0.15761	2.01	2.01	3.35%	3.29%	2.01	3.32%
500	72.43	72.76	0.14485	0.14553	74.91	75.13	0.14981	0.15027	2.48	2.37	3.42%	3.26%	2.42	3.33%
692	**96.32**	**95.28**	**0.13919**	**0.13769**	**99.70**	**98.34**	**0.14408**	**0.14212**	**3.38**	**3.06**	**3.51%**	**3.21%**	**3.19**	**3.34%**
700	97.31	96.22	0.13902	0.13746	100.73	99.31	0.14391	0.14187	3.42	3.09	3.51%	3.21%	3.23	3.34%
750	103.54	102.08	0.13805	0.13611	107.19	105.36	0.14292	0.14047	3.66	3.27	3.54%	3.20%	3.43	3.34%
800	109.76	107.95	0.13720	0.13494	113.65	111.40	0.14206	0.13925	3.89	3.45	3.54%	3.20%	3.63	3.34%
850	115.98	113.81	0.13645	0.13390	120.11	117.44	0.14130	0.13817	4.13	3.63	3.56%	3.19%	3.84	3.35%
900	122.20	119.68	0.13578	0.13298	126.56	123.49	0.14063	0.13721	4.36	3.81	3.57%	3.18%	4.04	3.35%
950	128.42	125.54	0.13518	0.13215	133.02	129.53	0.14002	0.13635	4.60	3.99	3.58%	3.18%	4.24	3.35%
1,000	134.65	131.41	0.13465	0.13141	139.48	135.58	0.13948	0.13558	4.83	4.17	3.59%	3.17%	4.45	3.35%
1,250	165.76	160.73	0.13260	0.12858	171.76	165.80	0.13741	0.13264	6.01	5.07	3.63%	3.15%	5.46	3.35%
1,500	196.87	190.05	0.13124	0.12670	204.05	196.02	0.13603	0.13068	7.18	5.97	3.65%	3.14%	6.47	3.36%
1,750	227.98	219.37	0.13027	0.12536	236.33	226.24	0.13505	0.12928	8.36	6.87	3.67%	3.13%	7.49	3.36%
2,000	259.09	248.69	0.12954	0.12435	268.62	256.46	0.13431	0.12823	9.53	7.77	3.68%	3.12%	8.50	3.36%
2,250	290.20	278.01	0.12898	0.12356	300.90	286.68	0.13373	0.12742	10.71	8.67	3.69%	3.12%	9.52	3.36%
2,500	321.31	307.34	0.12852	0.12293	333.19	316.91	0.13328	0.12676	11.88	9.57	3.70%	3.11%	10.53	3.36%
3,000	383.53	365.98	0.12784	0.12199	397.76	377.35	0.13259	0.12578	14.23	11.37	3.71%	3.11%	12.56	3.37%
3,500	445.75	424.62	0.12736	0.12132	462.33	437.79	0.13209	0.12508	16.58	13.17	3.72%	3.10%	14.59	3.37%
4,000	507.97	483.27	0.12699	0.12082	526.90	498.23	0.13173	0.12456	18.93	14.97	3.73%	3.10%	16.62	3.37%
5,000	632.41	600.55	0.12648	0.12011	656.04	619.12	0.13121	0.12382	23.64	18.57	3.74%	3.09%	20.68	3.37%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY2 RATES AND PROPOSED MRP RY3 RATES
SCHEDULE "MMA"
DISTRICT OF COLUMBIA

	MRP RY2 RATES				MRP RY3 RATES				INCREASE					
KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)	($)	(%)
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	ANNUAL	ANNUAL
0	16.63	17.05	-	-	17.52	17.94	-	-	0.89	0.89	5.35%	5.22%	0.89	5.27%
100	23.34	24.72	0.23338	0.24723	24.31	25.69	0.24309	0.25694	0.97	0.97	4.16%	3.92%	0.97	4.02%
200	31.78	34.55	0.15891	0.17273	32.83	35.60	0.16417	0.17799	1.05	1.05	3.30%	3.04%	1.05	3.14%
300	40.23	44.37	0.13409	0.14789	41.36	45.50	0.13787	0.15167	1.13	1.13	2.81%	2.55%	1.13	2.65%
400	48.67	54.19	0.12168	0.13548	49.89	55.40	0.12471	0.13851	1.21	1.21	2.49%	2.23%	1.21	2.33%
500	59.01	64.59	0.11802	0.12918	60.48	65.93	0.12097	0.13185	1.47	1.33	2.49%	2.06%	1.39	2.23%
1000	110.70	116.60	0.11070	0.11660	113.47	118.54	0.11347	0.11854	2.77	1.94	2.50%	1.66%	2.29	2.00%
2000	214.08	220.62	0.10704	0.11031	219.44	223.76	0.10972	0.11188	5.37	3.14	2.51%	1.42%	4.07	1.87%
3000	317.46	324.64	0.10582	0.10821	325.42	328.99	0.10847	0.10966	7.96	4.35	2.51%	1.34%	5.85	1.82%
4000	420.84	428.66	0.10521	0.10716	431.39	434.21	0.10785	0.10855	10.56	5.56	2.51%	1.30%	7.64	1.80%
5000	524.22	532.68	0.10484	0.10654	537.37	539.44	0.10747	0.10789	13.15	6.76	2.51%	1.27%	9.42	1.78%
6000	627.60	636.70	0.10460	0.10612	643.34	644.66	0.10722	0.10744	15.75	7.97	2.51%	1.25%	11.21	1.77%
7000	730.98	740.71	0.10443	0.10582	749.32	749.89	0.10705	0.10713	18.34	9.17	2.51%	1.24%	12.99	1.76%
7500	782.67	792.72	0.10436	0.10570	802.30	802.50	0.10697	0.10700	19.64	9.78	2.51%	1.23%	13.89	1.76%
8000	834.35	844.73	0.10429	0.10559	855.29	855.11	0.10691	0.10689	20.94	10.38	2.51%	1.23%	14.78	1.76%
8500	886.04	896.74	0.10424	0.10550	908.28	907.73	0.10686	0.10679	22.23	10.98	2.51%	1.22%	15.67	1.76%
9000	937.73	948.75	0.10419	0.10542	961.26	960.34	0.10681	0.10670	23.53	11.59	2.51%	1.22%	16.57	1.75%
9500	989.42	1,000.76	0.10415	0.10534	1,014.25	1,012.95	0.10676	0.10663	24.83	12.19	2.51%	1.22%	17.46	1.75%
10000	1,041.11	1,052.77	0.10411	0.10528	1,067.24	1,065.56	0.10672	0.10656	26.13	12.79	2.51%	1.21%	18.35	1.75%
12500	1,299.56	1,312.82	0.10396	0.10503	1,332.18	1,328.63	0.10657	0.10629	32.61	15.81	2.51%	1.20%	22.81	1.74%
15000	1,558.01	1,572.86	0.10387	0.10486	1,597.11	1,591.69	0.10647	0.10611	39.10	18.82	2.51%	1.20%	27.27	1.74%
17500	1,816.46	1,832.91	0.10380	0.10474	1,862.05	1,854.75	0.10640	0.10599	45.59	21.84	2.51%	1.19%	31.74	1.74%
20000	2,074.91	2,092.96	0.10375	0.10465	2,126.98	2,117.81	0.10635	0.10589	52.08	24.86	2.51%	1.19%	36.20	1.74%
22500	2,333.36	2,353.01	0.10370	0.10458	2,391.92	2,380.88	0.10631	0.10582	58.56	27.87	2.51%	1.18%	40.66	1.73%
25000	2,591.80	2,613.05	0.10367	0.10452	2,656.85	2,643.94	0.10627	0.10576	65.05	30.89	2.51%	1.18%	45.12	1.73%
30000	3,108.70	3,133.15	0.10362	0.10444	3,186.73	3,170.06	0.10622	0.10567	78.03	36.92	2.51%	1.18%	54.05	1.73%
35000	3,625.60	3,653.24	0.10359	0.10438	3,716.60	3,696.19	0.10619	0.10561	91.00	42.95	2.51%	1.18%	62.97	1.73%
40000	4,142.49	4,173.33	0.10356	0.10433	4,246.47	4,222.31	0.10616	0.10556	103.97	48.98	2.51%	1.17%	71.89	1.73%
50000	5,176.29	5,213.52	0.10353	0.10427	5,306.21	5,274.56	0.10612	0.10549	129.92	61.04	2.51%	1.17%	89.74	1.73%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY

EXAMPLES COMPARING BILLS UNDER MRP RY2 RATES AND PROPOSED MRP RY3 RATES
SCHEDULE "GS ND"
DISTRICT OF COLUMBIA

	MRP RY2 RATES				MRP RY3 RATES				INCREASE					
KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)	($)	(%)
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	ANNUAL	ANNUAL
0	34.33	34.33	-	-	36.33	36.33	-	-	2.00	2.00	5.83%	5.83%	2.00	5.83%
10	35.68	35.64	3.56780	3.56352	37.68	37.63	3.76787	3.76316	2.00	2.00	5.61%	5.61%	2.00	5.61%
20	37.03	36.94	1.85130	1.84702	39.03	38.93	1.95137	1.94666	2.00	1.99	5.40%	5.39%	1.99	5.39%
30	38.37	38.25	1.27913	1.27485	40.38	40.23	1.34587	1.34116	2.00	1.99	5.21%	5.20%	1.99	5.21%
40	39.72	39.55	0.99305	0.98877	41.72	41.54	1.04312	1.03841	2.00	1.99	5.04%	5.03%	1.99	5.03%
50	41.07	40.86	0.82140	0.81712	43.07	42.84	0.86147	0.85676	2.00	1.98	4.87%	4.85%	1.99	4.86%
100	47.81	47.38	0.47810	0.47382	49.82	49.35	0.49817	0.49346	2.01	1.96	4.20%	4.14%	1.98	4.16%
150	54.55	53.91	0.36366	0.35939	56.56	55.85	0.37707	0.37236	2.01	1.95	3.68%	3.62%	1.98	3.65%
200	61.29	60.43	0.30645	0.30217	63.30	62.36	0.31652	0.31181	2.01	1.93	3.28%	3.19%	1.96	3.23%
250	68.03	66.96	0.27212	0.26784	70.05	68.87	0.28019	0.27548	2.02	1.91	2.97%	2.85%	1.96	2.90%
300	74.77	73.49	0.24923	0.24495	76.79	75.38	0.25597	0.25126	2.02	1.89	2.70%	2.57%	1.94	2.63%
400	88.25	86.54	0.22062	0.21635	90.28	88.39	0.22569	0.22098	2.03	1.85	2.30%	2.14%	1.93	2.21%
500	101.73	99.59	0.20346	0.19918	103.76	101.41	0.20753	0.20282	2.04	1.82	2.01%	1.83%	1.91	1.90%
600	115.21	112.64	0.19201	0.18774	117.25	114.42	0.19542	0.19071	2.04	1.78	1.77%	1.58%	1.89	1.66%
700	128.69	125.69	0.18384	0.17956	130.74	127.44	0.18677	0.18206	2.05	1.74	1.59%	1.38%	1.87	1.47%
800	142.17	138.75	0.17771	0.17343	144.23	140.46	0.18028	0.17557	2.06	1.71	1.45%	1.23%	1.86	1.32%
900	155.65	151.80	0.17294	0.16867	157.71	153.47	0.17524	0.17052	2.06	1.67	1.32%	1.10%	1.83	1.19%
1,000	169.13	164.85	0.16913	0.16485	171.20	166.49	0.17120	0.16649	2.07	1.64	1.22%	0.99%	1.82	1.09%
1,250	202.83	197.48	0.16226	0.15798	204.92	199.03	0.16393	0.15922	2.09	1.54	1.03%	0.78%	1.77	0.89%
1,500	236.53	230.11	0.15768	0.15341	238.63	231.56	0.15909	0.15438	2.11	1.45	0.89%	0.63%	1.73	0.74%
1,750	270.23	262.74	0.15442	0.15014	272.35	264.10	0.15563	0.15092	2.13	1.36	0.79%	0.52%	1.68	0.63%
2,000	303.93	295.37	0.15196	0.14769	306.07	296.64	0.15303	0.14832	2.14	1.27	0.70%	0.43%	1.63	0.55%
2,500	371.33	360.63	0.14853	0.14425	373.50	361.72	0.14940	0.14469	2.18	1.09	0.59%	0.30%	1.54	0.42%
3,000	438.72	425.89	0.14624	0.14196	440.94	426.80	0.14698	0.14227	2.22	0.91	0.51%	0.21%	1.46	0.34%
3,500	506.12	491.15	0.14461	0.14033	508.37	491.88	0.14525	0.14054	2.25	0.72	0.44%	0.15%	1.36	0.27%
4,000	573.52	556.41	0.14338	0.13910	575.81	556.96	0.14395	0.13924	2.29	0.54	0.40%	0.10%	1.27	0.23%
5,000	708.32	686.93	0.14166	0.13739	710.68	687.11	0.14214	0.13742	2.36	0.18	0.33%	0.03%	1.09	0.16%
6,000	843.12	817.45	0.14052	0.13624	845.55	817.27	0.14092	0.13621	2.43	-0.19	0.29%	-0.02%	0.90	0.11%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY

EXAMPLES COMPARING BILLS UNDER MRP RY2 RATES AND PROPOSED MRP RY3 RATES
SCHEDULE "GS D LV"
DISTRICT OF COLUMBIA

			MRP RY2 RATES				MRP RY3 RATES				INCREASE			
KW	Hours	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
			SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
10	100	1000	254.36	258.49	0.25436	0.25849	263.51	266.74	0.26351	0.26674	9.15	8.26	3.60%	3.20%
	200	2000	374.48	382.73	0.18724	0.19137	387.19	393.64	0.19359	0.19682	12.71	10.91	3.39%	2.85%
	300	3000	494.60	506.98	0.16487	0.16899	510.86	520.54	0.17029	0.17351	16.26	13.56	3.29%	2.67%
	400	4000	614.72	631.23	0.15368	0.15781	634.53	647.44	0.15863	0.16186	19.81	16.21	3.22%	2.57%
	500	5000	734.85	755.47	0.14697	0.15109	758.21	774.34	0.15164	0.15487	23.36	18.87	3.18%	2.50%
	600	6000	854.97	879.72	0.14249	0.14662	881.88	901.24	0.14698	0.15021	26.91	21.52	3.15%	2.45%
25	100	2,500	577.78	588.09	0.23111	0.23524	600.66	608.73	0.24026	0.24349	22.89	20.64	3.96%	3.51%
	200	5,000	878.08	898.71	0.17562	0.17974	909.84	925.98	0.18197	0.18520	31.77	27.27	3.62%	3.03%
	300	7,500	1,178.38	1,209.33	0.15712	0.16124	1,219.03	1,243.23	0.16254	0.16576	40.64	33.90	3.45%	2.80%
	400	10,000	1,478.69	1,519.94	0.14787	0.15199	1,528.21	1,560.48	0.15282	0.15605	49.52	40.53	3.35%	2.67%
	500	12,500	1,778.99	1,830.56	0.14232	0.14644	1,837.39	1,877.73	0.14699	0.15022	58.40	47.16	3.28%	2.58%
	600	15,000	2,079.30	2,141.18	0.13862	0.14275	2,146.58	2,194.98	0.14311	0.14633	67.28	53.80	3.24%	2.51%
50	100	5,000	1,116.80	1,137.43	0.22336	0.22749	1,162.57	1,178.71	0.23251	0.23574	45.77	41.28	4.10%	3.63%
	200	10,000	1,717.41	1,758.67	0.17174	0.17587	1,780.94	1,813.20	0.17809	0.18132	63.53	54.54	3.70%	3.10%
	300	15,000	2,318.02	2,379.90	0.15453	0.15866	2,399.31	2,447.70	0.15995	0.16318	81.29	67.80	3.51%	2.85%
	400	20,000	2,918.63	3,001.14	0.14593	0.15006	3,017.67	3,082.20	0.15088	0.15411	99.05	81.07	3.39%	2.70%
	500	25,000	3,519.23	3,622.37	0.14077	0.14489	3,636.04	3,716.70	0.14544	0.14867	116.81	94.33	3.32%	2.60%
	600	30,000	4,119.84	4,243.61	0.13733	0.14145	4,254.41	4,351.20	0.14181	0.14504	134.57	107.59	3.27%	2.54%
75	100	7,500	1,655.83	1,686.77	0.22078	0.22490	1,724.48	1,748.68	0.22993	0.23316	68.66	61.91	4.15%	3.67%
	200	15,000	2,556.74	2,618.62	0.17045	0.17457	2,652.03	2,700.43	0.17680	0.18003	95.30	81.81	3.73%	3.12%
	300	22,500	3,457.65	3,550.48	0.15367	0.15780	3,579.59	3,652.18	0.15909	0.16232	121.93	101.70	3.53%	2.86%
	400	30,000	4,358.56	4,482.33	0.14529	0.14941	4,507.14	4,603.93	0.15024	0.15346	148.57	121.60	3.41%	2.71%
	500	37,500	5,259.48	5,414.19	0.14025	0.14438	5,434.69	5,555.68	0.14492	0.14815	175.21	141.49	3.33%	2.61%
	600	45,000	6,160.39	6,346.04	0.13690	0.14102	6,362.24	6,507.43	0.14138	0.14461	201.85	161.39	3.28%	2.54%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY2 RATES AND PROPOSED MRP RY3 RATES - DELIVERY ONLY
SCHEDULE "MGT LV "
DISTRICT OF COLUMBIA

HOURS		MRP RY2 RATES				MRP RY3 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**25 KW**				
200	5,000	804.66	804.57	0.16093	0.16091	819.11	818.99	0.16382	0.16380	14.45	14.42	1.80%	1.79%
300	7,500	895.62	895.48	0.11942	0.11940	905.04	904.86	0.12067	0.12065	9.42	9.38	1.05%	1.05%
400	10,000	986.57	986.39	0.09866	0.09864	990.96	990.73	0.09910	0.09907	4.39	4.34	0.44%	0.44%
500	12,500	1,077.53	1,077.31	0.08620	0.08618	1,076.89	1,076.61	0.08615	0.08613	(0.64)	(0.70)	-0.06%	-0.06%
600	15,000	1,168.49	1,168.22	0.07790	0.07788	1,162.82	1,162.48	0.07752	0.07750	(5.66)	(5.74)	-0.48%	-0.49%
									50 KW				
200	10,000	1,372.32	1,372.14	0.13723	0.13721	1,401.21	1,400.98	0.14012	0.14010	28.89	28.84	2.11%	2.10%
300	15,000	1,554.24	1,553.97	0.10362	0.10360	1,573.07	1,572.73	0.10487	0.10485	18.84	18.76	1.21%	1.21%
400	20,000	1,736.15	1,735.79	0.08681	0.08679	1,744.93	1,744.47	0.08725	0.08722	8.78	8.68	0.51%	0.50%
500	25,000	1,918.06	1,917.61	0.07672	0.07670	1,916.79	1,916.22	0.07667	0.07665	(1.27)	(1.40)	-0.07%	-0.07%
600	30,000	2,099.97	2,099.44	0.07000	0.06998	2,088.65	2,087.96	0.06962	0.06960	(11.32)	(11.48)	-0.54%	-0.55%
									75 KW				
200	15,000	1,939.99	1,939.72	0.12933	0.12931	1,983.32	1,982.98	0.13222	0.13220	43.34	43.26	2.23%	2.23%
300	22,500	2,212.85	2,212.45	0.09835	0.09833	2,241.11	2,240.59	0.09960	0.09958	28.26	28.14	1.28%	1.27%
400	30,000	2,485.72	2,485.19	0.08286	0.08284	2,498.90	2,498.21	0.08330	0.08327	13.18	13.02	0.53%	0.52%
500	37,500	2,758.59	2,757.92	0.07356	0.07354	2,756.69	2,755.82	0.07351	0.07349	(1.91)	(2.10)	-0.07%	-0.08%
600	45,000	3,031.46	3,030.66	0.06737	0.06735	3,014.48	3,013.44	0.06699	0.06697	(16.99)	(17.22)	-0.56%	-0.57%
									100 KW				
200	20,000	2,507.65	2,507.29	0.12538	0.12536	2,565.43	2,564.97	0.12827	0.12825	57.78	57.68	2.30%	2.30%
300	30,000	2,871.47	2,870.94	0.09572	0.09570	2,909.15	2,908.46	0.09697	0.09695	37.68	37.52	1.31%	1.31%
400	40,000	3,235.30	3,234.58	0.08088	0.08086	3,252.87	3,251.95	0.08132	0.08130	17.57	17.36	0.54%	0.54%
500	50,000	3,599.13	3,598.23	0.07198	0.07196	3,596.58	3,595.43	0.07193	0.07191	(2.54)	(2.80)	-0.07%	-0.08%
600	60,000	3,962.95	3,961.88	0.06605	0.06603	3,940.30	3,938.92	0.06567	0.06565	(22.65)	(22.96)	-0.57%	-0.58%

KWH DISTRIBUTION

	ON PK	INT	OFF PK
200 HOURS USE =	31%	29%	40%
300 HOURS USE =	33%	27%	40%
400 HOURS USE =	30%	26%	44%
500 HOURS USE =	27%	25%	48%
600 HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY2 RATES AND PROPOSED MRP RY3 RATES - DELIVERY ONLY
SCHEDULE "MGT LV "
DISTRICT OF COLUMBIA

HOURS		MRP RY2 RATES				MRP RY3 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**200 KW**				
200	40,000	4,778.30	4,777.58	0.11946	0.11944	4,893.87	4,892.95	0.12235	0.12232	115.57	115.36	2.42%	2.41%
300	60,000	5,505.95	5,504.88	0.09177	0.09175	5,581.30	5,579.92	0.09302	0.09300	75.35	75.04	1.37%	1.36%
400	80,000	6,233.60	6,232.17	0.07792	0.07790	6,268.74	6,266.90	0.07836	0.07834	35.13	34.72	0.56%	0.56%
500	100,000	6,961.25	6,959.47	0.06961	0.06959	6,956.17	6,953.87	0.06956	0.06954	(5.08)	(5.59)	-0.07%	-0.08%
600	120,000	7,688.90	7,686.76	0.06407	0.06406	7,643.61	7,640.85	0.06370	0.06367	(45.30)	(45.91)	-0.59%	-0.60%
									400 KW				
200	80,000	9,319.60	9,318.17	0.11650	0.11648	9,550.74	9,548.90	0.11938	0.11936	231.13	230.72	2.48%	2.48%
300	120,000	10,774.90	10,772.76	0.08979	0.08977	10,925.61	10,922.85	0.09105	0.09102	150.70	150.09	1.40%	1.39%
400	160,000	12,230.21	12,227.35	0.07644	0.07642	12,300.48	12,296.79	0.07688	0.07685	70.27	69.45	0.57%	0.57%
500	200,000	13,685.51	13,681.93	0.06843	0.06841	13,675.35	13,670.74	0.06838	0.06835	(10.16)	(11.19)	-0.07%	-0.08%
600	240,000	15,140.81	15,136.52	0.06309	0.06307	15,050.22	15,044.69	0.06271	0.06269	(90.60)	(91.83)	-0.60%	-0.61%
									600 KW				
200	120,000	13,860.90	13,858.76	0.11551	0.11549	14,207.61	14,204.85	0.11840	0.11837	346.70	346.09	2.50%	2.50%
300	180,000	16,043.86	16,040.64	0.08913	0.08911	16,269.91	16,265.77	0.09039	0.09037	226.05	225.13	1.41%	1.40%
400	240,000	18,226.81	18,222.52	0.07595	0.07593	18,332.22	18,326.69	0.07638	0.07636	105.40	104.17	0.58%	0.57%
500	300,000	20,409.77	20,404.40	0.06803	0.06801	20,394.52	20,387.62	0.06798	0.06796	(15.24)	(16.78)	-0.07%	-0.08%
600	360,000	22,592.72	22,586.28	0.06276	0.06274	22,456.83	22,448.54	0.06238	0.06236	(135.89)	(137.74)	-0.60%	-0.61%
									800 KW				
200	160,000	18,402.21	18,399.35	0.11501	0.11500	18,864.48	18,860.79	0.11790	0.11788	462.27	461.45	2.51%	2.51%
300	240,000	21,312.81	21,308.52	0.08880	0.08879	21,614.22	21,608.69	0.09006	0.09004	301.40	300.17	1.41%	1.41%
400	320,000	24,223.42	24,217.70	0.07570	0.07568	24,363.96	24,356.59	0.07614	0.07611	140.54	138.90	0.58%	0.57%
500	400,000	27,134.02	27,126.87	0.06784	0.06782	27,113.70	27,104.49	0.06778	0.06776	(20.33)	(22.38)	-0.07%	-0.08%
600	480,000	30,044.63	30,036.04	0.06259	0.06258	29,863.44	29,852.39	0.06222	0.06219	(181.19)	(183.65)	-0.60%	-0.61%

KWH DISTRIBUTION

		ON PK	INT	OFF PK
200	HOURS USE =	31%	29%	40%
300	HOURS USE =	33%	27%	40%
400	HOURS USE =	30%	26%	44%
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Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY

EXAMPLES COMPARING BILLS UNDER MRP RY2 RATES AND PROPOSED MRP RY3 RATES - DELIVERY ONLY
SCHEDULE "GT LV "
DISTRICT OF COLUMBIA

HOURS		MRP RY2 RATES				MRP RY3 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**100 KW**				
200	20,000	3,529.22	3,551.20	0.17646	0.17756	3,996.09	4,020.10	0.19980	0.20101	466.87	468.91	13.23%	13.20%
300	30,000	3,899.61	3,932.57	0.12999	0.13109	4,328.00	4,364.01	0.14427	0.14547	428.38	431.44	10.99%	10.97%
400	40,000	4,270.00	4,313.95	0.10675	0.10785	4,659.90	4,707.92	0.11650	0.11770	389.90	393.98	9.13%	9.13%
500	50,000	4,640.39	4,695.32	0.09281	0.09391	4,991.80	5,051.83	0.09984	0.10104	351.41	356.51	7.57%	7.59%
600	60,000	5,010.78	5,076.70	0.08351	0.08461	5,323.71	5,395.74	0.08873	0.08993	312.93	319.04	6.25%	6.28%
									300 KW				
200	60,000	7,738.78	7,804.70	0.12898	0.13008	8,171.71	8,243.74	0.13620	0.13740	432.93	439.04	5.59%	5.63%
300	90,000	8,849.95	8,948.83	0.09833	0.09943	9,167.42	9,275.47	0.10186	0.10306	317.47	326.64	3.59%	3.65%
400	120,000	9,961.12	10,092.96	0.08301	0.08411	10,163.13	10,307.20	0.08469	0.08589	202.01	214.24	2.03%	2.12%
500	150,000	11,072.29	11,237.09	0.07382	0.07491	11,158.84	11,338.93	0.07439	0.07559	86.55	101.84	0.78%	0.91%
600	180,000	12,183.46	12,381.22	0.06769	0.06878	12,154.55	12,370.66	0.06753	0.06873	(28.91)	(10.56)	-0.24%	-0.09%
									500 KW				
200	100,000	11,948.34	12,058.21	0.11948	0.12058	12,347.32	12,467.38	0.12347	0.12467	398.98	409.18	3.34%	3.39%
300	150,000	13,800.29	13,965.09	0.09200	0.09310	14,006.84	14,186.93	0.09338	0.09458	206.55	221.84	1.50%	1.59%
400	200,000	15,652.24	15,871.97	0.07826	0.07936	15,666.36	15,906.48	0.07833	0.07953	14.12	34.51	0.09%	0.22%
500	250,000	17,504.19	17,778.85	0.07002	0.07112	17,325.88	17,626.03	0.06930	0.07050	(178.31)	(152.82)	-1.02%	-0.86%
600	300,000	19,356.14	19,685.73	0.06452	0.06562	18,985.40	19,345.58	0.06328	0.06449	(370.74)	(340.15)	-1.92%	-1.73%
									1,000 KW				
200	200,000	22,472.24	22,691.97	0.11236	0.11346	22,786.36	23,026.48	0.11393	0.11513	314.12	334.51	1.40%	1.47%
300	300,000	26,176.14	26,505.73	0.08725	0.08835	26,105.40	26,465.58	0.08702	0.08822	(70.74)	(40.15)	-0.27%	-0.15%
400	400,000	29,880.03	30,319.50	0.07470	0.07580	29,424.44	29,904.68	0.07356	0.07476	(455.60)	(414.82)	-1.52%	-1.37%
500	500,000	33,583.93	34,133.26	0.06717	0.06827	32,743.48	33,343.77	0.06549	0.06669	(840.46)	(789.48)	-2.50%	-2.31%
600	600,000	37,287.83	37,947.02	0.06215	0.06325	36,062.51	36,782.87	0.06010	0.06130	(1,225.32)	(1,164.15)	-3.29%	-3.07%

KWH DISTRIBUTION

		ON PK	INT	OFF PK
200	HOURS USE =	31%	29%	40%
300	HOURS USE =	33%	27%	40%
400	HOURS USE =	30%	26%	44%
500	HOURS USE =	27%	25%	48%
600	HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY2 RATES AND PROPOSED MRP RY3 RATES - DELIVERY ONLY
SCHEDULE "GT LV "
DISTRICT OF COLUMBIA

HOURS		MRP RY2 RATES				MRP RY3 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**2,000 KW**				
200	400,000	43,520.03	43,959.50	0.10880	0.10990	38,903.28	39,308.36	0.09726	0.09827	(4,616.76)	(4,651.14)	-10.61%	-10.58%
300	600,000	50,927.83	51,587.02	0.08488	0.08598	44,944.62	45,552.24	0.07491	0.07592	(5,983.21)	(6,034.79)	-11.75%	-11.70%
400	800,000	58,335.63	59,214.55	0.07292	0.07402	50,985.95	51,796.11	0.06373	0.06475	(7,349.67)	(7,418.43)	-12.60%	-12.53%
500	1,000,000	65,743.42	66,842.07	0.06574	0.06684	57,027.29	58,039.99	0.05703	0.05804	(8,716.13)	(8,802.08)	-13.26%	-13.17%
600	1,200,000	73,151.22	74,469.60	0.06096	0.06206	63,068.63	64,283.87	0.05256	0.05357	(10,082.59)	(10,185.73)	-13.78%	-13.68%
									4,000 KW				
200	800,000	85,615.63	86,494.55	0.10702	0.10812	76,865.95	77,676.11	0.09608	0.09710	(8,749.67)	(8,818.43)	-10.22%	-10.20%
300	1,200,000	100,431.22	101,749.60	0.08369	0.08479	88,948.63	90,163.87	0.07412	0.07514	(11,482.59)	(11,585.73)	-11.43%	-11.39%
400	1,600,000	115,246.81	117,004.65	0.07203	0.07313	101,031.31	102,651.63	0.06314	0.06416	(14,215.50)	(14,353.03)	-12.33%	-12.27%
500	2,000,000	130,062.40	132,259.71	0.06503	0.06613	113,113.98	115,139.38	0.05656	0.05757	(16,948.42)	(17,120.32)	-13.03%	-12.94%
600	2,400,000	144,877.99	147,514.76	0.06037	0.06146	125,196.66	127,627.14	0.05217	0.05318	(19,681.33)	(19,887.62)	-13.58%	-13.48%
									6,000 KW				
200	1,200,000	127,711.22	129,029.60	0.10643	0.10752	114,828.63	116,043.87	0.09569	0.09670	(12,882.59)	(12,985.73)	-10.09%	-10.06%
300	1,800,000	149,934.61	151,912.18	0.08330	0.08440	132,952.65	134,775.50	0.07386	0.07488	(16,981.96)	(17,136.68)	-11.33%	-11.28%
400	2,400,000	172,157.99	174,794.76	0.07173	0.07283	151,076.66	153,507.14	0.06295	0.06396	(21,081.33)	(21,287.62)	-12.25%	-12.18%
500	3,000,000	194,381.38	197,677.34	0.06479	0.06589	169,200.68	172,238.77	0.05640	0.05741	(25,180.71)	(25,438.57)	-12.95%	-12.87%
600	3,600,000	216,604.77	220,559.92	0.06017	0.06127	187,324.69	190,970.41	0.05203	0.05305	(29,280.08)	(29,589.51)	-13.52%	-13.42%
									8,000 KW				
200	1,600,000	169,806.81	171,564.65	0.10613	0.10723	152,791.31	154,411.63	0.09549	0.09651	(17,015.50)	(17,153.03)	-10.02%	-10.00%
300	2,400,000	199,437.99	202,074.76	0.08310	0.08420	176,956.66	179,387.14	0.07373	0.07474	(22,481.33)	(22,687.62)	-11.27%	-11.23%
400	3,200,000	229,069.18	232,584.87	0.07158	0.07268	201,122.02	204,362.65	0.06285	0.06386	(27,947.16)	(28,222.21)	-12.20%	-12.13%
500	4,000,000	258,700.36	263,094.97	0.06468	0.06577	225,287.37	229,338.16	0.05632	0.05733	(33,412.99)	(33,756.81)	-12.92%	-12.83%
600	4,800,000	288,331.55	293,605.08	0.06007	0.06117	249,452.72	254,313.68	0.05197	0.05298	(38,878.82)	(39,291.40)	-13.48%	-13.38%

KWH DISTRIBUTION

		ON PK	INT	OFF PK
200	HOURS USE =	31%	29%	40%
300	HOURS USE =	33%	27%	40%
400	HOURS USE =	30%	26%	44%
500	HOURS USE =	27%	25%	48%
600	HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY2 RATES AND PROPOSED MRP RY3 RATES - DELIVERY ONLY
SCHEDULE "GT 3A "
DISTRICT OF COLUMBIA

HOURS		MRP RY2 RATES				MRP RY3 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**1,000 KW**				
200	200,000	14,749.25	14,653.24	0.07375	0.07327	15,424.29	15,314.83	0.07712	0.07657	675.04	661.59	4.58%	4.51%
300	300,000	16,850.13	16,706.11	0.05617	0.05569	17,552.69	17,388.49	0.05851	0.05796	702.56	682.38	4.17%	4.08%
400	400,000	18,951.01	18,758.98	0.04738	0.04690	19,681.09	19,462.16	0.04920	0.04866	730.08	703.18	3.85%	3.75%
500	500,000	21,051.89	20,811.86	0.04210	0.04162	21,809.49	21,535.83	0.04362	0.04307	757.60	723.97	3.60%	3.48%
600	600,000	23,152.77	22,864.73	0.03859	0.03811	23,937.89	23,609.50	0.03990	0.03935	785.12	744.77	3.39%	3.26%
									2,000 KW				
200	400,000	29,301.01	29,108.98	0.07325	0.07277	30,651.09	30,432.16	0.07663	0.07608	1,350.08	1,323.18	4.61%	4.55%
300	600,000	33,502.77	33,214.73	0.05584	0.05536	34,907.89	34,579.50	0.05818	0.05763	1,405.12	1,364.77	4.19%	4.11%
400	800,000	37,704.53	37,320.48	0.04713	0.04665	39,164.69	38,726.84	0.04896	0.04841	1,460.16	1,406.36	3.87%	3.77%
500	1,000,000	41,906.29	41,426.23	0.04191	0.04143	43,421.49	42,874.18	0.04342	0.04287	1,515.20	1,447.95	3.62%	3.50%
600	1,200,000	46,108.05	45,531.98	0.03842	0.03794	47,678.29	47,021.52	0.03973	0.03918	1,570.24	1,489.54	3.41%	3.27%
									5,000 KW				
200	1,000,000	72,956.29	72,476.23	0.07296	0.07248	76,331.49	75,784.18	0.07633	0.07578	3,375.20	3,307.95	4.63%	4.56%
300	1,500,000	83,460.69	82,740.60	0.05564	0.05516	86,973.50	86,152.52	0.05798	0.05744	3,512.81	3,411.92	4.21%	4.12%
400	2,000,000	93,965.09	93,004.97	0.04698	0.04650	97,615.50	96,520.87	0.04881	0.04826	3,650.41	3,515.90	3.88%	3.78%
500	2,500,000	104,469.49	103,269.34	0.04179	0.04131	108,257.50	106,889.21	0.04330	0.04276	3,788.01	3,619.87	3.63%	3.51%
600	3,000,000	114,973.89	113,533.71	0.03832	0.03784	118,899.50	117,257.56	0.03963	0.03909	3,925.61	3,723.85	3.41%	3.28%
									7,500 KW				
200	1,500,000	109,335.69	108,615.60	0.07289	0.07241	114,398.50	113,577.52	0.07627	0.07572	5,062.81	4,961.92	4.63%	4.57%
300	2,250,000	125,092.29	124,012.15	0.05560	0.05512	130,361.50	129,130.04	0.05794	0.05739	5,269.21	5,117.89	4.21%	4.13%
400	3,000,000	140,848.89	139,408.71	0.04695	0.04647	146,324.50	144,682.56	0.04877	0.04823	5,475.61	5,273.85	3.89%	3.78%
500	3,750,000	156,605.49	154,805.26	0.04176	0.04128	162,287.51	160,235.07	0.04328	0.04273	5,682.01	5,429.81	3.63%	3.51%
600	4,500,000	172,362.09	170,201.82	0.03830	0.03782	178,250.51	175,787.59	0.03961	0.03906	5,888.42	5,585.77	3.42%	3.28%

KWH DISTRIBUTION

	ON PK	INT	OFF PK
200 HOURS USE =	31%	29%	40%
300 HOURS USE =	33%	27%	40%
400 HOURS USE =	30%	26%	44%
500 HOURS USE =	27%	25%	48%
600 HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY2 RATES AND PROPOSED MRP RY3 RATES - DELIVERY ONLY
SCHEDULE "GT 3A "
DISTRICT OF COLUMBIA

HOURS		MRP RY2 RATES				MRP RY3 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**10,000 KW**				
200	2,000,000	145,715.09	144,754.97	0.07286	0.07238	152,465.50	151,370.87	0.07623	0.07569	6,750.41	6,615.90	4.63%	4.57%
300	3,000,000	166,723.89	165,283.71	0.05557	0.05509	173,749.50	172,107.56	0.05792	0.05737	7,025.61	6,823.85	4.21%	4.13%
400	4,000,000	187,732.69	185,812.45	0.04693	0.04645	195,033.51	192,844.25	0.04876	0.04821	7,300.82	7,031.80	3.89%	3.78%
500	5,000,000	208,741.50	206,341.19	0.04175	0.04127	216,317.52	213,580.93	0.04326	0.04272	7,576.02	7,239.75	3.63%	3.51%
600	6,000,000	229,750.30	226,869.93	0.03829	0.03781	237,601.52	234,317.62	0.03960	0.03905	7,851.22	7,447.69	3.42%	3.28%
									20,000 KW				
200	4,000,000	291,232.69	289,312.45	0.07281	0.07233	304,733.51	302,544.25	0.07618	0.07564	13,500.82	13,231.80	4.64%	4.57%
300	6,000,000	333,250.30	330,369.93	0.05554	0.05506	347,301.52	344,017.62	0.05788	0.05734	14,051.22	13,647.69	4.22%	4.13%
400	8,000,000	375,267.90	371,427.41	0.04691	0.04643	389,869.53	385,491.00	0.04873	0.04819	14,601.63	14,063.59	3.89%	3.79%
500	10,000,000	417,285.50	412,484.89	0.04173	0.04125	432,437.54	426,964.38	0.04324	0.04270	15,152.04	14,479.49	3.63%	3.51%
600	12,000,000	459,303.11	453,542.37	0.03828	0.03780	475,005.55	468,437.76	0.03958	0.03904	15,702.45	14,895.39	3.42%	3.28%
									30,000 KW				
200	6,000,000	436,750.30	433,869.93	0.07279	0.07231	457,001.52	453,717.62	0.07617	0.07562	20,251.22	19,847.69	4.64%	4.57%
300	9,000,000	499,776.70	495,456.15	0.05553	0.05505	520,853.54	515,927.69	0.05787	0.05733	21,076.84	20,471.54	4.22%	4.13%
400	12,000,000	562,803.11	557,042.37	0.04690	0.04642	584,705.55	578,137.76	0.04873	0.04818	21,902.45	21,095.39	3.89%	3.79%
500	15,000,000	625,829.51	618,628.59	0.04172	0.04124	648,557.57	640,347.83	0.04324	0.04269	22,728.06	21,719.24	3.63%	3.51%
600	18,000,000	688,855.91	680,214.81	0.03827	0.03779	712,409.59	702,557.90	0.03958	0.03903	23,553.67	22,343.08	3.42%	3.28%
									40,000 KW				
200	8,000,000	582,267.90	578,427.41	0.07278	0.07230	609,269.53	604,891.00	0.07616	0.07561	27,001.63	26,463.59	4.64%	4.58%
300	12,000,000	666,303.11	660,542.37	0.05553	0.05505	694,405.55	687,837.76	0.05787	0.05732	28,102.45	27,295.39	4.22%	4.13%
400	16,000,000	750,338.31	742,657.33	0.04690	0.04642	779,541.57	770,784.52	0.04872	0.04817	29,203.26	28,127.19	3.89%	3.79%
500	20,000,000	834,373.52	824,772.29	0.04172	0.04124	864,677.60	853,731.27	0.04323	0.04269	30,304.08	28,958.98	3.63%	3.51%
600	24,000,000	918,408.72	906,887.25	0.03827	0.03779	949,813.62	936,678.03	0.03958	0.03903	31,404.90	29,790.78	3.42%	3.28%

KWH DISTRIBUTION

	ON PK	INT	OFF PK
200 HOURS USE =	31%	29%	40%
300 HOURS USE =	33%	27%	40%
400 HOURS USE =	30%	26%	44%
500 HOURS USE =	27%	25%	48%
600 HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER MRP RY2 RATES AND PROPOSED MRP RY3 RATES - DELIVERY ONLY
SCHEDULE "GT 3B "
DISTRICT OF COLUMBIA

HOURS		MRP RY2 RATES				MRP RY3 RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**10,000 KW**				
200	2,000,000	39,223.17	42,963.64	0.01961	0.02148	40,061.27	44,110.82	0.02003	0.02206	838.09	1,147.18	2.14%	2.67%
300	3,000,000	51,992.31	55,732.78	0.01733	0.01858	52,800.47	56,850.02	0.01760	0.01895	808.16	1,117.24	1.55%	2.00%
400	4,000,000	64,761.45	68,501.92	0.01619	0.01713	65,539.67	69,589.22	0.01638	0.01740	778.22	1,087.30	1.20%	1.59%
500	5,000,000	77,530.59	81,271.06	0.01551	0.01625	78,278.87	82,328.42	0.01566	0.01647	748.28	1,057.36	0.97%	1.30%
600	6,000,000	90,299.73	94,040.20	0.01505	0.01567	91,018.07	95,067.62	0.01517	0.01584	718.34	1,027.42	0.80%	1.09%
									20,000 KW				
200	4,000,000	78,134.69	85,615.63	0.01953	0.02140	79,925.05	88,024.15	0.01998	0.02201	1,790.35	2,408.52	2.29%	2.81%
300	6,000,000	103,672.97	111,153.91	0.01728	0.01853	105,403.45	113,502.55	0.01757	0.01892	1,730.48	2,348.64	1.67%	2.11%
400	8,000,000	129,211.25	136,692.18	0.01615	0.01709	130,881.85	138,980.95	0.01636	0.01737	1,670.60	2,288.77	1.29%	1.67%
500	10,000,000	154,749.52	162,230.46	0.01547	0.01622	156,360.25	164,459.35	0.01564	0.01645	1,610.73	2,228.89	1.04%	1.37%
600	12,000,000	180,287.80	187,768.74	0.01502	0.01565	181,838.65	189,937.75	0.01515	0.01583	1,550.85	2,169.01	0.86%	1.16%
									30,000 KW				
200	6,000,000	117,046.21	128,267.62	0.01951	0.02138	119,788.83	131,937.48	0.01996	0.02199	2,742.62	3,669.86	2.34%	2.86%
300	9,000,000	155,353.63	166,575.03	0.01726	0.01851	158,006.43	170,155.08	0.01756	0.01891	2,652.80	3,580.05	1.71%	2.15%
400	12,000,000	193,661.04	204,882.45	0.01614	0.01707	196,224.03	208,372.68	0.01635	0.01736	2,562.99	3,490.23	1.32%	1.70%
500	15,000,000	231,968.45	243,189.86	0.01546	0.01621	234,441.63	246,590.28	0.01563	0.01644	2,473.17	3,400.42	1.07%	1.40%
600	18,000,000	270,275.87	281,497.28	0.01502	0.01564	272,659.23	284,807.88	0.01515	0.01582	2,383.36	3,310.60	0.88%	1.18%
									40,000 KW				
200	8,000,000	155,957.73	170,919.61	0.01949	0.02136	159,652.61	175,850.81	0.01996	0.02198	3,694.88	4,931.20	2.37%	2.89%
300	12,000,000	207,034.28	221,996.16	0.01725	0.01850	210,609.41	226,807.61	0.01755	0.01890	3,575.12	4,811.45	1.73%	2.17%
400	16,000,000	258,110.84	273,072.71	0.01613	0.01707	261,566.21	277,764.41	0.01635	0.01736	3,455.37	4,691.70	1.34%	1.72%
500	20,000,000	309,187.39	324,149.27	0.01546	0.01621	312,523.01	328,721.21	0.01563	0.01644	3,335.62	4,571.95	1.08%	1.41%
600	24,000,000	360,263.94	375,225.82	0.01501	0.01563	363,479.81	379,678.01	0.01514	0.01582	3,215.87	4,452.19	0.89%	1.19%

KWH DISTRIBUTION

	ON PK	INT	OFF PK
200 HOURS USE =	31%	29%	40%
300 HOURS USE =	33%	27%	40%
400 HOURS USE =	30%	26%	44%
500 HOURS USE =	27%	25%	48%
600 HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

P.R. Blazunas
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (F) – 8

CLEAN

RATE SCHEDULES

FOR

ELECTRIC SERVICE

IN THE

DISTRICT OF COLUMBIA

pepco®
An Exelon Company

RATES AND REGULATORY PRACTICES GROUP

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RESIDENTIAL SERVICE

SCHEDULE "R"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for low voltage electric service where the use is primarily for residential purposes and for farm operations where the electricity for both farm and residential purposes is delivered through the same meter.

Available only in individual residences and in individually metered dwelling units in multi-family buildings.

Not available for residential premises in which five (5) or more rooms are for hire.

Not available for seasonal loads metered separately from lighting and other usage in the same occupancy.

Not available for temporary, auxiliary or emergency service.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, three wire, 120/240 volts, or three wire, 120/208 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge – Residential	$ 18.56 per month	$ 18.56 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ 0.01288 per kwhr	$ 0.01288 per kwhr
In excess of 400 kilowatt hours	$ 0.03541 per kwhr	$ 0.02630 per kwhr

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge – Residential	$ 20.18 per month	$ 20.18 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ 0.01495 per kwhr	$ 0.01495 per kwhr
In excess of 400 kilowatt hours	$ 0.04094 per kwhr	$ 0.03064 per kwhr

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge – Residential	$ 21.60 per month	$ 21.60 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ 0.01691 per kwhr	$ 0.01691 per kwhr
In excess of 400 kilowatt hours	$ 0.04612 per kwhr	$ 0.03471 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Service from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.62 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS
Standard Offer Service - Residential
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount
Optional Meter Equipment Related Services
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Residential Direct Load Control Rider
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

MASTER METERED APARTMENT SERVICE
SCHEDULE "MMA"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for low voltage electric service for multiple application to master-metered apartment buildings where the use is predominantly residential and not for retail business establishments. Not available for separately metered service billed on Schedule "GS ND" that did not qualify for multiple application of the residential rate as of December 31, 1982.

Not available for seasonal loads metered separately from lighting and other usage in the same occupancy.

Not available for temporary, auxiliary or emergency service.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, three wire, 120/240 volts, or three wire, 120/208 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 13.91 per month	$ 13.91 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ 0.00912 per kwhr	$ 0.00912 per kwhr
In excess of 400 kilowatt hours	$ 0.03003 per kwhr	$ 0.01654 per kwhr

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 14.90 per month	$ 14.90 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ 0.00988 per kwhr	$ 0.00988 per kwhr
In excess of 400 kilowatt hours	$ 0.03282 per kwhr	$ 0.01782 per kwhr

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 15.79 per month	$ 15.79 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ 0.01050 per kwhr	$ 0.01050 per kwhr
In excess of 400 kilowatt hours	$ 0.03523 per kwhr	$ 0.01884 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Service from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.62 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

DC - MMA

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS
Standard Offer Service - Residential
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Optional Meter Equipment Related Services
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Residential Direct Load Control Rider
Underground Project Charge
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

GENERAL SERVICE – NON DEMAND

SCHEDULE "GS ND"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for "GS LV" customers whose maximum monthly demand is less than 25 kW. Customers whose maximum demand is between 25 kW and 99 kW will be served on Schedule GS LV or GS 3A subject to the provisions stated therein. Customers whose maximum demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months will be transferred to Schedule "GT LV", "GT 3A", or "GT 3B" in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz and for primary service furnished directly from the Company's electric system at voltages of 4.16 kV, 13.2 kV, or 33 kV, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnects, regulators and protective equipment.

Not available for railway propulsion service.

Not available for secondary temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts for GS Low Voltage Non Demand customers. For GS 3A Non Demand customers, the service under this schedule, normally will be alternating current, sixty hertz, three phase, three wire, at 4.16kV, 13.2kV or 33 kV. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE
GS LOW VOLTAGE NON DEMAND

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 32.10 per month	$ 32.10 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.04851 per kwhr	$ 0.04231 per kwhr

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 34.33 per month	$ 34.33 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.05237 per kwhr	$ 0.04564 per kwhr

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 36.33 per month	$ 36.33 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.05594 per kwhr	$ 0.04878 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

Demand metering equipment will be installed and charges subsequent to the installation of this equipment will be computed under the billing demand provision when the customer's load is of such a magnitude and of such a nature as to indicate any of the following:

1. Monthly energy consumption in excess of 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive).

2. Monthly energy consumption in excess of 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive).

3. A monthly demand greater than or equal to twenty-five (25) kilowatts in a single month.

Demand accounts are reviewed annually. The account will be billed under non-demand billing provision when the consumption for each of the previous twelve (12) months is below 6,000 kilowatt-hours and the demand is less than twenty-five (25) kilowatts.

BILLING DEMAND

The billing demand shall be the maximum thirty (30) minute demand recorded during the month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Small Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

GENERAL SERVICE - LOW VOLTAGE

SCHEDULE "GS LV"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area, except if the customer's maximum demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months, the customer will be transferred to Schedule "GT LV", "GT 3A", or "GT 3B" in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June. Customers with monthly maximum demands less than 25 kW are served on Schedule "GS ND" subject to the provisions stated therein.

Available for low voltage electric service at sixty hertz.

Not available for railway propulsion service.

Not available for secondary temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 38.75 per month	$ 38.75 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.03460 per kwhr	$ 0.02595 per kwhr
Demand Charge	$ 9.43 per kw	$ 9.43 per kw

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 38.75 per month	$ 38.75 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.03819 per kwhr	$ 0.02859 per kwhr
Demand Charge	$ 10.10 per kw	$ 10.10 per kw

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 38.75 per month	$ 38.75 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.04174 per kwhr	$ 0.03124 per kwhr
Demand Charge	$ 10.66 per kw	$ 10.66 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

Demand metering equipment will be installed and charges subsequent to the installation of this equipment will be computed under the billing demand provision when the customer's load is of such a magnitude and of such a nature as to indicate any of the following:

1. Monthly energy consumption in excess of 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive).

2. Monthly energy consumption in excess of 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive).

3. A monthly demand greater than or equal to twenty-five (25) kilowatts in a single month.

Demand accounts are reviewed annually. The account will be billed under non-demand billing provision when the consumption for each of the previous twelve (12) months is below 6,000 kilowatt-hours and the demand is less than twenty-five (25) kilowatts.

BILLING DEMAND

The billing demand shall be the maximum thirty (30) minute demand recorded during the month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

GENERAL SERVICE - PRIMARY SERVICE

SCHEDULE "GS 3A"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS", or Distribution Service in the District of Columbia portion of the Company's service area, except if the customer's maximum demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months, the customer will be transferred to Schedule "GT LV", "GT 3A", or "GT 3B" in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June. Customers with monthly maximum demands less than 25 kW are served on Schedule "GS ND" subject to the provisions stated therein.

Available for primary service furnished directly from the Company's electric system at voltages of 4.16 kV, 13.2 kV or 33 kV, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnects, regulators and protective equipment.

Not available for railway propulsion service.

Not available for secondary temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

CHARACTER OF SERVICE

The service under this schedule, normally will be alternating current, sixty hertz, three phase, three wire, at 4.16kV, 13.2kV or 33kV. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 89.41 per month	$ 89.41 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.01907 per kwhr	$ 0.01240 per kwhr
Demand Charge	$ 10.82 per kw	$ 10.82 per kw

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 89.41 per month	$ 89.41 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.01987 per kwhr	$ 0.01289 per kwhr
Demand Charge	$ 10.82 per kw	$ 10.82 per kw

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 89.41 per month	$ 89.41 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.02063 per kwhr	$ 0.01338 per kwhr
Demand Charge	$ 10.82 per kw	$ 10.82 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

Demand metering equipment will be installed and charges subsequent to the installation of this equipment will be computed under the demand billing provision when the customer's load is of such a magnitude and of such a nature as to indicate any of the following:

1. Monthly energy consumption in excess of 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive).

2. Monthly energy consumption in excess of 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive).

3. A monthly demand greater than or equal to twenty-five (25) kilowatts in a single month.

Demand accounts are reviewed annually. The account will be billed under non-demand billing provision when the consumption for each of the previous twelve (12) months is below 6,000 kilowatt-hours and the demand is less than twenty-five (25) kilowatts.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMAND

The billing demand shall be the maximum thirty (30) minute demand recorded during the month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED MEDIUM GENERAL SERVICE - LOW VOLTAGE
SCHEDULE "MGT LV"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider "SOS" or Distribution Service when modified by Rider "SOS" in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "MGT LV" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "MGT LV" even if the party responsible for the account should change. Removal from Schedule "MGT LV" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "MGT LV" whose maximum thirty (30) minute demand is less than eighty (80) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "MGT LV", the customer will remain on Schedule "MGT LV" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz.

Available for standby service when modified by Schedule "S".

Not available for temporary service.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 237.00 per month	$ 237.00 per month
Kilowatt-hour Charge	$ 0.01482 per kwhr	$ 0.01482 per kwhr
Kilowatt Charge Maximum	$ 15.17 per kw	$ 15.17 per kw

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 237.00 per month	$ 237.00 per month
Kilowatt-hour Charge	$ 0.01675 per kwhr	$0.01673 per kwhr
Kilowatt Charge Maximum	$ 16.26 per kw	$ 16.26 per kw

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 237.00 per month	$ 237.00 per month
Kilowatt-hour Charge	$ 0.01865 per kwhr	$ 0.01863 per kwhr
Kilowatt Charge Maximum	$ 17.24 per kw	$ 17.24 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

DC – MGT LV

Billing Credit - A monthly billing credit in the amount of $0.75 per bill will be applied to the bill of each customer receiving generation services from an alternative supplier for each month that the alternative supplier renders a bill to the customer on a consolidated basis for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

TEMPORARY SERVICE

SCHEDULE "T"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for low voltage electric service for construction or other commercial purposes furnished through service connection facilities of a temporary rather than a permanent nature, or for temporary electric service supplied for a limited time, such as for carnivals, festivals, etc.

However, customers receiving Temporary Service on a continuous basis for five (5) years will normally be transferred to the appropriate General Service Low Voltage Schedule "GS LV" or "GS ND" based on the customer's maximum demand, in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June.

CHARACTER OF SERVICE

The service supplied under this schedule will be alternating current, sixty hertz, at any of the approved classes of service.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 32.10 per month	$ 32.10 per month
Kilowatt-hour Charge	$ 0.05741 per kwhr	$ 0.06308 per kwhr

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 34.33 per month	$ 34.33 per month
Kilowatt-hour Charge	$ 0.06209 per kwhr	$ 0.06824 per kwhr

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 36.33 per month	$ 36.33 per month
Kilowatt-hour Charge	$ 0.06642 per kwhr	$ 0.07309 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Standard Offer Service – Small Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED GENERAL SERVICE - LOW VOLTAGE
SCHEDULE "GT LV"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider “SOS” or Distribution Service when modified by Rider “SOS” in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds one thousand (1000) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "GT LV" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "GT LV" even if the party responsible for the account should change. Removal from Schedule "GT LV" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "GT LV" whose maximum thirty (30) minute demand is less than nine hundred (900) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "GT LV", the customer will remain on Schedule "GT LV" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz.

Available for standby service when modified by Schedule "S".

Not available for temporary service.

Not available for multiple application to master-metered apartment buildings except for those master-metered apartments served under Schedule "GT LV" prior to December 31, 1982 which will continue to be served under Schedule "GT LV".

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 940.60 per month	$ 940.60 per month
Kilowatt-hour Charge	$ 0.01449 per kwhr	$ 0.01550 per kwhr
Kilowatt Charge Maximum	$ 13.77 per kw	$ 13.77 per kw

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 1,424.44 per month	$ 1,424.44 per month
Kilowatt-hour Charge	$ 0.01601 per kwhr	$ 0.01711 per kwhr
Kilowatt Charge Maximum	$ 14.47 per kw	$ 14.47 per kw

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 1,908.28 per month	$ 1,908.28 per month
Kilowatt-hour Charge	$ 0.01747 per kwhr	$ 0.01867 per kwhr
Kilowatt Charge Maximum	$ 15.07 per kw	$ 15.07 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company’s General Terms and Conditions will

receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 per bill will be applied to the bill of each customer receiving generation services from an alternative supplier for each month that the alternative supplier renders a bill to the customer on a consolidated basis for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED GENERAL SERVICE - PRIMARY SERVICE

SCHEDULE "GT 3A"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "GT 3A" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "GT 3A" even if the party responsible for the account should change. Removal from Schedule "GT 3A" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "GT 3A" whose maximum thirty (30) minute demand is less than eighty (80) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "GT 3A", the customer will remain on Schedule "GT 3A" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for primary service furnished directly from the Company's electric system at voltages of 4.16 kV, 13.2 kV or 33 kV, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnectors, regulators and protective equipment.

Available for standby service when modified by Schedule "S".

Not available for temporary service.

Not available for multiple application to master-metered apartment buildings except for those master-metered apartments served under Schedule "GT 3A" prior to December 31, 1982 which will continue to be served under Schedule "GT 3A".

CHARACTER OF SERVICE

The service under this schedule, normally will be alternating current, sixty hertz, three phase, three wire, at 4.16kV, 13.2kV or 33kV. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 197.49 per month	$ 197.49 per month
Kilowatt-hour Charge	$ 0.00526 per kwhr	$ 0.00486 per kwhr
Kilowatt Charge Maximum	$ 10.27 per kw	$ 10.27 per kw

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 197.49 per month	$ 197.49 per month
Kilowatt-hour Charge	$ 0.00606 per kwhr	$ 0.00558 per kwhr
Kilowatt Charge Maximum	$ 10.96 per kw	$ 10.96 per kw

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 197.49 per month	$ 197.49 per month
Kilowatt-hour Charge	$ 0.00685 per kwhr	$ 0.00631 per kwhr
Kilowatt Charge Maximum	$ 11.58 per kw	$ 11.58 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 per bill will be applied to the bill of each customer receiving generation services from an alternative supplier for each month that the alternative supplier renders a bill to the customer on a consolidated basis for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED GENERAL SERVICE - HIGH VOLTAGE SERVICE
SCHEDULE "GT 3B"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider “SOS” or Distribution Service in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "GT 3B" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "GT 3B" even if the party responsible for the account should change. Removal from Schedule "GT 3B" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "GT 3B" whose maximum thirty (30) minute demand is less than eighty (80) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "GT 3B", the customer will remain on Schedule "GT 3B" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for standby service when modified by Schedule "S".

Available for high voltage service furnished directly from the Company's electric system at voltages of 66 kV or above, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnectors, regulators and protective equipment.

Not available for temporary service.

Not available for multiple application to master-metered apartment buildings except for those master-metered apartments served under Schedule "GT 3B" prior to December 31, 1982 which will continue to be served under Schedule "GT 3B".

CHARACTER OF SERVICE

The service under this schedule, normally will be 66kV or above. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 311.66 per month	$ 311.66 per month
Kilowatt-hour Charge	$ 0.00000 per kwhr	$ 0.00000 per kwhr
Kilowatt Charge Maximum	$ 1.84 per kw	$ 2.23 per kw
	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 311.66 per month	$ 311.66 per month
Kilowatt-hour Charge	$ 0.00000 per kwhr	$0.00000 per kwhr
Kilowatt Charge Maximum	$ 1.95 per kw	$ 2.37 per kw
	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 311.66 per month	$ 311.66 per month
Kilowatt-hour Charge	$ 0.00000 per kwhr	$ 0.00000 per kwhr
Kilowatt Charge Maximum	$ 2.05 per kw	$ 2.50 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider.
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

RAPID TRANSIT SERVICE

SCHEDULE "RT"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for rapid transit electric service furnished directly from the Company's distribution, subtransmission or transmission systems at available voltages of 13.2kV and higher where the customer provides, at the customer's own expense, all necessary transformers or converting apparatus, switches, disconnectors, regulators, and protective equipment.

Available only at points of delivery on contiguous authority right-of-way.

Also available for low voltage service for purposes of operating electric chiller plants used for the purpose of providing chilled water to passenger stations associated with the rapid transit service.

Not available for partial or auxiliary service.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, three phase, three wire, high tension at 13.2kV or such voltage as is specified by the Company on the basis of its available facilities and the magnitude of load to be served.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 7,203.15 per month	$ 7,203.15 per month

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 7,673.12 per month	$ 7,673.12 per month

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 8,096.09 per month	$ 8,096.09 per month

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMAND

The monthly billing demand will be the maximum thirty (30) minute integrated coincident demand of all delivery points recorded during the billing month.

BILLING ENERGY
The monthly billing energy will be the sum of the registrations of kilowatt-hours of all delivery points.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations", except as modified by the agreement by and between the Company and the customer.

APPLICABLE RIDERS
Standard Offer Service – Large Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

STREET LIGHTING SERVICE

SCHEDULE "SL"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service for street, highway and park lighting purposes in the District of Columbia portion of the Company's service area when owned by agencies of Federal and District of Columbia governments. Also available to governmental and non-governmental customers for holiday lighting and seasonal street decoration lighting where the lights are in public space and where the only load supplied is lighting load. Schedule "SL" is not available for services that supply any load other than lighting.

CHARACTER OF SERVICE

Electricity supplied to multiple lights normally will be sixty hertz, single phase, 120 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)
Distribution Service Charge	
Customer Charge	
Metered Account	$ 19.85 per month
Unmetered Account	$ 16.97 per month
Kilowatt-hour Charge	$ 0.00867 per kwh

	Rate Year 2 (January 1, 2021 – December 31, 2021)
Distribution Service Charge	
Customer Charge	
Metered Account	$ 22.51 per month
Unmetered Account	$ 19.25 per month
Kilowatt-hour Charge	$ 0.00972 per kwh

	Rate Year 3 (January 1, 2022 – December 31, 2022)
Distribution Service Charge	
Customer Charge	
Metered Account	$ 25.17 per month
Unmetered Account	$ 21.52 per month
Kilowatt-hour Charge	$ 0.01065 per kwh

The per kwh charge shall be adjusted for any Major Service Outages as defined in Section 3699 of Chapter 36, Electric Quality Service Standards in Title 15 of the District of Columbia Municipal Regulations.

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

The charges under this schedule are for delivery only and do not include furnishing and/or maintaining street lighting equipment.

MEASUREMENTS OF ELECTRICITY

If electricity delivered for street lighting is unmetered, monthly kilowatt-hour consumption will be computed on the basis of manufacturers' wattage ratings of installed lamps, auxiliary devices where required, and scheduled 4,200 hours of burning time. If metered, watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

Lights controlled for night burning only will be billed at the monthly rate for Standard Night Burning street lights. Lights not controlled for night burning only will be billed at the monthly rate for 24-Hour Burning street lights.

The kilowatt-hours calculated from billing wattages will be reduced by 5.5 percent each month to provide for normal outages.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations". Holiday and decorative street lighting service connections will be considered temporary service connections as defined in the "Electric Service Rules and Regulations" and will be priced accordingly.

APPLICABLE RIDERS
Standard Offer Service – Small Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Telecommunication Network Charge
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

TRAFFIC SIGNAL SERVICE

SCHEDULE "TS"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service to agencies of the Federal and District of Columbia governments, for operation of traffic signals in the District of Columbia portion of the Company's service area.

CHARACTER OF SERVICE

Electricity supplied for traffic signal purposes normally will be sixty hertz, single phase, 120 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)
Distribution Service Charge	
Customer Charge	$ 4.26 per month
Kilowatt-hour Charge	$ 0.02775 per kwh
	Rate Year 2 (January 1, 2021 – December 31, 2021)
Distribution Service Charge	
Customer Charge	$ 4.26 per month
Kilowatt-hour Charge	$ 0.02934 per kwh
	Rate Year 3 (January 1, 2022 – December 31, 2022)
Distribution Service Charge	
Customer Charge	$ 4.26 per month
Kilowatt-hour Charge	$ 0.03077 per kwh

The per kwh charge shall be adjusted for any Major Service Outages as defined in Section 3699 of Chapter 36, Electric Quality Service Standards in Title 15 of the District of Columbia Municipal Regulations.

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

The charges under this schedule are for delivery only and do not include furnishing and/or maintaining traffic signal equipment.

MEASUREMENT OF ELECTRICITY

Electricity delivered to traffic signals is unmetered. Monthly kilowatt-hour consumption will be computed on the basis of manufacturers' wattage ratings of installed devices and estimated hours of burning time.

The kilowatt-hours calculated from billing wattages will be reduced by 1.5 percent each month to provide for normal outages.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

DC - TS

APPLICABLE RIDERS
Standard Offer Service – Small Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

CHARGES FOR SERVICING
STREET LIGHTS SERVED FROM OVERHEAD LINES
SCHEDULE "SSL-OH"

APPLICABILITY
Applicable only to luminaries meeting ANSI Standards for street lighting equipment when owned by the Company and mounted on Company-owned wooden poles or on poles of another utility with whom the Company has an attachment agreement.

AVAILABILITY
Available in the District of Columbia portion of the Company's service area to Federal Governmental Agencies for servicing street, highway and park lighting equipment when the electricity supplying such equipment is furnished by the Company from overhead lines and is accessible by conventional wheeled construction and maintenance vehicles.

Available only for lights having a manufacturers' nominal rating of:

Incandescent*	10,000	lumens or less
Mercury Vapor*	100 - 400	watts
High Pressure Sodium	70 - 400	watts
Metal Halide	400	watts

*Not available for new installation or replacement of defective fixtures.

CHARACTER OF SERVICE
Service rendered under this schedule will consist of (1) furnishing, installing and maintaining street lighting fixtures and mounting arms or brackets, (2) furnishing, installing, connecting, operating and maintaining the electric service circuits connecting the street lighting equipment to the Company's distribution system, (3) group relamping, (every six (6) months for incandescent, every four (4) years for mercury vapor and every five (5) years for high pressure sodium), (4) washing of globes, (5) furnishing and installing replacement globes, lamps, ballasts and light sensitive switches as needed to maintain the system in an operating mode; all normally limited, to standard items of equipment meeting ANSI Standards for street lighting equipment and approved by the Company for maintenance.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Fixed Charges	**O&M Charges**
Incandescent Lights* - Night Burning		
Without Globe - all sizes	$ 3.128 per lamp	$0.049 per lamp
With Globe - all sizes	$ 4.568 per lamp	$1.079 per lamp
*Not available for new installation or replacement of defective fixtures.		
Mercury Vapor Lights* - Night Burning		
175 Watt	$ 9.735 per lamp	$0.963 per lamp
250 Watt	$ 11.122 per lamp	$0.975 per lamp
*Not available for new installation or replacement of defective fixtures.		
Metal Halide Lights – Night Burning		
400 Watt	$ 37.643 per lamp	$1.573 per lamp

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Fixed Charges	**O&M Charges**
Incandescent Lights* - Night Burning		
Without Globe - all sizes	$ 3.453 per lamp	$ 0.054 per lamp
With Globe - all sizes	$ 5.042 per lamp	$ 1.192 per lamp
*Not available for new installation or replacement of defective fixtures.		

Mercury Vapor Lights* - Night Burning		
175 Watt	$ 10.746 per lamp	$ 1.063 per lamp
250 Watt	$ 12.277 per lamp	$ 1.077 per lamp
*Not available for new installation or replacement of defective fixtures.		
Metal Halide Lights – Night Burning		
400 Watt	$ 41.550 per lamp	$ 1.736 per lamp

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Fixed Charges	**O&M Charges**
Incandescent Lights* - Night Burning		
Without Globe - all sizes	$ 3.745 per lamp	$ 0.059 per lamp
With Globe - all sizes	$ 5.468 per lamp	$ 1.292 per lamp
*Not available for new installation or replacement of defective fixtures.		
Mercury Vapor Lights* - Night Burning		
175 Watt	$ 11.655 per lamp	$ 1.153 per lamp
250 Watt	$ 13.316 per lamp	$ 1.168 per lamp
*Not available for new installation or replacement of defective fixtures.		
Metal Halide Lights – Night Burning		
400 Watt	$ 45.067 per lamp	$ 1.883 per lamp

The above charges will be separate from and in addition to charges for electricity supplied under the provisions of Schedule "SL".

NON-STANDARD EQUIPMENT
Non Company approved ANSI equipment, if accepted by the Company for maintenance, will be subject to special contracts which may include an initial installation charge.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Excess Deferred Income Tax Credit

CHARGES FOR SERVICING
STREET LIGHTS SERVED FROM UNDERGROUND LINES
SCHEDULE "SSL-UG"

APPLICABILITY
Applicable only to posts and luminaries meeting ANSI Standards for street lighting equipment furnished by the customer.

AVAILABILITY
Available in the District of Columbia portion of the Company's service area to Federal Governmental Agencies for servicing street, highway and park lighting equipment when the electricity supplying such equipment is furnished by the Company from unmetered underground lines and is accessible by conventional wheeled construction and maintenance vehicles.

Available only for lights having a manufacturers' nominal rating of:

Incandescent*	10,000	lumens or less
Mercury Vapor*	250 - 400	watts
High Pressure Sodium	150	watts
Metal Halide	100 - 400	watts

*Not available for new installation or replacement of defective fixtures.

CHARACTER OF SERVICE
Service rendered under this schedule will consist of (1) furnishing, installing, connecting, operating and maintaining the electric service circuits connecting the street lighting equipment to the Company's distribution system, (2) furnishing and installing post foundations and setting customer owned posts on foundations, (3) installing customer owned street lighting fixtures, (4) group relamping, (every six (6) months for incandescent, every two (2) years for metal halide, every four (4) years for mercury vapor and every five (5) years for high pressure sodium), (5) washing of globes, (6) furnishing and installing of replacement globes, lamps, remote ballasts, and light sensitive switches as needed to maintain the system in an operating mode, (7) repainting posts at approximately six (6) year intervals; all normally limited to standard items of equipment meeting ANSI Standards for street lighting equipment and accepted by the Company for maintenance.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Fixed Charges	**O&M Charges**
Incandescent Lights* - Night Burning		
With Globe - all sizes	$ 43.768 per lamp	$1.978 per lamp
*Not available for new installation or replacement of defective fixtures.		
Mercury Vapor Lights* - Night Burning		
250 Watt	$ 44.146 per lamp	$1.777 per lamp
400 Watt	$ 51.766 per lamp	$2.208 per lamp
*Not available for new installation or replacement of defective fixtures.		
High Pressure Sodium Lights - Night Burning		
150 Watt	$ 38.714 per lamp	$1.450 per lamp
Metal Halide Lights – Night Burning		
100 Watt	$ 33.360 per lamp	$1.304 per lamp
175 Watt	$ 37.643 per lamp	$1.573 per lamp
400 Watt	$ 37.643 per lamp	$1.573 per lamp

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Fixed Charges	**O&M Charges**
Incandescent Lights* - Night Burning		
With Globe - all sizes	$ 48.311 per lamp	$ 2.183 per lamp
*Not available for new installation or replacement of defective fixtures.		

Mercury Vapor Lights* - Night Burning		
250 Watt	$ 48.728 per lamp	$ 1.962 per lamp
400 Watt	$ 57.139 per lamp	$ 2.437 per lamp
*Not available for new installation or replacement of defective fixtures.		
High Pressure Sodium Lights - Night Burning		
150 Watt	$ 42.732 per lamp	$ 1.600 per lamp
Metal Halide Lights – Night Burning		
100 Watt	$ 36.823 per lamp	$ 1.440 per lamp
175 Watt	$ 41.550 per lamp	$ 1.736 per lamp
400 Watt	$ 41.550 per lamp	$ 1.736 per lamp

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Fixed Charges	**O&M Charges**
Incandescent Lights* - Night Burning		
With Globe - all sizes	$ 52.400 per lamp	$ 2.368 per lamp
*Not available for new installation or replacement of defective fixtures.		
Mercury Vapor Lights* - Night Burning		
250 Watt	$ 52.852 per lamp	$ 2.128 per lamp
400 Watt	$ 61.975 per lamp	$ 2.643 per lamp
*Not available for new installation or replacement of defective fixtures.		
High Pressure Sodium Lights - Night Burning		
150 Watt	$ 46.348 per lamp	$ 1.736 per lamp
Metal Halide Lights – Night Burning		
100 Watt	$ 39.939 per lamp	$ 1.561 per lamp
175 Watt	$ 45.067 per lamp	$ 1.883 per lamp
400 Watt	$ 45.067 per lamp	$ 1.883 per lamp

Other

Posts furnished by the Company, costing*:

$ 15.00 and less	$ 1.139 each
$ 15.01 to $ 45.00, inclusive	$ 1.517 each
$ 45.01 to $ 75.00, inclusive	$ 3.410 each
$ 75.01 to $100.00, inclusive	$ 5.687 each
$100.01 to $160.00, inclusive	$10.047 each

*Not available for new installation or replacement of defective posts.

The above charges will be separate from and in addition to charges for electricity supplied under the provisions of Schedule "SL".

CUSTOMER RESPONSIBILITY AS TO FURNISHING, INSTALLING AND MAINTAINING EQUIPMENT
The street lighting posts, fixtures and brackets (if required) shall be furnished by the customer for installation by the Company as set forth under "Character of Service" above. Ballasts for all High Pressure Sodium Lights and any Mercury Vapor Lights to be installed in or on upright posts shall be furnished by the customer. All Metal Halide lamps and ballasts shall be furnished by the customer for installation by the Company.

All maintenance of equipment furnished by the customer will be performed at the customer's expense, except as set forth under "Character of Service".

NON-STANDARD EQUIPMENT
Non-company approved ANSI accepted equipment and non-standard, special, experimental and any other such post and luminaries which do not meet ANSI Standards for street lighting equipment, if accepted by the Company for maintenance, will be subjected to special contracts. Lights of this type will be installed in accordance with the customer's instruction, and all installation costs charged to the customer.

DC - SSL - UG

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Excess Deferred Income Tax Credit

TELECOMMUNICATIONS NETWORK SERVICE

SCHEDULE "TN"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for unmetered electric service to multiple telecommunications network devices or other devices with similar load characteristics served directly by the Company and not exceeding 1,800 watts per device. For devices that are currently served by meter, the Customer may choose to have the meter removed at the Customer's expense and the month Customer Charge without Meter will apply.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, 120 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 15.43 per month	$ 15.43 per month
Kilowatt-hour Charge	$ 0.01200 per kwhr	$ 0.01200 per kwhr

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 15.43 per month	$ 15.43 per month
Kilowatt-hour Charge	$ 0.01165 per kwh	$ 0.01165 per kwh

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 15.43 per month	$ 15.43 per month
Kilowatt-hour Charge	$ 0.01132 per kwh	$ 0.01132 per kwh

Customer Charges/Kilowatt-hour Charge – For devices that are served through a meter, the Customer shall pay the monthly "Customer Charge with Meter" and the kilowatt-hour charge will be applied to metered usage. For devices served without a meter, the Customer shall pay the monthly "Customer Charge without Meter" and the kilowatt-hour charge will be applied to estimated monthly usage based on metered usages for similar devices. If similar metered data do not exist, at the customer's option, the monthly usage will be estimated base on either the manufacturer's average wattage ratings with no allowance for outage, or on the basis of statistically valid sample estimates using actual current and voltage readings.

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

MEASUREMENTS OF ELECTRICITY

Monthly kilowatt-hour consumption will be computed on the basis of manufacturer's average wattage ratings of installed devices, with no allowance for outages. The charges under this rider are for electricity only.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Standard Offer Services – Small Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

LED OUTDOOR LIGHTING SERVICE

SCHEDULE "OL LED"

AVAILABILITY
Available for Distribution Service and Standard Offer Service when modified by Rider "SOS" in the District of Columbia portion of the Company's overhead service area for customer-owned outdoor lighting purposes on customers' premises subject to local ordinance or other appropriate approval.

Not available for street lighting purposes.

CHARACTER OF SERVICE

Electricity will be supplied from distribution system facilities on a metered basis.

MONTHLY RATE
Charge for supply of electricity for operation:

	Summer	Winter
	Rate Year 1 (May 1, 2020 – December 31, 2020)	
Distribution Service Charge		
Customer Charge		
Service at secondary voltage:	$8.76 per customer per month	$8.76 per customer per month
Energy Charge:		
Service at secondary voltage:	$0.00895 per kwhr	$0.00895 per kwhr
	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge		
Service at secondary voltage:	$8.76 per customer per month	$8.76 per customer per month
Energy Charge:		
Service at secondary voltage:	$0.00895 per kwhr	$0.00895 per kwhr
	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge		
Service at secondary voltage:	$8.76 per customer per month	$8.76 per customer per month
Energy Charge:		
Service at secondary voltage:	$0.00895 per kwhr	$0.00895 per kwhr

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations" and it is further understood that:

1. Normally, lighting fixtures will not be installed on poles carrying 34.5 kV or higher voltages, or on poles supporting voltage regulators, two or more transformers or other similar equipment.

2. The Company reserves the right to discontinue the service at any time when the lighting fixture involved has been frequently damaged, apparently as a result of vandalism.

DC -OL-LED

APPLICABLE RIDERS
Standard Offer Service - Small Commercial
Administrative Credit
Delivery Tax Surcharge
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustained Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider

REDLINE

RATE SCHEDULES

FOR

ELECTRIC SERVICE

IN THE

DISTRICT OF COLUMBIA

An Exelon Company

RATES AND REGULATORY PRACTICES GROUP

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RESIDENTIAL SERVICE

SCHEDULE "R"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for low voltage electric service where the use is primarily for residential purposes and for farm operations where the electricity for both farm and residential purposes is delivered through the same meter.

Available only in individual residences and in individually metered dwelling units in multi-family buildings.

Not available for residential premises in which five (5) or more rooms are for hire.

Not available for seasonal loads metered separately from lighting and other usage in the same occupancy.

Not available for temporary, auxiliary or emergency service.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, three wire, 120/240 volts, or three wire, 120/208 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge – Residential	$ ~~15.09~~18.56 per month	$ ~~15.06~~18.56 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ ~~0.00800~~0.01288 per kwhr	$ ~~0.00800~~0.01288 per kwhr
In excess of 400 kilowatt hours	$ ~~0.02283~~0.03541 per kwhr	$ ~~0.01594~~0.02630 per kwhr

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge – Residential	$ 20.18 per month	$ 20.18 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ 0.01495 per kwhr	$ 0.01495 per kwhr
In excess of 400 kilowatt hours	$ 0.04094 per kwhr	$ 0.03064 per kwhr

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge – Residential	$ 21.60 per month	$ 21.60 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ 0.01691 per kwhr	$ 0.01691 per kwhr
In excess of 400 kilowatt hours	$ 0.04612 per kwhr	$ 0.03471 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Service from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.62 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS
Standard Offer Service - Residential
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount
Optional Meter Equipment Related Services
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Residential Direct Load Control Rider
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

MASTER METERED APARTMENT SERVICE
SCHEDULE "MMA"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for low voltage electric service for multiple application to master-metered apartment buildings where the use is predominantly residential and not for retail business establishments. Not available for separately metered service billed on Schedule "GS ND" that did not qualify for multiple application of the residential rate as of December 31, 1982.

Not available for seasonal loads metered separately from lighting and other usage in the same occupancy.

Not available for temporary, auxiliary or emergency service.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, three wire, 120/240 volts, or three wire, 120/208 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ ~~11.84~~13.91 per month	$ ~~11.84~~13.91 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ ~~0.00891~~0.00912 per kwhr	$ ~~0.00891~~0.00912 per kwhr
In excess of 400 kilowatt hours	$ ~~0.02542~~0.03003 per kwhr	$ ~~0.01774~~0.01654 per kwhr

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 14.90 per month	$ 14.90 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ 0.00988 per kwhr	$ 0.00988 per kwhr
In excess of 400 kilowatt hours	$ 0.03282 per kwhr	$ 0.01782 per kwhr

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 15.79 per month	$ 15.79 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ 0.01050 per kwhr	$ 0.01050 per kwhr
In excess of 400 kilowatt hours	$ 0.03523 per kwhr	$ 0.01884 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Service from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.62 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS
Standard Offer Service - Residential
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Optional Meter Equipment Related Services
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Residential Direct Load Control Rider
Underground Project Charge
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

GENERAL SERVICE – NON DEMAND

SCHEDULE "GS ND"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for "GS LV" customers whose maximum monthly demand is less than 25 kW. Customers whose maximum demand is between 25 kW and 99 kW will be served on Schedule GS LV or GS 3A subject to the provisions stated therein. Customers whose maximum demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months will be transferred to Schedule "GT LV", "GT 3A", or "GT 3B" in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz and for primary service furnished directly from the Company's electric system at voltages of 4.16 kV, 13.2 kV, or 33 kV, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnects, regulators and protective equipment.

Not available for railway propulsion service.

Not available for secondary temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts for GS Low Voltage Non Demand customers. For GS 3A Non Demand customers, the service under this schedule, normally will be alternating current, sixty hertz, three phase, three wire, at 4.16kV, 13.2kV or 33 kV. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE
GS LOW VOLTAGE NON DEMAND

	Summer	Winter
	Rate Year 1 (May 1, 2020 – December 31, 2020)	
Distribution Service Charge		
Customer Charge	$ ~~27.42~~32.10 per month	$ ~~27.42~~32.10 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ ~~0.04173~~0.04851 per kwhr	$ ~~0.03266~~0.04231 per kwhr
	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 34.33 per month	$ 34.33 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.05237 per kwhr	$ 0.04564 per kwhr
	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 36.33 per month	$ 36.33 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.05594 per kwhr	$ 0.04878 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

Demand metering equipment will be installed and charges subsequent to the installation of this equipment will be computed under the billing demand provision when the customer's load is of such a magnitude and of such a nature as to indicate any of the following:

1. Monthly energy consumption in excess of 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive).

2. Monthly energy consumption in excess of 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive).

3. A monthly demand greater than or equal to twenty-five (25) kilowatts in a single month.

Demand accounts are reviewed annually. The account will be billed under non-demand billing provision when the consumption for each of the previous twelve (12) months is below 6,000 kilowatt-hours and the demand is less than twenty-five (25) kilowatts.

BILLING DEMAND

The billing demand shall be the maximum thirty (30) minute demand recorded during the month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Small Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

GENERAL SERVICE - LOW VOLTAGE

SCHEDULE "GS LV"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area, except if the customer's maximum demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months, the customer will be transferred to Schedule "GT LV", "GT 3A", or "GT 3B" in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June. Customers with monthly maximum demands less than 25 kW are served on Schedule "GS ND" subject to the provisions stated therein.

Available for low voltage electric service at sixty hertz.

Not available for railway propulsion service.

Not available for secondary temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ ~~35.17~~38.75 per month	$ ~~35.17~~38.75 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ ~~0.02807~~0.03460 per kwhr	$ ~~0.02127~~0.02595 per kwhr
Demand Charge	$ ~~8.06~~9.43 per kw	$ ~~8.06~~9.43 per kw

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 38.75 per month	$ 38.75 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.03819 per kwhr	$ 0.02859 per kwhr
Demand Charge	$ 10.10 per kw	$ 10.10 per kw

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 38.75 per month	$ 38.75 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.04174 per kwhr	$ 0.03124 per kwhr
Demand Charge	$ 10.66 per kw	$ 10.66 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

Demand metering equipment will be installed and charges subsequent to the installation of this equipment will be computed under the billing demand provision when the customer's load is of such a magnitude and of such a nature as to indicate any of the following:

1. Monthly energy consumption in excess of 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive).

2. Monthly energy consumption in excess of 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive).

3. A monthly demand greater than or equal to twenty-five (25) kilowatts in a single month.

Demand accounts are reviewed annually. The account will be billed under non-demand billing provision when the consumption for each of the previous twelve (12) months is below 6,000 kilowatt-hours and the demand is less than twenty-five (25) kilowatts.

BILLING DEMAND

The billing demand shall be the maximum thirty (30) minute demand recorded during the month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

GENERAL SERVICE - PRIMARY SERVICE

SCHEDULE "GS 3A"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS", or Distribution Service in the District of Columbia portion of the Company's service area, except if the customer's maximum demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months, the customer will be transferred to Schedule "GT LV", "GT 3A", or "GT 3B" in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June. Customers with monthly maximum demands less than 25 kW are served on Schedule "GS ND" subject to the provisions stated therein.

Available for primary service furnished directly from the Company's electric system at voltages of 4.16 kV, 13.2 kV or 33 kV, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnects, regulators and protective equipment.

Not available for railway propulsion service.

Not available for secondary temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

CHARACTER OF SERVICE

The service under this schedule, normally will be alternating current, sixty hertz, three phase, three wire, at 4.16kV, 13.2kV or 33kV. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 89.41 per month	$ 89.41 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ ~~0.02054~~0.01907 per kwhr	$ ~~0.01476~~0.01240 per kwhr
Demand Charge	$ 10.82 per kw	$ 10.82 per kw

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 89.41 per month	$ 89.41 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.01987 per kwhr	$ 0.01289 per kwhr
Demand Charge	$ 10.82 per kw	$ 10.82 per kw

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 89.41 per month	$ 89.41 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.02063 per kwhr	$ 0.01338 per kwhr
Demand Charge	$ 10.82 per kw	$ 10.82 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

Demand metering equipment will be installed and charges subsequent to the installation of this equipment will be computed under the demand billing provision when the customer's load is of such a magnitude and of such a nature as to indicate any of the following:

1. Monthly energy consumption in excess of 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive).

2. Monthly energy consumption in excess of 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive).

3. A monthly demand greater than or equal to twenty-five (25) kilowatts in a single month.

Demand accounts are reviewed annually. The account will be billed under non-demand billing provision when the consumption for each of the previous twelve (12) months is below 6,000 kilowatt-hours and the demand is less than twenty-five (25) kilowatts.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMAND

The billing demand shall be the maximum thirty (30) minute demand recorded during the month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED MEDIUM GENERAL SERVICE - LOW VOLTAGE SCHEDULE "MGT LV"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider "SOS" or Distribution Service when modified by Rider "SOS" in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "MGT LV" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "MGT LV" even if the party responsible for the account should change. Removal from Schedule "MGT LV" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "MGT LV" whose maximum thirty (30) minute demand is less than eighty (80) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "MGT LV", the customer will remain on Schedule "MGT LV" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz.

Available for standby service when modified by Schedule "S".

Not available for temporary service.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ ~~456.76~~237.00 per month	$ ~~456.76~~237.00 per month
Kilowatt-hour Charge	$ ~~0.00958~~0.01482 per kwhr	$ ~~0.00958~~0.01482 per kwhr
Kilowatt Charge Maximum	$ ~~11.88~~15.17 per kw	$ ~~11.88~~15.17 per kw

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 237.00 per month	$ 237.00 per month
Kilowatt-hour Charge	$ 0.01675 per kwhr	$0.01673 per kwhr
Kilowatt Charge Maximum	$ 16.26 per kw	$ 16.26 per kw

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 237.00 per month	$ 237.00 per month
Kilowatt-hour Charge	$ 0.01865 per kwhr	$ 0.01863 per kwhr
Kilowatt Charge Maximum	$ 17.24 per kw	$ 17.24 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 per bill will be applied to the bill of each customer receiving generation services from an alternative supplier for each month that the alternative supplier renders a bill to the customer on a consolidated basis for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

TEMPORARY SERVICE

SCHEDULE "T"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for low voltage electric service for construction or other commercial purposes furnished through service connection facilities of a temporary rather than a permanent nature, or for temporary electric service supplied for a limited time, such as for carnivals, festivals, etc.

However, customers receiving Temporary Service on a continuous basis for five (5) years will normally be transferred to the appropriate General Service Low Voltage Schedule "GS LV" or "GS ND" based on the customer's maximum demand, in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June.

CHARACTER OF SERVICE

The service supplied under this schedule will be alternating current, sixty hertz, at any of the approved classes of service.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ ~~27.42~~32.10 per month	$ ~~27.42~~32.10 per month
Kilowatt-hour Charge	$ ~~0.06223~~0.05741 per kwhr	$ ~~0.04853~~0.06308 per kwhr

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 34.33 per month	$ 34.33 per month
Kilowatt-hour Charge	$ 0.06209 per kwhr	$ 0.06824 per kwhr

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 36.33 per month	$ 36.33 per month
Kilowatt-hour Charge	$ 0.06642 per kwhr	$ 0.07309 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Standard Offer Service – Small Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED GENERAL SERVICE - LOW VOLTAGE
SCHEDULE "GT LV"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider "SOS" or Distribution Service when modified by Rider "SOS" in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds one thousand (1000) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "GT LV" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "GT LV" even if the party responsible for the account should change. Removal from Schedule "GT LV" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "GT LV" whose maximum thirty (30) minute demand is less than nine hundred (900) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "GT LV", the customer will remain on Schedule "GT LV" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz.

Available for standby service when modified by Schedule "S".

Not available for temporary service.

Not available for multiple application to master-metered apartment buildings except for those master-metered apartments served under Schedule "GT LV" prior to December 31, 1982 which will continue to be served under Schedule "GT LV".

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ ~~456.76~~940.60 per month	$ ~~456.76~~940.60 per month
Kilowatt-hour Charge	$ ~~0.00958~~0.01449 per kwhr	$ ~~0.00958~~0.01550 per kwhr
Kilowatt Charge Maximum	$ ~~11.88~~13.77 per kw	$ ~~11.88~~13.77 per kw
	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 1,424.44 per month	$ 1,424.44 per month
Kilowatt-hour Charge	$ 0.01601 per kwhr	$ 0.01711 per kwhr
Kilowatt Charge Maximum	$ 14.47 per kw	$ 14.47 per kw
	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 1,908.28 per month	$ 1,908.28 per month
Kilowatt-hour Charge	$ 0.01747 per kwhr	$ 0.01867 per kwhr
Kilowatt Charge Maximum	$ 15.07 per kw	$ 15.07 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will

receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 per bill will be applied to the bill of each customer receiving generation services from an alternative supplier for each month that the alternative supplier renders a bill to the customer on a consolidated basis for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED GENERAL SERVICE - PRIMARY SERVICE

SCHEDULE "GT 3A"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "GT 3A" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "GT 3A" even if the party responsible for the account should change. Removal from Schedule "GT 3A" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "GT 3A" whose maximum thirty (30) minute demand is less than eighty (80) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "GT 3A", the customer will remain on Schedule "GT 3A" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for primary service furnished directly from the Company's electric system at voltages of 4.16 kV, 13.2 kV or 33 kV, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnectors, regulators and protective equipment.

Available for standby service when modified by Schedule "S".

Not available for temporary service.

Not available for multiple application to master-metered apartment buildings except for those master-metered apartments served under Schedule "GT 3A" prior to December 31, 1982 which will continue to be served under Schedule "GT 3A".

CHARACTER OF SERVICE

The service under this schedule, normally will be alternating current, sixty hertz, three phase, three wire, at 4.16kV, 13.2kV or 33kV. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ ~~187.64~~197.49 per month	$ ~~187.64~~197.49 per month
Kilowatt-hour Charge	$ ~~0.00454~~0.00526 per kwhr	$ ~~0.00453~~0.00486 per kwhr
Kilowatt Charge Maximum	$ ~~8.86~~10.27 per kw	$ ~~8.86~~10.27 per kw

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 197.49 per month	$ 197.49 per month
Kilowatt-hour Charge	$ 0.00606 per kwhr	$ 0.00558 per kwhr
Kilowatt Charge Maximum	$ 10.96 per kw	$ 10.96 per kw

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 197.49 per month	$ 197.49 per month
Kilowatt-hour Charge	$ 0.00685 per kwhr	$ 0.00631 per kwhr
Kilowatt Charge Maximum	$ 11.58 per kw	$ 11.58 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 per bill will be applied to the bill of each customer receiving generation services from an alternative supplier for each month that the alternative supplier renders a bill to the customer on a consolidated basis for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED GENERAL SERVICE - HIGH VOLTAGE SERVICE SCHEDULE "GT 3B"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "GT 3B" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "GT 3B" even if the party responsible for the account should change. Removal from Schedule "GT 3B" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "GT 3B" whose maximum thirty (30) minute demand is less than eighty (80) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "GT 3B", the customer will remain on Schedule "GT 3B" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for standby service when modified by Schedule "S".

Available for high voltage service furnished directly from the Company's electric system at voltages of 66 kV or above, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnectors, regulators and protective equipment.

Not available for temporary service.

Not available for multiple application to master-metered apartment buildings except for those master-metered apartments served under Schedule "GT 3B" prior to December 31, 1982 which will continue to be served under Schedule "GT 3B".

CHARACTER OF SERVICE

The service under this schedule, normally will be 66kV or above. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ ~~423.38~~311.66 per month	$ ~~423.38~~311.66 per month
Kilowatt-hour Charge	$ 0.00000 per kwhr	$ 0.00000 per kwhr
Kilowatt Charge Maximum	$ ~~1.79~~1.84 per kw	$ ~~1.92~~2.23 per kw

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 311.66 per month	$ 311.66 per month
Kilowatt-hour Charge	$ 0.00000 per kwhr	$ 0.00000 per kwhr
Kilowatt Charge Maximum	$ 1.95 per kw	$ 2.37 per kw

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 311.66 per month	$ 311.66 per month
Kilowatt-hour Charge	$ 0.00000 per kwhr	$ 0.00000 per kwhr
Kilowatt Charge Maximum	$ 2.05 per kw	$ 2.50 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider.
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

RAPID TRANSIT SERVICE

SCHEDULE "RT"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for rapid transit electric service furnished directly from the Company's distribution, subtransmission or transmission systems at available voltages of 13.2kV and higher where the customer provides, at the customer's own expense, all necessary transformers or converting apparatus, switches, disconnectors, regulators, and protective equipment.

Available only at points of delivery on contiguous authority right-of-way.

Also available for low voltage service for purposes of operating electric chiller plants used for the purpose of providing chilled water to passenger stations associated with the rapid transit service.

Not available for partial or auxiliary service.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, three phase, three wire, high tension at 13.2kV or such voltage as is specified by the Company on the basis of its available facilities and the magnitude of load to be served.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ ~~6,216.22~~7,203.15 per month	$ ~~6,216.22~~7,203.15 per month

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 7,673.12 per month	$ 7,673.12 per month

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 8,096.09 per month	$ 8,096.09 per month

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMAND

The monthly billing demand will be the maximum thirty (30) minute integrated coincident demand of all delivery points recorded during the billing month.

BILLING ENERGY
The monthly billing energy will be the sum of the registrations of kilowatt-hours of all delivery points.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations", except as modified by the agreement by and between the Company and the customer.

APPLICABLE RIDERS
Standard Offer Service – Large Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

STREET LIGHTING SERVICE

SCHEDULE "SL"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service for street, highway and park lighting purposes in the District of Columbia portion of the Company's service area when owned by agencies of Federal and District of Columbia governments. Also available to governmental and non-governmental customers for holiday lighting and seasonal street decoration lighting where the lights are in public space and where the only load supplied is lighting load. Schedule "SL" is not available for services that supply any load other than lighting.

CHARACTER OF SERVICE

Electricity supplied to multiple lights normally will be sixty hertz, single phase, 120 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)
Distribution Service Charge	
Customer Charge	
Metered Account	$~~17.19~~ 19.85 per month
Unmetered Account	$~~14.70~~ 16.97 per month
Kilowatt-hour Charge	$ ~~0.006150~~0.00867 per kwh

	Rate Year 2 (January 1, 2021 – December 31, 2021)
Distribution Service Charge	
Customer Charge	
Metered Account	$ 22.51 per month
Unmetered Account	$ 19.25 per month
Kilowatt-hour Charge	$ 0.00972 per kwh

	Rate Year 3 (January 1, 2022 – December 31, 2022)
Distribution Service Charge	
Customer Charge	
Metered Account	$ 25.17 per month
Unmetered Account	$ 21.52 per month
Kilowatt-hour Charge	$ 0.01065 per kwh

The per kwh charge shall be adjusted for any Major Service Outages as defined in Section 3699 of Chapter 36, Electric Quality Service Standards in Title 15 of the District of Columbia Municipal Regulations.

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

The charges under this schedule are for delivery only and do not include furnishing and/or maintaining street lighting equipment.

MEASUREMENTS OF ELECTRICITY

If electricity delivered for street lighting is unmetered, monthly kilowatt-hour consumption will be computed on the basis of manufacturers' wattage ratings of installed lamps, auxiliary devices where required, and scheduled 4,200 hours of burning time. If metered, watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

Lights controlled for night burning only will be billed at the monthly rate for Standard Night Burning street lights. Lights not controlled for night burning only will be billed at the monthly rate for 24-Hour Burning street lights.

The kilowatt-hours calculated from billing wattages will be reduced by 5.5 percent each month to provide for normal outages.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations". Holiday and decorative street lighting service connections will be considered temporary service connections as defined in the "Electric Service Rules and Regulations" and will be priced accordingly.

APPLICABLE RIDERS
Standard Offer Service – Small Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Telecommunication Network Charge
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

TRAFFIC SIGNAL SERVICE

SCHEDULE "TS"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service to agencies of the Federal and District of Columbia governments, for operation of traffic signals in the District of Columbia portion of the Company's service area.

CHARACTER OF SERVICE

Electricity supplied for traffic signal purposes normally will be sixty hertz, single phase, 120 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)
Distribution Service Charge	
Customer Charge	$ ~~8.03~~4.26 per month
Kilowatt-hour Charge	$ ~~0.02203~~0.02775 per kwh
	Rate Year 2 (January 1, 2021 – December 31, 2021)
Distribution Service Charge	
Customer Charge	$ 4.26 per month
Kilowatt-hour Charge	$ 0.02934 per kwh
	Rate Year 3 (January 1, 2022 – December 31, 2022)
Distribution Service Charge	
Customer Charge	$ 4.26 per month
Kilowatt-hour Charge	$ 0.03077 per kwh

The per kwh charge shall be adjusted for any Major Service Outages as defined in Section 3699 of Chapter 36, Electric Quality Service Standards in Title 15 of the District of Columbia Municipal Regulations.

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

The charges under this schedule are for delivery only and do not include furnishing and/or maintaining traffic signal equipment.

MEASUREMENT OF ELECTRICITY

Electricity delivered to traffic signals is unmetered. Monthly kilowatt-hour consumption will be computed on the basis of manufacturers' wattage ratings of installed devices and estimated hours of burning time.

The kilowatt-hours calculated from billing wattages will be reduced by 1.5 percent each month to provide for normal outages.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

DC - TS

APPLICABLE RIDERS
Standard Offer Service – Small Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

CHARGES FOR SERVICING
STREET LIGHTS SERVED FROM OVERHEAD LINES
SCHEDULE "SSL-OH"

APPLICABILITY
Applicable only to luminaries meeting ANSI Standards for street lighting equipment when owned by the Company and mounted on Company-owned wooden poles or on poles of another utility with whom the Company has an attachment agreement.

AVAILABILITY
Available in the District of Columbia portion of the Company's service area to Federal Governmental Agencies for servicing street, highway and park lighting equipment when the electricity supplying such equipment is furnished by the Company from overhead lines and is accessible by conventional wheeled construction and maintenance vehicles.

Available only for lights having a manufacturers' nominal rating of:

Incandescent*	10,000	lumens or less
Mercury Vapor*	100 - 400	watts
High Pressure Sodium	70 - 400	watts
Metal Halide	400	watts

*Not available for new installation or replacement of defective fixtures.

CHARACTER OF SERVICE
Service rendered under this schedule will consist of (1) furnishing, installing and maintaining street lighting fixtures and mounting arms or brackets, (2) furnishing, installing, connecting, operating and maintaining the electric service circuits connecting the street lighting equipment to the Company's distribution system, (3) group relamping, (every six (6) months for incandescent, every four (4) years for mercury vapor and every five (5) years for high pressure sodium), (4) washing of globes, (5) furnishing and installing replacement globes, lamps, ballasts and light sensitive switches as needed to maintain the system in an operating mode; all normally limited, to standard items of equipment meeting ANSI Standards for street lighting equipment and approved by the Company for maintenance.

MONTHLY RATE

Rate Year 1 (May 1, 2020 – December 31, 2020)

	Fixed Charges	O&M Charges
Incandescent Lights* - Night Burning		
Without Globe - all sizes	$ ~~2.492~~3.128 per lamp	$~~0.039~~0.049 per lamp
With Globe - all sizes	$ ~~3.639~~4.568 per lamp	$~~0.860~~1.079 per lamp
*Not available for new installation or replacement of defective fixtures.		
Mercury Vapor Lights* - Night Burning		
175 Watt	$ ~~7.756~~9.735 per lamp	$~~0.767~~0.963 per lamp
250 Watt	$ ~~8.861~~11.122 per lamp	$~~0.777~~0.975 per lamp
*Not available for new installation or replacement of defective fixtures.		
Metal Halide Lights – Night Burning		
400 Watt	$ ~~29.990~~37.643 per lamp	$~~1.253~~1.573 per lamp

Rate Year 2 (January 1, 2021 – December 31, 2021)

	Fixed Charges	O&M Charges
Incandescent Lights* - Night Burning		
Without Globe - all sizes	$ 3.453 per lamp	$ 0.054 per lamp
With Globe - all sizes	$ 5.042 per lamp	$ 1.192 per lamp
*Not available for new installation or replacement of defective fixtures.		

DC - SSL - OH

Mercury Vapor Lights* - Night Burning		
175 Watt	$ 10.746 per lamp	$ 1.063 per lamp
250 Watt	$ 12.277 per lamp	$ 1.077 per lamp
*Not available for new installation or replacement of defective fixtures.		
Metal Halide Lights – Night Burning		
400 Watt	$ 41.550 per lamp	$ 1.736 per lamp

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Fixed Charges	**O&M Charges**
Incandescent Lights* - Night Burning		
Without Globe - all sizes	$ 3.745 per lamp	$ 0.059 per lamp
With Globe - all sizes	$ 5.468 per lamp	$ 1.292 per lamp
*Not available for new installation or replacement of defective fixtures.		
Mercury Vapor Lights* - Night Burning		
175 Watt	$ 11.655 per lamp	$ 1.153 per lamp
250 Watt	$ 13.316 per lamp	$ 1.168 per lamp
*Not available for new installation or replacement of defective fixtures.		
Metal Halide Lights – Night Burning		
400 Watt	$ 45.067 per lamp	$ 1.883 per lamp

The above charges will be separate from and in addition to charges for electricity supplied under the provisions of Schedule "SL".

NON-STANDARD EQUIPMENT
Non Company approved ANSI equipment, if accepted by the Company for maintenance, will be subject to special contracts which may include an initial installation charge.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Excess Deferred Income Tax Credit

CHARGES FOR SERVICING
STREET LIGHTS SERVED FROM UNDERGROUND LINES
SCHEDULE "SSL-UG"

APPLICABILITY
Applicable only to posts and luminaries meeting ANSI Standards for street lighting equipment furnished by the customer.

AVAILABILITY
Available in the District of Columbia portion of the Company's service area to Federal Governmental Agencies for servicing street, highway and park lighting equipment when the electricity supplying such equipment is furnished by the Company from unmetered underground lines and is accessible by conventional wheeled construction and maintenance vehicles.

Available only for lights having a manufacturers' nominal rating of:

Incandescent*	10,000	lumens or less
Mercury Vapor*	250 - 400	watts
High Pressure Sodium	150	watts
Metal Halide	100 - 400	watts

*Not available for new installation or replacement of defective fixtures.

CHARACTER OF SERVICE
Service rendered under this schedule will consist of (1) furnishing, installing, connecting, operating and maintaining the electric service circuits connecting the street lighting equipment to the Company's distribution system, (2) furnishing and installing post foundations and setting customer owned posts on foundations, (3) installing customer owned street lighting fixtures, (4) group relamping, (every six (6) months for incandescent, every two (2) years for metal halide, every four (4) years for mercury vapor and every five (5) years for high pressure sodium), (5) washing of globes, (6) furnishing and installing of replacement globes, lamps, remote ballasts, and light sensitive switches as needed to maintain the system in an operating mode, (7) repainting posts at approximately six (6) year intervals; all normally limited to standard items of equipment meeting ANSI Standards for street lighting equipment and accepted by the Company for maintenance.

MONTHLY RATE

Rate Year 1 (May 1, 2020 – December 31, 2020)

	Fixed Charges	O&M Charges
Incandescent Lights* - Night Burning		
With Globe - all sizes	$ ~~34.870~~43.768 per lamp	$~~1.576~~1.978 per lamp
*Not available for new installation or replacement of defective fixtures.		
Mercury Vapor Lights* - Night Burning		
250 Watt	$ ~~35.171~~44.146 per lamp	$~~1.416~~1.777 per lamp
400 Watt	$ ~~41.242~~51.766 per lamp	$~~1.759~~2.208 per lamp
*Not available for new installation or replacement of defective fixtures.		
High Pressure Sodium Lights - Night Burning		
150 Watt	$ ~~30.843~~38.714 per lamp	$~~1.155~~1.450 per lamp
Metal Halide Lights – Night Burning		
100 Watt	$ ~~26.578~~33.360 per lamp	$~~1.039~~1.304 per lamp
175 Watt	$ ~~29.990~~37.643 per lamp	$~~1.253~~1.573 per lamp
400 Watt	$ ~~29.990~~37.643 per lamp	$~~1.253~~1.573 per lamp

Rate Year 2 (January 1, 2021 – December 31, 2021)

	Fixed Charges	O&M Charges
Incandescent Lights* - Night Burning		
With Globe - all sizes	$ 48.311 per lamp	$ 2.183 per lamp
*Not available for new installation or replacement of defective fixtures.		

DC - SSL - UG

Mercury Vapor Lights* - Night Burning		
250 Watt	$ 48.728 per lamp	$ 1.962 per lamp
400 Watt	$ 57.139 per lamp	$ 2.437 per lamp
*Not available for new installation or replacement of defective fixtures.		
High Pressure Sodium Lights - Night Burning		
150 Watt	$ 42.732 per lamp	$ 1.600 per lamp
Metal Halide Lights – Night Burning		
100 Watt	$ 36.823 per lamp	$ 1.440 per lamp
175 Watt	$ 41.550 per lamp	$ 1.736 per lamp
400 Watt	$ 41.550 per lamp	$ 1.736per lamp

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Fixed Charges	**O&M Charges**
Incandescent Lights* - Night Burning		
With Globe - all sizes	$ 52.400 per lamp	$ 2.368 per lamp
*Not available for new installation or replacement of defective fixtures.		
Mercury Vapor Lights* - Night Burning		
250 Watt	$ 52.852 per lamp	$ 2.128 per lamp
400 Watt	$ 61.975 per lamp	$ 2.643 per lamp
*Not available for new installation or replacement of defective fixtures.		
High Pressure Sodium Lights - Night Burning		
150 Watt	$ 46.348 per lamp	$ 1.736 per lamp
Metal Halide Lights – Night Burning		
100 Watt	$ 39.939 per lamp	$ 1.561 per lamp
175 Watt	$ 45.067 per lamp	$ 1.883 per lamp
400 Watt	$ 45.067 per lamp	$ 1.883 per lamp

Other

Posts furnished by the Company, costing*:

$ 15.00 and less	$ 1.139 each
$ 15.01 to $ 45.00, inclusive	$ 1.517 each
$ 45.01 to $ 75.00, inclusive	$ 3.410 each
$ 75.01 to $100.00, inclusive	$ 5.687 each
$100.01 to $160.00, inclusive	$10.047 each

*Not available for new installation or replacement of defective posts.

The above charges will be separate from and in addition to charges for electricity supplied under the provisions of Schedule "SL".

CUSTOMER RESPONSIBILITY AS TO FURNISHING, INSTALLING AND MAINTAINING EQUIPMENT
The street lighting posts, fixtures and brackets (if required) shall be furnished by the customer for installation by the Company as set forth under "Character of Service" above. Ballasts for all High Pressure Sodium Lights and any Mercury Vapor Lights to be installed in or on upright posts shall be furnished by the customer. All Metal Halide lamps and ballasts shall be furnished by the customer for installation by the Company.

All maintenance of equipment furnished by the customer will be performed at the customer's expense, except as set forth under "Character of Service".

NON-STANDARD EQUIPMENT
Non-company approved ANSI accepted equipment and non-standard, special, experimental and any other such post and luminaries which do not meet ANSI Standards for street lighting equipment, if accepted by the Company for maintenance, will be subjected to special contracts. Lights of this type will be installed in accordance with the customer's instruction, and all installation costs charged to the customer.

DC - SSL - UG

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Excess Deferred Income Tax Credit

TELECOMMUNICATIONS NETWORK SERVICE

SCHEDULE "TN"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for unmetered electric service to multiple telecommunications network devices or other devices with similar load characteristics served directly by the Company and not exceeding 1,800 watts per device. For devices that are currently served by meter, the Customer may choose to have the meter removed at the Customer's expense and the month Customer Charge without Meter will apply.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, 120 volts.

MONTHLY RATE

	Rate Year 1 (May 1, 2020 – December 31, 2020)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 15.43 per month	$ 15.43 per month
Kilowatt-hour Charge	$~~0.01288~~ 0.01200 per kwhr	$ ~~0.01288~~0.01200 per kwhr

	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 15.43 per month	$ 15.43 per month
Kilowatt-hour Charge	$ 0.01165 per kwh	$ 0.01165 per kwh

	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge	$ 15.43 per month	$ 15.43 per month
Kilowatt-hour Charge	$ 0.01132 per kwh	$ 0.01132 per kwh

Customer Charges/Kilowatt-hour Charge – For devices that are served through a meter, the Customer shall pay the monthly "Customer Charge with Meter" and the kilowatt-hour charge will be applied to metered usage. For devices served without a meter, the Customer shall pay the monthly "Customer Charge without Meter" and the kilowatt-hour charge will be applied to estimated monthly usage based on metered usages for similar devices. If similar metered data do not exist, at the customer's option, the monthly usage will be estimated base on either the manufacturer's average wattage ratings with no allowance for outage, or on the basis of statistically valid sample estimates using actual current and voltage readings.

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

MEASUREMENTS OF ELECTRICITY

Monthly kilowatt-hour consumption will be computed on the basis of manufacturer's average wattage ratings of installed devices, with no allowance for outages. The charges under this rider are for electricity only.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Standard Offer Services – Small Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

LED OUTDOOR LIGHTING SERVICE

SCHEDULE "OL LED"

AVAILABILITY

Available for Distribution Service and Standard Offer Service when modified by Rider "SOS" in the District of Columbia portion of the Company's overhead service area for customer-owned outdoor lighting purposes on customers' premises subject to local ordinance or other appropriate approval.

Not available for street lighting purposes.

CHARACTER OF SERVICE

Electricity will be supplied from distribution system facilities on a metered basis.

MONTHLY RATE

Charge for supply of electricity for operation:

	Summer	Winter
	Rate Year 1 (May 1, 2020 – December 31, 2020)	
Distribution Service Charge		
Customer Charge		
Service at secondary voltage:	$8.76 per customer per month	$8.76 per customer per month
Energy Charge:		
Service at secondary voltage:	$0.00895 per kwhr	$0.00895 per kwhr
	Rate Year 2 (January 1, 2021 – December 31, 2021)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge		
Service at secondary voltage:	$8.76 per customer per month	$8.76 per customer per month
Energy Charge:		
Service at secondary voltage:	$0.00895 per kwhr	$0.00895 per kwhr
	Rate Year 3 (January 1, 2022 – December 31, 2022)	
	Summer	**Winter**
Distribution Service Charge		
Customer Charge		
Service at secondary voltage:	$8.76 per customer per month	$8.76 per customer per month
Energy Charge:		
Service at secondary voltage:	$0.00895 per kwhr	$0.00895 per kwhr

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations" and it is further understood that:

1. Normally, lighting fixtures will not be installed on poles carrying 34.5 kV or higher voltages, or on poles supporting voltage regulators, two or more transformers or other similar equipment.

2. The Company reserves the right to discontinue the service at any time when the lighting fixture involved has been frequently damaged, apparently as a result of vandalism.

DC -OL-LED

APPLICABLE RIDERS
Standard Offer Service - Small Commercial
Administrative Credit
Delivery Tax Surcharge
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustained Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider

P.R. Blazunas
Direct Exhibit
DC. P.S.C - - May, 2019

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Weather Normalization

How Are Sales (kWh) Weather Normalized?

The Company weather normalizes sales by making an additive weather normalization adjustment to actual sales. The weather normalization adjustment is equal to the amount of sales calculated to be above (or below) the sales that would have occurred if the weather had been normal. The weather normalization adjustment is estimated by multiplying the difference between actual weather and normal weather, measured as degree days, by a weather normalization factor for each revenue class. For example, if the observed weather during the month is 125 heating degree days and the normal for the month is 100 heating degree days, then the difference of 25 heating degree days will be multiplied times the class weather normalization factors for the different classes to yield the class weather normalization adjustments.

Actual Weather

The weather parameter used in the Company's monthly weather normalization is degree days based on dry bulb temperatures recorded at the Reagan National Airport. The calculation is illustrated in the simple example range of temperatures provided in Table 1. Degree days are calculated by averaging the hourly dry bulb temperature and calculating the amount that the daily average dry bulb temperature in degrees Fahrenheit is over 65° for Cooling Degree Days and under 65° for Heating Degree Days. For example, if the average dry bulb temperature was 72°, degree days for that day are 72°- 65° or 7° cooling degree days. This calculation is repeated for each day of the month and summed to produce degrees days for the respective month. Table 2 presents actual degree days by month used to weather normalize the calendar year 2018 sales.

Normal Weather

Normal weather is defined as the average weather (heating degree days or cooling degree days) over the most recent thirty-year period prior to the period being weather normalized. For each month, normal weather is calculated by taking the arithmetic average of the most recent 30 years of heating degree days or cooling degree days for that month. As an example, to calculate normal weather for a June 2018 weather normalization adjustment, we would average the total monthly cooling degree days observed in June over the period 1988-2017. Table 3 presents 30-year average degree days by month used to weather normalize the calendar year 2018 sales.

Weather Normalization Factor Estimation

Pepco's weather normalization factors are prepared during the Company's annual weather normalization study covering data from the most recent heating and cooling season. For example, in the 2018 study that was completed in December 2017, the cooling period was defined as April 1, 2017 through September 30, 2017. The winter period was defined as December 1, 2016 through March 31, 2017. Weather normalization factors are estimated by regressing daily sales by class against daily heating or cooling degrees. Each regression equation includes a constant term, weather variables measuring heating and cooling degree days, and two dummy variables for Saturdays and Sundays. Holidays are included as a separate dummy variable for each holiday.

Once the regression equation estimation step is complete, the coefficients associated with the two heating (base 65° and base 35°) degree day variables are designated as the weather normalization factors for the heating season, by class. Similarly, the coefficient in each equation for the cooling degrees term (base 65°) is designated as the weather normalization factor for the summer cooling season, by class. Appendix A reports the weather normalized factors estimated for the use in 2018.

Appendix

Table 1

Example of Cooling/Heating Degrees for a given Day

Observed Temperature	Cooling Degrees (65°)	Heating Degrees (65°)
55°	0°	10°
65°	0°	0°
72°	7°	0°

Table 2

Observed Cooling/Heating Degrees (January 2018 – December 2018)

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
HDD 65	920	732	572	497	155	3	0	-	1	62	379	649
HDD 35	155	59	5	1	-	-	-	-	-	-	1	5
CDD 65	-	1	3	12	109	266	436	477	420	223	30	0

Table 3

30-Year Average Cooling/Heating Degrees (January 2018 – December 2018)

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
HDD 65	809	835	631	408	154	35	1	-	5	90	329	605
HDD 35	63	78	31	3	-	-	-	-	-	-	1	18
CDD 65	0	0	2	13	62	219	404	458	334	116	14	1

Table 4

2018 Weather Normalization Factors

PEPCO DC	CDD 65	HDD 65	HDD 35
RES	236,049	96,616	121,962
RTM	1,667	634	672
MMA	21,265	2,789	3,860
GSND	10,294	5,955	9,278
GSD	30,558	10,714	21,498
GTLV	182,110	52,566	165,363
3A	89,988	-	-
3B	906	398	-
MET	2,396	525	-

P.R. Blazunas
Direct Exhibit
DC. P.S.C - - May, 2019

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Pepco DC Conditional Demand Analysis

Methodology and Results

PRESENTED TO

Pepco

PRESENTED BY

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December 2017

THE Brattle GROUP

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Agenda

Objective

Replication of Pepco Analysis

Literature Review and Benchmarking

Methodology

Results

Conclusions

Objective

Pepco retained The Brattle Group to review, replicate, and improve upon their existing Conditional Demand Analysis (CDA)

CDA is a regression-based approach to estimate end-use electricity consumption for major residential appliances

As part of our engagement with Pepco, we reviewed the literature and built a model which is consistent with best practices in CDA and estimated Annual End Use (AEUs) for major appliances

This slide deck presents the details of our analysis

Replication Overview

As a first step, we reproduced Pepco's original results which were filed with the DC Public Service Commission as part of FC 1139

- Reviewed Pepco's methodology for processing raw survey data
  - Survey data is inherently incomplete with inconsistencies, so Pepco created criteria for correcting inconsistencies
  - We found that Pepco's data processing steps were adequate and reasonable
- Specified an Ordinary Least Squares (OLS) regression designed to match Pepco's model, which excluded a constant term and excluded robust standard errors

Replication Methodology

After creating a replication of Pepco's base model, we conducted the following steps to recreate Pepco's AEUs

1. Estimated the aforementioned model, which is a panel dataset containing 1,993 unique customers, each with 365 days of consumption data for year.
2. Set all control variables to zero, except the variables related to the specific appliance in question.
3. Created appliance usage predictions with the model
4. Multiplied the predicted value by the customer weights (provided by Bellomy Research)
5. Summed the predicted usage for each appliance by month, so dataset is customer-month level
6. Averaged all customer AEUs, leaving one observation for each appliance for each month.

Replication Results

We were able to exactly replicate Pepco's conditional demand model. With respect to appliance-specific AEUs, we were able to recreate Pepco's results, allowing for some rounding. However, our analysis indicates that Pepco may have switched "toaster" and "microwave" AEUs.

Brattle Recreation

Parameter	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
heat	563.9	602.0	389.3	108.8	10.8	4.2	0.0	0.0	0.0	125.8	218.8	275.5	2,299.0
ac	0.0	0.0	0.0	14.6	228.8	349.3	454.9	390.6	257.0	7.3	4.6	0.9	1,707.9
ewtrh	116.1	116.0	94.6	60.9	50.7	48.0	49.4	49.6	48.0	64.6	74.1	80.9	852.9
frig	55.2	49.9	54.8	53.4	55.2	53.1	55.3	55.4	53.6	55.3	53.3	55.0	649.6
freez	10.9	9.9	10.9	10.7	11.1	10.7	11.1	11.1	10.7	11.0	10.7	11.0	129.9
toaster	3.8	3.5	3.8	3.7	3.8	3.7	3.8	3.9	3.7	3.8	3.7	3.8	45.1
micro	39.4	35.6	39.1	38.1	39.5	38.1	39.5	39.5	38.2	39.4	37.9	39.3	463.6
vacuum	36.2	32.7	35.9	35.0	36.1	34.6	35.9	36.2	35.0	36.1	34.7	36.0	424.3
washdry	22.0	19.9	21.8	21.3	22.0	21.2	21.9	22.0	21.3	21.9	21.2	21.9	258.4
cooking	3.8	3.4	3.7	3.7	3.8	3.6	3.8	3.8	3.7	3.8	3.6	3.8	44.5
tv	25.4	23.0	25.2	24.5	25.3	24.4	25.4	25.4	24.6	25.4	24.4	25.3	298.2
incan	43.5	39.3	43.2	42.1	43.5	42.0	43.7	43.7	42.3	43.6	42.1	43.4	512.4
otherlamp	4.0	3.7	4.0	3.9	4.0	3.9	4.0	4.1	3.9	4.0	3.9	4.0	47.5
Household total	924.2	938.8	726.3	420.7	534.6	636.7	748.7	685.2	542.3	442.1	533.0	600.7	7,733.2

Pepco Output

Monthly and Annual Average Energy Usage for DC Home Appliances (Year=2015)

Unit\Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year Total
Average Annual Usage for Heat	563.7	602.1	389.3	108.8	10.8	4.2	0.0	0.0	0.0	125.8	218.8	275.5	**2298.8**
Average Annual Usage for AC	0.0	0.0	0.0	14.6	228.8	349.3	454.9	390.6	257.0	7.3	4.6	0.9	**1708.0**
Average Annual Usage for EWtrHt	115.9	116.0	94.6	60.9	50.7	48.0	49.4	49.6	48.0	64.6	74.1	80.9	**852.7**
Average Annual Usage for frig	55.2	49.9	54.8	53.4	55.2	53.1	55.3	55.4	53.6	55.3	53.3	55.1	**649.6**
Average Annual Usage for freezer	11.1	9.9	10.9	10.7	11.1	10.8	11.1	11.1	10.8	11.0	10.7	11.0	**130.1**
Average Annual Usage for toaster	39.4	35.6	39.1	38.1	39.5	38.1	39.5	39.5	38.2	39.4	37.9	39.3	**463.6**
Average Annual Usage for Micro	3.8	3.5	3.8	3.7	3.8	3.7	3.8	3.9	3.7	3.8	3.7	3.8	**45.1**
Average Annual Usage for Vaccum	36.1	32.7	35.9	35.0	36.1	34.6	35.9	36.2	35.0	36.1	34.7	36.0	**424.2**
Average Annual Usage for WashDry	22.0	19.9	21.8	21.3	22.0	21.2	21.9	22.0	21.3	22.0	21.2	21.9	**258.4**
Average Annual Usage for cooking	3.8	3.4	3.7	3.7	3.8	3.6	3.8	3.8	3.7	3.8	3.7	3.8	**44.5**
Average Annual Usage for TV	25.4	23.0	25.2	24.5	25.3	24.4	25.4	25.4	24.6	25.4	24.5	25.3	**298.2**
Average Annual Usage for Incandescent	43.5	39.3	43.2	42.1	43.5	42.0	43.7	43.7	42.4	43.6	42.1	43.4	**512.3**
Average Annual Usage for OthrLamps	4.0	3.7	4.0	3.9	4.0	3.9	4.1	4.1	3.9	4.0	3.9	4.0	**47.5**
Household Total	**923.9**	**938.8**	**726.3**	**420.7**	**534.6**	**636.7**	**748.7**	**685.2**	**542.4**	**442.1**	**533.0**	**600.7**	**7732.9**

Literature Consulted

After replicating Pepco's analysis, we conducted a rigorous literature review to understand best practices for Conditional Demand Analysis (CDA)

- Parti and Parti, 1980
- Aigner, Soroohian, and Kerwin, 1984
- LaFrance and Perron, 1994
- Blaney, Inglis, and Janney, 1994
- Bartels and Fiebig, 2000
- Lins, Silva, and Rosa 2002
- Swan and Ugursal, 2009
- Tiedemann, 2007
- KEMA, 2010
- EIA RECS, 2013

Key Takeaways from the literature

- **Constant term:** CDA requires the use of a constant term to account for consumption from appliances which is not specifically parameterized. Without a constant term, other miscellaneous load is falsely distributed among modeled appliances, biasing results.

- **Aggregate appliances:** CDA often has significant collinearity (*) issues. Aggregating appliances into a group (*e.g.,* miscellaneous kitchen) can help alleviate these concerns.

- **Outliers and inconsistent data:** Dropping some outliers and data with extreme inconsistency provides greater accuracy, a common practice in any data analysis

- **Both art and science:** There is no basic specification for a CDA. Each analysis is different due to survey structure and underlying population

(*) Collinearity occurs when the model includes variables that are correlated not just to the dependent variable, but also to each other. This leads to unstable and unreliable parameter estimates for individual variables, which are important for CDA

Model Changes

Our analysis incorporates our key takeaways from the literature review and introduces a new specification for modeling appliance usage

- Omit refrigerator due to collinearity with the constant term; separately back-out our refrigerator AEU from the constant term
- Combine electric water heat and electric cooking (all-electric households) to account for collinearity issues
- Combine kitchen appliances (toaster, microwave, freezer) into a single term
- More granular approach to accounting for heat pumps in both heating and cooling parameters
- Do not use logarithm of people in household

Model Considerations

Including a constant term is a necessity to conduct an unbiased CDA but does result in collinearity issues. We took a rigorous approach to trying ascertain AEUs for collinear appliances. For example, for estimating refrigerator usage, we considered the following:

- Include controls for the age of the fridge
- Make different assumptions for the "did not answer" responses
- Interact refrigerator with housing time
- Interact refrigerator with income
- Interact refrigerator with number of people
- Interact refrigerator with freezer
- Consider refrigerator as a binary instead of a "# of refrigerator"
- Many combinations and permutations of above

Regardless of how we have considered refrigerator usage, the implied AEU was negative, indicating bias. Therefore, we omitted refrigerator from the equation and included it as part of the constant term

Parameter Estimates for CDA

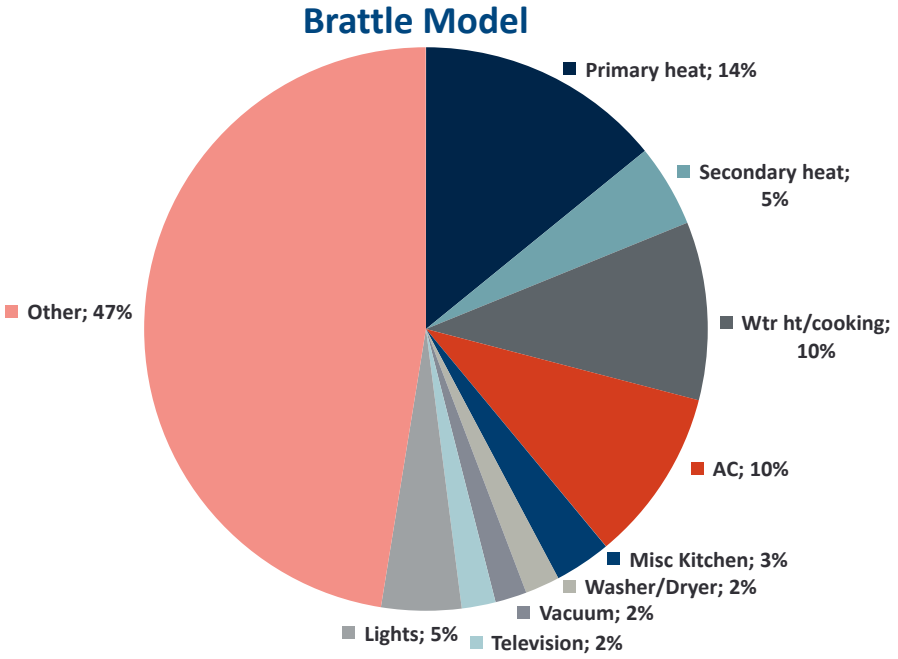
AvgHDD_EPrimHeat	0.491***	AvgCDD_sqft_HmInsl_HeatPump	5.94e-05***
	(0.00902)		(7.60e-06)
AvgHDD_sqft_EPrimHeat	0.000410***	Ewtht_plus_cooking_HDD	0.0917***
	(2.50e-05)		(0.00318)
AvgHDD_sqft_NumPeople_EPrimHeat	2.72e-05***	Ewtht_plus_cooking_CDD	0.174***
	(2.56e-06)		(0.00351)
AvgHDD_sqft_Apartment_EPrimHeat	-0.000550***	Ewtht_plus_cooking_HmInsl	-1.050***
	(2.35e-05)		(0.0400)
AvgHDD_sqft_townhouse_EPrimHeat	-0.000484***	Vaccum_sqft	0.000881***
	(2.40e-05)		(5.45e-05)
AvgHDD_sqft_SnglFamily_EPrimHeat	-0.000400***	washdry_NumPeople	0.183***
	(2.71e-05)		(0.0110)
AvgHDD_HeatPump	0.0189**	TV_NumTV	0.280***
	(0.00836)		(0.0208)
AvgHDD_sqft_HeatPump	-2.50e-05***	NumIncandescent_Incandescent	0.0850***
	(6.49e-06)		(0.00611)
AvgHDD_sqft_HmInsl_HeatPump	9.56e-05***	Incan_sqft	0.000714***
	(5.45e-06)		(5.60e-05)
AvgHDD_sqft_ESecHeat	0.000117***	OtherLamps_NumOthrLamps	0.0360***
	(3.56e-06)		(0.00418)
AvgCDD_WindowCentral	0.304***	OtherLamps_sqft	-0.000645***
	(0.00868)		(4.53e-05)
AvgCDD_sqft_WindowCentral	1.03e-05	Vaccum_NumPpl	-0.242***
	(8.04e-06)		(0.0276)
AvgCDD_sqft_HmIsl_WindowCentral	8.68e-05***	misc_kitchen	0.501***
	(6.75e-06)		(0.0351)
AvgCDD_sqft_TownHouse_WindCent	3.76e-05***		
	(6.48e-06)	Constant	10.71***
AvgCDD_sqft_SnglFamily_WindCent	7.14e-05***		(0.0833)
	(8.08e-06)		
AvgCDD_HeatPump	0.263***	Observations	693,806
	(0.0102)	Adjusted R-squared	0.117
AvgCDD_sqft_HeatPump	-1.01e-05	Robust standard errors in parentheses	
	(8.53e-06)	*** p<0.01, ** p<0.05, * p<0.1	

Note: Including a constant term reduces the R-squared value

AEU Results

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Annual
Primary heat	283.7	303.7	194.3	55.9	5.6	2.1	0.0	0.0	0.0	64.8	112.8	135.3	1158.2
Secondary heat	94.6	101.2	64.8	18.7	1.9	0.7	0.0	0.0	0.0	21.6	37.6	45.1	386.1
Water heat/cooking	117.2	127.6	76.3	17.1	51.0	82.1	108.7	91.8	56.5	18.8	40.4	49.4	836.9
AC	0.0	0.0	0.0	7.0	109.2	166.7	216.3	186.1	122.5	3.5	2.2	0.4	813.8
Misc Kitchen	22.5	20.3	22.4	21.8	22.5	21.7	22.5	22.5	21.8	22.6	21.8	22.5	264.8
Washer/Dryer	13.8	12.4	13.7	13.3	13.7	13.3	13.7	13.8	13.3	13.8	13.3	13.7	161.9
Vacuum	12.7	11.5	12.7	12.3	12.8	12.3	12.7	12.8	12.3	12.7	12.3	12.7	149.9
Television	13.6	12.3	13.5	13.1	13.5	13.0	13.5	13.6	13.1	13.5	13.1	13.5	159.3
Lights	31.9	28.8	31.7	30.8	31.9	30.7	31.9	31.9	30.9	31.9	30.8	31.8	375.1
Other	330.7	298.7	329.2	319.8	330.0	318.1	329.9	330.9	320.4	331.0	319.2	329.3	3887.1
Monthly total	920.6	916.5	758.6	509.8	592.0	660.8	749.1	703.4	590.9	534.2	603.6	653.7	8193.1

- Brattle model leads to reasonable AEUs for all appliances explicitly captured in the model
- It has a large "Other" category that includes the collinear appliances (such as refrigerator)
- We back out the refrigerator load using engineering data (next slide)



Identifying Refrigerator Load

To separate the refrigerator AEU from the "Other" category, we used estimates provided by EnergyStar

- EnergyStar has website that provides estimates of refrigerator energy consumption based on age and style (we used an average style)
- We mapped the EnergyStar age categories to Pepco RASS refrigerator age categories
- We assigned the implied weighted average AEU of the refrigerators to households for which no refrigerator age was provided
- We gross-up the fridge consumption for multi-fridge households

Refrigerator AEU Calculation

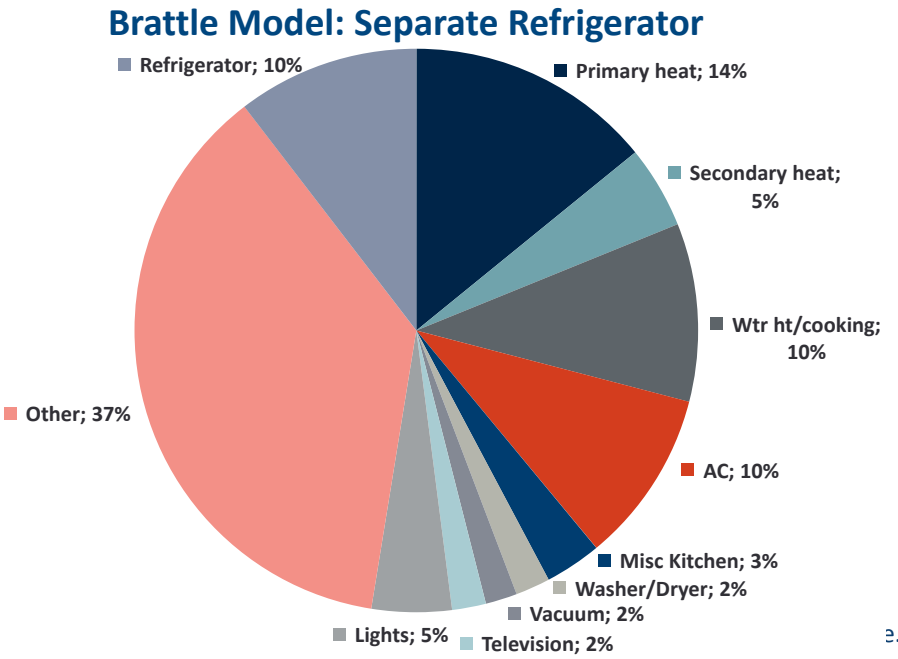
Pepco RASS Category	Percent of Total *(%)*	EnergyStar AEU *(kWh)*
1 to 5	29.8%	539
6 to 10	24.2%	762
11 to 20	15.4%	1,110
21 +	3.6%	2,070
No Age Provided	27.0%	808
Weighted Average		808
Multi-Fridge Households		5.80%
Total Fridge AEU		**855**

EnergyStar Source:
https://www.energystar.gov/index.cfm?fuseaction=refrig.calculator

AEU Results—Refrigerator identified

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Annual
Primary heat	283.7	303.7	194.3	55.9	5.6	2.1	0.0	0.0	0.0	64.8	112.8	135.3	1158.2
Secondary heat	94.6	101.2	64.8	18.7	1.9	0.7	0.0	0.0	0.0	21.6	37.6	45.1	386.1
Water heat/cooking	117.2	127.6	76.3	17.1	51.0	82.1	108.7	91.8	56.5	18.8	40.4	49.4	836.9
AC	0.0	0.0	0.0	7.0	109.2	166.7	216.3	186.1	122.5	3.5	2.2	0.4	813.8
Misc Kitchen	22.5	20.3	22.4	21.8	22.5	21.7	22.5	22.5	21.8	22.6	21.8	22.5	264.8
Washer/Dryer	13.8	12.4	13.7	13.3	13.7	13.3	13.7	13.8	13.3	13.8	13.3	13.7	161.9
Vacuum	12.7	11.5	12.7	12.3	12.8	12.3	12.7	12.8	12.3	12.7	12.3	12.7	149.9
Television	13.6	12.3	13.5	13.1	13.5	13.0	13.5	13.6	13.1	13.5	13.1	13.5	159.3
Lights	31.9	28.8	31.7	30.8	31.9	30.7	31.9	31.9	30.9	31.9	30.8	31.8	375.1
Other	258.0	233.1	256.5	249.5	257.4	247.8	257.3	258.3	250.1	258.3	248.9	256.7	3031.9
Refrigerator	72.6	65.6	72.6	70.3	72.6	70.3	72.6	72.6	70.3	72.6	70.3	72.6	855.2
Monthly total	920.6	916.5	758.6	509.8	592.0	660.8	749.1	703.4	590.9	534.2	603.6	653.7	8193.1

- After identifying the refrigerator load, the "Other" category represents 37% of the overall annual energy use



"Other" Category

The components in the "Other" group were not able to be modeled independently for this analysis, due to sample size, variation, data availability, or collinearity

The "Other" category inherently includes end-uses such as the following, many of which were not included in Pepco's original analysis.

- Dishwasher
- Computer
- Smart tech
- Toaster oven
- Electric tea kettle
- Ceiling fan
- Box fan
- Dehumidifier
- Air purifier
- Exercise machines
- Home audio system
- Home security system

Comparison of AEUs: Pepco vs. Brattle Models

	Saturation Rate	Pepco Base *(kWh)*	Brattle Base *(kWh)*	Pepco Base *(% Share)*	Brattle Base *(% Share)*
Heat	92%	2,299	1,544	30%	19%
AC	95%	1,708	814	22%	10%
Water Heat	83%	853	na	11%	na
Oven/Stove	70%	45	na	1%	na
Water Heat & Oven/Stove	90%	na	837	na	10%
Incandescant	89%	512	na	7%	na
Other Light	63%	48	na	1%	na
Lights	98%	na	375	na	5%
Freezer	17%	130	na	2%	na
Toaster	41%	464	na	6%	na
Microwave	90%	45	na	1%	na
Misc Kitchen	94%	na	265	na	3%
Vacuum	78%	424	150	5%	2%
Washer/Dryer	61%	258	162	3%	2%
TV	85%	298	159	4%	2%
Refrigerator	97%	650	855	8%	10%
Other*	63%	na	3,032	na	37%

Using AEU Estimates to Inform "Baseline" Consumption

AEU estimates can inform what level of consumption constitutes "baseline usage"

For example, baseline usage is approximately 337 kWh/month if it includes the following parameters:

- Primary heat
- AC
- Electric water heating and cooking
- Refrigerator
- Lighting

Baseline Consumption

Month	Baseline *(kWh)*
January	505
February	526
March	375
April	181
May	270
June	352
July	429
August	382
September	280
October	192
November	257
December	289
Average	**337**

Conclusions

- Several appliance AEUs from Pepco's initial CDA were likely biased due to the omission of a constant term
- Inclusion of a constant term results in the omission of some appliances from the model, but it leads to unbiased results for appliance parameters included in the model (for instance, the AEU for vacuum cleaners is much lower in the base Brattle specification)
- We implemented several other changes to the model that yielded more reliable AEUs (*i.e.*, lower miscellaneous kitchen equipment load, lower heating and cooling load, lower TV load, a sizable other load category that captures various end uses)
  - Because refrigerators generally run 24/7 with a low variability due to behavioral factors, we have not been able to separate the refrigerator AEU from the "other" category, but backed it out using Energy Star data

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P.R. Blazunas
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (F) – 11

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA
MARGINAL DISTRIBUTION COST STUDY

Introduction

The Potomac Electric Power Company (Pepco or the Company) performed a distribution marginal cost study as part of its preparation for the Company's distribution rate case filing. Marginal distribution costs are defined as the additional costs associated with a one unit increase in electricity demand or additional customers. Through this study, Pepco developed new primary and secondary marginal capacity costs and new customer related marginal costs. The marginal cost study was designed to reflect the restructured electric utility market in the District of Columbia. Specifically, generation related marginal costs were not calculated as part of this study because Pepco no longer owns and operates generating facilities and prices for electric energy are determined by the competitive wholesale market. Transmission related marginal costs were not calculated because these activities are not a component of this rate case filing. Pepco conducted the marginal cost study based upon previously established District of Columbia Public Service Commission (Commission) guidelines for performing these studies and the Company's most recent method of developing distribution marginal costs.

Description of Marginal Cost Study

Marginal distribution costs were calculated using the planned investment approach, which is similar to the method used by Pepco to develop previous distribution marginal costs. The planned investment approach is forward looking and relies upon the Company's most recent five-year forecast of distribution plant expenditures, excluding contributions in aid of

construction (CIAC). The study period for these expenditures is 2015 through 2019 and all expenditures are expressed in year 2014 dollars. Pepco relied upon the planned investment approach for three reasons: 1) the Commission has found the planned investment approach to be reasonable for calculating marginal costs, 2) accurate marginal costs can be calculated in this manner, and 3) this approach is one of the most frequently used methods to calculate electric distribution marginal costs.

An overall cost of capital of 7.65 percent was used to calculate the carrying charge rate for the marginal cost study. This is based upon the capital structure and the cost of preferred stock, common stock, and debt authorized by the Commission in Order No. 17424, Formal Case No. 1103. The overall carrying charge rate was determined to be 9.87 percent.

The forecast distribution plant additions were classified by the Company's distribution system planners as "distribution," "services" or "miscellaneous." The distribution plant items are for facilities designed to serve a distribution function, including distribution substations and overhead and underground circuits. Services items are the result of customer service orders. The miscellaneous distribution items are for various projects which result in improvements to the distribution systems and relocation/replacement of plant due to street and highway construction or Metro transit construction activities. Pepco distribution system planners assigned the projects to functional categories. The planners identified specific projects attributable to the growth in electricity demand according to the criteria established by the District of Columbia Public Service Commission in 1991 in Order No. 9868, Formal Case No. 905. Expenditures are considered demand related if they are one or more of the following:

1. Required to correct thermal overloads.

2. Required to correct voltage deficiencies – either high voltage or low voltage.
3. Required to maintain system reliability.
4. Required to improve system reliability.
5. Required to meet new safety requirements.
6. Upgrades to older equipment necessary to meet new environmental laws.

Projects were classified as not attributable to growth in demand if they are planned repairs to old facilities, replacement of old facilities for reasons other than those items identified above, or if they are required due to planned relocation of Pepco distribution equipment.

Any project expenditures determined to be "inframarginal" were excluded according to the treatment of these expenditures recommended in the Commission's discussion of this issue in Order No. 9868, Formal Case No. 905. Expenditures were identified as "inframarginal" on the basis of Pepco studies that identified the proportions of planned expenditures associated with the substation building itself, landscaping for the building, paving, fencing, and sidewalks.

The forecast expenditures for the distribution projects classified as "distribution" or "miscellaneous" which are partially attributable to growth in demand were divided into their respective demand and non-demand portions. The allocation of demand versus non-demand portions of expenditures for projects with both components was based upon recent studies conducted by Pepco's distribution system planners. Project expenditures identified under the "services" classification were divided into demand and customer portions based upon the most recent Company study of these components.

Total forecast expenditures attributable to growth in demand for primary distribution projects were then developed by summing the demand portions of forecast expenditures for projects classified as distribution, miscellaneous, and the primary demand portion of services. This total was divided by total growth in Pepco forecast non-coincident area peak demand (NCAP) over the planning period to obtain the primary distribution marginal capacity cost per kW, as shown in Table 1. Also included in Table 1 is the distribution operations and maintenance (O&M) cost associated with forecast expenditures for demand-related primary distribution projects. The primary distribution O&M expense per kW of NCAP was derived based on a study of primary and secondary O&M expenses for calendar 2009.

In a similar fashion, the demand portion of secondary services forecast project expenditures was divided by the growth in NCAP at secondary to determine the secondary distribution capacity marginal cost, as shown in Table 2. Also shown in Table 2 is the secondary distribution O&M cost associated with forecast expenditures for demand-related secondary distribution projects.

Table 3 contains the secondary distribution marginal customer cost. This was calculated by dividing the customer portion of the forecast services expenditures by the growth in customers (excluding those served at high voltage) over the five-year period. Also shown in Table 3 is the secondary distribution O&M cost associated with forecast expenditures for customer-related secondary distribution projects. The respective meter costs associated with adding a customer for each of the major rate schedules are displayed on the lower section of Table 3.

Total annual customer-related costs, including customer accounts expense, are summarized in Table 4. Customer accounts expense was estimated based on a study of

customer accounts expense, customer service and information expense, and customer sales expense over a five-year period.

In summary, Pepco's primary distribution annual marginal cost per each kW of NCAP demand growth is $352.57. Pepco's secondary distribution annual marginal cost per each kW of NCAP demand growth is $209.39. Pepco's secondary distribution annual marginal customer cost is $200.98, excluding metering costs. Total annual customer related distribution costs vary by rate schedule and are displayed in Table 4.

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA
PRIMARY DISTRIBUTION MARGINAL CAPACITY COST
(2014 Dollars)

Total demand-caused primary distribution expenditures ($000; 2015-2019)		$664,011
Contributions in Aid of Construction		$0
Net demand-caused primary distribution expenditures ($000; 2015-2019)		$664,011
Five-year growth in primary NCAP MW		224
Incremental cost ($/NCAP KW)		$2,964.34
Real carrying charge rate		9.87%
Annualized cost ($/NCAP KW)		$292.58
Distribution O&M ($/NCAP KW)	$	59.99
Total annual cost ($/NCAP KW)		$352.57

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA
SECONDARY DISTRIBUTION MARGINAL CAPACITY COST
(2014 Dollars)

Total demand-caused secondary distribution expenditures ($000; 2015-2019)		$189,473
Contributions in Aid of Construction		$0
Net demand-caused secondary distribution expenditures ($000; 2015-2019)		$189,473
Five-year growth in secondary NCAP MW		177
Incremental cost ($/NCAP KW)		$1,070.02
Real carrying charge rate		9.87%
Annualized cost ($/NCAP KW)		$105.61
Distribution O&M ($/NCAP KW)	$	103.78
Total annual cost ($/NCAP KW)		$209.39

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA
SECONDARY DISTRIBUTION MARGINAL CUSTOMER COST
(2014 Dollars)

Total demand-caused secondary distribution expenditures ($000; 2015-2019)	$44,444
Contributions in Aid of Construction	$0
Net demand-caused secondary distribution expenditures ($000; 2015-2019)	$44,444
Five-year growth in customer excluding high voltage	31,112
Installed cost per customer	$1,428.51
Real carrying charge rate	9.87%
Annualized cost per customer	$140.99
O&M expense per customer	$ 59.99
Annual customer cost	$200.98
Meter Costs:	
Residential	$202.78
Residential-Time-Metered	$232.63
Master Metered Apartments	$666.69
GS-Non-demand	$666.69
GS-Low voltage	$412.98
GS-High voltage	$4,757.80
GT-Low voltage	$412.98
GT-High voltage	$4,757.80
Metro-RT	$23,789.00
Annualized meter costs:	
Residential	$20.01
Residential-Time-Metered	$22.96
Master Metered Apartments	$65.80
GS-Non-demand	$65.80
GS-Low voltage	$40.76
GS-High voltage	$469.59
GT-Low voltage	$40.76
GT-High voltage	$469.59
Metro-RT	$2,347.97

POTOMAC ELECTRIC POWER COMPANY
DISTRICT OF COLUMBIA
TOTAL ANNUAL CUSTOMER COSTS
(2014 Dollars)

	Annualized Customer & Meter Cost	Customer Accounts	Customer Total
Residential	$221.00	$91.61	$312.61
Residential-TM	$223.94	$98.95	$322.89
MMA	$266.78	$127.04	$393.82
GS-Non-demand	$266.78	$136.53	$403.31
GS-Low voltage	$241.74	$136.53	$378.27
GS-High voltage	$670.58	$319.58	$990.16
GT-Low voltage	$241.74	$160.02	$401.76
GT-High voltage	$670.58	$244.90	$915.48
Metro-RT	$2,548.96	$4,145.75	$6,694.70

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Pepco - District of Columbia
Development of Proposed Distribution Rates

Revenue Allocation of Distribution Revenue Requirements Results for Traditional Test Period Compliance Filing

	Proposed
Proposed Increase in Revenue Requirement ($ Millions)	**$88.632**

(A)	(B)		(C) = $88.632 * B
	Proposed		
Rate Class	Allocation of Proposed Revenue Requirement Increase (%)		Allocation of Proposed Revenue Requirement Increase ($ Millions)
Overall System Increase	**100.00%**	**$**	**88.632**
R	35.09%	$	31.101
MMA	2.10%	$	1.858
GS-LV	9.33%	$	8.270
GS-3A	0.00%	$	-
MGT-LV	26.31%	$	23.320
GT-LV	14.88%	$	13.186
GT-3B	0.08%	$	0.075
GT-3A	10.39%	$	9.212
RT	1.35%	$	1.199
SL-S	0.21%	$	0.189
SL-E	0.21%	$	0.185
TS	0.04%	$	0.037
TN	0.00%	$	-

Notes:
- For the purposes of cost of service and revenue allocation, Schedule "GS-LV" shown above is inclusive of Schedules "GS-ND," "T", and "GS-DLV."
- Schedule "OL-LED" is not shown since there are no active customers on this Schedule as of the time of this filing.

Pepco - District of Columbia
Development of Proposed Distribution Rates
Rate Class Allocation of Distribution Revenue Requirements Results

Current Annualized Revenue and Allocation of Proposed Increase in Distribution Revenues by Rate Schedule

	Current	Proposed		
Rate Schedule	Total Revenue ($)	Increase ($)	Increase (%)	Total Revenue ($)
R	$ 77,912,081	$ 31,101,360	39.92%	$ 109,013,441
MMA	$ 10,445,791	$ 1,858,030	17.79%	$ 12,303,821
GS-ND	$ 13,427,430	$ 2,388,384	17.79%	$ 15,815,814
T	$ 1,268,963	$ 225,715	17.79%	$ 1,494,678
GS-DLV	$ 31,799,559	$ 5,656,299	17.79%	$ 37,455,859
GS-3A	$ 51,577	$ -	0.00%	$ 51,577
MGT-LV	$ 131,106,778	$ 23,320,423	17.79%	$ 154,427,202
GT-LV	$ 74,132,619	$ 13,186,229	17.79%	$ 87,318,848
GT-3B	$ 419,955	$ 74,699	17.79%	$ 494,653
GT-3A	$ 51,787,789	$ 9,211,676	17.79%	$ 60,999,465
RT	$ 6,739,348	$ 1,198,752	17.79%	$ 7,938,100
SL-S	$ 631,022	$ 188,539	29.88%	$ 819,562
SL-E	$ 463,974	$ 184,838	39.84%	$ 648,812
TS	$ 208,323	$ 37,055	17.79%	$ 245,379
TN	$ 71,978	$ -	0.00%	$ 71,978
Total	**$ 400,467,188**	**$ 88,632,000**		**$ 489,099,188**

Notes:
- For the purposes of cost of service and revenue allocation, Schedule "GS-LV" shown above is inclusive of Schedules "GS-ND," "T", and "GS-DLV."
- Schedule "OL-LED" is not shown since there are no active customers on this Schedule as of the time of this filing.

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Pepco - District of Columbia
Traditional Test Period Compliance Filing - Distribution Rates

	Present	Proposed
Residential		
Customer	$ 15.09	$ 18.86
	$ 15.09	$ 18.86
Winter		
1st 400 kwh	$ 0.00800	$ 0.01307
Excess of 400 kwh	$ 0.01594	$ 0.02605
Summer		
1st 400 kwh	$ 0.00800	$ 0.01307
Excess of 400 kwh	$ 0.02283	$ 0.03731
MMA		
Customer	$ 11.84	$ 13.95
	$ 11.84	$ 13.95
Winter		
1st 400 kwh	$ 0.00891	$ 0.00949
Excess of 400 kwh	$ 0.01774	$ 0.01889
Summer		
1st 400 kwh	$ 0.00891	$ 0.00949
Excess of 400 kwh	$ 0.02542	$ 0.02707
GSLV ND		
Customer	$ 27.42	$ 32.30
Summer kWh	$ 0.04173	$ 0.05074
Winter kWh	$ 0.03266	$ 0.03971
T		
Customer	$ 27.42	$ 32.30
Summer kWh	$ 0.06223	$ 0.06759
Winter kWh	$ 0.04853	$ 0.05271
GS LV D		
Customer	$ 35.17	$ 38.75
kW	$ 8.06	$ 9.46
Summer kWh	$ 0.02807	$ 0.03406
Winter kWh	$ 0.02127	$ 0.02581
GS 3A (GS HV)		
Customer	$ 89.41	$ 89.41
kW	$ 10.82	$ 10.82
Summer kWh	$ 0.02054	$ 0.02208
Winter kWh	$ 0.01476	$ 0.01587
MGT LV		
Customer	$ 456.76	$ 237.00
Summer kWh	$ 0.00958	$ 0.01316
Winter kWh	$ 0.00958	$ 0.01316
kW	$ 11.88	$ 15.07
GT LV		
Customer	$ 456.76	$ 940.60
Summer kWh	$ 0.00958	$ 0.01343
Winter kWh	$ 0.00958	$ 0.01343
kW	$ 11.88	$ 13.76

Pepco - District of Columbia
Traditional Test Period Compliance Filing - Distribution Rates

	Present	Proposed
GT 3A (GS HV Other)		
Customer	$ 187.64	$ 197.49
Summer kWh	$ 0.00454	$ 0.00554
Winter kWh	$ 0.00453	$ 0.00553
kW	$ 8.86	$ 10.35
GT 3B (GS HV 69kV)		
Customer	$ 423.38	$ 311.66
kWh		
kW Summer	$ 1.79	$ 1.83
kW Winter	$ 1.92	$ 1.97
RT (Metro)		
Customer	$ 6,216.22	$ 7,246.07
SL-E		
Customer - Metered Accounts	$ 17.19	$ 19.85
Customer - Unmetered Accounts	$ 14.70	$ 16.97
kWh	$ 0.00615	$ 0.00829
TS		
Customer	$ 8.03	$ 4.26
kWh	$ 0.02203	$ 0.02636
SL-S		
Fixed - OVERHEAD INCANDESCENT Without GLOBE	$ 2.492	$ 3.158
Fixed - OVERHEAD INCANDESCENT With GLOBE	$ 3.639	$ 4.611
Fixed - OVERHEAD MERCURY VAPOR 175 WATT	$ 7.756	$ 9.828
Fixed - OVERHEAD MERCURY VAPOR 250 WATT	$ 8.861	$ 11.228
Fixed - OVERHEAD METAL HALIDE 400 WATT	$ 29.990	$ 38.000
Fixed - UNDERGROUND INCANDESCENT With GLOBE	$ 34.870	$ 44.183
Fixed - UNDERGROUND MERCURY VAPOR 250 WATT	$ 35.171	$ 44.565
Fixed - UNDERGROUND MERCURY VAPOR 400 WATT	$ 41.242	$ 52.257
Fixed - UNDERGROUND HIGH PRESSURE SODIUM 150 WATT	$ 30.843	$ 39.081
Fixed - UNDERGROUND METAL HALIDE 100 WATT	$ 26.578	$ 33.677
Fixed - UNDERGROUND METAL HALIDE 175 WATT	$ 29.990	$ 38.000
Fixed - UNDERGROUND METAL HALIDE 400 WATT	$ 29.990	$ 38.000
O&M - OVERHEAD INCANDESCENT Without GLOBE	$ 0.039	$ 0.049
O&M - OVERHEAD INCANDESCENT With GLOBE	$ 0.860	$ 1.090
O&M - OVERHEAD MERCURY VAPOR 175 WATT	$ 0.767	$ 0.972
O&M - OVERHEAD MERCURY VAPOR 250 WATT	$ 0.777	$ 0.985
O&M - OVERHEAD METAL HALIDE 400 WATT	$ 1.253	$ 1.588
O&M - UNDERGROUND INCANDESCENT With GLOBE	$ 1.576	$ 1.997
O&M - UNDERGROUND MERCURY VAPOR 250 WATT	$ 1.416	$ 1.794
O&M - UNDERGROUND MERCURY VAPOR 400 WATT	$ 1.759	$ 2.229
O&M - UNDERGROUND HIGH PRESSURE SODIUM 150 WATT	$ 1.155	$ 1.463
O&M - UNDERGROUND METAL HALIDE 100 WATT	$ 1.039	$ 1.317
O&M - UNDERGROUND METAL HALIDE 175 WATT	$ 1.253	$ 1.588
O&M - UNDERGROUND METAL HALIDE 400 WATT	$ 1.253	$ 1.588
TN		
Customer	$ 15.43	$ 15.43
Summer kWh	$ 0.01288	$ 0.01227
Winter kWh	$ 0.01288	$ 0.01227
OL LED		
Customer	$ 8.76	$ 8.76
kWh	$ 0.00895	$ 0.00895

P.R. Blazunas
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (F) – 14

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule Residential ("R")	**Current**	**Proposed**
Distribution Functional Revenue Requirements Total	$ 77,912,081	$ 109,013,441
Proposed Change to Revenue Requirement ($)		$ 31,101,360
Proposed Change to Revenue Requirement (%)		39.92%
Customer Charge Recovery ($)		$ 62,171,462
Volumetric Charge Recovery ($)		$ 46,841,980
Customer Charge Recovery (%)	64%	57%
Volumetric Charge Recovery (%)	36%	43%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)	(G) = H - A	(H)	(I) = H * (B+C+D)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**	**Weather Normalization**	**Weather Normalized Billing Determinants**	**Weather Normalized Revenue**
Residential Monthly Customer Charge	3,296,472	$ 15.09			$ 49,743,762		-	3,296,472	49,743,762
Kilowatt-hour charge									
First 400 kWh									
Summer	479,754,157	$ 0.00800	$ (0.00014)	$ (0.00047)	$ 3,545,383	1	(32,560,075)	447,194,082	$ 3,304,764
Winter	619,095,009	$ 0.00800	$ (0.00014)	$ (0.00047)	$ 4,575,112	2	(13,514,448)	605,580,561	$ 4,475,240
Over 400 kWh									
Summer	548,551,090	$ 0.02283	$ (0.00039)	$ (0.00133)	$ 11,579,914	3	(34,207,720)	514,343,370	$ 10,857,789
Winter	634,720,170	$ 0.01594	$ (0.00027)	$ (0.00093)	$ 9,355,775	4	(14,219,547)	620,500,623	$ 9,146,179
Total kWh Charge	2,282,120,426				$ 29,056,184		(94,501,790)	2,187,618,636	27,783,972
Total Distribution					**$ 78,799,947**				**$ 77,527,735**
BSA/Revenue Annualization					**$ (887,866)**				
Total Annualized Authorized Revenue					**$ 77,912,081**				
Proposed Distribution Revenue Increase/Decrease									
Proposed Distribution Revenue									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Target Recovery of Proposed Change to Revenue Requirement through Customer Charge (%)									
Target Recovery of Proposed Change to Revenue Requirement through Customer Charge ($)									
Customer Charge based on 40% Recovery of Proposed Change to Revenue Requirement through Customer Charge									
Proposed Customer Charge									
Average Billing Period Energy Use (kWh)	**692**								

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule Residential ("R")		**Proposed**
Distribution Functional Revenue Requirements Total	$	109,013,441
Proposed Change to Revenue Requirement ($)	$	31,101,360
Proposed Change to Revenue Requirement (%)		39.92%
Customer Charge Recovery ($)	$	62,171,462
Volumetric Charge Recovery ($)	$	46,841,980
Customer Charge Recovery (%)		57%
Volumetric Charge Recovery (%)		43%

Delivery Service	**(J)** = ($18.86 / B) -1 = [(O-((M+N)*H))) - (B*H)] / (B*H) **Proposed Rate Increase (%)**	**(K)** = B*J **Proposed Rate Increase ($)**	**(L)** = B+K **Proposed Rate**	**(M)** **5 Year EDIT Credit**	**(N)** **10 Year EDIT Credit**	**(O)** = (1+J) * I = (L+M+N) * H **Proposed Revenue**
Residential Monthly Customer Charge	24.98%	$ 3.77	$ 18.86			$ 62,171,462
Kilowatt-hour charge						
First 400 kWh						
Summer	63.36%	$0.00507	$ 0.01307	($0.00014)	($0.00047)	$ 5,571,619
Winter	63.36%	$0.00507	$ 0.01307	($0.00014)	($0.00047)	$ 7,544,966
Over 400 kWh						
Summer	63.43%	$0.01448	$ 0.03731	($0.00039)	($0.00133)	$ 18,305,529
Winter	63.43%	$0.01011	$ 0.02605	($0.00027)	($0.00093)	$ 15,419,866
Total kWh Charge						$ 46,841,980
Total Distribution						
BSA/Revenue Annualization						
Total Annualized Authorized Revenue						
Proposed Distribution Revenue Increase/Decrease						**$ 31,101,360**
Proposed Distribution Revenue						**$ 109,013,441**
Percent Change						**39.92%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$ 27.67**	
Present Customer Charge	**$ 15.09**	
Target Recovery of Proposed Change to Revenue Requirement through Customer Charge (%)	40%	
Target Recovery of Proposed Change to Revenue Requirement through Customer Charge ($)	$ 3.77	= 40% * $31,101,360 / 3,296,472
Customer Charge based on 40% Recovery of Proposed Change to Revenue Requirement through Customer Charge	$ 18.86	
Proposed Customer Charge	**$ 18.86**	
Average Billing Period Energy Use (kWh)	**692**	

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule Master Metered Apartments ("MMA")	**Current**	**Proposed**
Distribution Functional Revenue Requirements Total	$ 10,445,791	$ 12,303,821
Increase in Distribution Functional Revenue Requirements ($)		$ 1,858,030
Increase in Distribution Functional Revenue Requirements (%)		17.79%
Proposed Customer Charge Recovery ($)		$ 9,109,224
Proposed Volumetric Charge Recovery ($)		$ 3,194,597
Proposed Customer Charge Recovery (%)	72%	74%
Proposed Volumetric Charge Recovery (%)	28%	26%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)	(G) = H - A	(H)	(I) = H * (B+C+D)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**	**Weather Normalization**	**Weather Normalized Billing Determinants**	**Weather Normalized Revenue**
Residential Monthly Customer Charge	652,991	$ 11.84			$ 7,731,413		-	652,991	$ 7,731,413
Kilowatt-hour charge									
First 400 kWh									
Summer	95,304,051	$ 0.00891	$ (0.00049)	$ (0.00167)	$ 643,302	5	(3,737,915)	91,566,135	$ 618,071
Winter	116,074,987	$ 0.00891	$ (0.00049)	$ (0.00167)	$ 783,506	6	(1,124,427)	114,950,560	$ 775,916
Over 400 kWh									
Summer	64,101,150	$ 0.02542	$ (0.00140)	$ (0.00477)	$ 1,233,947	7	(2,403,644)	61,697,507	$ 1,187,677
Winter	27,170,302	$ 0.01774	$ (0.00098)	$ (0.00333)	$ 364,897	8	(352,959)	26,817,343	$ 360,157
Total kWh Charge	302,650,490				$ 3,025,653		(7,618,945)	295,031,545	$ 2,941,822
Total Distribution					**$ 10,757,066**				**$ 10,673,235**
BSA/Revenue Annualization					**$ (311,275)**				
Total Annualized Authorized Revenue					**$ 10,445,791**				
Proposed Distribution Revenue Increase/Decrease									
Proposed Distribution Revenue									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Ratio of Class Increase to System Average Increase									
Change based on Overall Class Increase ($)									
Proposed Customer Charge based on Overall Class Increase ($)									
Proposed Customer Charge									

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule Master Metered Apartments ("MMA")

		Proposed
Distribution Functional Revenue Requirements Total	$	12,303,821
Increase in Distribution Functional Revenue Requirements ($)	$	1,858,030
Increase in Distribution Functional Revenue Requirements (%)		17.79%
Proposed Customer Charge Recovery ($)	$	9,109,224
Proposed Volumetric Charge Recovery ($)	$	3,194,597
Proposed Customer Charge Recovery (%)		74%
Proposed Volumetric Charge Recovery (%)		26%

Delivery Service	(J) = ($13.95 / B) -1 = [(O-((M+N)*H))) - (B*H)] / (B*H) Proposed Rate Increase (%)	(K) = B*J Proposed Rate Increase ($)	(L) = B+K Proposed Rate	(M) 5 Year EDIT Credit	(N) 10 Year EDIT Credit	(O) = (1+J) * I = (L+M+N) * H Proposed Revenue
Residential Monthly Customer Charge	17.82%	$ 2.11	$ 13.95			$ 9,109,224
Kilowatt-hour charge						
First 400 kWh						
Summer	6.51%	$0.00058	$0.00949	($0.00049)	($0.00167)	$ 671,179
Winter	6.51%	$0.00058	$0.00949	($0.00049)	($0.00167)	$ 842,587
Over 400 kWh						
Summer	6.51%	$0.00165	$0.02707	($0.00140)	($0.00477)	$ 1,289,728
Winter	6.50%	$0.00115	$0.01889	($0.00098)	($0.00333)	$ 391,103
Total kWh Charge						$ 3,194,597
Total Distribution						
BSA/Revenue Annualization						
Total Annualized Authorized Revenue						
Proposed Distribution Revenue Increase/Decrease						**$ 1,858,030**
Proposed Distribution Revenue						**$ 12,303,821**
Percent Change						**17.79%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$**	**74.18**	
Present Customer Charge	**$**	**11.84**	
Ratio of Class Increase to System Average Increase		1.00	
Change based on Overall Class Increase ($)	$	2.11	= 17.79% * $11.84
Proposed Customer Charge based on Overall Class Increase ($)	$	13.95	
Proposed Customer Charge	**$**	**13.95**	

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule General Service Non Demand ("GS-ND")	**Current**	**Proposed**
Distribution Functional Revenue Requirements Total	$ 13,427,430	$ 15,815,814
Increase in Distribution Functional Revenue Requirements ($)		$ 2,388,384
Increase in Distribution Functional Revenue Requirements (%)		17.79%
Proposed Customer Charge Recovery ($)		$ 6,716,430
Proposed Volumetric Charge Recovery ($)		$ 9,099,384
Proposed Customer Charge Recovery (%)	44%	42%
Proposed Volumetric Charge Recovery (%)	56%	58%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)	(G) = H - A	(H)	(I) = H * (B+C+D)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**	**Weather Normalization**	**Weather Normalized Billing Determinants**	**Weather Normalized Revenue**
Monthly Customer Charge	207,939	$ 27.42			$ 5,701,687		-	207,939	$ 5,701,687
Distribution									
Kilowatt-hour Charge									
Summer	96,056,555	$ 0.04173	$ (0.00100)	$ (0.00342)	$ 3,583,870	9	(2,841,486)	93,215,069	$ 3,477,854
Winter	133,410,324	$ 0.03266	$ (0.00078)	$ (0.00267)	$ 3,896,916	10	(1,555,167)	131,855,157	$ 3,851,489
Total kWh Charge	229,466,879				$ 7,480,786		(4,396,653)	225,070,226	$ 7,329,343
Total Distribution					**$ 13,182,473**				**$ 13,031,031**
BSA/Revenue Annualization					**$ 244,957**				
Total Annualized Authorized Revenue					**$ 13,427,430**				
Proposed Distribution Revenue Increase/Decrease									
Proposed Distribution Revenue									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Ratio of Class Increase to System Average Increase									
Change based on Overall Class Increase ($)									
Proposed Customer Charge based on Overall Class Increase ($)									
Proposed Customer Charge									

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule General Service Non Demand ("GS-ND")		**Proposed**
Distribution Functional Revenue Requirements Total	$	15,815,814
Increase in Distribution Functional Revenue Requirements ($)	$	2,388,384
Increase in Distribution Functional Revenue Requirements (%)		17.79%
Proposed Customer Charge Recovery ($)	$	6,716,430
Proposed Volumetric Charge Recovery ($)	$	9,099,384
Proposed Customer Charge Recovery (%)		42%
Proposed Volumetric Charge Recovery (%)		58%

Delivery Service	**(J)** = ($32.3 / B) -1 = [(O-((M+N)*H))) - (B*H)] / (B*H) **Proposed Rate Increase (%)**	**(K)** = B*J **Proposed Rate Increase ($)**	**(L)** = B+K **Proposed Rate**	**(M)** **5 Year EDIT Credit**	**(N)** **10 Year EDIT Credit**	**(O)** = (1+J) * I = (L+M+N) * H **Proposed Revenue**
Monthly Customer Charge	17.80%	$ 4.88	$ 32.30			$ 6,716,430
Distribution						
Kilowatt-hour Charge						
Summer	21.59%	$0.00901	$0.05074	($0.00100)	($0.00342)	$ 4,317,758
Winter	21.60%	$0.00705	$0.03971	($0.00078)	($0.00267)	$ 4,781,626
Total kWh Charge						$ 9,099,384
Total Distribution						
BSA/Revenue Annualization						
Total Annualized Authorized Revenue						
Proposed Distribution Revenue Increase/Decrease						**$ 2,388,384**
Proposed Distribution Revenue						**$ 15,815,814**
Percent Change						**17.79%**

Customer Charge Rate Design			
Full Customer Cost from CCOSS	**$**	**38.75**	
Present Customer Charge	**$**	**27.42**	
Ratio of Class Increase to System Average Increase		1.00	
Change based on Overall Class Increase ($)	$	4.88	= 17.79% * $27.42
Proposed Customer Charge based on Overall Class Increase ($)	$	32.30	
Proposed Customer Charge	**$**	**32.30**	

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule Temporary Service ("T")	**Current**	**Proposed**
Distribution Functional Revenue Requirements Total	$ 1,268,963	$ 1,494,678
Proposed Change to Revenue Requirement ($)		$ 225,715
Proposed Change to Revenue Requirement (%)		17.79%
Customer Charge Recovery ($)		$ 116,312
Volumetric Charge Recovery ($)		$ 1,378,366
Customer Charge Recovery (%)	8%	8%
Volumetric Charge Recovery (%)	92%	92%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)	(G) = H - A	(H)	(I) = H * (B+C+D)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**	**Weather Normalization**	**Weather Normalized Billing Determinants**	**Weather Normalized Revenue**
Monthly Customer Charge	3,601	$ 27.42			$ 98,739		-	3,601	$ 98,739.42
Distribution									
Summer Energy Rate	9,307,308	$ 0.06223	$ (0.00097)	$ (0.00331)	$ 539,358	11	(284,000)	9,023,308	$ 522,901
Winter Energy Rate	16,531,688	$ 0.04853	$ (0.00076)	$ (0.00258)	$ 747,067	12	(182,552)	16,349,136	$ 738,817
Total kWh Charge	25,838,996				$ 1,286,425		(466,552)	25,372,444	$ 1,261,718
Total Distribution					**$ 1,385,165**				**$ 1,261,718**
BSA/Revenue Annualization					**$ (116,202)**				
Total Annualized Authorized Revenue					**$ 1,268,963**				
Proposed Distribution Revenue Increase/Decrease									
Proposed Distribution Revenue									
Percent Change									

Customer Charge Rate Design
Full Customer Cost from CCOSS
Proposed GS-ND Customer Charge

Proposed Customer Charge

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule Temporary Service ("T")		**Proposed**
Distribution Functional Revenue Requirements Total	$	1,494,678
Proposed Change to Revenue Requirement ($)	$	225,715
Proposed Change to Revenue Requirement (%)		17.79%
Customer Charge Recovery ($)	$	116,312
Volumetric Charge Recovery ($)	$	1,378,366
Customer Charge Recovery (%)		8%
Volumetric Charge Recovery (%)		92%

	(J) = ($32.3 / B) -1 = [(O-((M+N)*H))) - (B*H)] / (B*H)	**(K)** = B*J	**(L)** = B+K	**(M)**	**(N)**	**(O)** = (1+J) * I = (L+M+N) * H
Delivery Service	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	17.80%	$ 4.88	$ 32.30			$ 116,312
Distribution						
Summer Energy Rate	8.61%	$0.00536	$0.06759	($0.00097)	($0.00331)	$ 571,244
Winter Energy Rate	8.61%	$0.00418	$0.05271	($0.00076)	($0.00258)	$ 807,122
Total kWh Charge						$ 1,378,366
Total Distribution						
BSA/Revenue Annualization						
Total Annualized Authorized Revenue						
Proposed Distribution Revenue Increase/Decrease						**$ 225,715**
Proposed Distribution Revenue						**$ 1,494,678**
Percent Change						**17.79%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$**	**27.42**
Proposed GS-ND Customer Charge	$	32.30
Proposed Customer Charge	**$**	**32.30**

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule General Service Low Voltage ("GSD-LV")	**Current**	**Proposed**
Distribution Functional Revenue Requirements Total	$ 31,799,559	$ 37,455,859
Proposed Change to Revenue Requirement ($)		$ 5,656,299
Proposed Change to Revenue Requirement (%)		17.79%
Customer Charge Recovery ($)		$ 2,374,407
Demand Charge Recovery ($)		$ 17,903,968
Volumetric Charge Recovery ($)		$ 17,177,484
Customer Charge Recovery (%)	7%	6%
Demand Charge Recovery (%)	48%	48%
Volumetric Charge Recovery (%)	45%	46%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)	(G) = H - A	(H)	(I) = H * (B+C+D)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**	**Weather Normalization**	**Weather Normalized Billing Determinants**	**Weather Normalized Revenue**
Monthly Customer Charge	61,276	$ 35.17			$ 2,155,077		-	61,276	$ 2,155,077
Distribution									
Kilowatt-hour Charge									
Summer	283,446,851	$ 0.02807	$ (0.00043)	$ (0.00148)	$ 7,414,970	13	(8,300,075)	275,146,776	$ 7,197,840
Winter	345,267,257	$ 0.02127	$ (0.00033)	$ (0.00112)	$ 6,843,197	14	(3,303,176)	341,964,081	$ 6,777,728
Total kWh Charge	628,714,108				$ 14,258,167		(11,603,251)	617,110,857	$ 13,975,568
Demand Charge (Total kW)									
Summer	945,037	$ 8.06	$ (0.12)	$ (0.43)	$ 7,097,228		-	945,037	$ 7,097,228
Winter	1,064,387	$ 8.06	$ (0.12)	$ (0.43)	$ 7,993,546		-	1,064,387	$ 7,993,546
Total KW Charge	2,009,424				$ 15,090,774		-	2,009,424	$ 15,090,774
Total Distribution					**$ 31,504,018**				**$ 31,221,419**
BSA/Revenue Annualization					**$ 295,542**				
Total Annualized Authorized Revenue					**$ 31,799,559**				
Proposed Distribution Revenue Increase/Decrease									
Proposed Distribution Revenue									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Proposed Customer Charge									
Demand Charge Rate Design									
Present Demand Charge									
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)									
Calculated Demand Charge Increase									
Calculated Demand Charge									
Proposed Demand Charge									

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule General Service Low Voltage ("GSD-LV")

		Proposed
Distribution Functional Revenue Requirements Total	$	37,455,859
Proposed Change to Revenue Requirement ($)	$	5,656,299
Proposed Change to Revenue Requirement (%)		17.79%
Customer Charge Recovery ($)	$	2,374,407
Demand Charge Recovery ($)	$	17,903,968
Volumetric Charge Recovery ($)		1717748354%
Customer Charge Recovery (%)		6%
Demand Charge Recovery (%)		
Volumetric Charge Recovery (%)		

Delivery Service	**(J)** = ($38.75 / B) -1 = [(O-((M+N)*H))) - (B*H)] / (B*H) = ($9.46 / B) -1 **Proposed Rate Increase (%)**	**(K)** = B*J **Proposed Rate Increase ($)**	**(L)** = B+K **Proposed Rate**	**(M)** **5 Year EDIT Credit**	**(N)** **10 Year EDIT Credit**	**(O)** = (1+J) * I = (L+M+N) * H **Proposed Revenue**
Monthly Customer Charge	10.18%	$ 3.58	$ 38.75			$ 2,374,407
Distribution						
Kilowatt-hour Charge						
Summer	21.35%	$0.00599	$0.03406	($0.00043)	($0.00148)	$ 8,846,923
Winter	21.35%	$0.00454	$0.02581	($0.00033)	($0.00112)	$ 8,330,560
Total kWh Charge						$ 17,177,484
Demand Charge (Total kW)						
Summer	17.37%	$ 1.40	$ 9.46	($0.12)	($0.43)	$ 8,420,280
Winter	17.37%	$ 1.40	$ 9.46	($0.12)	($0.43)	$ 9,483,688
Total KW Charge						$ 17,903,968
Total Distribution						
BSA/Revenue Annualization						
Total Annualized Authorized Revenue						
Proposed Distribution Revenue Increase/Decrease						**$ 5,656,299**
Proposed Distribution Revenue						**$ 37,455,859**
Percent Change						**17.79%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$ 38.75**	
Present Customer Charge	**$ 35.17**	
Proposed Customer Charge	**$ 38.75**	

Demand Charge Rate Design

Present Demand Charge	**$ 8.06**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)	50%	= [$5,656,299 - ($2,374,407 - $2,155,077)] * ($15,090,774 / ($15,090,774 + $13,975,568)) / $5,656,299
Calculated Demand Charge Increase	$ 1.40	= (49.91% * $5,656,299) / 2,009,424
Calculated Demand Charge	$ 9.46	
Proposed Demand Charge	**$ 9.46**	

Pepco - District of Columbia
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Schedule General Service Primary Service - General Service ("GS 3A")

	Current	Proposed
Distribution Functional Revenue Requirements Total	$ 51,577	$ 51,577
Proposed Change to Revenue Requirement ($)		$ -
Proposed Change to Revenue Requirement (%)		0.00%
Customer Charge Recovery ($)		$ 5,812
Demand Charge Recovery ($)		$ 25,882
Volumetric Charge Recovery ($)		$ 19,883
Customer Charge Recovery (%)	12%	11%
Demand Charge Recovery (%)	52%	50%
Volumetric Charge Recovery (%)	37%	39%

Delivery Service	(A) Billing Determinants	(B) Current Rate	(C) 5 Year EDIT Credit	(D) 10 Year EDIT Credit	(E) = A * (B+C+D) Present Revenue	(F) Billing Determinant Adjustment No.	(G) = H - A Weather Normalization	(H) Weather Normalized Billing Determinants	(I) = H * (B+C+D) Weather Normalized Revenue
Monthly Customer Charge	65	$ 89.41			$ 5,812		-	65	$ 5,812
Distribution									
Kilowatt-hour Charge									
Summer	551,065	$ 0.02054	$ (0.00035)	$ (0.00118)	$ 10,476	15	(16,212)	534,853	$ 10,168
Winter	609,202	$ 0.01476	$ (0.00025)	$ (0.00085)	$ 8,322	16	(6,961)	602,241	$ 8,227
Total kWh Charge	1,160,267				$ 18,797		(23,172)	1,137,095	$ 18,394
Demand Charge (Total kW)									
Summer	1,216	$ 10.82	$ (0.18)	$ (0.62)	$ 12,184		-	1,216	$ 12,184
Winter	1,367	$ 10.82	$ (0.18)	$ (0.62)	$ 13,697		-	1,367	$ 13,697
Total KW Charge	2,583				$ 25,882		-	2,583	$ 25,882
Total Distribution					**$ 50,491**				**$ 50,087**
BSA/Revenue Annualization					**$ 1,086**				
Total Annualized Authorized Revenue					**$ 51,577**				
Proposed Distribution Revenue Increase/Decrease									
Proposed Distribution Revenue									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Proposed Customer Charge									
Demand Charge Rate Design									
Present Demand Charge									
Proposed Demand Charge									

Pepco - District of Columbia
Development of Distribution Rates
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Schedule General Service Primary Service - General Service ("GS 3A")

		Proposed
Distribution Functional Revenue Requirements Total	$	51,577
Proposed Change to Revenue Requirement ($)	$	-
Proposed Change to Revenue Requirement (%)		0.00%
Customer Charge Recovery ($)	$	5,812
Demand Charge Recovery ($)	$	25,882
Volumetric Charge Recovery ($)	$	19,883
Customer Charge Recovery (%)		11%
Demand Charge Recovery (%)		50%
Volumetric Charge Recovery (%)		39%

Delivery Service	(J) = ($89.41 / B) -1 = [(O-((M+N)*H))) - (B*H)] / (B*H) = ($10.82 / B) -1 Proposed Rate Increase (%)	(K) = B*J Proposed Rate Increase ($)	(L) = B+K Proposed Rate	(M) 5 Year EDIT Credit	(N) 10 Year EDIT Credit	(O) = (1+J) * I = (L+M+N) * H Proposed Revenue
Monthly Customer Charge	0.00%	$ -	$ 89.41			$ 5,812
Distribution						
Kilowatt-hour Charge						
Summer	7.49%	$0.00154	$0.02208	($0.00035)	($0.00118)	$ 10,991
Winter	7.49%	$0.00111	$0.01587	($0.00025)	($0.00085)	$ 8,893
Total kWh Charge						$ 19,883
Demand Charge (Total kW)						
Summer	0.00%	$ -	$ 10.82	($0.18)	($0.62)	$ 12,184
Winter	0.00%	$ -	$ 10.82	($0.18)	($0.62)	$ 13,697
Total KW Charge						$ 25,882
Total Distribution						
BSA/Revenue Annualization						
Total Annualized Authorized Revenue						
Proposed Distribution Revenue Increase/Decrease						**$ -**
Proposed Distribution Revenue						**$ 51,577**
Percent Change						**0.00%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$ 163.90**
Present Customer Charge	**$ 89.41**
Proposed Customer Charge	**$ 89.41**

Demand Charge Rate Design

Present Demand Charge	**$ 10.82**
Proposed Demand Charge	**$ 10.82**

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Schedule Time Metered Medium General Service - Low Voltage ("MGT-LV")

	Current	Proposed
Distribution Functional Revenue Requirements Total	$ 131,106,778	$ 154,427,202
Proposed Change to Revenue Requirement ($)		$ 23,320,423
Proposed Change to Revenue Requirement (%)		17.79%
Customer Charge Recovery ($)		$ 9,231,503
Demand Charge Recovery ($)		$ 108,199,492
Volumetric Charge Recovery ($)		$ 36,996,207
Customer Charge Recovery (%)	14%	6%
Demand Charge Recovery (%)	66%	70%
Volumetric Charge Recovery (%)	21%	24%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)	(G) = H - A	(H)	(I) = H * (B+C+D)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**	**Weather Normalization**	**Weather Normalized Billing Determinants**	**Weather Normalized Revenue**
Monthly Customer Charge	38,952	$ 456.76			$ 17,791,716		-	38,952	$ 17,791,716
Distribution									
Kilowatt-hour Charge									
Summer	1,341,961,511	$ 0.00958	$ (0.00015)	$ (0.00051)	$ 11,970,297	17	(32,312,944)	1,309,648,566	$ 11,682,065
Winter	1,661,804,977	$ 0.00958	$ (0.00015)	$ (0.00051)	$ 14,823,300	18	(11,111,326)	1,650,693,651	$ 14,724,187
Total kWh Charge	3,003,766,488				$ 26,793,597		(43,424,270)	2,960,342,217	$ 26,406,253
Demand Charge (Total kW)									
Summer	3,402,217	$ 11.88	$ (0.19)	$ (0.64)	$ 37,594,502		-	3,402,217	$ 37,594,502
Winter	4,196,062	$ 11.88	$ (0.19)	$ (0.64)	$ 46,366,481		-	4,196,062	$ 46,366,481
Total KW Charge	7,598,279				$ 83,960,982		-	7,598,279	$ 83,960,982
Total Distribution					**$ 128,546,295**				**$ 128,158,950**
BSA/Revenue Annualization					**$ 2,560,484**				
Total Annualized Authorized Revenue					**$ 131,106,778**				
Proposed Distribution Revenue Increase/Decrease									
Proposed Distribution Revenue									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Proposed Customer Charge									
Demand Charge Rate Design									
Present Demand Charge									
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)									
Calculated Demand Charge Increase									
Calculated Demand Charge									
Proposed Demand Charge									

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule Time Metered Medium General Service - Low Voltage ("MGT-LV")

		Proposed
Distribution Functional Revenue Requirements Total	$	154,427,202
Proposed Change to Revenue Requirement ($)	$	23,320,423
Proposed Change to Revenue Requirement (%)		17.79%
Customer Charge Recovery ($)	$	9,231,503
Demand Charge Recovery ($)	$	108,199,492
Volumetric Charge Recovery ($)	$	36,996,207
Customer Charge Recovery (%)		6%
Demand Charge Recovery (%)		70%
Volumetric Charge Recovery (%)		24%

Delivery Service	(J) = ($237. / B) -1 = [(O-((M+N)*H))) - (B*H)] / (B*H) = ($15.07 / B) -1 Proposed Rate Increase (%)	(K) = B*J Proposed Rate Increase ($)	(L) = B+K Proposed Rate	(M) 5 Year EDIT Credit	(N) 10 Year EDIT Credit	(O) = (1+J) * I = (L+M+N) * H Proposed Revenue
Monthly Customer Charge	-48.11%	$ (219.76)	$ 237.00			$ 9,231,503
Distribution						
Kilowatt-hour Charge						
Summer	37.34%	$0.00358	$0.01316	($0.00015)	($0.00051)	$ 16,367,037
Winter	37.34%	$0.00358	$0.01316	($0.00015)	($0.00051)	$ 20,629,171
Total kWh Charge						$ 36,996,207
Demand Charge (Total kW)						
Summer	26.85%	$ 3.19	$ 15.07	($0.19)	($0.64)	$ 48,447,575
Winter	26.85%	$ 3.19	$ 15.07	($0.19)	($0.64)	$ 59,751,917
Total KW Charge						$ 108,199,492
Total Distribution						
BSA/Revenue Annualization						
Total Annualized Authorized Revenue						
Proposed Distribution Revenue Increase/Decrease						**$ 23,320,423**
Proposed Distribution Revenue						**$ 154,427,202**
Percent Change						**17.79%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$**	**237.00**
Present Customer Charge	**$**	**456.76**
Proposed Customer Charge	**$**	**237.00**

Demand Charge Rate Design

Present Demand Charge	**$**	**11.88**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)		104%	= [$23,320,423 - ($9,231,503 - $17,791,716)] * ($83,960,982 / ($83,960,982 + $26,406,253)) / $23,320,423
Calculated Demand Charge Increase	$	3.19	= (104.% * $23,320,423) / 7,598,279
Calculated Demand Charge	$	15.07	
Proposed Demand Charge	**$**	**15.07**	

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Schedule Time Metered General Service Low Voltage - General Service ("GT-LV")

	Current	Proposed
Distribution Functional Revenue Requirements Total	$ 74,132,619	$ 87,318,848
Proposed Change to Revenue Requirement ($)		$ 13,186,229
Proposed Change to Revenue Requirement (%)		17.79%
Customer Charge Recovery ($)		$ 3,103,984
Demand Charge Recovery ($)		$ 60,643,615
Volumetric Charge Recovery ($)		$ 23,571,249
Customer Charge Recovery (%)	2%	4%
Demand Charge Recovery (%)	74%	69%
Volumetric Charge Recovery (%)	24%	27%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)	(G) = H - A	(H)	(I) = H * (B+C+D)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**	**Weather Normalization**	**Weather Normalized Billing Determinants**	**Weather Normalized Revenue**
Monthly Customer Charge	3,300	$ 456.76			$ 1,507,308		-	3,300	$ 1,507,308
Distribution									
Kilowatt-hour Charge									
Summer	807,006,951	$ 0.00958	$ (0.00015)	$ (0.00051)	$ 7,198,502	19	(19,462,726)	787,544,226	$ 7,024,894
Winter	1,064,884,594	$ 0.00958	$ (0.00015)	$ (0.00051)	$ 9,498,771	20	(7,180,183)	1,057,704,411	$ 9,434,723
Total kWh Charge	1,871,891,545				$ 16,697,273		(26,642,909)	1,845,248,637	$ 16,459,618
Demand Charge (Total kW)									
Summer	2,034,014	$ 11.88	$ (0.19)	$ (0.64)	$ 22,475,851		-	2,034,014	$ 22,475,851
Winter	2,656,134	$ 11.88	$ (0.19)	$ (0.64)	$ 29,350,285		-	2,656,134	$ 29,350,285
Total KW Charge	4,690,148				$ 51,826,136		-	4,690,148	$ 51,826,136
Total Distribution					**$ 70,030,717**				**$ 69,793,062**
BSA/Revenue Annualization					**$ 4,101,902**				
Total Annualized Authorized Revenue					**$ 74,132,619**				
Proposed Distribution Revenue Increase/Decrease									
Proposed Distribution Revenue									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Target Movement Toward Full Cost (%)									
Target Movement Toward Full Cost ($)									
Change to Present based on Target Movement Toward Full Cost									
Proposed Customer Charge									
Demand Charge Rate Design									
Present Demand Charge									
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)									
Calculated Demand Charge Increase									
Calculated Demand Charge									
Proposed Demand Charge									

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule Time Metered General Service Low Voltage - General Service ("GT-LV")

		Proposed
Distribution Functional Revenue Requirements Total	$	87,318,848
Proposed Change to Revenue Requirement ($)	$	13,186,229
Proposed Change to Revenue Requirement (%)		17.79%
Customer Charge Recovery ($)	$	3,103,984
Demand Charge Recovery ($)	$	60,643,615
Volumetric Charge Recovery ($)	$	23,571,249
Customer Charge Recovery (%)		4%
Demand Charge Recovery (%)		69%
Volumetric Charge Recovery (%)		27%

Delivery Service	(J) = ($940.6 / B) -1 = [(O-((M+N)*H))) - (B*H)] / (B*H) = ($13.76 / B) -1 Proposed Rate Increase (%)	(K) = B*J Proposed Rate Increase ($)	(L) = B+K Proposed Rate	(M) 5 Year EDIT Credit	(N) 10 Year EDIT Credit	(O) = (1+J) * I = (L+M+N) * H Proposed Revenue
Monthly Customer Charge	105.93%	$ 483.84	$ 940.60			$ 3,103,984
Distribution						
Kilowatt-hour Charge						
Summer	40.23%	$0.00385	$0.01343	($0.00015)	($0.00051)	$ 10,060,108
Winter	40.23%	$0.00385	$0.01343	($0.00015)	($0.00051)	$ 13,511,141
Total kWh Charge						$ 23,571,249
Demand Charge (Total kW)						
Summer	15.82%	$ 1.88	$ 13.76	($0.19)	($0.64)	$ 26,299,797
Winter	15.82%	$ 1.88	$ 13.76	($0.19)	($0.64)	$ 34,343,818
Total KW Charge						$ 60,643,615
Total Distribution						
BSA/Revenue Annualization						
Total Annualized Authorized Revenue						
Proposed Distribution Revenue Increase/Decrease						**$ 13,186,229**
Proposed Distribution Revenue						**$ 87,318,848**
Percent Change						**17.79%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$**	**3,816.50**	
Present Customer Charge	**$**	**456.76**	
Target Movement Toward Full Cost (%)		14%	
Target Movement Toward Full Cost ($)	$	483.84	= 14.4% * ($3816.5 - $456.76)
Change to Present based on Target Movement Toward Full Cost	$	940.60	
Proposed Customer Charge	**$**	**940.60**	

Demand Charge Rate Design

Present Demand Charge	**$**	**11.88**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)		67%	= [$13,186,229 - ($3,103,984 - $1,507,308)] * ($51,826,136 / ($51,826,136 + $16,459,618)) / $13,186,229
Calculated Demand Charge Increase	$	1.88	= (66.71% * $13,186,229) / 4,690,148
Calculated Demand Charge	$	13.76	
Proposed Demand Charge	**$**	**13.76**	

Pepco - District of Columbia
Development of Distribution Rates
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Schedule Time Metered General Service - High Voltage ("GT-3B")

	Current	Proposed
Distribution Functional Revenue Requirements Total	$ 419,955	$ 494,653
Proposed Change to Revenue Requirement ($)		$ 74,699
Proposed Change to Revenue Requirement (%)		17.79%
Customer Charge Recovery ($)		$ 3,740
Demand Charge Recovery ($)		$ 490,914
Customer Charge Recovery (%)	1%	1%
Demand Charge Recovery (%)	99%	99%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)	(G) = H - A	(H)	(I) = H * (B+C+D)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**	**Weather Normalization**	**Weather Normalized Billing Determinants**	**Weather Normalized Revenue**
Monthly Customer Charge	12	$ 423.38			$ 5,081		-	12	$ 5,081
Demand Charge (Total kW)									
Summer	170,489	$ 1.79	$ (0.14)	$ (0.47)	$ 201,177		-	170,489	$ 201,177
Winter	216,073	$ 1.92	$ (0.15)	$ (0.51)	$ 272,252		-	216,073	$ 272,252
Total KW Charge	386,562				$ 473,429		-	386,562	$ 473,429
Total Distribution					**$ 478,510**				**$ 478,510**
BSA/Revenue Annualization					**$ (58,555)**				
Total Annualized Authorized Revenue					**$ 419,955**				
Proposed Distribution Revenue Increase/Decrease									
Proposed Distribution Revenue									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Proposed Customer Charge									

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Schedule Time Metered General Service - High Voltage ("GT-3B")

Distribution Functional Revenue Requirements Total	
Proposed Change to Revenue Requirement ($)	
Proposed Change to Revenue Requirement (%)	
Customer Charge Recovery ($)	
Demand Charge Recovery ($)	
Customer Charge Recovery (%)	
Demand Charge Recovery (%)	

	(J) = ($311.66 / B) -1 = [(O-((M+N)*H))) - (B*H)] / (B*H)	(K) = B*J	(L) = B+K	(M)	(N)	(O) = (1+J) * I = (L+M+N) * H
Delivery Service	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	-26.39%	$ (111.72)	$ 311.66			$ 3,740
Demand Charge (Total kW)						
Summer	2.43%	$0.04	$ 1.83	$ (0.14)	$ (0.47)	$ 208,607
Winter	2.42%	$0.05	$ 1.97	$ (0.15)	$ (0.51)	$ 282,307
Total KW Charge						$ 490,914
Total Distribution						
BSA/Revenue Annualization						
Total Annualized Authorized Revenue						
Proposed Distribution Revenue Increase/Decrease						**$ 74,699**
Proposed Distribution Revenue						**$ 494,653**
Percent Change						**17.79%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$ 311.66**
Present Customer Charge	**$ 423.38**
Proposed Customer Charge	**$ 311.66**

Pepco - District of Columbia
Development of Distribution Rates
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Schedule Time Metered General Service - Primary Service ("GT 3A")

	Current	Proposed
Distribution Functional Revenue Requirements Total	$ 51,787,789	$ 60,999,465
Proposed Change to Revenue Requirement ($)		$ 9,211,676
Proposed Change to Revenue Requirement (%)		17.79%
Customer Charge Recovery ($)		$ 368,710
Demand Charge Recovery ($)		$ 48,505,833
Volumetric Charge Recovery ($)		$ 12,124,921
Customer Charge Recovery (%)	1%	1%
Demand Charge Recovery (%)	80%	80%
Volumetric Charge Recovery (%)	19%	20%

Delivery Service	(A) Billing Determinants	(B) Current Rate	(C) 5 Year EDIT Credit	(D) 10 Year EDIT Credit	(E) = A * (B+C+D) Present Revenue	(F) Billing Determinant Adjustment No.	(G) = H - A Weather Normalization	(H) Weather Normalized Billing Determinants	(I) = H * (B+C+D) Weather Normalized Revenue
Monthly Customer Charge	1,867	$ 187.64			$ 350,324		-	1,867	$ 350,324
Distribution									
Kilowatt-hour Charge									
Summer	1,102,431,669	$ 0.00454	$ (0.00007)	$ (0.00024)	$ 4,663,286	21	(26,326,034)	1,076,105,635	$ 4,551,927
Winter	1,244,208,828	$ 0.00453	$ (0.00007)	$ (0.00024)	$ 5,250,561	22	-	1,244,208,828	$ 5,250,561
Total kWh Charge	2,346,640,497				$ 9,913,847		(26,326,034)	2,320,314,463	$ 9,802,488
Demand Charge (Total kW)									
Summer	2,335,482	$ 8.86	$ (0.14)	$ (0.47)	$ 19,267,727		-	2,335,482	$ 19,267,727
Winter	2,644,583	$ 8.86	$ (0.14)	$ (0.47)	$ 21,817,810		-	2,644,583	$ 21,817,810
Total KW Charge	4,980,065				$ 41,085,536		-	4,980,065	$ 41,085,536
Total Distribution					**$ 51,349,707**				**$ 51,238,348**
BSA/Revenue Annualization					**$ 438,081**				
Total Annualized Authorized Revenue					**$ 51,787,789**				
Proposed Distribution Revenue Increase/Decrease									
Proposed Distribution Revenue									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Proposed Customer Charge									
Demand Charge Rate Design									
Present Demand Charge									
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)									
Calculated Demand Charge Increase									
Calculated Demand Charge									
Proposed Demand Charge									

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Schedule Time Metered General Service - Primary Service ("GT 3A")

		Proposed
Distribution Functional Revenue Requirements Total	$	60,999,465
Proposed Change to Revenue Requirement ($)	$	9,211,676
Proposed Change to Revenue Requirement (%)		17.79%
Customer Charge Recovery ($)	$	368,710
Demand Charge Recovery ($)	$	48,505,833
Volumetric Charge Recovery ($)	$	12,124,921
Customer Charge Recovery (%)		1%
Demand Charge Recovery (%)		80%
Volumetric Charge Recovery (%)		20%

Delivery Service	**(J)** = ($197.49 / B) -1 = [(O-((M+N)*H))) - (B*H)] / (B*H) = ($10.35 / B) -1 **Proposed Rate Increase (%)**	**(K)** = B*J **Proposed Rate Increase ($)**	**(L)** = B+K **Proposed Rate**	**(M)** **5 Year EDIT Credit**	**(N)** **10 Year EDIT Credit**	**(O)** = (1+J) * I = (L+M+N) * H **Proposed Revenue**
Monthly Customer Charge	5.25%	$ 9.85	$ 197.49			$ 368,710
Distribution						
Kilowatt-hour Charge						
Summer	22.07%	$0.00100	$0.00554	($0.00007)	($0.00024)	$ 5,630,382
Winter	22.07%	$0.00100	$0.00553	($0.00007)	($0.00024)	$ 6,494,539
Total kWh Charge						$ 12,124,921
Demand Charge (Total kW)						
Summer	16.82%	$ 1.49	$ 10.35	($0.14)	($0.47)	$ 22,747,595
Winter	16.82%	$ 1.49	$ 10.35	($0.14)	($0.47)	$ 25,758,238
Total KW Charge						$ 48,505,833
Total Distribution						
BSA/Revenue Annualization						
Total Annualized Authorized Revenue						
Proposed Distribution Revenue Increase/Decrease						**$ 9,211,676**
Proposed Distribution Revenue						**$ 60,999,465**
Percent Change						**17.79%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$**	**197.49**
Present Customer Charge	**$**	**187.64**
Proposed Customer Charge	**$**	**197.49**

Demand Charge Rate Design

Present Demand Charge	**$**	**8.86**	
Proportional Split of Residual Revenue Change following Customer Charge Rate Change between Demand and Volumetric based on Share of Revenue (%)		81%	= [$9,211,676 - ($368,710 - $350,324)] * ($41,085,536 / ($41,085,536 + $9,802,488)) / $9,211,676
Calculated Demand Charge Increase	$	1.49	= (80.58% * $9,211,676) / 4,980,065
Calculated Demand Charge	$	10.35	
Proposed Demand Charge	**$**	**10.35**	

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule- Rapid Transit Service ("RT")

	Current	Proposed
Distribution Functional Revenue Requirements Total	$ 6,739,348	$ 7,938,100
Proposed Change to Revenue Requirement ($)		$ 1,198,752
Proposed Change to Revenue Requirement (%)		17.79%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Annualized Authorized Revenue**
Monthly Customer Charge	1,164	$ 6,216.22	$ (96.57)	$ (329.83)	$ 6,739,350	$ 6,739,350
Total					$ 6,739,350	$ 6,739,350
BSA/Revenue Annualization						**$ (2)**
Total Annualized Authorized Revenue						**$ 6,739,348**
Proposed Distribution Revenue Increase/Decrease						
Proposed Distribution Revenue						
Percent Change						

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule- Rapid Transit Service ("RT")

	Current	Proposed
Distribution Functional Revenue Requirements Total	$ 6,739,348	$ 7,938,100
Proposed Change to Revenue Requirement ($)		$ 1,198,752
Proposed Change to Revenue Requirement (%)		17.79%

	(A)	(B)	(G) = (H / B)	(H) = I - B	(I) = [L - ((J+K)*A))] / A	(J)	(K)	(L) = $7,938,100
Delivery Service	**Billing Determinants**	**Current Rate**	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	1,164	$ 6,216.22	16.57%	$ 1,029.85	$ 7,246.07	$ (96.57)	$ (329.83)	$ 7,938,100
Total								$ 7,938,100
BSA/Revenue Annualization								
Total Annualized Authorized Revenue								
Proposed Distribution Revenue Increase/Decrease								**$ 1,198,752**
Proposed Distribution Revenue								**$ 7,938,100**
Percent Change								**17.79%**

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Servicing Street Lights -Schedules ("SSL-OH") & ("SSL-UG")

	Current	Proposed
Distribution Functional Revenue Requirements Total	$ 631,022	$ 819,562
Proposed Change to Revenue Requirement ($)		$ 188,539
Proposed Change to Revenue Requirement (%)		29.88%

	(A)	(B)	(C)	(D) = A * B	(E) = A * C	(F)	(G)	(H) = A *(B+C+F+G)
	Billing Determinants	CURRENT RATE FIXED	CURRENT RATE O & M	ANNUALIZED REVENUE FIXED	ANNUALIZED REVENUE O & M	5 Year EDIT Credit	10 Year EDIT Credit	TOTAL REVENUE
OVERHEAD								
INCANDESCENT								
Without GLOBE	144	$ 2.492	$ 0.039	$ 359	$ 6	$ (0.189)	$ (0.646)	$ 244
With GLOBE	12	$ 3.639	$ 0.860	$ 43.668	$ 10.320	$ (0.189)	$ (0.646)	$ 44
TOTAL INCANDESCENT	156							$ 288
MERCURY VAPOR								
175 WATT	0	$ 7.756	$ 0.767	$ -	$ -	$ (0.189)	$ (0.646)	$ -
250 WATT	0	$ 8.861	$ 0.777	$ -	$ -	$ (0.189)	$ (0.646)	$ -
TOTAL MERCURY VAPOR	0							$ -
METAL HALIDE								
400 WATT	12	$ 29.990	$ 1.253	$ 359.880	$ 15.036	$ (0.189)	$ (0.646)	$ 365
TOTAL METAL HALIDE	12							$ 365
TOTAL OVERHEAD	168							$ 653
UNDERGROUND								
INCANDESCENT								
With GLOBE	2,076	$ 34.870	$ 1.576	$ 72,390.120	$ 3,271.776	$ (0.189)	$ (0.646)	$ 73,928
TOTAL INCANDESCENT	2,076							$ 73,928
MERCURY VAPOR								
250 WATT	2,796	$ 35.171	$ 1.416	$ 98,338.116	$ 3,959.136	$ (0.189)	$ (0.646)	$ 99,963
400 WATT	336	$ 41.242	$ 1.759	$ 13,857.312	$ 591.024	$ (0.189)	$ (0.646)	$ 14,168
TOTAL MERCURY VAPOR	3,132							$ 114,130
HIGH PRESSURE SODIUM								
150 WATT	0	$ 30.843	$ 1.155	$ -	$ -	$ (0.189)	$ (0.646)	$ -
TOTAL HIGH PRESURE SODIUM	0							$ -
METAL HALIDE								
100 WATT	2,772	$ 26.578	$ 1.039	$ 73,674.216	$ 2,880.108	$ (0.189)	$ (0.646)	$ 74,240
175 WATT	12,504	$ 29.990	$ 1.253	$ 374,994.960	$ 15,667.512	$ (0.189)	$ (0.646)	$ 380,222
400 WATT	0	$ 29.990	$ 1.253	$ -	$ -	$ (0.189)	$ (0.646)	$ -
TOTAL METAL HALIDE	15,276							$ 454,461
TOTAL UNDERGROUND	20,484							$ 642,520
TOTAL OH & UG	**20,652**							**$ 643,173**

Total Distribution	**643,173**
BSA/Revenue Annualization	**(12,151)**
Total Annualized Authorized Revenue	**631,022**
Rate Component Change (%)	

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Servicing Street Lights -Schedules ("SSL-OH") & ("SSL-UG")

		Proposed
Distribution Functional Revenue Requirements Total	$	819,562
Proposed Change to Revenue Requirement ($)	$	188,539
Proposed Change to Revenue Requirement (%)		29.88%

	(I) = [(M-(K+L)*A)*D/(D+E)] / A	(J) = [(M-(K+L)*A)*E/(D+E)] / A	(K)	(L)	(M) = A *(I+J+K+L)
	PROPOSED RATE FIXED	PROPOSED RATE O & M	5 Year EDIT Credit	10 Year EDIT Credit	ANNUALIZED REVENUE
OVERHEAD					
INCANDESCENT					
Without GLOBE	$ 3.158	$ 0.049	$ (0.189)	$ (0.646)	$ 342
With GLOBE	$ 4.611	$ 1.090	$ (0.189)	$ (0.646)	$ 58
TOTAL INCANDESCENT					$ 400
MERCURY VAPOR					
175 WATT	$ 9.828	$ 0.972	$ (0.189)	$ (0.646)	$ -
250 WATT	$ 11.228	$ 0.985	$ (0.189)	$ (0.646)	$ -
TOTAL MERCURY VAPOR					$ -
METAL HALIDE					
400 WATT	$ 38.000	$ 1.588	$ (0.189)	$ (0.646)	$ 465
TOTAL METAL HALIDE					$ 465
TOTAL OVERHEAD					$ 865
UNDERGROUND					
INCANDESCENT					
With GLOBE	$ 44.183	$ 1.997	$ (0.189)	$ (0.646)	$ 94,137
TOTAL INCANDESCENT					$ 94,137
MERCURY VAPOR					
250 WATT	$ 44.565	$ 1.794	$ (0.189)	$ (0.646)	$ 127,285
400 WATT	$ 52.257	$ 2.229	$ (0.189)	$ (0.646)	$ 18,027
TOTAL MERCURY VAPOR					$ 145,312
HIGH PRESSURE SODIUM					
150 WATT	$ 39.081	$ 1.463	$ (0.189)	$ (0.646)	$ -
TOTAL HIGH PRESURE SODIUM					$ -
METAL HALIDE					
100 WATT	$ 33.677	$ 1.317	$ (0.189)	$ (0.646)	$ 94,686
175 WATT	$ 38.000	$ 1.588	$ (0.189)	$ (0.646)	$ 484,562
400 WATT	$ 38.000	$ 1.588	$ (0.189)	$ (0.646)	$ -
TOTAL METAL HALIDE					$ 579,249
TOTAL UNDERGROUND					$ 818,697
TOTAL OH & UG					**$ 819,562**
Total Distribution					$ -
BSA/Revenue Annualization					**$ 819,562**
Total Annualized Authorized Revenue					
Rate Component Change (%)					26.71%

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-Street Lighting Service Energy ("SL-E")	**Current**	**Proposed**
Distribution Functional Revenue Requirements Total	$ 463,974	$ 648,812
Proposed Change to Revenue Requirement ($)		$ 184,838
Proposed Change to Revenue Requirement (%)		39.84%
Customer Charge Recovery ($)	$ 5,597	$ 6,463
Volumetric Charge Recovery ($)	$ 458,378	$ 642,349
Customer Charge Recovery (%)	1%	1%
Volumetric Charge Recovery (%)	99%	99%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)
	Billing Determinants	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**
Delivery Service						
Monthly Customer Charge						
Metered Accounts	264	$ 17.19			$ 4,538	
Unmetered Accounts	72	$ 14.70			$ 1,058	
Kilowatt-hour Charge	79,310,898	$ 0.00615	$ (0.00004)	$ (0.00015)	$ 472,693	
	79,310,898					
Total Distribution					**$ 478,290**	
BSA/Revenue Annualization					**$ (14,315)**	
Total Annualized Authorized Revenue					**$ 463,974**	
Proposed Distribution Revenue Increase/Decrease						
Proposed Distribution Revenue						
Percent Change						
Customer Charge Rate Design						
Full Customer Cost from CCOSS						
Present Customer Charge						
Target Movement Toward Full Cost (%)						
Target Movement Toward Full Cost ($)						
Change to Present based on Target Movement Toward Full Cost						
Proposed Customer Charge (as % of Present)						

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-Street Lighting Service Energy ("SL-E")

		Proposed
Distribution Functional Revenue Requirements Total	$	648,812
Proposed Change to Revenue Requirement ($)	$	184,838
Proposed Change to Revenue Requirement (%)		39.84%
Customer Charge Recovery ($)	$	6,463
Volumetric Charge Recovery ($)	$	642,349
Customer Charge Recovery (%)		1%
Volumetric Charge Recovery (%)		99%

	(G) = (I / B) - 1 = [(L-((J+K)*A))) - (B*A)] / (B*A)	(H) = (115% * B) - B = B * G	(I) = B + H	(J)	(K)	(L) = A * (I+J+K)
	Proposed Rate Increase (%)	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Delivery Service						
Monthly Customer Charge						
Metered Accounts	15.47%	$ 2.66	$ 19.85			$ 5,240
Unmetered Accounts	15.47%	$ 2.27	$ 16.97			$ 1,222
Kilowatt-hour Charge	34.78%	$0.00214	$0.00829	$ (0.00004)	$ (0.00015)	$ 642,349
						$ 642,349
Total Distribution						
BSA/Revenue Annualization						
Total Annualized Authorized Revenue						
Proposed Distribution Revenue Increase/Decrease						**$ 184,838**
Proposed Distribution Revenue						**$ 648,812**
Percent Change						**39.84%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$**	**34.90**	
Present Customer Charge	**$**	**17.19**	
Target Movement Toward Full Cost (%)		15%	
Target Movement Toward Full Cost ($)	$	2.66	= 15% * ($34.9 - $17.19)
Change to Present based on Target Movement Toward Full Cost	$	19.85	
Proposed Customer Charge (as % of Present)		**115%**	= $19.85 / $17.19)

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-Traffic Signal Service ("TS")	**Current**	**RY1**
Distribution Functional Revenue Requirements Total	$ 208,323	$ 245,379
Proposed Change to Revenue Requirement ($)		$ 37,055
Proposed Change to Revenue Requirement (%)		17.79%
Customer Charge Recovery ($)	$ 289	$ 153
Volumetric Charge Recovery ($)	$ 208,034	$ 245,225
Customer Charge Recovery (%)	0%	0%
Volumetric Charge Recovery (%)	100%	100%

	(A)	**(B)**	**(C)**	**(D)**	**(E)** = A * (B+C+D)	**(F)**
	Billing Determinants	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**
Delivery Service						
Monthly Customer Charge	36	$ 8.03			$ 289	
Kilowatt-hour Charge	10,461,996	$ 0.02203	$ (0.00066)	$ (0.00226)	$ 199,929	
	10,461,996					
Total Distribution					**$ 200,218**	
BSA/Revenue Annualization					**$ 8,106**	
Total Annualized Authorized Revenue					**$ 208,323**	
Proposed Distribution Revenue Increase/Decrease						
Proposed Distribution Revenue						
Percent Change						
Customer Charge Rate Design						
Full Customer Cost from CCOSS						
Present Customer Charge						
Proposed Customer Charge						

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-Traffic Signal Service ("TS")		**RY1**
Distribution Functional Revenue Requirements Total	$	245,379
Proposed Change to Revenue Requirement ($)	$	37,055
Proposed Change to Revenue Requirement (%)		17.79%
Customer Charge Recovery ($)	$	153
Volumetric Charge Recovery ($)	$	245,225
Customer Charge Recovery (%)		0%
Volumetric Charge Recovery (%)		100%

	(G) = ($4.26 / B) -1 = [(L-((J+K)*A))) - (B*A)] / (B*A)	**(H)** = B * G	**(I)** = B + H	**(J)**	**(K)**	**(L)** = A * (I+J+K)
	Proposed Rate Increase (%)	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Delivery Service						
Monthly Customer Charge	-46.97%	$ (3.77)	$ 4.26			$ 153
Kilowatt-hour Charge	19.65%	$0.00433	$0.02636	$ (0.00066)	$ (0.00226)	$ 245,225
						$ 245,225
Total Distribution						
BSA/Revenue Annualization						
Total Annualized Authorized Revenue						
Proposed Distribution Revenue Increase/Decrease						**$ 37,055**
Proposed Distribution Revenue						**$ 245,379**
Percent Change						**17.79%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$**	**4.26**
Present Customer Charge	**$**	**8.03**
Proposed Customer Charge	**$**	**4.26**

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-Telecommunications Network Service ("TN")

	Current	Proposed
Distribution Functional Revenue Requirements Total	$ 71,978	$ 71,978
Proposed Change to Revenue Requirement ($)		$ -
Proposed Change to Revenue Requirement (%)		0.00%
Customer Charge Recovery ($)		$ 56,116
Volumetric Charge Recovery ($)		$ 15,861
Customer Charge Recovery (%)	76%	78%
Volumetric Charge Recovery (%)	24%	22%

	(A)	(B)	(C)	(D)	(E) = A * (B+C+D)	(F)	(G) = H - A	(H)	(I) = H * (B+C+D)
Delivery Service	**Billing Determinants**	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**	**Weather Normalization**	**Weather Normalized Billing Determinants**	**Weather Normalized Revenue**
Monthly Customer Charge	6,372	$ 15.43	$ (1.50001)	$ (5.12327)	$ 56,116		-	6,372	56,116
Distribution									
Summer Energy	1,111,220	$ 0.01288	$ (0.00140)	$ (0.00478)	$ 7,445	23	(33,585)	1,077,635	7,220
Winter Energy	1,539,728	$ 0.01288	$ (0.00140)	$ (0.00478)	$ 10,316	24	(14,129)	1,525,599	10,222
Total kWh Charge	2,650,948				$ 17,761		(47,714)	2,603,234	17,442
Total Distribution					**$ 73,878**				**$ 73,558**
BSA/Revenue Annualization					**$ (1,900)**				
Total Annualized Authorized Revenue					**$ 71,978**				
Proposed Distribution Revenue Increase/Decrease									
Proposed Distribution Revenue									
Percent Change									
Customer Charge Rate Design									
Full Customer Cost from CCOSS									
Present Customer Charge									
Proposed Customer Charge									

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-Telecommunications Network Service ("TN")

		Proposed
Distribution Functional Revenue Requirements Total	$	71,978
Proposed Change to Revenue Requirement ($)	$	-
Proposed Change to Revenue Requirement (%)		0.00%
Customer Charge Recovery ($)	$	56,116
Volumetric Charge Recovery ($)	$	15,861
Customer Charge Recovery (%)		78%
Volumetric Charge Recovery (%)		22%

	(J) = ($15.43 / B) -1 = [(O-((M+N)*H))) - (B*H)] / (B*H)	(K) = B*J	(L) = B+K	(M)	(N)	(O) = (1+J) * I = (L+M+N) * H
Delivery Service	**Proposed Rate Increase (%)**	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Monthly Customer Charge	0.00%	$ -	$ 15.43	$ (1.50001)	$ (5.12327)	$ 56,116
Distribution						
Summer Energy	-4.71%	($0.00061)	$ 0.01227	($0.00140)	($0.00478)	$ 6,566
Winter Energy	-4.71%	($0.00061)	$ 0.01227	($0.00140)	($0.00478)	$ 9,295
Total kWh Charge						$ 15,861
Total Distribution						
BSA/Revenue Annualization						
Total Annualized Authorized Revenue						
Proposed Distribution Revenue Increase/Decrease						**$ -**
Proposed Distribution Revenue						**$ 71,978**
Percent Change						**0.00%**

Customer Charge Rate Design

Full Customer Cost from CCOSS	**$**	**17.00**
Present Customer Charge	**$**	**15.43**
Proposed Customer Charge	**$**	**15.43**

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-LED Outdoor Lighting Service ("OL LED")	**Current**	**RY1**
Distribution Functional Revenue Requirements Total	$ -	-
Proposed Change to Revenue Requirement ($)		-
Proposed Change to Revenue Requirement (%)		-

	Billing Determinants	**Current Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Present Revenue**	**Billing Determinant Adjustment No.**
Delivery Service						
Monthly Customer Charge	-	$ 8.76			$ -	
Kilowatt-hour Charge	-	$ 0.00895	$ -	$ -	$ -	
	-				$ -	
Total					**$ -**	
Proposed Distribution Revenue Increase/Decrease						
Proposed Distribution Revenue						
Percent Change						

Pepco - District of Columbia
Development of Distribution Rates
Billing Data for 12 Months Actual Ending December 2018

Schedule-LED Outdoor Lighting Service ("OL LED")	**RY1**
Distribution Functional Revenue Requirements Total	-
Proposed Change to Revenue Requirement ($)	-
Proposed Change to Revenue Requirement (%)	-

	Proposed Rate Increase (%)	**Proposed Rate Increase ($)**	**Proposed Rate**	**5 Year EDIT Credit**	**10 Year EDIT Credit**	**Proposed Revenue**
Delivery Service						
Monthly Customer Charge	0.00%	$ -	$ 8.76			$ -
Kilowatt-hour Charge	0.00%	$0.00000	$ 0.00895	$ -	$ -	$ -
						$ -
Total						
Proposed Distribution Revenue Increase/Decrease						**$ -**
Proposed Distribution Revenue						**$ -**
Percent Change						**0.00%**

P.R. Blazunas
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (F) – 15

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED RATES
SCHEDULE "R"
DISTRICT OF COLUMBIA

	CURRENT RATES				PROPOSED RATES				INCREASE					
KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)	($)	(%)
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	ANNUAL	ANNUAL
0	17.03	17.11	-	-	20.80	20.88	-	-	3.77	3.77	22.14%	22.03%	3.77	22.08%
10	17.29	17.37	1.72928	1.73728	21.12	21.20	2.11173	2.11973	3.82	3.82	22.09%	21.99%	3.82	22.03%
20	17.56	17.64	0.87778	0.88178	21.43	21.51	1.07173	1.07573	3.88	3.88	22.10%	22.00%	3.88	22.04%
30	17.82	17.90	0.59394	0.59661	21.75	21.83	0.72507	0.72773	3.93	3.93	22.06%	21.96%	3.93	22.00%
40	18.74	18.84	0.46839	0.47105	22.72	22.83	0.56810	0.57076	3.99	3.99	21.30%	21.18%	3.99	21.23%
50	19.65	19.79	0.39306	0.39572	23.70	23.83	0.47392	0.47657	4.04	4.04	20.56%	20.42%	4.04	20.48%
100	24.24	24.50	0.24241	0.24505	28.56	28.82	0.28556	0.28820	4.32	4.32	17.82%	17.63%	4.32	17.71%
200	33.42	33.94	0.16708	0.16971	38.28	38.80	0.19138	0.19402	4.86	4.86	14.54%	14.32%	4.86	14.41%
300	42.59	43.38	0.14197	0.14460	48.00	48.79	0.15999	0.16262	5.41	5.41	12.70%	12.47%	5.41	12.57%
400	51.76	52.82	0.12941	0.13204	57.72	58.77	0.14429	0.14693	5.95	5.95	11.49%	11.27%	5.95	11.36%
500	62.31	62.99	0.12462	0.12598	69.75	69.99	0.13950	0.13999	7.44	7.00	11.94%	11.11%	7.18	11.46%
692	**82.56**	**82.52**	**0.11931**	**0.11925**	**92.86**	**91.54**	**0.13418**	**0.13228**	**10.30**	**9.02**	**12.48%**	**10.93%**	**9.55**	**11.57%**
700	83.40	83.34	0.11915	0.11905	93.82	92.44	0.13403	0.13206	10.41	9.10	12.48%	10.92%	9.65	11.57%
750	88.68	88.42	0.11824	0.11790	99.84	98.05	0.13311	0.13073	11.16	9.63	12.58%	10.89%	10.27	11.60%
800	93.95	93.51	0.11744	0.11689	105.85	103.66	0.13232	0.12958	11.90	10.15	12.67%	10.85%	10.88	11.61%
850	99.22	98.59	0.11673	0.11599	111.87	109.27	0.13161	0.12856	12.64	10.68	12.74%	10.83%	11.50	11.63%
900	104.50	103.68	0.11611	0.11520	117.89	114.88	0.13098	0.12765	13.39	11.20	12.81%	10.80%	12.11	11.64%
950	109.77	108.77	0.11555	0.11449	123.90	120.50	0.13042	0.12684	14.13	11.73	12.87%	10.78%	12.73	11.66%
1,000	115.04	113.85	0.11504	0.11385	129.92	126.11	0.12992	0.12611	14.87	12.25	12.93%	10.76%	13.34	11.67%
1,250	141.41	139.29	0.11313	0.11143	160.00	154.16	0.12800	0.12333	18.59	14.88	13.15%	10.68%	16.43	11.72%
1,500	167.78	164.72	0.11185	0.10981	190.09	182.22	0.12672	0.12148	22.31	17.50	13.30%	10.62%	19.50	11.75%
1,750	194.14	190.15	0.11094	0.10866	220.17	210.28	0.12581	0.12016	26.03	20.13	13.41%	10.59%	22.59	11.78%
2,000	220.51	215.58	0.11026	0.10779	250.26	238.33	0.12513	0.11917	29.74	22.75	13.49%	10.55%	25.66	11.79%
2,250	246.88	241.01	0.10972	0.10712	280.34	266.39	0.12460	0.11840	33.46	25.38	13.55%	10.53%	28.75	11.81%
2,500	273.24	266.44	0.10930	0.10658	310.42	294.45	0.12417	0.11778	37.18	28.00	13.61%	10.51%	31.83	11.82%
3,000	325.98	317.31	0.10866	0.10577	370.59	350.56	0.12353	0.11685	44.61	33.25	13.68%	10.48%	37.98	11.84%
3,500	378.71	368.17	0.10820	0.10519	430.76	406.67	0.12307	0.11619	52.05	38.50	13.74%	10.46%	44.15	11.85%
4,000	431.44	419.03	0.10786	0.10476	490.93	462.79	0.12273	0.11570	59.48	43.75	13.79%	10.44%	50.30	11.86%
5,000	536.91	520.76	0.10738	0.10415	611.26	575.01	0.12225	0.11500	74.35	54.25	13.85%	10.42%	62.63	11.87%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED RATES
SCHEDULE "MMA"
DISTRICT OF COLUMBIA

	CURRENT RATES				PROPOSED RATES				INCREASE					
KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)	($)	(%)
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	ANNUAL	ANNUAL
0	13.57	13.99	-	-	15.68	16.10	-	-	2.11	2.11	15.55%	15.08%	2.11	15.27%
100	20.10	21.48	0.20097	0.21482	22.37	23.75	0.22368	0.23753	2.27	2.27	11.30%	10.57%	2.27	10.86%
200	28.36	31.12	0.14181	0.15562	30.79	33.56	0.15396	0.16778	2.43	2.43	8.57%	7.81%	2.43	8.11%
300	36.62	40.77	0.12208	0.13588	39.22	43.36	0.13072	0.14453	2.59	2.59	7.07%	6.35%	2.59	6.63%
400	44.89	50.41	0.11222	0.12602	47.64	53.16	0.11910	0.13290	2.75	2.75	6.13%	5.46%	2.75	5.72%
500	54.40	60.72	0.10880	0.12143	57.42	63.69	0.11485	0.12738	3.02	2.97	5.55%	4.89%	2.99	5.15%
1000	101.97	112.27	0.10197	0.11227	106.33	116.33	0.10633	0.11633	4.36	4.06	4.28%	3.62%	4.19	3.88%
2000	197.11	215.36	0.09855	0.10768	204.15	221.61	0.10208	0.11080	7.05	6.25	3.58%	2.90%	6.58	3.17%
3000	292.25	318.46	0.09742	0.10615	301.97	326.89	0.10066	0.10896	9.73	8.43	3.33%	2.65%	8.97	2.92%
4000	387.38	421.56	0.09685	0.10539	399.79	432.17	0.09995	0.10804	12.41	10.61	3.20%	2.52%	11.36	2.79%
5000	482.52	524.65	0.09650	0.10493	497.61	537.45	0.09952	0.10749	15.09	12.79	3.13%	2.44%	13.75	2.71%
6000	577.66	627.75	0.09628	0.10463	595.43	642.73	0.09924	0.10712	17.78	14.98	3.08%	2.39%	16.15	2.66%
7000	672.79	730.85	0.09611	0.10441	693.25	748.01	0.09904	0.10686	20.46	17.16	3.04%	2.35%	18.54	2.62%
7500	720.36	782.40	0.09605	0.10432	742.16	800.65	0.09895	0.10675	21.80	18.25	3.03%	2.33%	19.73	2.61%
8000	767.93	833.95	0.09599	0.10424	791.07	853.29	0.09888	0.10666	23.14	19.34	3.01%	2.32%	20.92	2.59%
8500	815.50	885.49	0.09594	0.10418	839.98	905.93	0.09882	0.10658	24.48	20.43	3.00%	2.31%	22.12	2.58%
9000	863.07	937.04	0.09590	0.10412	888.89	958.57	0.09877	0.10651	25.82	21.52	2.99%	2.30%	23.31	2.57%
9500	910.64	988.59	0.09586	0.10406	937.80	1,011.21	0.09872	0.10644	27.16	22.61	2.98%	2.29%	24.51	2.56%
10000	958.21	1,040.14	0.09582	0.10401	986.71	1,063.85	0.09867	0.10638	28.51	23.71	2.98%	2.28%	25.71	2.56%
12500	1,196.05	1,297.88	0.09568	0.10383	1,231.26	1,327.04	0.09850	0.10616	35.21	29.16	2.94%	2.25%	31.68	2.52%
15000	1,433.89	1,555.63	0.09559	0.10371	1,475.81	1,590.24	0.09839	0.10602	41.92	34.62	2.92%	2.23%	37.66	2.50%
17500	1,671.73	1,813.37	0.09553	0.10362	1,720.36	1,853.44	0.09831	0.10591	48.62	40.07	2.91%	2.21%	43.63	2.49%
20000	1,909.58	2,071.11	0.09548	0.10356	1,964.91	2,116.64	0.09825	0.10583	55.33	45.53	2.90%	2.20%	49.61	2.48%
22500	2,147.42	2,328.86	0.09544	0.10350	2,209.46	2,379.84	0.09820	0.10577	62.04	50.99	2.89%	2.19%	55.59	2.47%
25000	2,385.26	2,586.60	0.09541	0.10346	2,454.01	2,643.04	0.09816	0.10572	68.74	56.44	2.88%	2.18%	61.57	2.46%
30000	2,860.95	3,102.08	0.09536	0.10340	2,943.11	3,169.44	0.09810	0.10565	82.16	67.35	2.87%	2.17%	73.52	2.45%
35000	3,336.64	3,617.57	0.09533	0.10336	3,432.21	3,695.84	0.09806	0.10560	95.57	78.27	2.86%	2.16%	85.48	2.44%
40000	3,812.32	4,133.06	0.09531	0.10333	3,921.30	4,222.24	0.09803	0.10556	108.98	89.18	2.86%	2.16%	97.43	2.44%
50000	4,763.69	5,164.03	0.09527	0.10328	4,899.50	5,275.03	0.09799	0.10550	135.81	111.00	2.85%	2.15%	121.34	2.43%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY

EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED RATES
SCHEDULE "GS ND"
DISTRICT OF COLUMBIA

	CURRENT RATES				PROPOSED RATES				INCREASE					
KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)	($)	(%)
	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	ANNUAL	ANNUAL
0	27.42	27.42	-	-	32.30	32.30	-	-	4.88	4.88	17.80%	17.80%	4.88	17.80%
10	28.64	28.57	2.86372	2.85710	33.60	33.51	3.35967	3.35109	4.96	4.94	17.32%	17.29%	4.95	17.30%
20	29.85	29.72	1.49272	1.48610	34.89	34.72	1.74467	1.73609	5.04	5.00	16.88%	16.82%	5.02	16.85%
30	31.07	30.87	1.03572	1.02910	36.19	35.93	1.20633	1.19776	5.12	5.06	16.48%	16.39%	5.09	16.43%
40	32.29	32.02	0.80722	0.80060	37.49	37.14	0.93717	0.92859	5.20	5.12	16.10%	15.99%	5.15	16.04%
50	33.51	33.18	0.67012	0.66350	38.78	38.35	0.77567	0.76709	5.28	5.18	15.76%	15.61%	5.22	15.67%
100	39.59	38.93	0.39592	0.38930	45.27	44.41	0.45267	0.44409	5.67	5.48	14.32%	14.08%	5.56	14.18%
150	45.68	44.69	0.30452	0.29790	51.75	50.46	0.34500	0.33642	6.07	5.78	13.29%	12.93%	5.90	13.08%
200	51.76	50.44	0.25882	0.25220	58.23	56.52	0.29117	0.28259	6.47	6.08	12.50%	12.05%	6.24	12.24%
250	57.85	56.20	0.23140	0.22478	64.72	62.57	0.25887	0.25029	6.87	6.38	11.88%	11.35%	6.58	11.57%
300	63.94	61.95	0.21312	0.20650	71.20	68.63	0.23733	0.22876	7.26	6.68	11.35%	10.78%	6.92	11.03%
400	76.11	73.46	0.19027	0.18365	84.17	80.74	0.21042	0.20184	8.06	7.27	10.59%	9.90%	7.60	10.19%
500	88.28	84.97	0.17656	0.16994	97.13	92.85	0.19427	0.18569	8.85	7.87	10.02%	9.26%	8.28	9.59%
600	100.45	96.48	0.16742	0.16080	110.10	104.95	0.18350	0.17492	9.65	8.47	9.61%	8.78%	8.96	9.13%
700	112.63	107.99	0.16090	0.15428	123.07	117.06	0.17581	0.16723	10.44	9.07	9.27%	8.40%	9.64	8.77%
800	124.80	119.50	0.15600	0.14938	136.03	129.17	0.17004	0.16147	11.23	9.67	9.00%	8.09%	10.32	8.48%
900	136.97	131.01	0.15219	0.14557	149.00	141.28	0.16556	0.15698	12.03	10.27	8.78%	7.84%	11.00	8.24%
1,000	149.14	142.52	0.14914	0.14252	161.97	153.39	0.16197	0.15339	12.82	10.87	8.60%	7.63%	11.68	8.04%
1,250	179.57	171.30	0.14366	0.13704	194.38	183.66	0.15551	0.14693	14.81	12.36	8.25%	7.22%	13.38	7.66%
1,500	210.01	200.08	0.14000	0.13338	226.80	213.94	0.15120	0.14262	16.79	13.86	8.00%	6.93%	15.08	7.38%
1,750	240.44	228.85	0.13739	0.13077	259.22	244.21	0.14812	0.13955	18.78	15.36	7.81%	6.71%	16.79	7.18%
2,000	270.87	257.63	0.13543	0.12881	291.63	274.48	0.14582	0.13724	20.77	16.85	7.67%	6.54%	18.48	7.02%
2,500	331.73	315.18	0.13269	0.12607	356.47	335.03	0.14259	0.13401	24.74	19.85	7.46%	6.30%	21.89	6.80%
3,000	392.59	372.73	0.13086	0.12424	421.30	395.57	0.14043	0.13186	28.71	22.84	7.31%	6.13%	25.29	6.64%
3,500	453.45	430.28	0.12956	0.12294	486.13	456.12	0.13890	0.13032	32.68	25.83	7.21%	6.00%	28.68	6.52%
4,000	514.31	487.83	0.12858	0.12196	550.97	516.66	0.13774	0.12917	36.65	28.83	7.13%	5.91%	32.09	6.43%
5,000	636.04	602.94	0.12721	0.12059	680.63	637.75	0.13613	0.12755	44.59	34.81	7.01%	5.77%	38.89	6.31%
6,000	757.76	718.04	0.12629	0.11967	810.30	758.84	0.13505	0.12647	52.54	40.80	6.93%	5.68%	45.69	6.22%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY

EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED RATES
SCHEDULE "GS D LV"
DISTRICT OF COLUMBIA

			CURRENT RATES				PROPOSED RATES				INCREASE			
KW	Hours	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
			SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
10	100	1000	220.28	227.20	0.22028	0.22720	243.85	249.32	0.24385	0.24932	23.57	22.12	10.70%	9.74%
	200	2000	330.28	344.12	0.16514	0.17206	359.85	370.78	0.17992	0.18539	29.57	26.66	8.95%	7.75%
	300	3000	440.29	461.05	0.14676	0.15368	475.85	492.25	0.15862	0.16408	35.56	31.20	8.08%	6.77%
	400	4000	550.30	577.98	0.13757	0.14449	591.85	613.72	0.14796	0.15343	41.55	35.74	7.55%	6.18%
	500	5000	660.30	694.90	0.13206	0.13898	707.85	735.19	0.14157	0.14704	47.55	40.28	7.20%	5.80%
	600	6000	770.31	811.83	0.12838	0.13530	823.85	856.65	0.13731	0.14278	53.54	44.82	6.95%	5.52%
25	100	2,500	497.94	515.24	0.19917	0.20609	551.50	565.17	0.22060	0.22607	53.56	49.93	10.76%	9.69%
	200	5,000	772.95	807.55	0.15459	0.16151	841.50	868.84	0.16830	0.17377	68.55	61.28	8.87%	7.59%
	300	7,500	1,047.97	1,099.87	0.13973	0.14665	1,131.50	1,172.50	0.15087	0.15633	83.53	72.64	7.97%	6.60%
	400	10,000	1,322.98	1,392.18	0.13230	0.13922	1,421.50	1,476.17	0.14215	0.14762	98.51	83.99	7.45%	6.03%
	500	12,500	1,598.00	1,684.50	0.12784	0.13476	1,711.50	1,779.84	0.13692	0.14239	113.50	95.34	7.10%	5.66%
	600	15,000	1,873.01	1,976.81	0.12487	0.13179	2,001.50	2,083.51	0.13343	0.13890	128.48	106.69	6.86%	5.40%
50	100	5,000	960.70	995.30	0.19214	0.19906	1,064.25	1,091.59	0.21285	0.21832	103.55	96.28	10.78%	9.67%
	200	10,000	1,510.73	1,579.93	0.15107	0.15799	1,644.25	1,698.92	0.16442	0.16989	133.51	118.99	8.84%	7.53%
	300	15,000	2,060.76	2,164.56	0.13738	0.14430	2,224.25	2,306.26	0.14828	0.15375	163.48	141.69	7.93%	6.55%
	400	20,000	2,610.80	2,749.20	0.13054	0.13746	2,804.24	2,913.59	0.14021	0.14568	193.45	164.40	7.41%	5.98%
	500	25,000	3,160.83	3,333.83	0.12643	0.13335	3,384.24	3,520.93	0.13537	0.14084	223.42	187.10	7.07%	5.61%
	600	30,000	3,710.86	3,918.46	0.12370	0.13062	3,964.24	4,128.27	0.13214	0.13761	253.38	209.81	6.83%	5.35%
75	100	7,500	1,423.47	1,475.37	0.18980	0.19672	1,577.00	1,618.00	0.21027	0.21573	153.53	142.64	10.79%	9.67%
	200	15,000	2,248.51	2,352.31	0.14990	0.15682	2,447.00	2,529.01	0.16313	0.16860	198.48	176.69	8.83%	7.51%
	300	22,500	3,073.56	3,229.26	0.13660	0.14352	3,316.99	3,440.01	0.14742	0.15289	243.43	210.75	7.92%	6.53%
	400	30,000	3,898.61	4,106.21	0.12995	0.13687	4,186.99	4,351.02	0.13957	0.14503	288.38	244.81	7.40%	5.96%
	500	37,500	4,723.66	4,983.16	0.12596	0.13288	5,056.99	5,262.02	0.13485	0.14032	333.33	278.86	7.06%	5.60%
	600	45,000	5,548.70	5,860.10	0.12330	0.13022	5,926.99	6,173.02	0.13171	0.13718	378.29	312.92	6.82%	5.34%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED RATES - DELIVERY ONLY
SCHEDULE "MGT LV "
DISTRICT OF COLUMBIA

HOURS		CURRENT RATES				PROPOSED RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**25 KW**				
200	5,000	863.77	863.77	0.17275	0.17275	737.38	737.38	0.14748	0.14748	(126.39)	(126.39)	-14.63%	-14.63%
300	7,500	929.15	929.15	0.12389	0.12389	809.57	809.57	0.10794	0.10794	(119.58)	(119.58)	-12.87%	-12.87%
400	10,000	994.53	994.53	0.09945	0.09945	881.76	881.76	0.08818	0.08818	(112.76)	(112.76)	-11.34%	-11.34%
500	12,500	1,059.91	1,059.91	0.08479	0.08479	953.95	953.95	0.07632	0.07632	(105.95)	(105.95)	-10.00%	-10.00%
600	15,000	1,125.28	1,125.28	0.07502	0.07502	1,026.14	1,026.14	0.06841	0.06841	(99.14)	(99.14)	-8.81%	-8.81%
									50 KW				
200	10,000	1,270.78	1,270.78	0.12708	0.12708	1,237.76	1,237.76	0.12378	0.12378	(33.01)	(33.01)	-2.60%	-2.60%
300	15,000	1,401.53	1,401.53	0.09344	0.09344	1,382.14	1,382.14	0.09214	0.09214	(19.39)	(19.39)	-1.38%	-1.38%
400	20,000	1,532.29	1,532.29	0.07661	0.07661	1,526.53	1,526.53	0.07633	0.07633	(5.77)	(5.77)	-0.38%	-0.38%
500	25,000	1,663.05	1,663.05	0.06652	0.06652	1,670.91	1,670.91	0.06684	0.06684	7.86	7.86	0.47%	0.47%
600	30,000	1,793.81	1,793.81	0.05979	0.05979	1,815.29	1,815.29	0.06051	0.06051	21.48	21.48	1.20%	1.20%
									75 KW				
200	15,000	1,677.78	1,677.78	0.11185	0.11185	1,738.14	1,738.14	0.11588	0.11588	60.36	60.36	3.60%	3.60%
300	22,500	1,873.92	1,873.92	0.08329	0.08329	1,954.72	1,954.72	0.08688	0.08688	80.80	80.80	4.31%	4.31%
400	30,000	2,070.06	2,070.06	0.06900	0.06900	2,171.29	2,171.29	0.07238	0.07238	101.23	101.23	4.89%	4.89%
500	37,500	2,266.20	2,266.20	0.06043	0.06043	2,387.86	2,387.86	0.06368	0.06368	121.67	121.67	5.37%	5.37%
600	45,000	2,462.33	2,462.33	0.05472	0.05472	2,604.44	2,604.44	0.05788	0.05788	142.11	142.11	5.77%	5.77%
									100 KW				
200	20,000	2,084.79	2,084.79	0.10424	0.10424	2,238.53	2,238.53	0.11193	0.11193	153.73	153.73	7.37%	7.37%
300	30,000	2,346.31	2,346.31	0.07821	0.07821	2,527.29	2,527.29	0.08424	0.08424	180.98	180.98	7.71%	7.71%
400	40,000	2,607.82	2,607.82	0.06520	0.06520	2,816.06	2,816.06	0.07040	0.07040	208.23	208.23	7.98%	7.98%
500	50,000	2,869.34	2,869.34	0.05739	0.05739	3,104.82	3,104.82	0.06210	0.06210	235.48	235.48	8.21%	8.21%
600	60,000	3,130.86	3,130.86	0.05218	0.05218	3,393.59	3,393.59	0.05656	0.05656	262.73	262.73	8.39%	8.39%

KWH DISTRIBUTION

		ON PK	INT	OFF PK
200	HOURS USE =	31%	29%	40%
300	HOURS USE =	33%	27%	40%
400	HOURS USE =	30%	26%	44%
500	HOURS USE =	27%	25%	48%
600	HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED RATES - DELIVERY ONLY
SCHEDULE "MGT LV "
DISTRICT OF COLUMBIA

HOURS		CURRENT RATES				PROPOSED RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**200 KW**				
200	40,000	3,712.82	3,712.82	0.09282	0.09282	4,240.06	4,240.06	0.10600	0.10600	527.23	527.23	14.20%	14.20%
300	60,000	4,235.86	4,235.86	0.07060	0.07060	4,817.59	4,817.59	0.08029	0.08029	581.73	581.73	13.73%	13.73%
400	80,000	4,758.89	4,758.89	0.05949	0.05949	5,395.11	5,395.11	0.06744	0.06744	636.22	636.22	13.37%	13.37%
500	100,000	5,281.92	5,281.92	0.05282	0.05282	5,972.64	5,972.64	0.05973	0.05973	690.72	690.72	13.08%	13.08%
600	120,000	5,804.95	5,804.95	0.04837	0.04837	6,550.17	6,550.17	0.05458	0.05458	745.22	745.22	12.84%	12.84%
									400 KW				
200	80,000	6,968.89	6,968.89	0.08711	0.08711	8,243.11	8,243.11	0.10304	0.10304	1,274.22	1,274.22	18.28%	18.28%
300	120,000	8,014.95	8,014.95	0.06679	0.06679	9,398.17	9,398.17	0.07832	0.07832	1,383.22	1,383.22	17.26%	17.26%
400	160,000	9,061.02	9,061.02	0.05663	0.05663	10,553.23	10,553.23	0.06596	0.06596	1,492.21	1,492.21	16.47%	16.47%
500	200,000	10,107.08	10,107.08	0.05054	0.05054	11,708.29	11,708.29	0.05854	0.05854	1,601.21	1,601.21	15.84%	15.84%
600	240,000	11,153.15	11,153.15	0.04647	0.04647	12,863.35	12,863.35	0.05360	0.05360	1,710.20	1,710.20	15.33%	15.33%
									600 KW				
200	120,000	10,224.95	10,224.95	0.08521	0.08521	12,246.17	12,246.17	0.10205	0.10205	2,021.22	2,021.22	19.77%	19.77%
300	180,000	11,794.05	11,794.05	0.06552	0.06552	13,978.76	13,978.76	0.07766	0.07766	2,184.71	2,184.71	18.52%	18.52%
400	240,000	13,363.15	13,363.15	0.05568	0.05568	15,711.35	15,711.35	0.06546	0.06546	2,348.20	2,348.20	17.57%	17.57%
500	300,000	14,932.25	14,932.25	0.04977	0.04977	17,443.94	17,443.94	0.05815	0.05815	2,511.69	2,511.69	16.82%	16.82%
600	360,000	16,501.34	16,501.34	0.04584	0.04584	19,176.53	19,176.53	0.05327	0.05327	2,675.18	2,675.18	16.21%	16.21%
									800 KW				
200	160,000	13,481.02	13,481.02	0.08426	0.08426	16,249.23	16,249.23	0.10156	0.10156	2,768.21	2,768.21	20.53%	20.53%
300	240,000	15,573.15	15,573.15	0.06489	0.06489	18,559.35	18,559.35	0.07733	0.07733	2,986.20	2,986.20	19.18%	19.18%
400	320,000	17,665.28	17,665.28	0.05520	0.05520	20,869.47	20,869.47	0.06522	0.06522	3,204.19	3,204.19	18.14%	18.14%
500	400,000	19,757.41	19,757.41	0.04939	0.04939	23,179.59	23,179.59	0.05795	0.05795	3,422.18	3,422.18	17.32%	17.32%
600	480,000	21,849.54	21,849.54	0.04552	0.04552	25,489.70	25,489.70	0.05310	0.05310	3,640.16	3,640.16	16.66%	16.66%

KWH DISTRIBUTION

		ON PK	INT	OFF PK
200	HOURS USE =	31%	29%	40%
300	HOURS USE =	33%	27%	40%
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POTOMAC ELECTRIC POWER COMPANY

EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED RATES - DELIVERY ONLY
SCHEDULE "GT LV "
DISTRICT OF COLUMBIA

HOURS		CURRENT RATES				PROPOSED RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**100 KW**				
200	20,000	2,111.57	2,111.57	0.10558	0.10558	2,816.67	2,816.67	0.14083	0.14083	705.10	705.10	33.39%	33.39%
300	30,000	2,386.48	2,386.48	0.07955	0.07955	3,108.20	3,108.20	0.10361	0.10361	721.72	721.72	30.24%	30.24%
400	40,000	2,661.38	2,661.38	0.06653	0.06653	3,399.73	3,399.73	0.08499	0.08499	738.35	738.35	27.74%	27.74%
500	50,000	2,936.29	2,936.29	0.05873	0.05873	3,691.26	3,691.26	0.07383	0.07383	754.98	754.98	25.71%	25.71%
600	60,000	3,211.19	3,211.19	0.05352	0.05352	3,982.79	3,982.79	0.06638	0.06638	771.60	771.60	24.03%	24.03%
									300 KW				
200	60,000	5,421.19	5,421.19	0.09035	0.09035	6,568.79	6,568.79	0.10948	0.10948	1,147.60	1,147.60	21.17%	21.17%
300	90,000	6,245.91	6,245.91	0.06940	0.06940	7,443.39	7,443.39	0.08270	0.08270	1,197.49	1,197.49	19.17%	19.17%
400	120,000	7,070.62	7,070.62	0.05892	0.05892	8,317.99	8,317.99	0.06932	0.06932	1,247.37	1,247.37	17.64%	17.64%
500	150,000	7,895.34	7,895.34	0.05264	0.05264	9,192.58	9,192.58	0.06128	0.06128	1,297.25	1,297.25	16.43%	16.43%
600	180,000	8,720.05	8,720.05	0.04844	0.04844	10,067.18	10,067.18	0.05593	0.05593	1,347.13	1,347.13	15.45%	15.45%
									500 KW				
200	100,000	8,730.81	8,730.81	0.08731	0.08731	10,320.92	10,320.92	0.10321	0.10321	1,590.11	1,590.11	18.21%	18.21%
300	150,000	10,105.34	10,105.34	0.06737	0.06737	11,778.58	11,778.58	0.07852	0.07852	1,673.25	1,673.25	16.56%	16.56%
400	200,000	11,479.86	11,479.86	0.05740	0.05740	13,236.25	13,236.25	0.06618	0.06618	1,756.38	1,756.38	15.30%	15.30%
500	250,000	12,854.39	12,854.39	0.05142	0.05142	14,693.91	14,693.91	0.05878	0.05878	1,839.52	1,839.52	14.31%	14.31%
600	300,000	14,228.91	14,228.91	0.04743	0.04743	16,151.57	16,151.57	0.05384	0.05384	1,922.65	1,922.65	13.51%	13.51%
									1,000 KW				
200	200,000	17,004.86	17,004.86	0.08502	0.08502	19,701.25	19,701.25	0.09851	0.09851	2,696.38	2,696.38	15.86%	15.86%
300	300,000	19,753.91	19,753.91	0.06585	0.06585	22,616.57	22,616.57	0.07539	0.07539	2,862.65	2,862.65	14.49%	14.49%
400	400,000	22,502.97	22,502.97	0.05626	0.05626	25,531.89	25,531.89	0.06383	0.06383	3,028.93	3,028.93	13.46%	13.46%
500	500,000	25,252.02	25,252.02	0.05050	0.05050	28,447.21	28,447.21	0.05689	0.05689	3,195.20	3,195.20	12.65%	12.65%
600	600,000	28,001.07	28,001.07	0.04667	0.04667	31,362.54	31,362.54	0.05227	0.05227	3,361.47	3,361.47	12.00%	12.00%

KWH DISTRIBUTION

		ON PK	INT	OFF PK
200	HOURS USE =	31%	29%	40%
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POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED RATES - DELIVERY ONLY
SCHEDULE "GT LV "
DISTRICT OF COLUMBIA

HOURS		CURRENT RATES				PROPOSED RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**2,000 KW**				
200	400,000	33,552.97	33,552.97	0.08388	0.08388	38,461.89	38,461.89	0.09615	0.09615	4,908.93	4,908.93	14.63%	14.63%
300	600,000	39,051.07	39,051.07	0.06509	0.06509	44,292.54	44,292.54	0.07382	0.07382	5,241.47	5,241.47	13.42%	13.42%
400	800,000	44,549.17	44,549.17	0.05569	0.05569	50,123.18	50,123.18	0.06265	0.06265	5,574.01	5,574.01	12.51%	12.51%
500	1,000,000	50,047.27	50,047.27	0.05005	0.05005	55,953.82	55,953.82	0.05595	0.05595	5,906.55	5,906.55	11.80%	11.80%
600	1,200,000	55,545.38	55,545.38	0.04629	0.04629	61,784.47	61,784.47	0.05149	0.05149	6,239.09	6,239.09	11.23%	11.23%
									4,000 KW				
200	800,000	66,649.17	66,649.17	0.08331	0.08331	75,983.18	75,983.18	0.09498	0.09498	9,334.01	9,334.01	14.00%	14.00%
300	1,200,000	77,645.38	77,645.38	0.06470	0.06470	87,644.47	87,644.47	0.07304	0.07304	9,999.09	9,999.09	12.88%	12.88%
400	1,600,000	88,641.58	88,641.58	0.05540	0.05540	99,305.76	99,305.76	0.06207	0.06207	10,664.18	10,664.18	12.03%	12.03%
500	2,000,000	99,637.79	99,637.79	0.04982	0.04982	110,967.05	110,967.05	0.05548	0.05548	11,329.26	11,329.26	11.37%	11.37%
600	2,400,000	110,633.99	110,633.99	0.04610	0.04610	122,628.34	122,628.34	0.05110	0.05110	11,994.34	11,994.34	10.84%	10.84%
									6,000 KW				
200	1,200,000	99,745.38	99,745.38	0.08312	0.08312	113,504.47	113,504.47	0.09459	0.09459	13,759.09	13,759.09	13.79%	13.79%
300	1,800,000	116,239.68	116,239.68	0.06458	0.06458	130,996.40	130,996.40	0.07278	0.07278	14,756.72	14,756.72	12.70%	12.70%
400	2,400,000	132,733.99	132,733.99	0.05531	0.05531	148,488.34	148,488.34	0.06187	0.06187	15,754.34	15,754.34	11.87%	11.87%
500	3,000,000	149,228.30	149,228.30	0.04974	0.04974	165,980.27	165,980.27	0.05533	0.05533	16,751.97	16,751.97	11.23%	11.23%
600	3,600,000	165,722.61	165,722.61	0.04603	0.04603	183,472.21	183,472.21	0.05096	0.05096	17,749.60	17,749.60	10.71%	10.71%
									8,000 KW				
200	1,600,000	132,841.58	132,841.58	0.08303	0.08303	151,025.76	151,025.76	0.09439	0.09439	18,184.18	18,184.18	13.69%	13.69%
300	2,400,000	154,833.99	154,833.99	0.06451	0.06451	174,348.34	174,348.34	0.07265	0.07265	19,514.34	19,514.34	12.60%	12.60%
400	3,200,000	176,826.40	176,826.40	0.05526	0.05526	197,670.92	197,670.92	0.06177	0.06177	20,844.51	20,844.51	11.79%	11.79%
500	4,000,000	198,818.82	198,818.82	0.04970	0.04970	220,993.49	220,993.49	0.05525	0.05525	22,174.68	22,174.68	11.15%	11.15%
600	4,800,000	220,811.23	220,811.23	0.04600	0.04600	244,316.07	244,316.07	0.05090	0.05090	23,504.85	23,504.85	10.64%	10.64%

KWH DISTRIBUTION

		ON PK	INT	OFF PK
200	HOURS USE =	31%	29%	40%
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POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED RATES - DELIVERY ONLY
SCHEDULE "GT 3A "
DISTRICT OF COLUMBIA

HOURS		CURRENT RATES				PROPOSED RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**1,000 KW**				
200	200,000	12,268.82	12,266.82	0.06134	0.06133	13,931.76	13,929.29	0.06966	0.06965	1,662.95	1,662.47	13.55%	13.55%
300	300,000	14,184.41	14,181.41	0.04728	0.04727	15,928.90	15,925.19	0.05310	0.05308	1,744.50	1,743.79	12.30%	12.30%
400	400,000	16,099.99	16,095.99	0.04025	0.04024	17,926.04	17,921.09	0.04482	0.04480	1,826.05	1,825.10	11.34%	11.34%
500	500,000	18,015.58	18,010.58	0.03603	0.03602	19,923.18	19,917.00	0.03985	0.03983	1,907.60	1,906.41	10.59%	10.58%
600	600,000	19,931.17	19,925.17	0.03322	0.03321	21,920.32	21,912.90	0.03653	0.03652	1,989.15	1,987.73	9.98%	9.98%
									2,000 KW				
200	400,000	24,349.99	24,345.99	0.06087	0.06086	27,666.04	27,661.09	0.06917	0.06915	3,316.05	3,315.10	13.62%	13.62%
300	600,000	28,181.17	28,175.17	0.04697	0.04696	31,660.32	31,652.90	0.05277	0.05275	3,479.15	3,477.73	12.35%	12.34%
400	800,000	32,012.35	32,004.35	0.04002	0.04001	35,654.59	35,644.70	0.04457	0.04456	3,642.25	3,640.35	11.38%	11.37%
500	1,000,000	35,843.52	35,833.52	0.03584	0.03583	39,648.87	39,636.50	0.03965	0.03964	3,805.35	3,802.98	10.62%	10.61%
600	1,200,000	39,674.70	39,662.70	0.03306	0.03305	43,643.15	43,628.31	0.03637	0.03636	3,968.45	3,965.60	10.00%	10.00%
									5,000 KW				
200	1,000,000	60,593.52	60,583.52	0.06059	0.06058	68,868.87	68,856.50	0.06887	0.06886	8,275.35	8,272.98	13.66%	13.66%
300	1,500,000	70,171.47	70,156.47	0.04678	0.04677	78,854.56	78,836.01	0.05257	0.05256	8,683.10	8,679.54	12.37%	12.37%
400	2,000,000	79,749.41	79,729.41	0.03987	0.03986	88,840.26	88,815.52	0.04442	0.04441	9,090.85	9,086.11	11.40%	11.40%
500	2,500,000	89,327.35	89,302.35	0.03573	0.03572	98,825.95	98,795.02	0.03953	0.03952	9,498.60	9,492.67	10.63%	10.63%
600	3,000,000	98,905.29	98,875.29	0.03297	0.03296	108,811.64	108,774.53	0.03627	0.03626	9,906.35	9,899.24	10.02%	10.01%
									7,500 KW				
200	1,500,000	90,796.47	90,781.47	0.06053	0.06052	103,204.56	103,186.01	0.06880	0.06879	12,408.10	12,404.54	13.67%	13.66%
300	2,250,000	105,163.38	105,140.88	0.04674	0.04673	118,183.10	118,155.27	0.05253	0.05251	13,019.72	13,014.39	12.38%	12.38%
400	3,000,000	119,530.29	119,500.29	0.03984	0.03983	133,161.64	133,124.53	0.04439	0.04437	13,631.35	13,624.24	11.40%	11.40%
500	3,750,000	133,897.21	133,859.71	0.03571	0.03570	148,140.18	148,093.79	0.03950	0.03949	14,242.97	14,234.09	10.64%	10.63%
600	4,500,000	148,264.12	148,219.12	0.03295	0.03294	163,118.71	163,063.05	0.03625	0.03624	14,854.59	14,843.93	10.02%	10.01%

KWH DISTRIBUTION

	ON PK	INT	OFF PK
200 HOURS USE =	31%	29%	40%
300 HOURS USE =	33%	27%	40%
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POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED RATES - DELIVERY ONLY
SCHEDULE "GT 3A "
DISTRICT OF COLUMBIA

HOURS		CURRENT RATES				PROPOSED RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**10,000 KW**				
200	2,000,000	120,999.41	120,979.41	0.06050	0.06049	137,540.26	137,515.52	0.06877	0.06876	16,540.85	16,536.11	13.67%	13.67%
300	3,000,000	140,155.29	140,125.29	0.04672	0.04671	157,511.64	157,474.53	0.05250	0.05249	17,356.35	17,349.24	12.38%	12.38%
400	4,000,000	159,311.18	159,271.18	0.03983	0.03982	177,483.02	177,433.55	0.04437	0.04436	18,171.84	18,162.37	11.41%	11.40%
500	5,000,000	178,467.06	178,417.06	0.03569	0.03568	197,454.41	197,392.56	0.03949	0.03948	18,987.34	18,975.50	10.64%	10.64%
600	6,000,000	197,622.95	197,562.95	0.03294	0.03293	217,425.79	217,351.57	0.03624	0.03623	19,802.84	19,788.63	10.02%	10.02%
									20,000 KW				
200	4,000,000	241,811.18	241,771.18	0.06045	0.06044	274,883.02	274,833.55	0.06872	0.06871	33,071.84	33,062.37	13.68%	13.68%
300	6,000,000	280,122.95	280,062.95	0.04669	0.04668	314,825.79	314,751.57	0.05247	0.05246	34,702.84	34,688.63	12.39%	12.39%
400	8,000,000	318,434.72	318,354.72	0.03980	0.03979	354,768.56	354,669.60	0.04435	0.04433	36,333.84	36,314.89	11.41%	11.41%
500	10,000,000	356,746.48	356,646.48	0.03567	0.03566	394,711.32	394,587.63	0.03947	0.03946	37,964.84	37,941.15	10.64%	10.64%
600	12,000,000	395,058.25	394,938.25	0.03292	0.03291	434,654.09	434,505.66	0.03622	0.03621	39,595.84	39,567.41	10.02%	10.02%
									30,000 KW				
200	6,000,000	362,622.95	362,562.95	0.06044	0.06043	412,225.79	412,151.57	0.06870	0.06869	49,602.84	49,588.63	13.68%	13.68%
300	9,000,000	420,090.60	420,000.60	0.04668	0.04667	472,139.94	472,028.62	0.05246	0.05245	52,049.34	52,028.02	12.39%	12.39%
400	12,000,000	477,558.25	477,438.25	0.03980	0.03979	532,054.09	531,905.66	0.04434	0.04433	54,495.84	54,467.41	11.41%	11.41%
500	15,000,000	535,025.91	534,875.91	0.03567	0.03566	591,968.24	591,782.70	0.03946	0.03945	56,942.33	56,906.80	10.64%	10.64%
600	18,000,000	592,493.56	592,313.56	0.03292	0.03291	651,882.39	651,659.75	0.03622	0.03620	59,388.83	59,346.19	10.02%	10.02%
									40,000 KW				
200	8,000,000	483,434.72	483,354.72	0.06043	0.06042	549,568.56	549,469.60	0.06870	0.06868	66,133.84	66,114.89	13.68%	13.68%
300	12,000,000	560,058.25	559,938.25	0.04667	0.04666	629,454.09	629,305.66	0.05245	0.05244	69,395.84	69,367.41	12.39%	12.39%
400	16,000,000	636,681.79	636,521.79	0.03979	0.03978	709,339.62	709,141.72	0.04433	0.04432	72,657.83	72,619.93	11.41%	11.41%
500	20,000,000	713,305.33	713,105.33	0.03567	0.03566	789,225.16	788,977.77	0.03946	0.03945	75,919.83	75,872.45	10.64%	10.64%
600	24,000,000	789,928.87	789,688.87	0.03291	0.03290	869,110.69	868,813.83	0.03621	0.03620	79,181.83	79,124.96	10.02%	10.02%

KWH DISTRIBUTION

	ON PK	INT	OFF PK
200 HOURS USE =	31%	29%	40%
300 HOURS USE =	33%	27%	40%
400 HOURS USE =	30%	26%	44%
500 HOURS USE =	27%	25%	48%
600 HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

POTOMAC ELECTRIC POWER COMPANY
EXAMPLES COMPARING BILLS UNDER PRESENT AND PROPOSED RATES - DELIVERY ONLY
SCHEDULE "GT 3B "
DISTRICT OF COLUMBIA

HOURS		CURRENT RATES				PROPOSED RATES				INCREASE			
USE	KWH	$ AMOUNT OF BILL		$/KWH		$ AMOUNT OF BILL		$/KWH		($)	($)	(%)	(%)
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
						MAXIMUM AND ON PEAK DEMAND =			**10,000 KW**				
200	2,000,000	37,090.10	37,890.10	0.01855	0.01895	38,025.85	38,855.39	0.01901	0.01943	935.75	965.30	2.52%	2.55%
300	3,000,000	49,523.46	50,323.46	0.01651	0.01677	50,765.05	51,594.59	0.01692	0.01720	1,241.59	1,271.14	2.51%	2.53%
400	4,000,000	61,956.82	62,756.82	0.01549	0.01569	63,504.25	64,333.79	0.01588	0.01608	1,547.43	1,576.98	2.50%	2.51%
500	5,000,000	74,390.18	75,190.18	0.01488	0.01504	76,243.45	77,072.99	0.01525	0.01541	1,853.27	1,882.82	2.49%	2.50%
600	6,000,000	86,823.54	87,623.54	0.01447	0.01460	88,982.65	89,812.19	0.01483	0.01497	2,159.11	2,188.66	2.49%	2.50%
									20,000 KW				
200	4,000,000	73,756.82	75,356.82	0.01844	0.01884	75,740.04	77,399.13	0.01894	0.01935	1,983.23	2,042.32	2.69%	2.71%
300	6,000,000	98,623.54	100,223.54	0.01644	0.01670	101,218.44	102,877.53	0.01687	0.01715	2,594.91	2,654.00	2.63%	2.65%
400	8,000,000	123,490.26	125,090.26	0.01544	0.01564	126,696.84	128,355.93	0.01584	0.01604	3,206.59	3,265.68	2.60%	2.61%
500	10,000,000	148,356.98	149,956.98	0.01484	0.01500	152,175.24	153,834.33	0.01522	0.01538	3,818.27	3,877.36	2.57%	2.59%
600	12,000,000	173,223.69	174,823.69	0.01444	0.01457	177,653.64	179,312.73	0.01480	0.01494	4,429.95	4,489.04	2.56%	2.57%
									30,000 KW				
200	6,000,000	110,423.54	112,823.54	0.01840	0.01880	113,454.24	115,942.87	0.01891	0.01932	3,030.70	3,119.34	2.74%	2.76%
300	9,000,000	147,723.62	150,123.62	0.01641	0.01668	151,671.84	154,160.47	0.01685	0.01713	3,948.22	4,036.86	2.67%	2.69%
400	12,000,000	185,023.69	187,423.69	0.01542	0.01562	189,889.44	192,378.07	0.01582	0.01603	4,865.74	4,954.38	2.63%	2.64%
500	15,000,000	222,323.77	224,723.77	0.01482	0.01498	228,107.04	230,595.67	0.01521	0.01537	5,783.26	5,871.90	2.60%	2.61%
600	18,000,000	259,623.85	262,023.85	0.01442	0.01456	266,324.64	268,813.27	0.01480	0.01493	6,700.79	6,789.42	2.58%	2.59%
									40,000 KW				
200	8,000,000	147,090.26	150,290.26	0.01839	0.01879	151,168.43	154,486.61	0.01890	0.01931	4,078.17	4,196.36	2.77%	2.79%
300	12,000,000	196,823.69	200,023.69	0.01640	0.01667	202,125.23	205,443.41	0.01684	0.01712	5,301.54	5,419.72	2.69%	2.71%
400	16,000,000	246,557.13	249,757.13	0.01541	0.01561	253,082.03	256,400.21	0.01582	0.01603	6,524.90	6,643.08	2.65%	2.66%
500	20,000,000	296,290.57	299,490.57	0.01481	0.01497	304,038.83	307,357.01	0.01520	0.01537	7,748.26	7,866.44	2.62%	2.63%
600	24,000,000	346,024.01	349,224.01	0.01442	0.01455	354,995.63	358,313.81	0.01479	0.01493	8,971.62	9,089.80	2.59%	2.60%

KWH DISTRIBUTION

	ON PK	INT	OFF PK
200 HOURS USE =	31%	29%	40%
300 HOURS USE =	33%	27%	40%
400 HOURS USE =	30%	26%	44%
500 HOURS USE =	27%	25%	48%
600 HOURS USE =	25%	24%	51%

Note: Generally representative of the customer's bill under current rates including seasonal SOS rates effective in June (Summer) and November (Winter) of 2019.

P.R. Blazunas
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (F) – 16

CLEAN

RATE SCHEDULES

FOR

ELECTRIC SERVICE

IN THE

DISTRICT OF COLUMBIA

An Exelon Company

RATES AND REGULATORY PRACTICES GROUP

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RESIDENTIAL SERVICE

SCHEDULE "R"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for low voltage electric service where the use is primarily for residential purposes and for farm operations where the electricity for both farm and residential purposes is delivered through the same meter.

Available only in individual residences and in individually metered dwelling units in multi-family buildings.

Not available for residential premises in which five (5) or more rooms are for hire.

Not available for seasonal loads metered separately from lighting and other usage in the same occupancy.

Not available for temporary, auxiliary or emergency service.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, three wire, 120/240 volts, or three wire, 120/208 volts.

MONTHLY RATE

	Summer	**Winter**
Distribution Service Charge		
Customer Charge – Residential	$ 18.86 per month	$ 18.86 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ 0.01307 per kwhr	$ 0.01307 per kwhr
In excess of 400 kilowatt hours	$ 0.03731 per kwhr	$ 0.02605 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Service from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.62 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS
Standard Offer Service - Residential
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount
Optional Meter Equipment Related Services
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Residential Direct Load Control Rider
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

MASTER METERED APARTMENT SERVICE
SCHEDULE "MMA"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for low voltage electric service for multiple application to master-metered apartment buildings where the use is predominantly residential and not for retail business establishments. Not available for separately metered service billed on Schedule "GS ND" that did not qualify for multiple application of the residential rate as of December 31, 1982.

Not available for seasonal loads metered separately from lighting and other usage in the same occupancy.

Not available for temporary, auxiliary or emergency service.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, three wire, 120/240 volts, or three wire, 120/208 volts.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$13.95 per month	$13.95 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ 0.00949 per kwhr	$ 0.00949 per kwhr
In excess of 400 kilowatt hours	$ 0.02707 per kwhr	$ 0.01889 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Service from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.62 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

DC - MMA

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS
Standard Offer Service - Residential
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Optional Meter Equipment Related Services
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Residential Direct Load Control Rider
Underground Project Charge
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

GENERAL SERVICE – NON DEMAND

SCHEDULE "GS ND"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for "GS LV" customers whose maximum monthly demand is less than 25 kW. Customers whose maximum demand is between 25 kW and 99 kW will be served on Schedule GS LV or GS 3A subject to the provisions stated therein. Customers whose maximum demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months will be transferred to Schedule "GT LV", "GT 3A", or "GT 3B" in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz and for primary service furnished directly from the Company's electric system at voltages of 4.16 kV, 13.2 kV, or 33 kV, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnects, regulators and protective equipment.

Not available for railway propulsion service.

Not available for secondary temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts for GS Low Voltage Non Demand customers. For GS 3A Non Demand customers, the service under this schedule, normally will be alternating current, sixty hertz, three phase, three wire, at 4.16kV, 13.2kV or 33 kV. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Summer	Winter
GS LOW VOLTAGE NON DEMAND		
Distribution Service Charge		
Customer Charge	$ 32.30 per month	$ 32.30 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.05074 per kwhr	$ 0.03971 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

DC - GS ND

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

Demand metering equipment will be installed and charges subsequent to the installation of this equipment will be computed under the billing demand provision when the customer's load is of such a magnitude and of such a nature as to indicate any of the following:

1. Monthly energy consumption in excess of 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive).

2. Monthly energy consumption in excess of 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive).

3. A monthly demand greater than or equal to twenty-five (25) kilowatts in a single month.

Demand accounts are reviewed annually. The account will be billed under non-demand billing provision when the consumption for each of the previous twelve (12) months is below 6,000 kilowatt-hours and the demand is less than twenty-five (25) kilowatts.

BILLING DEMAND

The billing demand shall be the maximum thirty (30) minute demand recorded during the month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Small Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

GENERAL SERVICE - LOW VOLTAGE

SCHEDULE "GS LV"

AVAILABILITY
Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area, except if the customer's maximum demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months, the customer will be transferred to Schedule "GT LV", "GT 3A", or "GT 3B" in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June. Customers with monthly maximum demands less than 25 kW are served on Schedule "GS ND" subject to the provisions stated therein.

Available for low voltage electric service at sixty hertz.

Not available for railway propulsion service.

Not available for secondary temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 38.75 per month	$ 38.75 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.03406 per kwhr	$ 0.02581 per kwhr
Demand Charge	$ 9.46 per kw	$ 9.46 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

Demand metering equipment will be installed and charges subsequent to the installation of this equipment will be computed under the billing demand provision when the customer's load is of such a magnitude and of such a nature as to indicate any of the following:

1. Monthly energy consumption in excess of 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive).

2. Monthly energy consumption in excess of 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive).

3. A monthly demand greater than or equal to twenty-five (25) kilowatts in a single month.

Demand accounts are reviewed annually. The account will be billed under non-demand billing provision when the consumption for each of the previous twelve (12) months is below 6,000 kilowatt-hours and the demand is less than twenty-five (25) kilowatts.

BILLING DEMAND

The billing demand shall be the maximum thirty (30) minute demand recorded during the month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

GENERAL SERVICE - PRIMARY SERVICE

SCHEDULE "GS 3A"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS", or Distribution Service in the District of Columbia portion of the Company's service area, except if the customer's maximum demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months, the customer will be transferred to Schedule "GT LV", "GT 3A", or "GT 3B" in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June. Customers with monthly maximum demands less than 25 kW are served on Schedule "GS ND" subject to the provisions stated therein.

Available for primary service furnished directly from the Company's electric system at voltages of 4.16 kV, 13.2 kV or 33 kV, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnects, regulators and protective equipment.

Not available for railway propulsion service.

Not available for secondary temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

CHARACTER OF SERVICE

The service under this schedule, normally will be alternating current, sixty hertz, three phase, three wire, at 4.16kV, 13.2kV or 33kV. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 89.41 per month	$ 89.41 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ 0.02208 per kwhr	$ 0.01587 per kwhr
Demand Charge	$ 10.82 per kw	$ 10.82 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

Demand metering equipment will be installed and charges subsequent to the installation of this equipment will be computed under the demand billing provision when the customer's load is of such a magnitude and of such a nature as to indicate any of the following:

1. Monthly energy consumption in excess of 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive).

2. Monthly energy consumption in excess of 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive).

3. A monthly demand greater than or equal to twenty-five (25) kilowatts in a single month.

Demand accounts are reviewed annually. The account will be billed under non-demand billing provision when the consumption for each of the previous twelve (12) months is below 6,000 kilowatt-hours and the demand is less than twenty-five (25) kilowatts.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMAND

The billing demand shall be the maximum thirty (30) minute demand recorded during the month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED MEDIUM GENERAL SERVICE - LOW VOLTAGE
SCHEDULE "MGT LV"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider “SOS” or Distribution Service when modified by Rider “SOS” in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "MGT LV" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "MGT LV" even if the party responsible for the account should change. Removal from Schedule "MGT LV" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "MGT LV" whose maximum thirty (30) minute demand is less than eighty (80) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "MGT LV", the customer will remain on Schedule "MGT LV" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz.

Available for standby service when modified by Schedule "S".

Not available for temporary service.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 237.00 per month	$ 237.00 per month
Kilowatt-hour Charge	$ 0.01316 per kwhr	$ 0.01316 per kwhr
Kilowatt Charge		
Maximum	$ 15.07 per kw	$ 15.07 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company’s General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider “SOS” – Standard Offer Service.

DC – MGT LV

Billing Credit - A monthly billing credit in the amount of $0.75 per bill will be applied to the bill of each customer receiving generation services from an alternative supplier for each month that the alternative supplier renders a bill to the customer on a consolidated basis for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

TEMPORARY SERVICE

SCHEDULE "T"

AVAILABILITY
Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for low voltage electric service for construction or other commercial purposes furnished through service connection facilities of a temporary rather than a permanent nature, or for temporary electric service supplied for a limited time, such as for carnivals, festivals, etc.

However, customers receiving Temporary Service on a continuous basis for five (5) years will normally be transferred to the appropriate General Service Low Voltage Schedule "GS LV" or "GS ND" based on the customer's maximum demand, in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June.

CHARACTER OF SERVICE
The service supplied under this schedule will be alternating current, sixty hertz, at any of the approved classes of service.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 32.30 per month	$ 32.30 per month
Kilowatt-hour Charge	$ 0.06759 per kwhr	$ 0.05271 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS
Summer – Billing months of June through October.
Winter – Billing months of November through May.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Standard Offer Service – Small Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED GENERAL SERVICE - LOW VOLTAGE
SCHEDULE "GT LV"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider “SOS” or Distribution Service when modified by Rider “SOS” in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds one thousand (1000) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "GT LV" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "GT LV" even if the party responsible for the account should change. Removal from Schedule "GT LV" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "GT LV" whose maximum thirty (30) minute demand is less than nine hundred (900) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "GT LV", the customer will remain on Schedule "GT LV" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz.

Available for standby service when modified by Schedule "S".

Not available for temporary service.

Not available for multiple application to master-metered apartment buildings except for those master-metered apartments served under Schedule "GT LV" prior to December 31, 1982 which will continue to be served under Schedule "GT LV".

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 940.60 per month	$ 940.60 per month
Kilowatt-hour Charge	$ 0.01343 per kwhr	$ 0.01343 per kwhr
Kilowatt Charge		
Maximum	$ 13.76 per kw	$ 13.76 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company’s General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider “SOS” – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 per bill will be applied to the bill of each customer receiving generation services from an alternative supplier for each month that the alternative supplier renders a bill to the customer on a consolidated basis for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED GENERAL SERVICE - PRIMARY SERVICE

SCHEDULE "GT 3A"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "GT 3A" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "GT 3A" even if the party responsible for the account should change. Removal from Schedule "GT 3A" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "GT 3A" whose maximum thirty (30) minute demand is less than eighty (80) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "GT 3A", the customer will remain on Schedule "GT 3A" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for primary service furnished directly from the Company's electric system at voltages of 4.16 kV, 13.2 kV or 33 kV, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnectors, regulators and protective equipment.

Available for standby service when modified by Schedule "S".

Not available for temporary service.

Not available for multiple application to master-metered apartment buildings except for those master-metered apartments served under Schedule "GT 3A" prior to December 31, 1982 which will continue to be served under Schedule "GT 3A".

CHARACTER OF SERVICE

The service under this schedule, normally will be alternating current, sixty hertz, three phase, three wire, at 4.16kV, 13.2kV or 33kV. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 197.49 per month	$ 197.49 per month
Kilowatt-hour Charge	$ 0.00554 per kwhr	$ 0.00553 per kwhr
Kilowatt Charge Maximum	$ 10.35 per kw	$ 10.35 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 per bill will be applied to the bill of each customer receiving generation services from an alternative supplier for each month that the alternative supplier renders a bill to the customer on a consolidated basis for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED GENERAL SERVICE - HIGH VOLTAGE SERVICE
SCHEDULE "GT 3B"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider “SOS” or Distribution Service in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "GT 3B" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "GT 3B" even if the party responsible for the account should change. Removal from Schedule "GT 3B" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "GT 3B" whose maximum thirty (30) minute demand is less than eighty (80) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "GT 3B", the customer will remain on Schedule "GT 3B" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for standby service when modified by Schedule "S".

Available for high voltage service furnished directly from the Company's electric system at voltages of 66 kV or above, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnectors, regulators and protective equipment.

Not available for temporary service.

Not available for multiple application to master-metered apartment buildings except for those master-metered apartments served under Schedule "GT 3B" prior to December 31, 1982 which will continue to be served under Schedule "GT 3B".

CHARACTER OF SERVICE

The service under this schedule, normally will be 66kV or above. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 311.66 per month	$ 311.66 per month
Kilowatt-hour Charge	$ 0.00000 per kwhr	$ 0.00000 per kwhr
Kilowatt Charge Maximum	$ 1.83 per kw	$ 1.97 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider.
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

RAPID TRANSIT SERVICE

SCHEDULE "RT"

AVAILABILITY
Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for rapid transit electric service furnished directly from the Company's distribution, subtransmission or transmission systems at available voltages of 13.2kV and higher where the customer provides, at the customer's own expense, all necessary transformers or converting apparatus, switches, disconnectors, regulators, and protective equipment.

Available only at points of delivery on contiguous authority right-of-way.

Also available for low voltage service for purposes of operating electric chiller plants used for the purpose of providing chilled water to passenger stations associated with the rapid transit service.

Not available for partial or auxiliary service.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, three phase, three wire, high tension at 13.2kV or such voltage as is specified by the Company on the basis of its available facilities and the magnitude of load to be served.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 7,246.07 per month	$ 7,246.07 per month

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS
Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMAND
The monthly billing demand will be the maximum thirty (30) minute integrated coincident demand of all delivery points recorded during the billing month.

BILLING ENERGY
The monthly billing energy will be the sum of the registrations of kilowatt-hours of all delivery points.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations", except as modified by the agreement by and between the Company and the customer.

APPLICABLE RIDERS
Standard Offer Service – Large Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

STREET LIGHTING SERVICE

SCHEDULE "SL"

AVAILABILITY
Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service for street, highway and park lighting purposes in the District of Columbia portion of the Company's service area when owned by agencies of Federal and District of Columbia governments. Also available to governmental and non-governmental customers for holiday lighting and seasonal street decoration lighting where the lights are in public space and where the only load supplied is lighting load. Schedule "SL" is not available for services that supply any load other than lighting.

CHARACTER OF SERVICE
Electricity supplied to multiple lights normally will be sixty hertz, single phase, 120 volts.

MONTHLY RATE

Distribution Service Charge	
Customer Charge	
Metered Account	$19.85 per month
Unmetered Account	$16.97 per month
Kilowatt-hour Charge	$ 0.00829 per kwh

The per kwh charge shall be adjusted for any Major Service Outages as defined in Section 3699 of Chapter 36, Electric Quality Service Standards in Title 15 of the District of Columbia Municipal Regulations.

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

The charges under this schedule are for delivery only and do not include furnishing and/or maintaining street lighting equipment.

MEASUREMENTS OF ELECTRICITY
If electricity delivered for street lighting is unmetered, monthly kilowatt-hour consumption will be computed on the basis of manufacturers' wattage ratings of installed lamps, auxiliary devices where required, and scheduled 4,200 hours of burning time. If metered, watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

Lights controlled for night burning only will be billed at the monthly rate for Standard Night Burning street lights. Lights not controlled for night burning only will be billed at the monthly rate for 24-Hour Burning street lights.

The kilowatt-hours calculated from billing wattages will be reduced by 5.5 percent each month to provide for normal outages.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations". Holiday and decorative street lighting service connections will be considered temporary service connections as defined in the "Electric Service Rules and Regulations" and will be priced accordingly.

APPLICABLE RIDERS
Standard Offer Service – Small Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Telecommunication Network Charge
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

TRAFFIC SIGNAL SERVICE

SCHEDULE "TS"

AVAILABILITY
Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service to agencies of the Federal and District of Columbia governments, for operation of traffic signals in the District of Columbia portion of the Company's service area.

CHARACTER OF SERVICE
Electricity supplied for traffic signal purposes normally will be sixty hertz, single phase, 120 volts.

MONTHLY RATE

Distribution Service Charge	
Customer Charge	$ 4.26 per month
Kilowatt-hour Charge	$ 0.02636 per kwh

The per kwh charge shall be adjusted for any Major Service Outages as defined in Section 3699 of Chapter 36, Electric Quality Service Standards in Title 15 of the District of Columbia Municipal Regulations.

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

The charges under this schedule are for delivery only and do not include furnishing and/or maintaining traffic signal equipment.

MEASUREMENT OF ELECTRICITY
Electricity delivered to traffic signals is unmetered. Monthly kilowatt-hour consumption will be computed on the basis of manufacturers' wattage ratings of installed devices and estimated hours of burning time.

The kilowatt-hours calculated from billing wattages will be reduced by 1.5 percent each month to provide for normal outages.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Standard Offer Service – Small Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge

Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

CHARGES FOR SERVICING
STREET LIGHTS SERVED FROM OVERHEAD LINES
SCHEDULE "SSL-OH"

APPLICABILITY
Applicable only to luminaries meeting ANSI Standards for street lighting equipment when owned by the Company and mounted on Company-owned wooden poles or on poles of another utility with whom the Company has an attachment agreement.

AVAILABILITY
Available in the District of Columbia portion of the Company's service area to Federal Governmental Agencies for servicing street, highway and park lighting equipment when the electricity supplying such equipment is furnished by the Company from overhead lines and is accessible by conventional wheeled construction and maintenance vehicles.

Available only for lights having a manufacturers' nominal rating of:

Incandescent*	10,000	lumens or less
Mercury Vapor*	100 - 400	watts
High Pressure Sodium	70 - 400	watts
Metal Halide	400	watts

*Not available for new installation or replacement of defective fixtures.

CHARACTER OF SERVICE
Service rendered under this schedule will consist of (1) furnishing, installing and maintaining street lighting fixtures and mounting arms or brackets, (2) furnishing, installing, connecting, operating and maintaining the electric service circuits connecting the street lighting equipment to the Company's distribution system, (3) group relamping, (every six (6) months for incandescent, every four (4) years for mercury vapor and every five (5) years for high pressure sodium), (4) washing of globes, (5) furnishing and installing replacement globes, lamps, ballasts and light sensitive switches as needed to maintain the system in an operating mode; all normally limited, to standard items of equipment meeting ANSI Standards for street lighting equipment and approved by the Company for maintenance.

MONTHLY RATE

	Fixed Charges	O&M Charges
Incandescent Lights* - Night Burning		
Without Globe - all sizes	$ 3.158 per lamp	$0.049 per lamp
With Globe - all sizes	$ 4.611 per lamp	$1.090 per lamp

*Not available for new installation or replacement of defective fixtures.

DC - SSL - OH

MONTHLY RATE (continued)

Mercury Vapor Lights* - Night Burning

175 Watt	$ 9.828 per lamp	$0.972 per lamp
250 Watt	$ 11.228 per lamp	$0.985 per lamp

*Not available for new installation or replacement of defective fixtures.

Metal Halide Lights – Night Burning

400 Watt	$ 38.000 per lamp	$1.588 per lamp

The above charges will be separate from and in addition to charges for electricity supplied under the provisions of Schedule "SL".

NON-STANDARD EQUIPMENT
Non Company approved ANSI equipment, if accepted by the Company for maintenance, will be subject to special contracts which may include an initial installation charge.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Excess Deferred Income Tax Credit

CHARGES FOR SERVICING
STREET LIGHTS SERVED FROM UNDERGROUND LINES
SCHEDULE "SSL-UG"

APPLICABILITY
Applicable only to posts and luminaries meeting ANSI Standards for street lighting equipment furnished by the customer.

AVAILABILITY
Available in the District of Columbia portion of the Company's service area to Federal Governmental Agencies for servicing street, highway and park lighting equipment when the electricity supplying such equipment is furnished by the Company from unmetered underground lines and is accessible by conventional wheeled construction and maintenance vehicles.

Available only for lights having a manufacturers' nominal rating of:

Incandescent*	10,000	lumens or less
Mercury Vapor*	250 - 400	watts
High Pressure Sodium	150	watts
Metal Halide	100 - 400	watts

*Not available for new installation or replacement of defective fixtures.

CHARACTER OF SERVICE
Service rendered under this schedule will consist of (1) furnishing, installing, connecting, operating and maintaining the electric service circuits connecting the street lighting equipment to the Company's distribution system, (2) furnishing and installing post foundations and setting customer owned posts on foundations, (3) installing customer owned street lighting fixtures, (4) group relamping, (every six (6) months for incandescent, every two (2) years for metal halide, every four (4) years for mercury vapor and every five (5) years for high pressure sodium), (5) washing of globes, (6) furnishing and installing of replacement globes, lamps, remote ballasts, and light sensitive switches as needed to maintain the system in an operating mode, (7) repainting posts at approximately six (6) year intervals; all normally limited to standard items of equipment meeting ANSI Standards for street lighting equipment and accepted by the Company for maintenance.

MONTHLY RATE

		Fixed Charges	O&M Charges
Incandescent Lights* - Night Burning			
With Globe	- all sizes	$ 44.183 per lamp	$1.997 per lamp

*Not available for new installation or replacement of defective fixtures.

Mercury Vapor Lights* - Night Burning

250 Watt	$ 44.565 per lamp	$1.794 per lamp
400 Watt	$ 52.257 per lamp	$2.229 per lamp

*Not available for new installation or replacement of defective fixtures.

MONTHLY RATE (continued)

High Pressure Sodium Lights - Night Burning

150 Watt	$ 39.081 per lamp	$1.463 per lamp

Metal Halide - Night Burning

100 Watt	$ 33.677 per lamp	$1.317 per lamp
175 Watt	$ 38.000 per lamp	$1.588 per lamp
400 Watt	$ 38.000 per lamp	$1.588 per lamp

Other

Posts furnished by the Company, costing*:

$ 15.00 and less	$ 1.139 each
$ 15.01 to $ 45.00, inclusive	$ 1.517 each
$ 45.01 to $ 75.00, inclusive	$ 3.410 each
$ 75.01 to $100.00, inclusive	$ 5.687 each
$100.01 to $160.00, inclusive	$10.047 each

*Not available for new installation or replacement of defective posts.

The above charges will be separate from and in addition to charges for electricity supplied under the provisions of Schedule "SL".

CUSTOMER RESPONSIBILITY AS TO FURNISHING, INSTALLING AND MAINTAINING EQUIPMENT
The street lighting posts, fixtures and brackets (if required) shall be furnished by the customer for installation by the Company as set forth under "Character of Service" above. Ballasts for all High Pressure Sodium Lights and any Mercury Vapor Lights to be installed in or on upright posts shall be furnished by the customer. All Metal Halide lamps and ballasts shall be furnished by the customer for installation by the Company.

All maintenance of equipment furnished by the customer will be performed at the customer's expense, except as set forth under "Character of Service".

NON-STANDARD EQUIPMENT
Non-company approved ANSI accepted equipment and non-standard, special, experimental and any other such post and luminaries which do not meet ANSI Standards for street lighting equipment, if accepted by the Company for maintenance, will be subjected to special contracts. Lights of this type will be installed in accordance with the customer's instruction, and all installation costs charged to the customer.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Excess Deferred Income Tax Credit

TELECOMMUNICATIONS NETWORK SERVICE

SCHEDULE "TN"

AVAILABILITY
Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for unmetered electric service to multiple telecommunications network devices or other devices with similar load characteristics served directly by the Company and not exceeding 1,800 watts per device. For devices that are currently served by meter, the Customer may choose to have the meter removed at the Customer's expense and the month Customer Charge without Meter will apply.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, 120 volts.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 15.43	$ 15.43
Kilowatt-hour Charge	$ 0.01227 per kwhr	$ 0.01227 per kwhr

Customer Charges/Kilowatt-hour Charge – For devices that are served through a meter, the Customer shall pay the monthly "Customer Charge with Meter" and the kilowatt-hour charge will be applied to metered usage. For devices served without a meter, the Customer shall pay the monthly "Customer Charge without Meter" and the kilowatt-hour charge will be applied to estimated monthly usage based on metered usages for similar devices. If similar metered data do not exist, at the customer's option, the monthly usage will be estimated base on either the manufacturer's average wattage ratings with no allowance for outage, or on the basis of statistically valid sample estimates using actual current and voltage readings.

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

MEASUREMENTS OF ELECTRICITY
Monthly kilowatt-hour consumption will be computed on the basis of manufacturer's average wattage ratings of installed devices, with no allowance for outages. The charges under this rider are for electricity only.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Standard Offer Services – Small Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

DC -OL-LED

LED OUTDOOR LIGHTING SERVICE

SCHEDULE "OL LED"

AVAILABILITY
Available for Distribution Service and Standard Offer Service when modified by Rider “SOS” in the District of Columbia portion of the Company's overhead service area for customer-owned outdoor lighting purposes on customers' premises subject to local ordinance or other appropriate approval.

Not available for street lighting purposes.

CHARACTER OF SERVICE

Electricity will be supplied from distribution system facilities on a metered basis.

MONTHLY RATE
Charge for supply of electricity for operation:

Distribution Service Charges
Customer Charge
Service at secondary voltage: $8.76 per customer per month
Energy Charge:
Service at secondary voltage: $0.00895 per kwhr

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company’s General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider “SOS” – Standard Offer Service.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations" and it is further understood that:

1. Normally, lighting fixtures will not be installed on poles carrying 34.5 kV or higher voltages, or on poles supporting voltage regulators, two or more transformers or other similar equipment.

2. The Company reserves the right to discontinue the service at any time when the lighting fixture involved has been frequently damaged, apparently as a result of vandalism.

APPLICABLE RIDERS
Standard Offer Service - Small Commercial
Administrative Credit
Delivery Tax Surcharge
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustained Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider

REDLINE

RATE SCHEDULES

FOR

ELECTRIC SERVICE

IN THE

DISTRICT OF COLUMBIA

An Exelon Company

RATES AND REGULATORY PRACTICES GROUP

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RESIDENTIAL SERVICE

SCHEDULE "R"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for low voltage electric service where the use is primarily for residential purposes and for farm operations where the electricity for both farm and residential purposes is delivered through the same meter.

Available only in individual residences and in individually metered dwelling units in multi-family buildings.

Not available for residential premises in which five (5) or more rooms are for hire.

Not available for seasonal loads metered separately from lighting and other usage in the same occupancy.

Not available for temporary, auxiliary or emergency service.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, three wire, 120/240 volts, or three wire, 120/208 volts.

MONTHLY RATE

	Summer	**Winter**
Distribution Service Charge		
Customer Charge – Residential	$~~15.09~~ 18.86 per month	$ ~~15.09~~18.86 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ ~~0.00800~~0.01307 per kwhr	$ ~~0.00800~~0.01307 per kwhr
In excess of 400 kilowatt hours	$ ~~0.02283~~0.03731 per kwhr	$ ~~0.01594~~0.02605 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Service from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.62 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS
Standard Offer Service - Residential
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount
Optional Meter Equipment Related Services
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Residential Direct Load Control Rider
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

MASTER METERED APARTMENT SERVICE
SCHEDULE "MMA"

AVAILABILITY
Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for low voltage electric service for multiple application to master-metered apartment buildings where the use is predominantly residential and not for retail business establishments. Not available for separately metered service billed on Schedule "GS ND" that did not qualify for multiple application of the residential rate as of December 31, 1982.

Not available for seasonal loads metered separately from lighting and other usage in the same occupancy.

Not available for temporary, auxiliary or emergency service.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, three wire, 120/240 volts, or three wire, 120/208 volts.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$~~11.84~~13.95 per month	$~~11.84~~13.95 per month
Kilowatt-hour Charge		
First 400 kilowatt-hours	$ ~~0.00891~~0.00949 per kwhr	$ ~~0.00891~~0.00949 per kwhr
In excess of 400 kilowatt hours	$ ~~0.02542~~0.02707 per kwhr	$ ~~0.01774~~0.01889 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Service from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.62 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS
Summer – Billing months of June through October.
Winter – Billing months of November through May.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS
Standard Offer Service - Residential
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Optional Meter Equipment Related Services
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Residential Direct Load Control Rider
Underground Project Charge
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

GENERAL SERVICE – NON DEMAND

SCHEDULE "GS ND"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for "GS LV" customers whose maximum monthly demand is less than 25 kW. Customers whose maximum demand is between 25 kW and 99 kW will be served on Schedule GS LV or GS 3A subject to the provisions stated therein. Customers whose maximum demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months will be transferred to Schedule "GT LV", "GT 3A", or "GT 3B" in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz and for primary service furnished directly from the Company's electric system at voltages of 4.16 kV, 13.2 kV, or 33 kV, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnects, regulators and protective equipment.

Not available for railway propulsion service.

Not available for secondary temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts for GS Low Voltage Non Demand customers. For GS 3A Non Demand customers, the service under this schedule, normally will be alternating current, sixty hertz, three phase, three wire, at 4.16kV, 13.2kV or 33 kV. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Summer	Winter
GS LOW VOLTAGE NON DEMAND		
Distribution Service Charge		
Customer Charge	$ ~~27.42~~32.30 per month	$ ~~27.42~~32.30 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ ~~0.04173~~0.05074 per kwhr	$ ~~0.03266~~0.03971 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

Demand metering equipment will be installed and charges subsequent to the installation of this equipment will be computed under the billing demand provision when the customer's load is of such a magnitude and of such a nature as to indicate any of the following:

1. Monthly energy consumption in excess of 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive).

2. Monthly energy consumption in excess of 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive).

3. A monthly demand greater than or equal to twenty-five (25) kilowatts in a single month.

Demand accounts are reviewed annually. The account will be billed under non-demand billing provision when the consumption for each of the previous twelve (12) months is below 6,000 kilowatt-hours and the demand is less than twenty-five (25) kilowatts.

BILLING DEMAND

The billing demand shall be the maximum thirty (30) minute demand recorded during the month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Small Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

GENERAL SERVICE - LOW VOLTAGE

SCHEDULE "GS LV"

AVAILABILITY
Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area, except if the customer's maximum demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months, the customer will be transferred to Schedule "GT LV", "GT 3A", or "GT 3B" in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June. Customers with monthly maximum demands less than 25 kW are served on Schedule "GS ND" subject to the provisions stated therein.

Available for low voltage electric service at sixty hertz.

Not available for railway propulsion service.

Not available for secondary temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ ~~35.17~~38.75 per month	$ ~~35.17~~38.75 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ ~~0.02807~~0.03406 per kwhr	$ ~~0.02127~~0.02581 per kwhr
Demand Charge	$ ~~8.06~~9.46 per kw	$ ~~8.06~~9.46 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

Demand metering equipment will be installed and charges subsequent to the installation of this equipment will be computed under the billing demand provision when the customer's load is of such a magnitude and of such a nature as to indicate any of the following:

1. Monthly energy consumption in excess of 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive).

2. Monthly energy consumption in excess of 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive).

3. A monthly demand greater than or equal to twenty-five (25) kilowatts in a single month.

Demand accounts are reviewed annually. The account will be billed under non-demand billing provision when the consumption for each of the previous twelve (12) months is below 6,000 kilowatt-hours and the demand is less than twenty-five (25) kilowatts.

BILLING DEMAND

The billing demand shall be the maximum thirty (30) minute demand recorded during the month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

GENERAL SERVICE - PRIMARY SERVICE

SCHEDULE "GS 3A"

AVAILABILITY

Available for either Standard Offer Service when modified by Rider "SOS", or Distribution Service in the District of Columbia portion of the Company's service area, except if the customer's maximum demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months, the customer will be transferred to Schedule "GT LV", "GT 3A", or "GT 3B" in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June. Customers with monthly maximum demands less than 25 kW are served on Schedule "GS ND" subject to the provisions stated therein.

Available for primary service furnished directly from the Company's electric system at voltages of 4.16 kV, 13.2 kV or 33 kV, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnects, regulators and protective equipment.

Not available for railway propulsion service.

Not available for secondary temporary service or supplementary loads metered separately from lighting and other usage in the same occupancy.

CHARACTER OF SERVICE

The service under this schedule, normally will be alternating current, sixty hertz, three phase, three wire, at 4.16kV, 13.2kV or 33kV. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 89.41 per month	$ 89.41 per month
Kilowatt-hour Charge		
All kilowatt-hours	$ ~~0.02054~~0.02208 per kwhr	$ ~~0.01476~~0.01587 per kwhr
Demand Charge	$ 10.82 per kw	$ 10.82 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

Demand metering equipment will be installed and charges subsequent to the installation of this equipment will be computed under the demand billing provision when the customer's load is of such a magnitude and of such a nature as to indicate any of the following:

1. Monthly energy consumption in excess of 6,000 kilowatt-hours in two (2) consecutive winter billing months (November through May, inclusive).

2. Monthly energy consumption in excess of 7,500 kilowatt-hours for a single summer billing month (June through October, inclusive).

3. A monthly demand greater than or equal to twenty-five (25) kilowatts in a single month.

Demand accounts are reviewed annually. The account will be billed under non-demand billing provision when the consumption for each of the previous twelve (12) months is below 6,000 kilowatt-hours and the demand is less than twenty-five (25) kilowatts.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMAND

The billing demand shall be the maximum thirty (30) minute demand recorded during the month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations."

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Net Energy Metering Rider
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED MEDIUM GENERAL SERVICE - LOW VOLTAGE SCHEDULE "MGT LV"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider "SOS" or Distribution Service when modified by Rider "SOS" in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand is equal to or in excess of one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "MGT LV" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "MGT LV" even if the party responsible for the account should change. Removal from Schedule "MGT LV" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "MGT LV" whose maximum thirty (30) minute demand is less than eighty (80) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "MGT LV", the customer will remain on Schedule "MGT LV" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz.

Available for standby service when modified by Schedule "S".

Not available for temporary service.

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ ~~456.76~~237.00 per month	$ ~~456.76~~237.00 per month
Kilowatt-hour Charge	$ ~~0.00958~~0.01316 per kwhr	$ ~~0.00958~~0.01316 per kwhr
Kilowatt Charge		
Maximum	$ ~~11.88~~15.07 per kw	$ ~~11.88~~15.07 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 per bill will be applied to the bill of each customer receiving generation services from an alternative supplier for each month that the alternative supplier renders a bill to the customer on a consolidated basis for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

TEMPORARY SERVICE

SCHEDULE "T"

AVAILABILITY
Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for low voltage electric service for construction or other commercial purposes furnished through service connection facilities of a temporary rather than a permanent nature, or for temporary electric service supplied for a limited time, such as for carnivals, festivals, etc.

However, customers receiving Temporary Service on a continuous basis for five (5) years will normally be transferred to the appropriate General Service Low Voltage Schedule "GS LV" or "GS ND" based on the customer's maximum demand, in accordance with the availability provisions therein. Rate schedule transfers will be made annually and become effective with the billing month of June.

CHARACTER OF SERVICE
The service supplied under this schedule will be alternating current, sixty hertz, at any of the approved classes of service.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ ~~27.42~~32.30 per month	$ ~~27.42~~32.30 per month
Kilowatt-hour Charge	$ ~~0.06223~~0.06759 per kwhr	$ ~~0.04853~~0.05271 per kwhr

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS
Summer – Billing months of June through October.
Winter – Billing months of November through May.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Standard Offer Service – Small Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED GENERAL SERVICE - LOW VOLTAGE
SCHEDULE "GT LV"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider "SOS" or Distribution Service when modified by Rider "SOS" in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds one thousand (1000) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "GT LV" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "GT LV" even if the party responsible for the account should change. Removal from Schedule "GT LV" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "GT LV" whose maximum thirty (30) minute demand is less than nine hundred (900) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "GT LV", the customer will remain on Schedule "GT LV" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for low voltage electric service at sixty hertz.

Available for standby service when modified by Schedule "S".

Not available for temporary service.

Not available for multiple application to master-metered apartment buildings except for those master-metered apartments served under Schedule "GT LV" prior to December 31, 1982 which will continue to be served under Schedule "GT LV".

CHARACTER OF SERVICE

The service supplied under this schedule normally will be alternating current, sixty hertz, either (i) single phase, three wire, 120/240 volts or 120/208 volts, or (ii) three phase, four wire, 120/208 volts or 265/460 volts.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ ~~456.76~~940.60 per month	$ ~~456.76~~940.60 per month
Kilowatt-hour Charge	$ ~~0.00958~~0.01343 per kwhr	$ ~~0.00958~~0.01343 per kwhr
Kilowatt Charge		
Maximum	$ ~~11.88~~13.76 per kw	$ ~~11.88~~13.76 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 per bill will be applied to the bill of each customer receiving generation services from an alternative supplier for each month that the alternative supplier renders a bill to the customer on a consolidated basis for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED GENERAL SERVICE - PRIMARY SERVICE

SCHEDULE "GT 3A"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "GT 3A" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "GT 3A" even if the party responsible for the account should change. Removal from Schedule "GT 3A" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "GT 3A" whose maximum thirty (30) minute demand is less than eighty (80) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "GT 3A", the customer will remain on Schedule "GT 3A" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for primary service furnished directly from the Company's electric system at voltages of 4.16 kV, 13.2 kV or 33 kV, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnectors, regulators and protective equipment.

Available for standby service when modified by Schedule "S".

Not available for temporary service.

Not available for multiple application to master-metered apartment buildings except for those master-metered apartments served under Schedule "GT 3A" prior to December 31, 1982 which will continue to be served under Schedule "GT 3A".

CHARACTER OF SERVICE

The service under this schedule, normally will be alternating current, sixty hertz, three phase, three wire, at 4.16kV, 13.2kV or 33kV. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ ~~187.64~~197.49 per month	$ ~~187.64~~197.49 per month
Kilowatt-hour Charge	$ ~~0.00454~~0.00554 per kwhr	$ ~~0.00453~~0.00553 per kwhr
Kilowatt Charge Maximum	$ ~~8.86~~10.35 per kw	$ ~~8.86~~10.35 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 per bill will be applied to the bill of each customer receiving generation services from an alternative supplier for each month that the alternative supplier renders a bill to the customer on a consolidated basis for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

TIME METERED GENERAL SERVICE - HIGH VOLTAGE SERVICE SCHEDULE "GT 3B"

AVAILABILITY

Shall be applicable for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area to customers whose maximum thirty (30) minute demand equals or exceeds one hundred (100) kilowatts during two (2) or more billing months within twelve (12) consecutive billing months. New customers will be qualified for Schedule "GT 3B" based on estimated load and energy consumption using the above criteria. Once a customer's account is established it will remain on Schedule "GT 3B" even if the party responsible for the account should change. Removal from Schedule "GT 3B" is based solely on the criteria stated in the following paragraph.

Any customer presently on Schedule "GT 3B" whose maximum thirty (30) minute demand is less than eighty (80) kilowatts for twelve (12) consecutive billing months, may at the customer's option elect to continue service on this schedule or elect to be served under any other available schedule. If the customer elects to stay on Schedule "GT 3B", the customer will remain on Schedule "GT 3B" for at least twelve (12) billing months. Rate schedule transfers will be made annually and become effective with the billing month of June.

Available for standby service when modified by Schedule "S".

Available for high voltage service furnished directly from the Company's electric system at voltages of 66 kV or above, when the customer provides at the customer's own expense, all necessary transformers, converting apparatus, switches, disconnectors, regulators and protective equipment.

Not available for temporary service.

Not available for multiple application to master-metered apartment buildings except for those master-metered apartments served under Schedule "GT 3B" prior to December 31, 1982 which will continue to be served under Schedule "GT 3B".

CHARACTER OF SERVICE

The service under this schedule, normally will be 66kV or above. Primary nominal service voltage levels will be specified by the Company on the basis of its available facilities and the magnitude of the load to be served.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ ~~423.38~~311.66 per month	$ ~~423.38~~311.66 per month
Kilowatt-hour Charge	$ 0.00000 per kwhr	$ 0.00000 per kwhr
Kilowatt Charge Maximum	$ ~~1.79~~1.83 per kw	$ ~~1.92~~1.97 per kw

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS

Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMANDS

Maximum (All Months) - The billing demand shall be the maximum thirty (30) minute demand recorded during the billing month.

METER READING

Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Standard Offer Service – Large Commercial
Administrative Credit
Power Factor
Delivery Tax
Public Space Occupancy Surcharge
Excess Facilities
Net Energy Metering Rider.
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Bill Stabilization Adjustment
Underground Project Charge Rider
Community Net Metering Rider
Underground Rider
Excess Deferred Income Tax Credit

RAPID TRANSIT SERVICE

SCHEDULE "RT"

AVAILABILITY
Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for rapid transit electric service furnished directly from the Company's distribution, subtransmission or transmission systems at available voltages of 13.2kV and higher where the customer provides, at the customer's own expense, all necessary transformers or converting apparatus, switches, disconnectors, regulators, and protective equipment.

Available only at points of delivery on contiguous authority right-of-way.

Also available for low voltage service for purposes of operating electric chiller plants used for the purpose of providing chilled water to passenger stations associated with the rapid transit service.

Not available for partial or auxiliary service.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, three phase, three wire, high tension at 13.2kV or such voltage as is specified by the Company on the basis of its available facilities and the magnitude of load to be served.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ ~~6,216.22~~7,246.07 per month	$ ~~6,216.22~~7,246.07 per month

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

BILLING MONTHS
Summer – Billing months of June through October.
Winter – Billing months of November through May.

BILLING DEMAND
The monthly billing demand will be the maximum thirty (30) minute integrated coincident demand of all delivery points recorded during the billing month.

BILLING ENERGY
The monthly billing energy will be the sum of the registrations of kilowatt-hours of all delivery points.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations", except as modified by the agreement by and between the Company and the customer.

APPLICABLE RIDERS
Standard Offer Service – Large Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Reserved Delivery Capacity Service
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

STREET LIGHTING SERVICE

SCHEDULE "SL"

AVAILABILITY
Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service for street, highway and park lighting purposes in the District of Columbia portion of the Company's service area when owned by agencies of Federal and District of Columbia governments. Also available to governmental and non-governmental customers for holiday lighting and seasonal street decoration lighting where the lights are in public space and where the only load supplied is lighting load. Schedule "SL" is not available for services that supply any load other than lighting.

CHARACTER OF SERVICE
Electricity supplied to multiple lights normally will be sixty hertz, single phase, 120 volts.

MONTHLY RATE

Distribution Service Charge	
Customer Charge	
Metered Account	$~~17.19~~19.85 per month
Unmetered Account	$~~14.70~~16.97 per month
Kilowatt-hour Charge	$ ~~0.00615~~0.00829 per kwh

The per kwh charge shall be adjusted for any Major Service Outages as defined in Section 3699 of Chapter 36, Electric Quality Service Standards in Title 15 of the District of Columbia Municipal Regulations.

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

The charges under this schedule are for delivery only and do not include furnishing and/or maintaining street lighting equipment.

MEASUREMENTS OF ELECTRICITY
If electricity delivered for street lighting is unmetered, monthly kilowatt-hour consumption will be computed on the basis of manufacturers' wattage ratings of installed lamps, auxiliary devices where required, and scheduled 4,200 hours of burning time. If metered, watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

Lights controlled for night burning only will be billed at the monthly rate for Standard Night Burning street lights. Lights not controlled for night burning only will be billed at the monthly rate for 24-Hour Burning street lights.

The kilowatt-hours calculated from billing wattages will be reduced by 5.5 percent each month to provide for normal outages.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations". Holiday and decorative street lighting service connections will be considered temporary service connections as defined in the "Electric Service Rules and Regulations" and will be priced accordingly.

APPLICABLE RIDERS
Standard Offer Service – Small Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Telecommunication Network Charge
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

TRAFFIC SIGNAL SERVICE

SCHEDULE "TS"

AVAILABILITY
Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service to agencies of the Federal and District of Columbia governments, for operation of traffic signals in the District of Columbia portion of the Company's service area.

CHARACTER OF SERVICE
Electricity supplied for traffic signal purposes normally will be sixty hertz, single phase, 120 volts.

MONTHLY RATE

Distribution Service Charge	
Customer Charge	$ ~~8.03~~4.26 per month
Kilowatt-hour Charge	$ ~~0.02203~~0.02636 per kwh

The per kwh charge shall be adjusted for any Major Service Outages as defined in Section 3699 of Chapter 36, Electric Quality Service Standards in Title 15 of the District of Columbia Municipal Regulations.

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

The charges under this schedule are for delivery only and do not include furnishing and/or maintaining traffic signal equipment.

MEASUREMENT OF ELECTRICITY
Electricity delivered to traffic signals is unmetered. Monthly kilowatt-hour consumption will be computed on the basis of manufacturers' wattage ratings of installed devices and estimated hours of burning time.

The kilowatt-hours calculated from billing wattages will be reduced by 1.5 percent each month to provide for normal outages.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Standard Offer Service – Small Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge

Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider
Excess Deferred Income Tax Credit

CHARGES FOR SERVICING
STREET LIGHTS SERVED FROM OVERHEAD LINES
SCHEDULE "SSL-OH"

APPLICABILITY
Applicable only to luminaries meeting ANSI Standards for street lighting equipment when owned by the Company and mounted on Company-owned wooden poles or on poles of another utility with whom the Company has an attachment agreement.

AVAILABILITY
Available in the District of Columbia portion of the Company's service area to Federal Governmental Agencies for servicing street, highway and park lighting equipment when the electricity supplying such equipment is furnished by the Company from overhead lines and is accessible by conventional wheeled construction and maintenance vehicles.

Available only for lights having a manufacturers' nominal rating of:

Incandescent*	10,000	lumens or less
Mercury Vapor*	100 - 400	watts
High Pressure Sodium	70 - 400	watts
Metal Halide	400	watts

*Not available for new installation or replacement of defective fixtures.

CHARACTER OF SERVICE
Service rendered under this schedule will consist of (1) furnishing, installing and maintaining street lighting fixtures and mounting arms or brackets, (2) furnishing, installing, connecting, operating and maintaining the electric service circuits connecting the street lighting equipment to the Company's distribution system, (3) group relamping, (every six (6) months for incandescent, every four (4) years for mercury vapor and every five (5) years for high pressure sodium), (4) washing of globes, (5) furnishing and installing replacement globes, lamps, ballasts and light sensitive switches as needed to maintain the system in an operating mode; all normally limited, to standard items of equipment meeting ANSI Standards for street lighting equipment and approved by the Company for maintenance.

MONTHLY RATE

	Fixed Charges	O&M Charges
Incandescent Lights* - Night Burning		
Without Globe - all sizes	$ ~~2.492~~3.158 per lamp	$~~0.039~~0.049 per lamp
With Globe - all sizes	$ ~~3.639~~4.611 per lamp	$~~0.860~~1.090 per lamp

*Not available for new installation or replacement of defective fixtures.

DC - SSL - OH

MONTHLY RATE (continued)

Mercury Vapor Lights* - Night Burning

175 Watt	$ ~~7.756~~9.828 per lamp	$~~0.767~~0.972 per lamp	
250 Watt	$ ~~8.861~~11.228 per lamp	$~~0.777~~0.985 per lamp	

*Not available for new installation or replacement of defective fixtures.

Metal Halide Lights – Night Burning

400 Watt	$ ~~29.990~~38.000 per lamp	$~~1.253~~1.588 per lamp

The above charges will be separate from and in addition to charges for electricity supplied under the provisions of Schedule "SL".

NON-STANDARD EQUIPMENT
Non Company approved ANSI equipment, if accepted by the Company for maintenance, will be subject to special contracts which may include an initial installation charge.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Excess Deferred Income Tax Credit

CHARGES FOR SERVICING
STREET LIGHTS SERVED FROM UNDERGROUND LINES
SCHEDULE "SSL-UG"

APPLICABILITY
Applicable only to posts and luminaries meeting ANSI Standards for street lighting equipment furnished by the customer.

AVAILABILITY
Available in the District of Columbia portion of the Company's service area to Federal Governmental Agencies for servicing street, highway and park lighting equipment when the electricity supplying such equipment is furnished by the Company from unmetered underground lines and is accessible by conventional wheeled construction and maintenance vehicles.

Available only for lights having a manufacturers' nominal rating of:

Incandescent*	10,000	lumens or less
Mercury Vapor*	250 - 400	watts
High Pressure Sodium	150	watts
Metal Halide	100 - 400	watts

*Not available for new installation or replacement of defective fixtures.

CHARACTER OF SERVICE
Service rendered under this schedule will consist of (1) furnishing, installing, connecting, operating and maintaining the electric service circuits connecting the street lighting equipment to the Company's distribution system, (2) furnishing and installing post foundations and setting customer owned posts on foundations, (3) installing customer owned street lighting fixtures, (4) group relamping, (every six (6) months for incandescent, every two (2) years for metal halide, every four (4) years for mercury vapor and every five (5) years for high pressure sodium), (5) washing of globes, (6) furnishing and installing of replacement globes, lamps, remote ballasts, and light sensitive switches as needed to maintain the system in an operating mode, (7) repainting posts at approximately six (6) year intervals; all normally limited to standard items of equipment meeting ANSI Standards for street lighting equipment and accepted by the Company for maintenance.

MONTHLY RATE

		Fixed Charges		O&M Charges	
Incandescent Lights* - Night Burning					
With Globe	- all sizes	$ ~~34.870~~44.183	per lamp	$~~1.576~~1.997	per lamp

*Not available for new installation or replacement of defective fixtures.

Mercury Vapor Lights* - Night Burning				
250 Watt	$ ~~35.171~~44.565	per lamp	$~~1.416~~1.794	per lamp
400 Watt	$ ~~41.242~~52.257	per lamp	$~~1.759~~2.229	per lamp

*Not available for new installation or replacement of defective fixtures.

MONTHLY RATE (continued)

High Pressure Sodium Lights - Night Burning

150 Watt	$ ~~30.843~~39.081 per lamp	$~~1.155~~1.463 per lamp

Metal Halide - Night Burning

100 Watt	$ ~~26.578~~33.677 per lamp	$~~1.039~~1.317 per lamp
175 Watt	$ ~~29.990~~38.000 per lamp	$~~1.253~~1.588 per lamp
400 Watt	$ ~~29.990~~38.000 per lamp	$~~1.253~~1.588 per lamp

Other

Posts furnished by the Company, costing*:

$ 15.00 and less	$ 1.139 each
$ 15.01 to $ 45.00, inclusive	$ 1.517 each
$ 45.01 to $ 75.00, inclusive	$ 3.410 each
$ 75.01 to $100.00, inclusive	$ 5.687 each
$100.01 to $160.00, inclusive	$10.047 each

*Not available for new installation or replacement of defective posts.

The above charges will be separate from and in addition to charges for electricity supplied under the provisions of Schedule "SL".

CUSTOMER RESPONSIBILITY AS TO FURNISHING, INSTALLING AND MAINTAINING EQUIPMENT
The street lighting posts, fixtures and brackets (if required) shall be furnished by the customer for installation by the Company as set forth under "Character of Service" above. Ballasts for all High Pressure Sodium Lights and any Mercury Vapor Lights to be installed in or on upright posts shall be furnished by the customer. All Metal Halide lamps and ballasts shall be furnished by the customer for installation by the Company.

All maintenance of equipment furnished by the customer will be performed at the customer's expense, except as set forth under "Character of Service".

NON-STANDARD EQUIPMENT
Non-company approved ANSI accepted equipment and non-standard, special, experimental and any other such post and luminaries which do not meet ANSI Standards for street lighting equipment, if accepted by the Company for maintenance, will be subjected to special contracts. Lights of this type will be installed in accordance with the customer's instruction, and all installation costs charged to the customer.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS

Excess Deferred Income Tax Credit

TELECOMMUNICATIONS NETWORK SERVICE

SCHEDULE "TN"

AVAILABILITY
Available for either Standard Offer Service when modified by Rider "SOS" or Distribution Service in the District of Columbia portion of the Company's service area for unmetered electric service to multiple telecommunications network devices or other devices with similar load characteristics served directly by the Company and not exceeding 1,800 watts per device. For devices that are currently served by meter, the Customer may choose to have the meter removed at the Customer's expense and the month Customer Charge without Meter will apply.

CHARACTER OF SERVICE
The service supplied under this schedule normally will be alternating current, sixty hertz, single phase, 120 volts.

MONTHLY RATE

	Summer	Winter
Distribution Service Charge		
Customer Charge	$ 15.43	$ 15.43
Kilowatt-hour Charge	$ ~~0.01288~~0.01227 per kwhr	$ ~~0.01288~~0.01227 per kwhr

Customer Charges/Kilowatt-hour Charge – For devices that are served through a meter, the Customer shall pay the monthly "Customer Charge with Meter" and the kilowatt-hour charge will be applied to metered usage. For devices served without a meter, the Customer shall pay the monthly "Customer Charge without Meter" and the kilowatt-hour charge will be applied to estimated monthly usage based on metered usages for similar devices. If similar metered data do not exist, at the customer's option, the monthly usage will be estimated base on either the manufacturer's average wattage ratings with no allowance for outage, or on the basis of statistically valid sample estimates using actual current and voltage readings.

Generation and Transmission Service Charges – Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

Billing Credit - A monthly billing credit in the amount of $0.75 will be applied to the bill of each customer receiving a consolidated bill from an alternative supplier for services provided both by Pepco and by the alternative supplier.

MEASUREMENTS OF ELECTRICITY
Monthly kilowatt-hour consumption will be computed on the basis of manufacturer's average wattage ratings of installed devices, with no allowance for outages. The charges under this rider are for electricity only.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations".

APPLICABLE RIDERS
Standard Offer Services – Small Commercial
Administrative Credit
Delivery Tax
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustainable Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Customer Base Rate Credit Rider
Underground Rider
Excess Deferred Income Tax Credit

LED OUTDOOR LIGHTING SERVICE

SCHEDULE "OL LED"

AVAILABILITY
Available for Distribution Service and Standard Offer Service when modified by Rider "SOS" in the District of Columbia portion of the Company's overhead service area for customer-owned outdoor lighting purposes on customers' premises subject to local ordinance or other appropriate approval.

Not available for street lighting purposes.

CHARACTER OF SERVICE

Electricity will be supplied from distribution system facilities on a metered basis.

MONTHLY RATE
Charge for supply of electricity for operation:

Distribution Service Charges
Customer Charge
Service at secondary voltage: $8.76 per customer per month
Energy Charge:
Service at secondary voltage: $0.00895 per kwhr

Generation and Transmission Service Charges - Customers who do not receive service from an alternative Electric Supplier as defined in the Company's General Terms and Conditions will receive Generation and Transmission Services from the Company under the provisions of Rider "SOS" – Standard Offer Service.

METER READING
Watt-hour meters will be read to the nearest multiple of the meter constant and bills rendered accordingly.

GENERAL TERMS AND CONDITIONS
This schedule is subject in all respects to the Company's "General Terms and Conditions for Furnishing Electric Service" and the Company's "Electric Service Rules and Regulations" and it is further understood that:

1. Normally, lighting fixtures will not be installed on poles carrying 34.5 kV or higher voltages, or on poles supporting voltage regulators, two or more transformers or other similar equipment.

2. The Company reserves the right to discontinue the service at any time when the lighting fixture involved has been frequently damaged, apparently as a result of vandalism.

APPLICABLE RIDERS
Standard Offer Service - Small Commercial
Administrative Credit
Delivery Tax Surcharge
Public Space Occupancy Surcharge
Residential Aid Discount Surcharge Rider
Sustained Energy Trust Fund
Energy Assistance Trust Fund
Underground Project Charge Rider
Underground Rider

IN THE MATTER OF THE APPLICATION OF POTOMAC ELECTRIC POWER COMPANY FOR AUTHORITY TO IMPLEMENT A MULTIYEAR RATE PLAN FOR ELECTRIC DISTRIBUTION SERVICE IN THE DISTRICT OF COLUMBIA	**)**	**Formal Case No. 1156**

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

VOLUME IV

DIRECT TESTIMONIES AND EXHIBITS OF

Mr. Robert B. Hevert
Ms. Julie E. Giese

R.B. Hevert
Direct Testimony
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (G)

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EXECUTIVE SUMMARY - ROBERT B. HEVERT

A fair and reasonable rate of return on common equity (sometimes referred to as the ROE or Cost of Equity) is necessary for Potomac Electric Power Company (Pepco or the Company) to provide an appropriate return to its equity investors. My analyses indicate that the Company's Cost of Equity currently is in the range of 10.00 percent to 11.00 percent, and within that range I find 10.30 percent to be a reasonable and appropriate estimate to be applied to the Company's traditional rate filing and its proposed Multiyear Rate Plan (MRP). Pepco continues to be unable to earn its authorized return, and its proposed MRP would provide the opportunity to earn a return more comparable to its peers.

To estimate the Company's ROE, I relied on several analytical techniques including the Discounted Cash Flow model, the Capital Asset Pricing Model, and the Bond Yield Plus Risk Premium approach. My testimony explains that all models are subject to assumptions, and each method provides a different perspective on security pricing. The use of multiple methods, therefore, is consistent with regulatory and financial practice.

The Cost of Equity is affected by various business and financial risks faced by Pepco, including its large capital expenditure plan which Pepco has not been able to fund sufficiently with internally generated cash flows. Over the past five years, Pepco has consistently underearned its authorized ROE, sometimes by a wide margin. The Commission's decision in this proceeding will have a direct bearing on the Company's ability to maintain its financial profile, credit ratings, and its access to the capital market at reasonable cost and terms.

Lastly, I find Pepco's proposed capital structure consisting of 50.46 percent common equity is consistent with the capital structures of comparable operating utility companies.

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF ROBERT B. HEVERT
FORMAL CASE NO. 1156

I. INTRODUCTION

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

A1. My name is Robert B. Hevert. I am a Partner of ScottMadden, Inc. (ScottMadden). My business address is 1900 West Park Drive, Suite 250, Westborough, MA 01581.

Q2. On whose behalf are you submitting this testimony?

A2. I am submitting this direct testimony (Direct Testimony) before the Public Service Commission of the District of Columbia (Commission) on behalf of Pepco, a wholly owned operating subsidiary of Exelon Corporation (Exelon).

Q3. Please describe your educational background.

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

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

A4. I have worked in regulated industries for over 30 years, having served as an executive and manager with consulting firms, a financial officer of a publicly traded natural gas utility, and an analyst at a telecommunications utility. In my role as a consultant, I have advised numerous energy and utility clients on a wide range of financial and economic issues, including corporate and asset-based transactions, asset and enterprise valuation, transaction due diligence, and strategic matters. As an expert

1 witness, I have provided testimony in more than 250 proceedings regarding various
2 financial and regulatory matters before numerous state utility regulatory agencies, the
3 Federal Energy Regulatory Commission (FERC), the Alberta Utilities Commission,
4 and United States Federal Court. A summary of my professional and educational
5 background, including a list of my testimony in prior proceedings, is included in
6 PEPCO (G)-10.

7 **II. PURPOSE AND OVERVIEW OF TESTIMONY**

8 **Q5. What is the purpose of your Direct Testimony?**

9 A5. The purpose of my Direct Testimony is to present evidence and provide the
10 Commission with a recommendation regarding the Company's ROE.[1] In developing
11 my recommendation, I considered several relevant factors, including the Company's
12 continuing inability to earn its allowed ROE and its proposed MRP, which is designed
13 to address this underearning and provide the Company an opportunity to earn a fair
14 return. As discussed in Section VI, multiyear rate plans provide the opportunity for
15 more timely recovery of investments and operating costs, supporting the ability to fund
16 operations with internally generated cash. The proposed MRP helps make the
17 Company more comparable to its peers,[2] which supports the proxy group-based
18 analyses I provide below.

19 I also assess the Company's proposed ratemaking capital structure, as provided
20 in the Direct Testimony of Company Witness Ziminsky. The analyses and conclusions

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[1] Throughout my testimony, I use the terms "ROE" and "Cost of Equity" interchangeably.

[2] The Company's MRP includes performance incentive mechanisms. As discussed in the Direct Testimony of William Zarakas, performance-based regulation is an umbrella term covering multiyear rate plans and performance incentive mechanisms. I demonstrate in PEPCO (G)-9 that performance-based regulation is found in 46.25 percent of the proxy group operating companies.

discussed in my Direct Testimony are supported by the data presented in PEPCO (G)-1 to PEPCO (G)-9. My Direct Testimony and accompanying exhibits were prepared by me or under my direct supervision and control.

Q6. Please briefly summarize your analytical approach and recommendation regarding the Company's Cost of Equity.

A6. Because all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. I, therefore, relied on three widely accepted approaches to develop my ROE recommendation: (1) the Constant Growth Discounted Cash Flow (DCF) model; (2) the Capital Asset Pricing Model (CAPM); and (3) the Bond Yield Plus Risk Premium method. Those analyses indicate that the Company's Cost of Equity currently is in the range of 10.00 percent to 11.00 percent, and within that range I find 10.30 percent to be a reasonable and appropriate estimate of the Company's Cost of Equity to be applied to the traditional rate filing and the proposed MRP.

No single model is more reliable than all others under all market conditions, and all require the use of reasoned judgment in their application and in interpreting their results. Therefore, the results of each ROE model must be assessed in the context of current and expected capital market conditions and relative to other appropriate benchmarks. In developing my recommendation, I recognized that the low and high ends of the range of results (set by the low end of the range of Constant Growth DCF model results and the high end of the range of CAPM results, respectively) are not likely to be reasonable estimates of the Company's Cost of Equity. In large measure, that is because those results are far removed from the returns recently authorized in

other jurisdictions and, in the case of certain DCF-based methods, fail to adequately reflect capital market changes.

My analyses and recommendation recognize that estimating the Cost of Equity is an empirical but not an entirely mathematical exercise. It relies on both quantitative and qualitative data and analyses, all of which are used to inform the judgment that inevitably must be applied. I, therefore, considered my analytical results in the context of such Company-specific and general capital market factors as those summarized above.

I also considered evolving capital market and business conditions, including changes in Federal Reserve monetary policy. Although I did not make explicit adjustments to my ROE estimates for those factors, I did consider them in determining where the Company's Cost of Equity falls within the range of analytical results. Given the risks facing the utility sector in general, including the specific business risks to which the Company is exposed, I believe my proposed ROE of 10.30 percent is a reasonable, although conservative, estimate of the Company's Cost of Equity. In my view, the factors that weigh most heavily in estimating the Cost of Equity likely indicate an ROE at the mid- to upper-end of the range.

Q7. How have capital markets changed since the Company requested an ROE of 10.10 percent in Formal Case No. 1150?

A7. As discussed in Section VII, the Federal Reserve has continued to advance its

"normalization"[3] policy, raising the Federal Funds rate four times since December 19, 2017 and continuing its balance sheet normalization program, including gradual reductions to its security holdings by reducing its reinvestment activities.[4] At the same time, volatility (as measured by the VIX Index, discussed in greater detail in Section VII) increased from 10.56 in mid-December 2017 to 14.52 as of March 29, 2019, indicating considerably greater market uncertainty.[5]

Q8. Please now summarize the results of the three methods discussed above and how they contributed to your ROE recommendation.

A8. The range of results produced by the three approaches noted above are as follows:

- The Discounted Cash Flow method indicates an ROE in the range of approximately 8.90 percent to 10.00 percent (please refer to Table 2);[6]
- Giving less weight to the highest and lowest results, the CAPM estimates suggest an ROE in the range of approximately 9.30 percent to 11.00 percent (please refer to Table 3);[7]
- The Bond Yield Plus Risk Premium approach suggests an ROE in the range of approximately 9.90 percent to 10.20 percent (please see

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[3] "Normalization" refers to the removal of the extraordinary monetary policy initiatives adopted in response to the 2008-2009 financial crisis. The Federal Reserve has stated that the two main components of its policy normalization will be "gradually raising its target range for the federal funds rate to more normal levels and gradually reducing the Federal Reserve's securities holdings." *See*: https://www.federalreserve.gov/monetarypolicy/policy-normalization.htm

[4] *Id*., and Federal Open Market Committee (FOMC) Press Release, June 14, 2017.

[5] Bloomberg Professional Services. Measured as a rolling 30-day average.

[6] As discussed above, my estimate of the indicated range approximates the overall range of model results. Moreover, for the reasons discussed below, I find the underlying assumptions of the DCF model inconsistent with the current capital market and believe the model's results should be viewed with caution.

[7] As discussed above, my estimate of the indicated range is narrower than the overall range of model results.

PEPCO (G)-5).[8]

Based on those estimates, I recommend an ROE in the range of 10.00 percent to 11.00 percent and, within that range, recommend an ROE of 10.30 percent. As discussed in more detail throughout the balance of my Direct Testimony, my conclusions and recommendations reflect the following considerations:

- Broad-based expectations for increases in long-term interest rates, as revealed in economists' consensus projections, which weigh in the evaluation of the DCF, CAPM, and Bond Yield Plus Risk Premium results;
- The capital-intensive nature of utility operations, indicating the need to finance large, long-lived investments with internally generated and externally acquired funds, both of which depend on the Company's ability to earn a reasonable return on its rate base;
- The need to maintain the financial profile required to access capital at reasonable rates, even during periods of capital market distress; and
- The Company's continuing inability to earn its authorized return, and the proposed MRP, which would provide the opportunity to earn a return more comparable to its peers.

Q9. Are there other factors that should be considered in determining the weight given to the methods and results summarized above?

A9. Yes, there are. All models used to estimate the Cost of Equity are subject to certain assumptions, which may become more, or less, relevant as market conditions and market data change. An important consideration is the consistency of each model's

[8] Results rounded.

underlying assumptions with current and expected market conditions and the reasonableness of its results relative to observable benchmarks. For example, the Constant Growth DCF model assumes the estimated Cost of Equity will remain constant in perpetuity. The Federal Reserve, however, is continuing to "normalize" monetary policy such that the conditions supporting current ROE estimates will not persist in the long run. Because that model does not allow us to incorporate such important factors or to reflect the expected risk associated with changing market conditions, its results should be viewed with caution.

Risk Premium-based methods (such as the Capital Asset Pricing Model), on the other hand, provide a measure of risk and have the benefit of directly considering investors' expectations regarding future market returns. Other Risk Premium approaches (such as the Bond Yield Plus Risk Premium approach) reflect the well-documented finding that the Cost of Equity does not move in lockstep with interest rates. For example, at times interest rates fall because investors are so risk averse, they would rather accept a very modest return on Treasury securities than take on the risk of equity ownership.[9] In such circumstances, low interest rates suggest an increasing, not a decreasing, Cost of Equity. Therefore, the important analytical issues relate to understanding each model's fundamental structure and assumptions and interpreting its results in the context of current and expected market conditions.

Because each model has its own strengths and weaknesses, it is important to

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[9] *See,* Beber, A., Brandt, M., & Kavajecz, K. Flight-to-Quality or Flight-to-Liquidity? Evidence from the Euro-Area Bond Market. (Working Paper 12376), National Bureau of Economic Research, July 2006, ("It is not uncommon to hear discussions in the academic or financial press describing a flight out of equities and into fixed income markets when the perceived risk in equity markets rises (e.g., Connolly, Stivers, and Sun, 2005; Underwood, 2006)").

recognize those differences in estimating the Cost of Equity. On balance, I believe the Constant Growth DCF model results should be viewed with caution[10] and given less weight than the other approaches. Because Risk Premium-based methods provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the Cost of Equity, those methods likewise should be given more weight than the Constant Growth DCF method. With those considerations in mind, I believe that my recommendation reasonably reflects investors' return requirements in the current market environment.

Q10. Does your recommendation balance the interests of investors and customers?

A10. Yes. Investors have many options available to them and will only invest in a firm if the expected return justifies the risks taken on in making that investment. Customers have an interest in safe, reliable, and efficient service, which depends on investors' willingness to commit the capital needed to maintain and improve the utility system. In that important sense, investors and customers have a common interest in a financially strong utility that is able to access low-cost capital when and as needed. To the extent the ROE is (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure the utility's financial integrity; and (3) commensurate with returns on

[10] Other jurisdictions have noted similar conclusions. *See, for example*, *Martha Coakley v. Bangor Hydro-Electric Company, Order on Initial Decision,* Opinion No. 531, 147 FERC ¶ 61,234 (2014), *Order On Paper Hearing* Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), and *Order On Rehearing* Opinion No. 531-B, 150 FERC ¶ 61,165 (2015); Massachusetts Department of Public Utilities, D.P.U. 13-90, *Petition of Fitchburg Gas and Electric Light Company (Electric Division) d/b/a Unitil*, May 30, 2014, at 219; *Formal Case No. 1093, In the Matter of the Investigation into the Reasonableness of Washington Gas Light Company's Existing Rates and Charges for Gas Service*, Before the Public Service Commission of the District of Columbia, Order No. 17132, May 15, 2013, at 17-18, 20. Also, an article recently published by Bloomberg notes the ultralow interest rate environment has "wrought havoc" on the DCF model. *See*, Kawa, Luke, "A Critical Idea in Valuing Stocks Is Being Made Obsolete by Low Rates," Bloomberg Business, October 13, 2016. http://www.bloomberg.com/news/articles/2016-10-13/a-critical-idea-in-valuing-stocks-is-being-madeobsolete-by-low-rates.

investments of comparable risk, the interests of investors and customers will be aligned. I believe my recommendation meets that objective.

Q11. Please summarize your conclusions regarding the Company's proposed capital structure.

A11. I find the Company's proposal in this case, which includes 50.46 percent common equity and 49.54 percent long-term debt, as derived in the Direct Testimony of Company Witness Ziminsky, is consistent with the capital structures that have been in place over several fiscal quarters at comparable operating utility companies. In light of its ongoing need to access external capital and given the consistency of its proposal with similarly situated utility companies, I believe the Company's proposed capital structure is reasonable and appropriate.

Q12. How is the remainder of your Direct Testimony organized?

A12. The remainder of my Direct Testimony is organized as follows:

- Section III – Discusses the regulatory guidelines and financial considerations pertinent to the development of the cost of capital;
- Section IV – Explains my selection of the proxy group of electric utilities used to develop my analytical results;
- Section V – Explains my analyses and the analytical basis for my ROE recommendation;
- Section VI – Provides a discussion of business risks and other considerations, including the proposed MRP, that have a direct bearing on the Company's Cost of Equity;
- Section VII – Briefly discusses the current capital market conditions and the

effect of those conditions on the Company's Cost of Equity;

- Section VIII – Addresses the reasonableness of the Company's proposed capital structure; and
- Section IX – Summarizes my conclusions and recommendations.

III. REGULATORY GUIDELINES AND FINANCIAL CONSIDERATIONS

Q13. Before addressing the specific aspects of this proceeding, please provide an overview of the issues surrounding the Cost of Equity in regulatory proceedings generally.

A13. In general terms, the Cost of Equity is the return investors require to make an equity investment in a firm. That is, investors will provide funds to a firm only if the return they *expect* is equal to, or greater than, the return they *require* to accept the risk of providing funds to the firm. From the firm's perspective, that required return, whether it is provided to debt or equity investors, has a cost. Individually, we speak of the "Cost of Debt" and the "Cost of Equity" as measures of those costs; together, they are referred to as the "Cost of Capital."

The Cost of Capital (including the costs of both debt and equity) is based on the economic principle of "opportunity costs." Investing in any asset, whether debt or equity securities, implies a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative, comparable risk investment opportunities. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk. In that important respect, the returns required by debt and equity investors represent a cost

to the Company.

Although both debt and equity have required costs, they differ in certain fundamental ways. Most noticeably, the Cost of Debt is contractually defined and can be directly observed as the interest rate or yield on debt securities.[11] The Cost of Equity, on the other hand, is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the Cost of Equity. Because equity investors bear the "residual risk," they take greater risks and require higher returns than debt holders. In that basic sense, equity and debt investors differ: they invest in different securities, face different risks, and require different returns.

While the Cost of Debt can be directly observed, the Cost of Equity must be estimated based on market data and various financial models. As discussed throughout my Direct Testimony, each model is subject to specific assumptions, which may be more or less applicable under differing market conditions. In addition, because the Cost of Equity is premised on opportunity costs, the models typically are applied to a group of "comparable" or "proxy" companies. The choice of models (including their inputs), the selection of proxy companies, and the interpretation of the model results all require the application of reasoned judgment. That judgment should consider data and information that is not necessarily included in the models themselves. In the end, the estimated Cost of Equity should reflect the return that investors require in light of the subject company's risks and the returns available on comparable investments.

[11] The observed interest rate may be adjusted to reflect issuance costs.

Q14. Please provide a brief summary of the guidelines established by the United States Supreme Court (the Court) for the purpose of determining the ROE.

A14. The Court established the guiding principles for establishing a fair return for capital in two cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia* (*Bluefield*);[12] and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* (*Hope*).[13] In those cases, the Court recognized that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

Q15. Has the Commission provided similar guidance?

A15. Yes. The Commission has relied on the *Hope* and *Bluefield* comparable risk, capital attraction, and financial integrity standards in prior Pepco rate decisions, including the Company's most recent fully litigated rate case, to establish the rate of return.[14] Based on those standards, the authorized ROE should provide the Company with the opportunity to earn a fair and reasonable return and should enable efficient access to external capital under a variety of market conditions.

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[12] *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-93 (1923).

[13] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

[14] *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, Formal Case No. 1139, Order No. 18846 (Jul. 25, 2017), at P 250.

Q16. Aside from those long-held standards, why is it important for a utility to be allowed the opportunity to earn a return adequate to attract capital at reasonable terms?

A16. A return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with the *Hope* and *Bluefield* standards, that return should be commensurate with the returns expected elsewhere in the market for investments of equivalent risk. The consequence of the Commission's order in this case, therefore, should be to provide the Company with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks.

To the extent the Company is provided a reasonable opportunity to earn its market-based Cost of Equity, neither customers nor shareholders should be disadvantaged. As noted earlier, a return that is adequate to attract capital at reasonable terms enables the Company to provide safe, reliable electric utility service while maintaining its financial integrity.

Q17. How is the Cost of Equity estimated in regulatory proceedings?

A17. As noted earlier, the Cost of Equity is estimated by the use of various financial models. By their nature, those models produce a range of results from which the ROE is determined. That determination must be based on a comprehensive review of relevant data and information; it does not necessarily lend itself to a strict mathematical solution. The key consideration in determining the ROE is to ensure the overall

analysis reasonably reflects investors' view of the financial markets in general, and the subject company (in the context of the proxy companies), in particular.

The use of multiple methods, and the consideration given to them, recently was addressed by FERC.[15] In its November 15, 2018 *Order Directing Briefs,* FERC found that "in light of current investor behavior and capital market conditions, relying on the DCF methodology alone will not produce a just and reasonable ROE".[16] In its October 16, 2018 *Order Directing Briefs*, FERC found that although it "previously relied solely on the DCF model to produce the evidentiary zone of reasonableness…", it is "concerned that relying on that methodology alone will not produce just and reasonable results."[17] As FERC explained, because the Cost of Equity depends on what the market expects, it is important to understand "how investors analyze and compare their investment opportunities."[18] FERC also explained that, although certain investors may give some weight to the DCF approach, other investors "place greater weight on one or more of the other methods…"[19] Those methods include the CAPM and the Risk

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[15] The methods recently considered by FERC include: (1) the Two-Step DCF model; (2) the Risk Premium model; (3) the CAPM; and (4) the Expected Earnings Approach. *See* Docket No. EL11-66-001, *et al*., *Order Directing Briefs*, 165 FERC ¶ 61,030 (Oct. 16, 2018) at P 32; Docket No. EL14-12-0031, *et al*., *Order Directing Briefs*, 165 FERC ¶ 61,118 (Nov. 15, 2018), at P 34.

[16] Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (Nov. 15, 2018), at P 34.

[17] Docket No. EL11-66-001, *et al*., *Order Directing Briefs*, 165 FERC ¶ 61,030 (Oct. 16, 2018), at P 30.

[18] *Id*., at P 33.

[19] *Id*., at P 35. *See*, generally, Docket No. PL19-4-000, *Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 166 FERC ¶ 61,207, Mar. 21, 2019.

Premium method, which I have applied in this proceeding.[20]

In summary, practitioners, academics, and regulatory commissions recognize that financial models are tools to be used in the ROE estimation process; they are descriptions of investor behavior, not precise quantifications of it. Consequently, the strict adherence to any single approach or to the specific results of any single approach can lead to flawed or misleading conclusions. That position is consistent with the *Hope* and *Bluefield* principle that it is the analytical result, as opposed to the method employed, that is controlling in arriving at ROE determinations. Thus, a reasonable ROE estimate appropriately considers multiple methods, and the reasonableness of their individual and collective results in the context of observable, relevant market information.

IV. PROXY GROUP SELECTION

Q18. As a preliminary matter, why is it necessary to select a group of proxy companies to determine the Cost of Equity for Pepco?

A18. First, it is important to bear in mind that the Cost of Equity for a given enterprise depends on the risks attendant to the business in which the company is engaged. According to financial theory, the value of a given company is equal to the aggregate market value of its constituent business units. The value of the individual business units reflects the risks and opportunities inherent in the business sectors in which those

[20] The Commission has also considered alternative ROE estimation methods. *See,* Order No. 18712, Formal Case No. 1137, In The Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service, at 25-26, ("In its decisions, the Commission has relied primarily on the DCF method to determine a utility's appropriate cost of common equity…nevertheless, the Commission's preference for the DCF model does not preclude consideration of other methods like the CAPM and RPM for calculating cost of equity in some instances…in addition, in determining the just and reasonable cost of equity, the Commission considers the entire record, which may include actions taken by other commissions and recent changes in the law. [citations omitted]").

1 units operate. In this proceeding, we are focused on estimating the Cost of Equity for
2 Pepco, whose parent is Exelon. Because the ROE is a market-based concept, and Pepco
3 is not a separate entity with its own stock price, it is necessary to establish a group of
4 companies that are both publicly traded and comparable to Pepco in certain
5 fundamental respects to serve as its "proxy" in the ROE estimation process.

6 Even if Pepco were a publicly traded entity, short-term events could bias its
7 market value during a given period of time. A significant benefit of using a proxy
8 group is that it serves to moderate the effects of anomalous, temporary events
9 associated with any one company.

10 **Q19. Does the selection of a proxy group suggest that analytical results will be tightly**
11 **centered around average (*i.e.*, mean) results?**

12 A19. Not necessarily. For example, the Constant Growth DCF model defines the
13 Cost of Equity as the sum of the expected dividend yield and projected long-term
14 growth. Despite the care taken to ensure risk comparability, market expectations with
15 respect to future risks and growth opportunities will vary from company to company.
16 Therefore, even within a group of similarly situated companies, it is common for
17 analytical results to reflect a seemingly wide range. At issue is how to estimate the
18 Cost of Equity from within that range. As discussed earlier, that determination
19 necessarily considers a wide range of both quantitative and qualitative information.

20 **Q20. Please provide a summary profile of Pepco.**

21 A20. Pepco is a wholly owned operating subsidiary of Exelon (NYSE: EXC). The
22 Company provides electric transmission, distribution, and default supply service to

approximately 359,000 customers in the District of Columbia.[21] Pepco's long-term corporate credit ratings currently are A-,[22] Baa1, and BBB from Standard & Poor's (S&P), Moody's Investor Services (Moody's), and FitchRatings (Fitch), respectively.[23] Pepco's and Exelon's credit ratings outlooks are currently positive or stable.

Q21. How did you select the companies included in your proxy group?

A21. A proxy group should include companies with risk profiles comparable to the subject company. In selecting the proxy group, my objective was to balance the dual objectives of selecting companies that are highly representative of the risks and prospects faced by the Company, while ensuring a sufficient number of companies in the group. Based on those two considerations, I began with the universe of companies that Value Line classifies as Electric Utilities and applied the following screening criteria:[24]

- Because certain of the models used in my analyses assume that earnings and dividends grow over time, I excluded companies that do not consistently pay quarterly cash dividends;
- To ensure the growth rates used in my analyses are not biased by a single analyst, I excluded companies that were not covered by at least two utility industry equity analysts;

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21 Data provided by Company.

22 S&P Global Ratings, March 1, 2019, *Exelon Upgraded To 'BBB+' On Successful Execution Of Growth Strategy; Subsidiary Ratings Also Raised; Outlook Stable.*

23 Bloomberg Professional Services.

24 This screening criteria is the same that I used in Formal Case No. 1139. In this docket, the Commission stated "Overall, the Commission finds the proxy groups selected by the parties to be similar and generally reasonable for purposes of assessing the investment risks of Pepco in the financial market." *Order No. 18846* at 89.

- All the companies in my proxy group have an investment-grade senior bond and/or corporate credit ratings from S&P;[25]
- To ensure the analytical results represent regulated utility operations, I excluded companies whose regulated operating income over the three most recently reported fiscal years comprised less than 60.00 percent of their consolidated total;
- To ensure the analytical results represent regulated electric utility operations, I excluded companies whose regulated electric operating income over the three most recently reported fiscal years represented less than 60.00 percent of their total regulated operating income; and
- To ensure the results of my analyses are not skewed by event-driven swings in market data, I excluded companies currently known to be party to a merger or other significant transaction.

Q22. Did you include Exelon in your analysis?

A22. No. To avoid the circular logic that otherwise would occur, it has been my consistent practice to exclude the subject company (or its parent) from the proxy group.

Q23. Why did you include vertically integrated utilities in your proxy group when Pepco is a transmission and distribution company?

A23. Although Pepco is a transmission and distribution (T&D) company, there are no "pure play" state-jurisdictional electric T&D companies that may be used as proxies

[25] A corporate rating generally rates the issuer's overall creditworthiness or capacity to pay its financial obligations, while a bond rating is a specific issue rating that speaks to the credit quality of an individual debt issue such as a corporate note or municipal bond.

for the Company's District of Columbia electric distribution operations.[26] I, therefore, concluded it is reasonable to include vertically integrated electric companies (that is, companies that own and operate regulated electric generation capacity) in my proxy group.

Q24. Does your proxy group include companies that have performance-based regulation mechanisms in place?

A24. Yes. Performance-based regulation mechanisms are commonly found in the proxy group. I demonstrate in PEPCO (G)-9 that performance-based regulation is found in 46.25 percent of the proxy group operating companies.

Q25. What companies met those screening criteria?

A25. The criteria discussed above resulted in the following group of 24 proxy companies:

[26] In Formal Case No. 1139, the Commission recognized the lack of "pure play" companies stating, "We are mindful that there are few absolute transmission and distribution companies that can serve as proxies for Pepco" *Order No. 18846* at ¶280.

Table 1: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Company, Inc.	AEP
Avangrid, Inc.	AGR
Black Hills Corporation	BKH
CMS Energy Corporation	CMS
Consolidated Edison, Inc.	ED
DTE Energy Company	DTE
Duke Energy Corporation	DUK
El Paso Electric Company	EE
Evergy, Inc.	EVRG
Eversource Energy	ES
Hawaiian Electric Industries, Inc.	HE
NextEra Energy, Inc.	NEE
NorthWestern Corporation	NWE
OGE Energy Corp.	OGE
Otter Tail Corporation	OTTR
Pinnacle West Capital Corporation	PNW
PNM Resources, Inc.	PNM
Portland General Electric Company	POR
Southern Company	SO
WEC Energy Group, Inc.	WEC
Xcel Energy Inc.	XEL

V. COST OF EQUITY ESTIMATION

Q26. Please briefly discuss the ROE in the context of the regulated rate of return.

A26. Regulated utilities primarily use common stock and long-term debt to finance their capital investments. The overall rate of return (ROR) weighs the costs of the individual sources of capital by their respective book values. While the cost of debt and cost of preferred stock can be directly observed, the Cost of Equity is market-based

and, therefore, must be estimated based on observable market information.

Q27. How is the requested ROE determined?

A27. Because the Cost of Equity is not directly observable, it must be estimated based on both quantitative and qualitative information. Although several empirical models have been developed for that purpose, all are subject to limiting assumptions or other constraints. Consequently, many finance texts recommend using multiple approaches to estimate the Cost of Equity.[27] When faced with the task of estimating the Cost of Equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed and, therefore, rely on multiple analytical approaches.

As discussed earlier, FERC has found that no individual model is more reliable than all others under all market conditions and that the application of judgement is important in developing ROE estimates. Regulatory commissions in other regulatory jurisdictions, including Hawaii, Maryland, Massachusetts, and North Carolina, have made similar findings.[28] As those commissions have found, it is both prudent and appropriate to use multiple methods to mitigate the effects of assumptions and inputs associated with any single approach. As such, I have considered the results of the Constant Growth DCF model, the Capital Asset Pricing Model, and the Bond Yield

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[27] *See, for example,* Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341, and Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed., 2000, at 214.

[28] *See*, *for example*: (1) Public Utilities Commission of the State of Hawaii, Docket No. 7700, Order No. 13704, *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval of Rate Increases and Revised Rate Schedules and Rules*, December 28, 1994 at 92; (2) Maryland Public Service Commission, Case No. 9443, Order No. 88432, *In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*, October 27, 2017, at 102; (3) The Commonwealth of Massachusetts Department of Public Utilities, *Investigation by the Department of Public Utilities*, Docket D.P.U. 15-155, September 30, 2016, at 376-378; and (4) State of North Carolina Utilities Commission, *In the Matter of Application of Public Service Company of North Carolina, Inc. for a General Increase in its Rates and Charges*, Docket No. G-5, Sub 565, *Order Approving Rate Increase and Integrity Management Tracker*, October 28, 2016, at 35-36.

Plus Risk Premium approach.

A. Constant Growth DCF Model

Q28. Please describe the Constant Growth DCF approach.

A28. The Constant Growth DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the Constant Growth DCF model expresses the Cost of Equity as the discount rate that sets the current price equal to expected cash flows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_t}{(1+k)^t} \quad [1]$$

where P_0 represents the current stock price, $D_1 \ldots D_t$ represent expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present-value calculation that can be simplified and rearranged into the familiar form:

$$k = \frac{D(1+g)}{P_0} + g \quad [2]$$

Equation [2] often is referred to as the "Constant Growth DCF" model, in which the first term $\frac{D(1+g)}{P_0}$ is the expected dividend yield and the second term g is the expected long-term growth rate.

Q29. What assumptions are required for the Constant Growth DCF model?

A29. The Constant Growth DCF model assumes: (1) earnings, book value, and dividends all grow at the same, constant rate in perpetuity; (2) the dividend payout ratio remains constant; (3) the P/E multiple remains constant in perpetuity; and (4) the discount rate is greater than the expected growth rate and remains constant over time. The model also assumes the Cost of Equity will remain constant, in perpetuity.

1 **Q30. What market data did you use to calculate the dividend yield component of your**
2 **DCF model?**
3 A30. The dividend yield is based on the proxy companies' current annualized
4 dividend and average closing stock prices over the 30-, 90-, and 180-trading day
5 periods as of March 29, 2019.
6 **Q31. Why did you use three averaging periods to calculate an average stock price?**
7 A31. I did so to ensure that the model's results are not skewed by anomalous events
8 that may affect stock prices on any given trading day. The use of averages is a common
9 practice across regulatory jurisdictions. In my view, averaging prices is helpful to
10 address short-term trading volatility not explained by fundamental financial
11 performance or other material disclosures or market events. At the same time, the
12 averaging period should be reasonably representative of expected capital market
13 conditions over the long term. Capital market conditions can rapidly change, and any
14 short-term period can capture either a temporary upswing or downswing in equity
15 valuations. In my view, a consistent method using three averaging periods mitigates
16 that potential volatility and, in my experience, using 30-, 90-, and 180-day averaging
17 periods is a reasonable approach.
18 **Q32. Did you make any adjustments to the dividend yield to account for periodic**
19 **growth in dividends?**
20 A32. Yes, I did. Because utilities increase their quarterly dividends at different times
21 throughout the year, it is reasonable to assume that dividend increases will be evenly
22 distributed over calendar quarters. Given that assumption, it is appropriate to calculate
23 the expected dividend yield by applying one-half of the long-term growth rate to the

current dividend yield.[29] That adjustment ensures the expected dividend yield is, on average, representative of the coming 12-month period and does not overstate the dividends to be paid during that time.

Q33. Is it important to select appropriate measures of long-term growth in applying the DCF model?

A33. Yes. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation [2] above) assumes a single growth estimate in perpetuity. To reduce the long-term growth rate to a single measure, we must assume a fixed payout ratio and the same constant growth rate for earnings per share (EPS), dividends per share, and book value per share. Because dividend growth can only be sustained by earnings growth, the model should incorporate a variety of measures of long-term earnings growth. That can be accomplished by averaging measures of long-term growth that tend to be least influenced by capital allocation decisions that companies may make in response to near-term changes in the business environment. Because such decisions may directly affect near-term dividend payout ratios, estimates of earnings growth are more indicative of long-term investor expectations than are dividend growth estimates. For the purposes of the Constant Growth DCF model, therefore, growth in EPS is the appropriate measure of long-term growth.

Q34. Please summarize the findings of academic research on the appropriate measure of growth for estimating equity returns using the DCF model.

A34. The relationship between various growth rates and stock valuation metrics has

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[29] *See,* Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., 2006, at 349-350. *See,* PEPCO (G)-1.

been the subject of much academic research.[30] As noted over 40 years ago by Charles Phillips in The Economics of Regulation:

> For many years, it was thought that investors bought utility stocks largely on the basis of dividends. More recently, however, studies indicate that the market is valuing utility stocks with reference to total per share earnings, so that the earnings-price ratio has assumed increased emphasis in rate cases.[31]

Phillips' conclusion continues to hold true. Subsequent academic research clearly and consistently indicates that measures of earnings and cash flow are strongly related to returns and that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices.[32] For example, Vander Weide and Carleton state that "[our] results … are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions."[33] Other research specifically notes the importance of analysts' growth estimates in determining the Cost of Equity and in the valuation of equity securities. Dr. Robert Harris notes that "a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices."[34] Citing Cragg and Malkiel, Dr. Harris notes that those authors "found that the evaluations of companies

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30 *See*, Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return,* Financial Management (Spring 1986).

31 Charles F. Phillips, Jr., The Economics of Regulation, at 285 (Rev. Ed. 1969).

32 *See*, *for example*, Christofi, Christofi, Lori and Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999); Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, (Summer 1992); and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

33 Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988). The Vander Weide and Carleton study was updated in 2004 under the direction of Dr. Vander Weide. The results of the updated study were consistent with the original study's conclusions.

34 Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

that analysts make are the sorts of ones on which market valuation is based."[35] Similarly, Brigham, Shome, and Vinson noted that "evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data, and (ii) investors do rely on analysts' forecasts."[36]

To that point, the research of Carleton and Vander Weide demonstrates that earnings growth projections have a statistically significant relationship to stock valuation levels, while dividend growth rates do not.[37] Those findings suggest investors form their investment decisions based on expectations of growth in earnings rather than dividends. Consequently, earnings growth, not dividend growth, is the appropriate estimate for the purpose of the Constant Growth DCF model.

Q35. Please summarize your inputs to the Constant Growth DCF model.

A35. I applied the DCF model to the proxy group of electric utility companies using the following inputs for the price and dividend terms:

1. The average daily closing prices for the 30-, 90-, and 180-trading days ended March 29, 2019 for the term P_0; and
2. The annualized dividend per share as of March 29, 2019 for the term D_0.

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

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

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35 *Id.*

36 Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management (Spring 1985).

37 *See*, Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

Q36. How did you calculate the high and low DCF results?

A36. For each proxy company, I calculated the mean, mean high, and mean low results. For the mean result, I combined the average of the EPS growth rate estimates reported by Value Line, Zacks, and First Call with the subject company's dividend yield for each proxy company and then calculated the average result for those estimates. I calculated the high DCF result by combining the maximum EPS growth rate estimate as reported by Value Line, Zacks, and First Call with the subject company's dividend yield. The mean high result is the average of those estimates. I used the same approach to calculate the low DCF result, using instead the minimum of the Value Line, Zacks, and First Call estimate for each proxy company and calculating the average result for those estimates.

Q37. What are the results of your DCF analysis?

A37. My Constant Growth DCF results are summarized in Table 2 (*see also,* PEPCO (G)-1).

Table 2: Constant Growth DCF Results[38]

	Median	Median High
30-Day Average	8.90%	9.68%
90-Day Average	9.01%	9.80%
180-Day Average	9.11%	9.96%

[38] *See also*, PEPCO (G)-1, which includes the Median Low estimates and Mean, Mean High and Mean Low estimates.

Q38. Do you believe the Constant Growth DCF model currently provides a reasonable estimate of the Company's Cost of Equity?

A38. No, I do not. In past proceedings, the Commission has indicated that it prefers the DCF model but considers other methods in determining the just and reasonable Cost of Equity.[39] Because the period over which my analyses were performed included market data that were inconsistent with the model's fundamental assumptions (discussed earlier), the DCF model produced results at odds with current observable capital market conditions. Regardless of the method employed, however, an authorized ROE that is well below returns authorized for other utilities (1) runs counter to the *Hope* and *Bluefield* "comparable risk" standard, (2) would place the Company at a competitive disadvantage, and (3) would make it difficult for the Company to compete for capital at reasonable terms.

Q39. Please summarize the reasons you believe the Constant Growth DCF model should not be given undue weight in this proceeding.

A39. As explained earlier, the model assumes that the return estimated today will be the same return required in the future, even though the Federal Reserve only recently has begun its move toward monetary policy normalization. That process of normalization, together with the uncertainty surrounding the "unwinding" of the assets put on the Federal Reserve's balance sheet during its "Quantitative Easing" initiatives

[39] In Formal Case No. 1139, the Commission stated "In its decisions, the Commission has relied primarily on the DCF model to determine a utility's appropriate cost of common equity because the Commission consistently has found that the DCF method produces results more reasonable than those of other methods…However, our reliance on the DCF model does not foreclose the parties from advocating the use of other methods in future rate proceedings. The Commission, as always, considers the entire record in determining the just and reasonable cost of equity, which may include action taken by other commissions and recent changes in the law." Order No. 18846, at ¶277.

1 introduce a degree of risk and a likelihood of increasing interest rates not present in the
2 current market. As also discussed later in my Direct Testimony, other methods more
3 directly reflect the risk premium required by investors in response to market and
4 industry risks. On balance, it is my view that the Constant Growth DCF method should
5 be given less weight than other methods in establishing the Company's ROE.

6 **Q40. With those points in mind, how did you reflect the Constant Growth DCF results**
7 **in your ROE range and recommendation?**

8 A40. I first recognized that the model's mean low results are well below a reasonable
9 estimate of the Company's Cost of Equity. For example, of the 1,585 electric utility
10 rate cases provided by Regulatory Research Associates that disclosed the awarded ROE
11 since 1980, only ten included an authorized ROE below 9.00 percent.[40] On that basis
12 alone, the mean low results are highly improbable.

13 I then considered why the Constant Growth model is producing such low
14 estimates of the Company's Cost of Equity. In one sense, relatively low dividend yields
15 should be associated with relatively high growth rates. That is, low dividend yields are
16 the result of relatively high stock prices which, in turn, should be associated with
17 relatively high growth rates. If those relationships do not hold, the model's results
18 should be viewed with some caution.

19 I also recognize that while the Constant Growth DCF model assumes existing
20 capital market conditions will remain constant, Risk Premium-based methods
21 (discussed later in this Section) more directly reflect the changing capital market

[40] Regulatory Research Associates. Eight of those ten were the outcome of Illinois formula rate plans. Excluding Illinois formula rate plans, since 2015, only one electric utility rate case included an authorized ROE below 9.00 percent.

environment (*see* Section VII). Because it is important to reflect the results of different models, and the mean and mean low Constant Growth DCF results are far-removed from recently authorized returns, I concluded that they should be given less weight than other methods in determining the Company's ROE.

B. CAPM Analysis

Q41. Please briefly describe the general form of the CAPM analysis.

A41. The CAPM is a risk premium approach that estimates the Cost of Equity as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security). As shown in Equation [3], the CAPM is defined by four components, each of which theoretically is a forward-looking estimate:

$$K_e = r_f + B(r_m - r_f) \quad [3]$$

where:

k = the required market ROE for a security;

β = the Beta coefficient of that security;

r_f = the risk-free rate of return; and

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

In Equation [3], the term ($r_m - r_f$) represents the Market Risk Premium.[41] According to the theory underlying the CAPM, because unsystematic risk can be diversified away by adding securities to their investment portfolio, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

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

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

where:

σ_j = the standard deviation of returns for company "*j*,"

σ_m = the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and

$\rho_{j,m}$ = the correlation of returns in between company *j* and the broad market.

The Beta coefficient, therefore, represents both relative volatility (*i.e.*, the standard deviation) of returns and the correlation in returns between the subject company and the overall market. Intuitively, higher Beta coefficients indicate the subject company's returns have moved in tandem with the overall market.

Q42. What risk-free rate assumptions did you include in your CAPM analysis?

A42. Because utility equity has a perpetual life (that is, it is a long-duration security), I used three different measures of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (*i.e.*, 2.99 percent):[42] (2) the near-term projected 30-year Treasury yield (*i.e.*, 3.13 percent):[43] and (3) the long-term projected 30-year Treasury yield (*i.e.*, 4.05 percent).[44]

Q43. Why have you relied on forward-looking interest rate projections in your ROE analyses?

A43. The Cost of Equity is a forward-looking concept, and it is important the inputs

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[42] Bloomberg Professional Services.

[43] *See,* Blue Chip Financial Forecasts, Vol. 38, No. 4, April 1, 2019, at 2. Consensus projections of the 30-year Treasury yield for the six quarters ending September 2020.

[44] *See,* Blue Chip Financial Forecasts, Vol. 37, No. 12, December 1, 2018, at 14. Consensus projections of the 30-year Treasury yield for the periods 2020-2024 and 2025-2029.

used in Cost of Equity models reflect forward-looking market expectations. The Federal Reserve has begun to unwind its Quantitative Easing initiatives (discussed in Section VII), and there is widespread expectation that rates will rise going forward. Although uncertainty remains regarding the timing of the Federal Reserve's actions and the future of interest rates, what is important is to reflect investor expectations. As FERC noted in Opinion No. 531, "the cost of common equity to a regulated enterprise depends upon what the market expects, not upon what ultimately happens."[45]

As discussed in Section VII, consensus projections from professional market participants indicate investors expect interest rates to rise. I appreciate that, in Formal Case No. 1139, the Commission expressed its concern that forward-looking interest rates were "speculative".[46] Although projections are inherently uncertain, the salient issue for application of the CAPM is the rates investors expect and how those expectations affect their investment decisions. I continue to believe those expectations should be reflected in the CAPM analysis.

Q44. What Market Risk Premium did you use in your CAPM analysis?

A44. To reflect current market expectations, I developed two forward-looking (*ex-ante*) estimates of the Market Risk Premium.

Q45. Please describe your *ex-ante* approach to estimating the Market Risk Premium.

A45. The approach is based on the market-required return, less the current 30-year Treasury bond yield. To estimate the market-required return, I calculated the market capitalization weighted average ROE based on the Constant Growth DCF model. To

[45] Opinion No. 531, 147 FERC ¶ 61,234, at P 88.
[46] Order No. 18846, at ¶284.

do so, I relied on dividend yields and growth rates from both Bloomberg and Value Line. For the Bloomberg-derived growth estimates, I calculated the expected dividend yield (using the same one-half growth rate assumption described earlier) and combined that amount with the projected earnings growth rate to arrive at the market capitalization weighted average DCF result. I performed that calculation for each of the companies for which Bloomberg provided both dividend yields and consensus growth rates. I then subtracted the current 30-year Treasury yield from that amount to arrive at the market DCF-derived *ex-ante* Market Risk Premium estimate. In the case of Value Line, I performed the same calculation, again using all companies for which five-year earnings growth rates were available. The results of those calculations are provided in PEPCO (G)-2.

Q46. Have you considered the Commission's concern expressed in Formal Case No. 1139 that Market Risk Premiums derived from Bloomberg and Value Line data were overstated?[47]

A46. Yes, I have. As a check to ensure the projected market returns are reasonable, I reviewed them in context of the observed market returns. In that regard, I note the Value Line and Bloomberg expected returns fall in approximately the 43rd and 49th percentile, respectively, of observed returns from 1926-2018. That is, the projected market returns from my study are consistent with historical market results and are generally near the median of actual market returns for over nine decades.

Lastly, I note the Bloomberg and Value Line data are market-reported measures of investor expectations, which is the type of data that should be given weight in Cost

[47] Order No. 18846, at ¶284.

of Equity analysis. Because the estimates generally are consistent with actual observed returns, I do not believe there is reason to consider them overstated.

Q47. How did you apply your expected Market Risk Premium and risk-free rate estimates?

A47. I relied on the *ex-ante* Market Risk Premiums discussed above, together with the current, near-term projected, and long-term projected 30-year Treasury bond yields, as inputs to my CAPM analysis.

Q48. What Beta coefficients did you use in your CAPM analysis?

A48. As shown in PEPCO (G)-3, I considered the Beta coefficients reported by Value Line and Bloomberg, both of which adjust their calculated (or raw) Beta coefficients to reflect the tendency of the Beta coefficient to regress to the market mean of 1.00. A notable difference between the two is that Value Line calculates the Beta coefficient over a five-year period, while Bloomberg's calculation is based on two years of data.

Q49. What are the results of your CAPM analysis?

A49. The results of my CAPM analysis are summarized in Table 3 (see also PEPCO (G)-4).

Table 3: Summary of CAPM Results

	Bloomberg-Derived Market Risk Premium	Value Line-Derived Market Risk Premium
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.99%)	8.31%	9.62%
Near-Term Projected 30-Year Treasury (3.13%)	8.45%	9.76%
Long-Term Projected 30-Year Treasury (4.05%)	9.37%	10.67%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.99%)	9.31%	10.85%
Near-Term Projected 30-Year Treasury (3.13%)	9.45%	11.00%
Long-Term Projected 30-Year Treasury (4.05%)	10.37%	11.91%

Q50. Do you have any observations regarding the CAPM results?

A50. Yes, I do. As shown in PEPCO (G)-3, the Beta coefficients provided by Bloomberg are notably below those provided by Value Line. As explained above, Beta coefficients measure two parameters – relative risk and correlation to the market. As a result of Federal policies, including the Federal Reserve's Quantitative Easing initiative and the Tax Cut and Jobs Act (TCJA), utilities traded differently than the overall market. For example, after the TCJA was enacted, utilities lost value relative to the broad market. That loss relative to the market reduced utilities' correlation with the market, reducing the Beta coefficient. Conversely (and as discussed below), the Federal Reserve's Quantitative Easing initiative intentionally reduced long-term interest rates, causing investors at times to rotate into the utility sector. Those effects are relatively pronounced for the Bloomberg Beta coefficients, which are calculated over two years rather than over the five-year period applied by Value Line.

At issue is whether we should expect those lower correlations to continue in the

future. Because Federal policy is being "normalized," it is more likely that correlations will revert to longer-term levels. If that is the case (and assuming relative risk remains constant), Beta coefficients will increase. In that case, the CAPM results based on Bloomberg Beta coefficients would be seen as understating the Company's Cost of Equity.[48]

C. Bond Yield Plus Risk Premium Approach

Q51. Please generally describe the Bond Yield Plus Risk Premium approach.

A51. This approach is based on the basic financial tenet that equity investors bear the residual risk associated with ownership and, therefore, require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders are riskier than returns to bondholders, equity investors must be compensated for bearing that additional risk. Risk premium approaches, therefore, estimate the Cost of Equity as the sum of the Equity Risk Premium and the yield on a particular class of bonds. Because the Equity Risk Premium is not directly observable, it typically is estimated using a variety of approaches, some of which incorporate *ex-ante*, or forward-looking, estimates of the Cost of Equity and others that consider historical, or ex-post, estimates. An alternative approach is to use actual authorized returns for electric utilities to estimate the Equity Risk Premium.

Q52. Please explain how you performed your Bond Yield Plus Risk Premium analysis.

A52. As discussed above, I first defined the Risk Premium as the difference between

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[48] Even under more normal conditions, the CAPM has been found to underestimate the Cost of Equity for relatively low-Beta firms (that is, firms with Beta coefficients less than 1.00). A means of addressing the tendency is the Empirical CAPM (ECAPM; *see*, Roger A Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 189 – 191. Dr. Morin notes the ECAPM is given by $R_f + (.25\ x\ MRP) + (.75\ x\ \beta\ x\ MRP)$. Although I did not apply the ECAPM in my Direct Testimony, its results would have provided further support for my ROE recommendation.

authorized ROEs and the then-prevailing level of long-term (*i.e.*, 30-year) Treasury yield. I then gathered data from 1,585 electric utility rate proceedings between January 1, 1980 and March 29, 2019. In addition to the authorized ROE, I calculated the average period between the filing of the case and the date of the final order (the lag period). To reflect the prevailing level of interest rates during the pendency of the proceedings, I calculated the average 30-year Treasury yield over the average lag period (approximately 200 days).

Because the data covers several economic cycles,[49] the analysis also may be used to assess the stability of the Equity Risk Premium. For example, prior research has shown that the Equity Risk Premium is inversely related to the level of interest rates.[50] That analysis is particularly relevant given the relatively low, but increasing, level of current Treasury yields.

Q53. How did you model the relationship between interest rates and the Equity Risk Premium?

A53. The basic method used was regression analysis, in which the observed Equity Risk Premium is the dependent variable and the average 30-year Treasury yield is the independent variable. Relative to the long-term historical average, the analytical period includes interest rates and authorized ROEs that are quite high during one period (*i.e.*, the 1980s) and that are quite low during another (*i.e.*, the post-Lehman bankruptcy

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

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

period). To account for that variability, I used the semi-log regression, in which the Equity Risk Premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$RP = \propto \ + \beta(LN(T_{30})) \quad [5]$$

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

Chart 1: Equity Risk Premium[51]

As Chart 1 illustrates, over time there has been a statistically significant, negative relationship between the 30-year Treasury yield and the Equity Risk Premium. Consequently, simply applying the long-term average Equity Risk Premium of 4.67 percent would significantly understate the Cost of Equity and produce results well below any reasonable estimate. Based on the regression coefficients in Chart 1, however, the implied ROE is between 9.92 percent and 10.17 percent (*see* PEPCO (G)-

[51] *See also* PEPCO (G)-5.

5). As noted earlier, the analysis also demonstrates that there has been a significant inverse relationship between the 30-year Treasury yield and the Equity Risk Premium.

VI. OTHER CONSIDERATIONS

A. Credit Ratings

Q54. What are the Company's credit ratings by the major rating agencies?

A54. As noted above, Pepco's long-term corporate credit ratings are currently A-, Baa1, and BBB from S&P, Moody's, and Fitch, respectively.

Q55. Please briefly describe the importance of the Company's credit ratings with respect to its ability to access the debt capital markets.

A55. The Company's credit ratings indicate the rating agencies' assessment of Pepco's ability to meet its obligations to its long-term debt holders. The higher the credit rating, the greater the perceived likelihood that debt investors will receive their expected interest and principal payments. As such, a company with a higher credit rating generally has access to a larger investor base, faces fewer restrictive covenants, and can issue long-term debt at lower costs. A higher credit rating at this time is particularly beneficial, given the Company's plans to invest a significant amount of capital in system reliability.

Conversely, lower credit ratings reflect increased investor risk. As a result, investors and credit providers expect to be paid more to provide funds to such an issuer. In addition to paying a higher interest rate to issue new debt, the Company would be required to pay higher annual fees on its credit facility if its credit rating were to fall. Moreover, lower credit ratings typically result in investors demanding more restrictive terms and covenants from the issuer. Due to ratings restrictions imposed by some

1 institutional investors, lower credit ratings also limit the pool of investors that otherwise
2 may invest in the Company. The additional financing costs associated with lower credit
3 ratings will only increase the costs to the Company's customers.

4 **Q56. In your experience, would equity investors have concerns similar to those of debt**
5 **investors?**

6 A56. Yes. A principal source of funding in the equity capital markets is provided by
7 large institutional equity investors.[52] Institutional equity investors often employ
8 industry-specific research analysts and seasoned utility portfolio managers with
9 considerable financial depth and expertise. My experience suggests institutional equity
10 investors consider many of the same metrics as fixed income (*i.e.*, debt) analysts and
11 rating agencies. Although the Cost of Equity does not move in lockstep with the cost
12 of debt, lower credit ratings imply a riskier enterprise and generally result in higher
13 costs of capital.

14 Institutional investors also have the wherewithal to assess the default risk and
15 consider the priority of payments for equity investors which, as noted earlier, falls
16 behind most other creditors. With lower credit ratings, the default risk increases which
17 causes an increase in the required Cost of Equity for the enterprise. Simply, to the
18 extent the Company's equity becomes even marginally less attractive relative to its
19 peers, the demand for that equity would fall, the ability to efficiently access additional
20 equity would be diminished, and the return required by equity investors would increase.

[52] The Company's parent, Exelon Corporation, institutional equity ownership level is 82.02 percent, S&P Global Market Intelligence, May 13, 2019.

1 **Q57. The Commission's decision in Formal Case No. 1139 noted that rating agencies**
2 **have an overall favorable outlook regarding electric utilities and their ability to**
3 **access the capital market. Have you reviewed the Company's credit ratings**
4 **relative to the proxy group?**

5 A57. Yes, I have. The Company's S&P credit rating (A-) is one notch above the
6 proxy group median, its Moody's credit rating is the same as the proxy group median
7 (Baa1), and its Fitch credit rating (BBB) is one notch below.

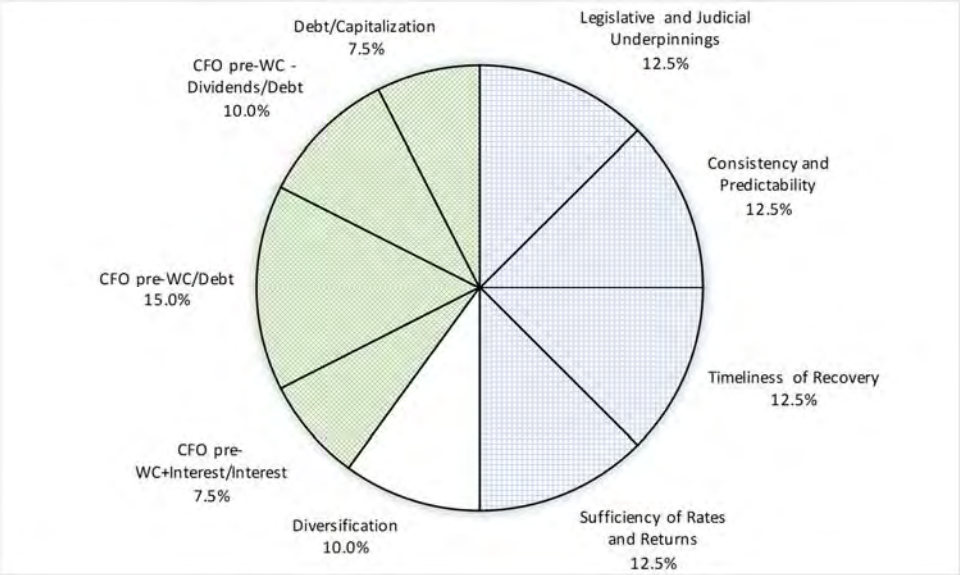
8 However, it is important to recognize that, although credit ratings are
9 directionally relevant measures of risk, they are not full measures of equity risk. As I
10 discussed earlier debt and equity are entirely different securities with different
11 risk/return characteristics, different lives, and different investors. Debt investors have
12 a contractual, priority claim on cash flows not available to equity investors and, as such,
13 equity investors alone bear the residual risk of ownership. Moreover, because the life
14 of debt is finite, debt investors' exposure to business and financial risk likewise is finite.
15 Equity, on the other hand, is perpetual and, as such, equity investors are exposed to
16 residual risk in perpetuity. Because debt and equity are distinct securities with different
17 risk and return profiles, debt and equity investors themselves have different risk and
18 return requirements. Additionally, from an overall investor standpoint, the District of
19 Columbia regulatory environment is rated below average by Regulatory Research
20 Associates, which suggests incrementally higher risk for equity investors.

21 **Q58. Does the authorized Return on Equity affect the Company's credit ratings and**
22 **access to both the debt and equity capital markets?**

23 A58. Yes. The rating agencies place considerable weight on a utility's regulatory

environment. For example, Moody's explains that its ratings are based on assessments of multiple factors, 50.00 percent of which relate to the nature of regulation (*see,* Chart 2). As Moody's recognizes, regulation and regulatory risk include a broad range of factors, including the timeliness and certainty of cost recovery and the consistency of regulatory policies, initiatives, and support. In my experience, the authorized ROE not only directly affects cash flow-related credit metrics, it is a visible indicator of regulatory support.

Chart 2: Moody's Ratings Criteria[53]



B. Capital Access

Q59. Do you have any preliminary thoughts on the importance of access to capital for electric utilities such as Pepco?

A59. Yes. Electric utilities are one of the most capital-intensive sectors of the S&P 500. On average, electric utilities in my proxy group generate only about one-third as

[53] Moody's Investors Service, *Regulated Electric and Gas Utilities*, June 23, 2017 at 4.

much revenue per dollar of assets as do the companies in the S&P 500.[54] To fund the significant capital expenditures needed to maintain, expand, and modernize existing infrastructure, electric utilities require sufficient internally generated cash flow and ongoing access to investor supplied capital. It, therefore, is critically important that regulation provide predictable, adequate, and achievable allowed returns that support utilities' financial integrity.

Q60. Please summarize Pepco's capital expenditure plans.

A60. As described in Company Witness McGowan's Direct Testimony, Pepco is undertaking significant capital investment in its distribution system. This includes investments to maintain and modernize Pepco's distribution infrastructure. The Company, therefore, is continuing to make substantial investments in its utility operations that will require access to external capital during the period of time that rates established in this proceeding will be in effect.

The financial community recognizes the need for timely cost recovery of the Company's capital expenditures. For example, in a March 2018 report regarding Pepco, Moody's specifically noted that the Company's sizable capital spending, which can have a negative effect on financial metrics, is a credit challenge.[55] Moody's also explained that the lack of capital trackers or other capital investment recovery mechanisms creates additional risk:

> Pepco is facing an elevated capital expenditure program, currently estimated at approximately $3.8 billion for the period 2016 to 2020, $2.5 billion of which is planned for the three-year period 2017-2019. These expenditures compare to $1.7 billion for the three-year period ended

[54] Bloomberg Professional Services.

[55] Moody's Investor Service, *Update to Credit Analysis: Potomac Electric Power Company*, March 30, 2018, at 2.

> 2013 - 2015. These elevated capital expenditures create some recovery risk for Pepco, because not all of the expenditures are directly tied to trackers or other transparent recovery mechanisms.[56]

From the investor's perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings.

Q61. Is it important that the regulatory process support the recovery of the Company's capital investment plans?

A61. Yes. As discussed throughout my Direct Testimony the allowed ROE should enable the subject utility to finance capital expenditures and working capital requirements at reasonable rates and to maintain its financial integrity in a variety of economic and capital market conditions. A return that is adequate to attract capital at reasonable terms enables the utility to provide safe and reliable service while maintaining its financial soundness. To the extent a utility is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders should be disadvantaged.

The ratemaking process is based on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have the opportunity to recover the return of and the market-required return on invested capital. Regulatory commissions recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms. Doing so balances the long-term interests of the utility and its customers.

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[56] Moody's Investor Service, *Regulated T&D utility subsidiary of Exelon Corporation,* January 20, 2017, at 3.

Further, the financial community carefully monitors utility companies' current and expected financial conditions as well as the regulatory environment in which those companies operate. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' assessments of risk.[57] That consideration is especially important during periods in which the utility expects to make significant capital investments, requiring efficient access to capital markets.

Q62. Have you undertaken any analyses to determine if Pepco is able to sufficiently fund capital expenditures with internally generated cash flow?

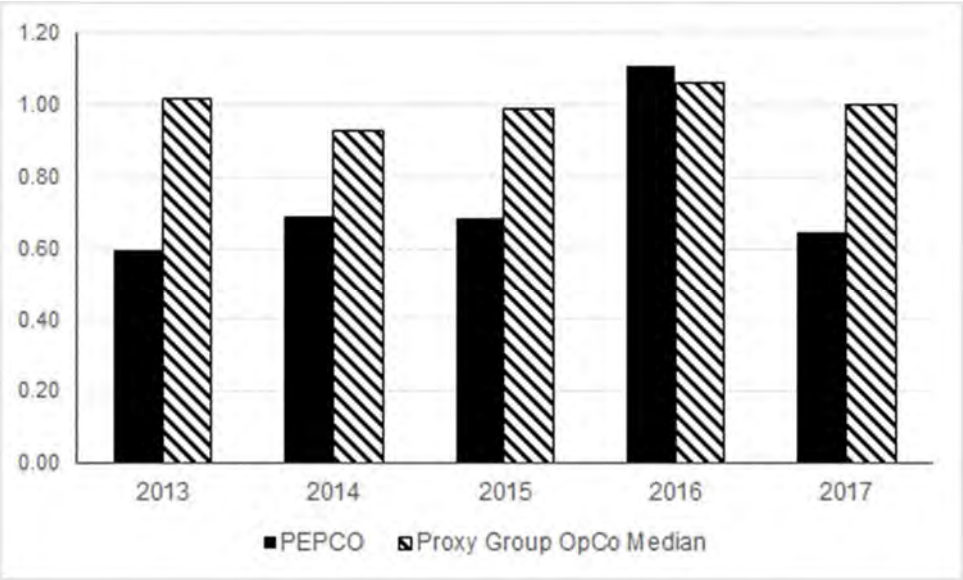
A62. Yes, I have. It is particularly important for a utility to fund capital investments with internally generated cash flow. With the exception of 2016, Pepco's ratio of cash flow from operating activities to capital expenditures has remained considerably below its peers (*see* Chart 3). Because its cash flows have been less able to support its capital investment, the Company must access external capital, increasing the potential for negative credit consequences.

Pepco's capital expenditure plan is significantly larger than its internally generated cash, which places downward pressure on its credit profile. The Company's requested ROE and MRP are important to provide the opportunity for it to earn a reasonable return on its capital investments. The Commission's decision in this proceeding will directly affect the Company's ability to fund capital investments with operating cash flows, and the financial community's view of the Company's financial profile. An authorized ROE that further strains the Company's ability to fund capital

[57] *See,* Moody's Investors Service, *Rating Methodology: Regulated Electric and Gas Utilities*, June 23, 2017, at 6-7, and Standard and Poor's, *Utilities: Key Credit Factors For The Regulated Utilities Industry*, November 19, 2013, at 6-8.

1 expenditures with internally generated cash flows could result in negative credit
2 consequences and higher equity and debt costs to customers.

Chart 3: Historical Cash Flow from Operating Activities to Capital Expenditures[58]



3 **Q63. Do you have any observations about Pepco's earned Return on Equity?**

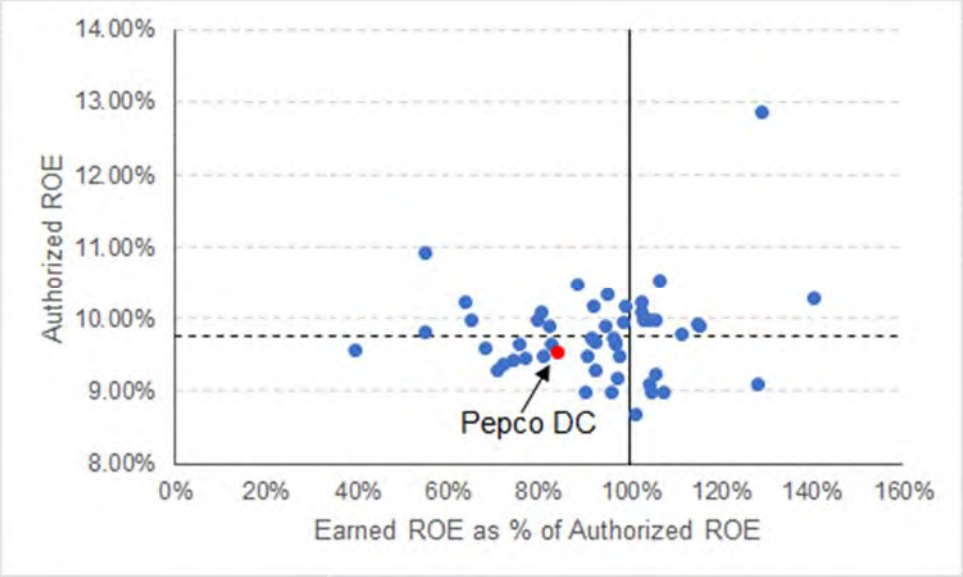
4 A63. Yes, I do. As demonstrated in Company Witness McGowan's Direct
5 Testimony, the Company has consistently underearned its authorized ROE, sometimes
6 by a wide margin, over the past five years. The Company's recent earnings level is
7 well below the returns available to other regulated electric utilities. Importantly, if the
8 Company continues to earn returns so far below prevailing levels, it will become
9 increasingly difficult to compete for capital against utilities whose earned returns are
10 more consistent with their authorized returns.

11 In Chart 4, I have provided a comparison of earned returns relative to authorized
12 returns for the Company and its peers. In 2018, Pepco's earned ROE was 8.01 percent,

[58] S&P Global Market Intelligence. Pepco's five-year cash flow from operations-to-capital expenditures ratio averaged 74.48 percent compared to the average of the proxy group median of 99.90 percent.

about 150 basis points below its authorized ROE.[59] Relative to its peers, Pepco's earned ROE as a percentage of its authorized ROE falls in the 32nd percentile. To the extent the Company chronically earns equity returns below its authorized returns, that deficit will put downward pressure on the earnings and cash flow-based metrics that are important to both debt and equity investors. In each case, the dilution resulting from underearning its authorized return will diminish the Company's financial integrity and, therefore, its ability to attract capital at reasonable terms under a variety of market circumstances.

Chart 4: Earned vs. Authorized ROE for Electric Utilities[60]



Q64. Have you also considered the relationship between capital expenditures and the earned return on common equity?

A64. Yes, I have. Generally, the "DuPont" formula disaggregates the Return on

[59] S&P Global Market Intelligence as of March 29, 2019.
[60] S&P Global Market Intelligence.

1 Common Equity into three components: (1) the Profit Margin (net income/revenues);
2 (2) Asset Turnover (revenues/net plant); and (3) the Equity Multiplier (net
3 plant/equity).[61] As PEPCO (G)-7 demonstrates, the proxy companies' Asset Turnover
4 rate declined from 2009 through 2018 from 52.65 percent to 36.90 percent and is
5 expected to remain at approximately the same level through Value Line's five-year
6 projection period. Over that same period (*i.e.*, 2009 through five years projected),
7 according to Value Line data, average Net Plant is expected to experience a cumulative
8 increase of approximately 26.77 percent. Because, as noted above, the utility industry
9 is going through a period of increased capital investment, the lag between the addition
10 of net plant and revenue generated by those investments dilutes the Asset Turnover
11 ratio, at least in the near term.

12 To gain an additional perspective on the relationship between plant additions
13 and Asset Turnover, I performed a regression analysis in which the annual change in
14 the Asset Turnover rate was the dependent variable, and the annual change in Net Plant
15 was the independent variable. As shown in PEPCO (G)-8, that analysis indicates a
16 statistically significant negative relationship between the two variables, such that as
17 annual net plant increases, the Asset Turnover ratio decreases. This, in turn, suggests
18 that an increase in capital expenditures also negatively affects the Return on Common
19 Equity, causing greater financial stress to the utility because, under the assumptions of
20 the "DuPont" formula, the Asset Turnover ratio is a component of the Return on
21 Common Equity. Therefore, as capital expenditures (*i.e.*, net plant) increase, the Asset

[61] The DuPont formula is commonly used by financial analysts to monitor specific operational and financial drivers of a company's earned ROE. The formula expands the calculation of the ROE into the product of three financial metrics: Profit Margin, Asset Turnover and the Equity Multiplier. That is, ROE = (earnings / revenue) x (revenue / assets) x (assets / equity).

Turnover ratio decreases, resulting in a decrease in the Return on Common Equity. To the extent investors value a company based on earnings and cash flow, this additional financial strain is a key concern.

Q65. What are your conclusions regarding the effect of Pepco's capital investment plan on its risk profile and cost of capital?

A65. Pepco's capital expenditure program is significant and will place additional pressure on its cash flows, making regulatory support more important in terms of Pepco's ability to finance these expenditures and earn a reasonable return on its planned investments. As such, the Commission's decision in this proceeding will have a direct bearing on the Company's ability to maintain its financial profile and its access to the capital market at reasonable cost and terms.

C. Multiyear Rate Plan

Q66. What are the implications for the Company's Cost of Equity of its proposed Multiyear Rate Plan?

A66. As noted earlier, the proposed MRP is designed to address earnings attrition resulting from inflationary pressures and high capital spending, both of which are commonplace in the utility industry. Because the MRP applies to future capital spending and operating costs, it is appropriate to consider its effect on the forward-looking cost of capital. In light of the relatively low level of long-term Treasury rates compared to their historical range, it is particularly important to consider the potential effect that increases in the level of interest rates would have on the Company's stock prices and its Cost of Equity during the MRP.

Q67. Does the proposed MRP create risk for the Company?

A67. As discussed earlier, electric utility companies are long-duration investments whose valuations are sensitive to changes in the required rate of return. Consequently, the interest rate risk to which equity holders are exposed relates to the long end of the yield curve, *i.e.*, the 30-year Treasury yield. For the reasons discussed in Section VII, it is reasonable to assume that on balance, long-term rates are more likely to increase than decrease during the MRP, representing a significant element of risk for equity investors.

Q68. Aside from interest rates, are there additional risks that may affect the Company's Cost of Equity over the MRP period?

A68. Yes, there are. The CAPM and DCF equations presented in Section V show that the Cost of Equity is a positive function of five factors: long-term Treasury yields, Beta coefficients, the Market Risk Premium, dividend yields, and growth rates. If any of those factors increase during the MRP period, the Cost of Equity will rise without a corresponding increase to allowed ROE. The value of Pepco's equity, all else remaining equal, would fall.

For example, equity valuations remain at risk to increases in broad market instability, movement of investments (rotation) out of the utility sector on the part of institutional investors, unexpected credit contractions, and other factors that affect both fundamental equity valuations and investor trading patterns. Changes in equity valuations or stock price volatility could increase dividend yields, Beta coefficients, and the Market Risk Premium, increasing the required ROE.

Q69. Are multiyear rate plans common in the utility industry?

A69. Yes, multiyear rate plans are a form of alternative rate mechanisms commonly found throughout the utility industry. Alternative rate mechanism objectives are multi-faceted and may include:

- Reducing risk, mitigating regulatory lag and providing more certainty in cost recovery;
- Facilitating new investments and promoting new technologies;
- Promoting social goals and increasing public benefits, including energy efficiency; and
- Reducing the frequency and cost of rate cases.[62]

To achieve these objectives, regulatory jurisdictions have adopted several types of ratemaking mechanisms. Capital trackers, which focus solely on recovery of investment expenditures, are the most common mechanism (51.00 percent of the proxy group operating companies). To address the limited cost recovery of capital trackers, many jurisdictions have incorporated broader ratemaking policies and alternative rate mechanisms, which generally include performance-based regulation (46.25 percent of proxy group),[63] future test years (38.75 percent of proxy group), formula rates (6.25 percent of proxy group), and the allowance of Construction Work in Progress in rate base (56.25 percent of proxy group).[64]

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[62] National Regulatory Research Institute, *Alternative Rate Mechanisms and Their Compatibility with State Utility Commission Objectives,* April 2014 at 17-18.

[63] Includes multiyear rate plans. As discussed in the Direct Testimony of Company Witness Zarakas, performance-based regulation is an umbrella term covering multiyear rate plans and performance incentive mechanisms.

[64] *Id,* at 31-64. *See,* PEPCO (G)-9 for proxy group percentages.

Q70. What are your conclusions related to the MRP proposal?

A70. Although the MRP proposal increases the opportunity for the Company to earn a reasonable return, I do not believe it enhances the Company's risk profile or reduces its Cost of Equity. As noted earlier, Moody's has highlighted the Company's credit risks because of the lack of capital tracking mechanisms and lagged cost recovery.[65] Further, the Company historically has not been able to earn its authorized ROE and ranks in the bottom third compared to its peers. The proposed MRP, therefore, would make the Company more comparable to its peers. It should not be viewed as reducing the Company's risk relative to comparable companies.

VII. CAPITAL MARKET ENVIRONMENT

Q71. Do economic conditions influence the required cost of capital and required return on common equity?

A71. Yes. As discussed in Section V, the models used to estimate the Cost of Equity are meant to reflect, and therefore are influenced by, current and expected capital market conditions. As such, it is important to assess the reasonableness of any financial model's results in the context of observable market data. To the extent a given model's assumptions are misaligned with such data or its results are inconsistent with basic financial principles, it is appropriate to consider whether alternative estimation techniques are likely to provide more meaningful and reliable results.

Q72. Do you have any general observations regarding the relationship between current capital market conditions and the Company's cost of equity?

A72. Yes, I do. Although the Federal Reserve completed its Quantitative Easing

[65] Moody's Investor Service, *Regulated T&D utility subsidiary of Exelon Corporation*, January 20, 2017, at 3.

initiative in October 2014, it was not until December 2015 that it raised the Federal Funds rate and began the process of rate normalization.[66] A significant issue is how investors likely will react as that process continues and eventually is completed. For example, increasing interest rates may be seen as an indication of expanding macroeconomic growth, in which case we reasonably could expect the growth rate component of the DCF model to increase. At the same time, sectors that historically have included dividend-paying companies have lost value, as increasing interest rates provide investors with alternative sources of current income. A more reasoned approach is to understand the relationships among capital market and macroeconomic variables, and to consider how those factors may affect different models and their results.

Q73. Does your recommendation consider the interest rate environment?

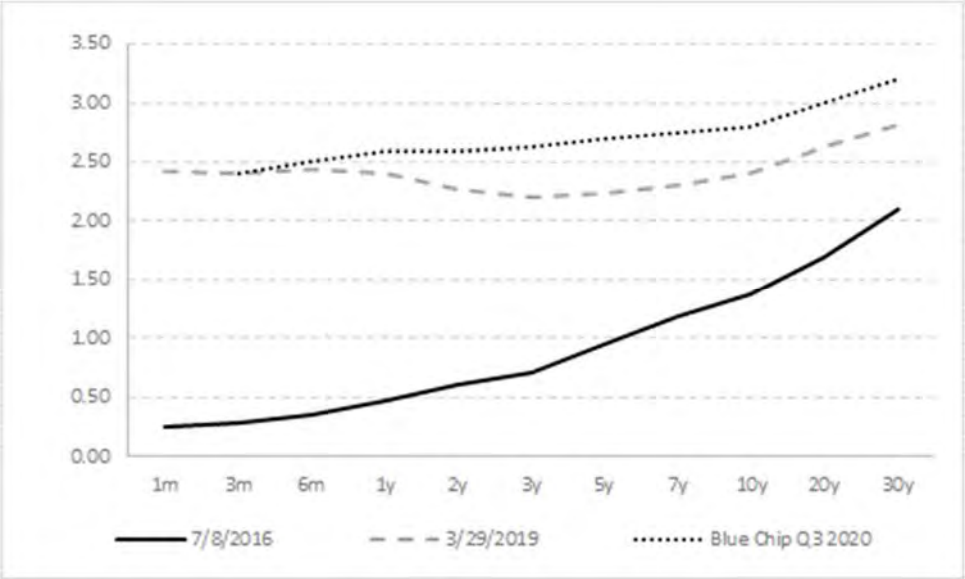
A73. Yes, it does. From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE recommendation, including assessments of capital market conditions, are consistent with the recommendation itself. Although all analyses require an element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst and the capital market environment in which the analyses were undertaken. Because the Cost of Equity is forward-looking, the salient issue is whether investors see the likelihood of increasing costs of capital during the period in which the rates set in this proceeding will be in effect.

Although the Federal Reserve's market intervention policies have kept interest

[66] Federal Reserve Press Release dated December 16, 2015.

rates historically low, since July 8, 2016 (when the 30-year Treasury fell to its secular low of 2.11 percent) rates have risen. As the Federal Reserve increased the Federal Funds target rate eight times between December 2016 and December 19, 2018 to 2.25 - 2.50 percent, short-term and long-term interest rates also increased (*see* Chart 5).[67]

Chart 5: Treasury Yield Curve: 7/8/2016, 3/29/2019 and Projected Q3 2020[68]



In a press conference following the December 2018 Federal Open Market Committee meeting, Chairman Powell discussed the recent increases in the Federal Funds rate and expectation for continued rate increases, noting a strengthening economy, a strong labor market, and rising wages.[69]

Lastly, in October 2017 the Federal Reserve initiated its balance sheet normalization program that includes gradual reductions to its security holdings by

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67 Federal Reserve Board Schedule H.15. One-year, 10-year and 30-year Treasury yields increased by 192 basis points, 104 basis points and 70 basis points, respectively, July 8, 2016 to March 29, 2019.

68 Federal Reserve Board Schedule H.15.; Blue Chip Financial Forecasts, Vol. 38, No. 4, April 1, 2019, at 2. 3-year, 7-year and 20-year projected Treasury yields interpolated.

69 Transcript of Chairman Powell's Press Conference, December 19, 2018.

1 decreasing reinvestment activities.[70] In the January 2019 meeting, the Federal Reserve
2 decided to continue with the balance sheet wind-down.[71] At the same time, the supply
3 of marketable U.S. Treasury securities has increased by approximately $1.14 trillion.[72]
4 The growing supply of Treasury securities from both the Federal Reserve and the U.S.
5 Treasury puts upward pressure on Treasury rates.[73]

6 **Q74. Has market volatility changed with the Federal Reserve's move toward monetary**
7 **policy normalization?**

8 A74. Yes, it has. A visible and widely reported measure of expected volatility is the
9 Cboe Options Exchange (Cboe) Volatility Index, often referred to as the VIX. As Cboe
10 explains, the VIX "is a calculation designed to produce a measure of constant, 30-day
11 expected volatility of the U.S. stock market, derived from real-time, mid-quote prices
12 of S&P 500® Index call and put options."[74] Simply, the VIX is a market-based
13 measure of expected volatility. Because volatility is a measure of risk, increases in the
14 VIX, or in its volatility, are a broad indicator of expected increases in market risk.

15 Although the VIX is not expressed as a percentage, it should be understood as
16 such. That is, if the VIX stood at 15.00, it would be interpreted as an expected standard

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70 *See*, https://www.federalreserve.gov/monetarypolicy/policy-normalization.htm and Federal Open Market Committee ("FOMC") Press Release, June 14, 2017. In its January 30, 2019 press release the FOMC noted that although it continues to view changes in the federal funds target rate as the "primary means of adjusting monetary policy", it also would adjust the details of its balance sheet normalization based on economic and financial developments. *See*, Federal Reserve Press Release dated January 30, 2019. At its March 2019 meeting, the FOMC determined it would hold the Federal Funds target rate constant, looking to current and expected economic conditions to determine future rate adjustments. *See*, Federal Reserve Press Release dated March 20, 2019.

71 Federal Reserve Press Release dated January 30, 2019.

72 U.S. Treasury, Monthly Statement of the Public Debt. *See,* https://www.treasurydirect.gov/govt/reports/pd/mspd/mspd.htm. U.S. marketable securities increased from $14.48 trillion to $15.62 trillion between December 31, 2017 and December 31, 2018.

73 Bond prices and bond yields move in opposite directions.

74 http://www.cboe.com/vix

deviation in annual market returns of 15.00 percent over the coming 30 days. Since 2000, the VIX has averaged about 19.66, which is highly consistent with the long-term standard deviation on annual market returns (19.80 percent, as reported by Duff & Phelps).

As Chart 6 demonstrates, in 2017 market volatility was well below its long-term average and moved within a somewhat narrow range; the VIX averaged about 11.09 with a standard deviation of 1.36. Throughout 2018 and into 2019, the VIX average increased to 16.61 with a standard deviation of 4.71. That is, from 2017 to 2018 both the level and the volatility of market volatility increased.

Chart 6: VIX Since January 2017[75]

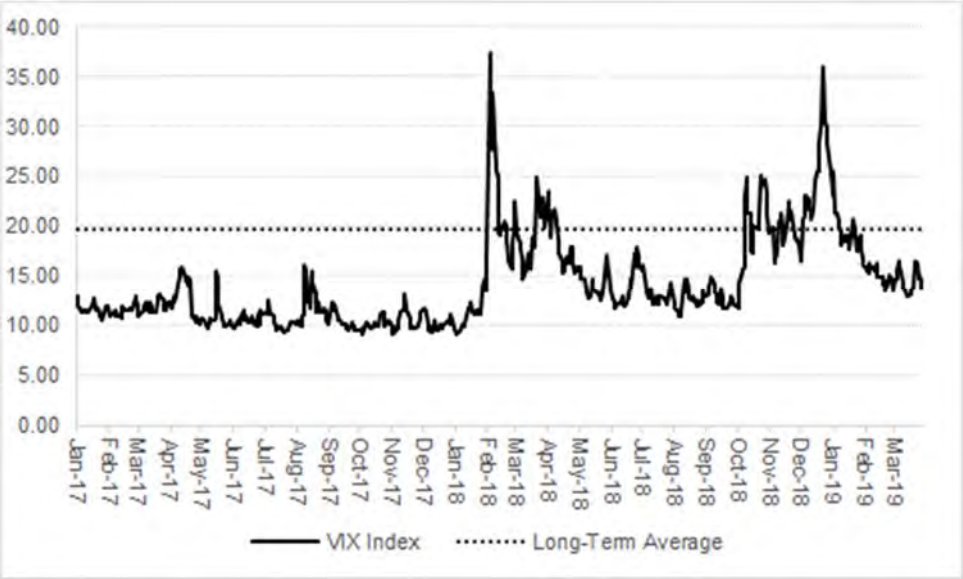

Table 4 further demonstrates the increase in market uncertainty from 2017 through the beginning of 2019. As that table notes, the standard deviation (that is, the volatility of volatility) in 2018-2019 is about 3.48 times higher than its 2017 level (1.36).

[75] Bloomberg Professional Services. Data as of March 29, 2019.

Table 4: VIX Levels and Volatility[76]

Long-Term Average	19.66
2018-2019 Average	16.61
2018-2019 Maximum	37.32
2018-2019 Minimum	9.15
2018-2019 Standard Deviation	4.71
2017 Average	11.09
2017 Maximum	16.04
2017 Minimum	9.14
2017 Standard Deviation	1.36

The increase in volatility is not surprising as market participants reassess investment alternatives in light of the Federal Reserve's shift toward monetary policy and, as discussed below, the recent passage of new tax legislation.

Q75. Is market volatility expected to remain above its 2017 and 2018 average levels?

A75. Yes, it is. One means of assessing market expectations regarding the future level of volatility is to review Cboe's "Term Structure of Volatility." As Cboe points out:

> The implied volatility term structure observed in SPX options markets is analogous to the term structure of interest rates observed in fixed income markets. Similar to the calculation of forward rates of interest, it is possible to observe the option market's expectation of future market volatility through use of the SPX implied volatility term structure.[77]

The expected VIX value in June 2020 is about 17.87, suggesting investors see a reversion toward the long-term average volatility over the coming months.[78] The expectation of increased volatility makes intuitive sense, given the Federal Reserve's movement toward normalizing monetary policy. That policy change includes reducing the liquidity provided to the financial markets during the Federal Reserve's

[76] Bloomberg Professional Services. Data as of March 29, 2019.
[77] http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data.
[78] *Id*., accessed April 2, 2019.

1 Quantitative Easing initiatives. Because that liquidity had the effect of dampening
2 volatility as it was added to the markets, it stands to reason that volatility will increase
3 as liquidity is diminished.

4 **Q76. Does the Federal Reserve's tightening of monetary policy have other implications**
5 **for the assessment of capital markets?**

6 A76. Yes. It is important to recognize that the Federal Reserve's reduction in
7 monetary stimulus is related to expectations of improved economic and financial
8 conditions and sustained growth in the overall economy. When increasing the Federal
9 Funds rate on December 19, 2018, the Federal Open Market Committee noted the labor
10 market continued to strengthen and that household spending was rising at a strong rate
11 while business fixed investment had moderated from its rapid pace earlier in the
12 year.[79] Although the Federal Reserve did not increase the Federal Funds rate in its
13 January 2019 meeting, the Federal Open Market Committee noted that the labor market
14 has continued to strengthen, and that economic activity continued to rise at a solid
15 rate.[80] From that perspective, we would expect to see higher growth estimates for
16 companies in the overall economy, including the utility sector.

17 **Q77. What conclusions do you draw from your analyses of the current capital market**
18 **environment, and how do those conclusions affect your ROE recommendation?**

19 A77. From an analytical perspective, it is important that the inputs and assumptions
20 used to arrive at an ROE determination, including assessments of capital market
21 conditions, are consistent with the conclusion itself. Although all analyses require an

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[79] Federal Reserve Press Release dated December 19, 2018.
[80] Federal Reserve Press Release dated January 30, 2019.

element of judgment, the application of that judgment must be made in the context of the quantitative and qualitative information available to the analyst and the capital market environment in which the analyses were undertaken. Because the application of financial models and interpretation of their results often is the subject of differences among analysts in regulatory proceedings, it is important to review and consider a variety of data points. That approach enables us to put in context both quantitative analyses and the associated recommendations. Further, because all models produce ranges of results, it is important to consider the type of information discussed above to determine where the Company's ROE falls within those ranges. As discussed throughout my testimony, doing so supports my recommended range of 10.00 percent to 11.00 percent.

VIII. CAPITAL STRUCTURE

Q78. What is the Company's proposed capital structure?

A78. As described in the Direct Testimony of Company Witness Ziminsky, the Company has proposed a capital structure of 50.46 percent common equity and 49.54 percent long-term debt.[81]

Q79. How does the capital structure affect the Cost of Equity?

A79. The capital structure relates to a company's financial risk, which represents the risk that a company may not have adequate cash flows to meet its financial obligations and is a function of the percentage of debt (or financial leverage) in its capital structure. In that regard, as the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt. Consequently, as the degree of

[81] Direct Testimony of Company Witness Ziminsky.

1 financial leverage increases, the risk of financial distress (*i.e.*, financial risk) also
2 increases. Because the capital structure can affect the subject company's overall level
3 of risk,[82] it is an important consideration in establishing a just and reasonable rate of
4 return.

5 **Q80. Please discuss your analysis of the capital structures of the proxy companies.**

6 A80. I calculated the average capital structure for each of the proxy companies over
7 the last eight quarters. As shown in PEPCO (G)-6, the mean of the proxy group actual
8 capital structures is 53.27 percent common equity and 46.73 percent long-term debt.
9 The common equity ratios range from 46.01 percent to 64.78 percent. Based on that
10 review, it is apparent that the Company's proposed capital structure in this case is
11 generally consistent with the capital structures of the proxy companies.

12 **Q81. What is your conclusion regarding an appropriate capital structure for Pepco?**

13 A81. Considering the range of proxy company equity ratios as well as the average
14 actual equity ratio of 53.27 percent for the proxy companies, I believe that Pepco's
15 proposed common equity ratio of 50.46 percent in this case is appropriate.

16 **IX. CONCLUSIONS AND RECOMMENDATION**

17 **Q82. What is your conclusion regarding the Company's Cost of Equity?**

18 A82. As discussed throughout my Direct Testimony, it is appropriate to consider
19 multiple methodologies to arrive at an ROE recommendation for Pepco. To that point,
20 in the current capital market environment Constant Growth DCF-based models should
21 be viewed with caution because they do not adequately reflect changing capital market
22 conditions and high levels of instability, while Risk Premium-based methods directly

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

1 reflect such changes and measures of risk. As such, I have given somewhat more
2 weight to the Risk Premium-based methods in arriving at my ROE recommendation.
3 I believe that a rate of return on common equity in the range of 10.00 percent
4 to 11.00 percent represents the range of equity investors' required rate of return for
5 investment in electric utilities similar to Pepco in today's capital markets. Within that
6 range, I believe that an ROE of 10.30 percent is reasonable and appropriate. In my
7 view, the 20.00 basis point increase in the proposed ROE since Formal Case No. 1150
8 is reasonable given the increase in interest rates and market volatility during 2018 and
9 early 2019.

10 **Q83. What is your conclusion regarding the Company's capital structure?**

11 A83. I conclude that the Company's proposed capital structure in this case, which
12 consists of 50.46 percent common equity and 49.54 percent long-term debt is consistent
13 with industry practice and on that basis, is reasonable and appropriate.

14 **Q84. Does this conclude your Direct Testimony?**

15 A84. Yes, it does.

R.B. Hevert
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (G) – 1

Constant Growth Discounted Cash Flow Model
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.35	$82.10	2.86%	2.95%	7.20%	6.00%	5.00%	6.07%	7.93%	9.02%	10.17%
Alliant Energy Corporation	LNT	$1.42	$46.41	3.06%	3.16%	6.00%	7.25%	6.50%	6.58%	9.15%	9.74%	10.42%
Ameren Corporation	AEE	$1.90	$72.04	2.64%	2.73%	6.80%	7.70%	6.50%	7.00%	9.22%	9.73%	10.44%
American Electric Power Company, Inc.	AEP	$2.68	$82.40	3.25%	3.34%	5.70%	5.57%	4.00%	5.09%	7.32%	8.43%	9.04%
Avangrid, Inc.	AGR	$1.76	$49.27	3.57%	3.74%	7.70%	9.20%	12.00%	9.63%	11.41%	13.38%	15.79%
Black Hills Corporation	BKH	$2.02	$72.12	2.80%	2.87%	4.80%	3.63%	6.50%	4.98%	6.48%	7.85%	9.39%
CMS Energy Corporation	CMS	$1.53	$54.57	2.80%	2.90%	6.40%	6.89%	7.00%	6.76%	9.29%	9.66%	9.90%
Consolidated Edison, Inc.	ED	$2.96	$83.19	3.56%	3.61%	2.00%	2.99%	3.00%	2.66%	5.59%	6.27%	6.61%
DTE Energy Company	DTE	$3.78	$123.25	3.07%	3.14%	6.00%	4.16%	5.00%	5.05%	7.29%	8.20%	9.16%
Duke Energy Corporation	DUK	$3.71	$89.77	4.13%	4.24%	5.00%	4.50%	5.50%	5.00%	8.73%	9.24%	9.75%
El Paso Electric Company	EE	$1.44	$57.00	2.53%	2.58%	4.10%	5.10%	3.00%	4.07%	5.56%	6.64%	7.69%
Evergy, Inc.	EVRG	$1.90	$56.91	3.34%	3.45%	6.70%	6.25%	NMF	6.48%	9.69%	9.92%	10.15%
Eversource Energy	ES	$2.14	$70.34	3.04%	3.13%	5.60%	5.88%	5.50%	5.66%	8.63%	8.79%	9.01%
Hawaiian Electric Industries, Inc.	HE	$1.28	$39.45	3.24%	3.34%	6.20%	7.80%	3.50%	5.83%	6.80%	9.17%	11.17%
NextEra Energy, Inc.	NEE	$5.00	$189.50	2.64%	2.74%	7.70%	7.46%	9.00%	8.05%	10.20%	10.80%	11.76%
NorthWestern Corporation	NWE	$2.30	$69.25	3.32%	3.36%	2.50%	2.74%	2.50%	2.58%	5.86%	5.94%	6.11%
OGE Energy Corp.	OGE	$1.46	$42.57	3.43%	3.53%	4.80%	NA	6.50%	5.65%	8.31%	9.18%	10.04%
Otter Tail Corporation	OTTR	$1.40	$50.04	2.80%	2.90%	7.00%	9.00%	5.00%	7.00%	7.87%	9.90%	11.92%
Pinnacle West Capital Corporation	PNW	$2.95	$94.00	3.14%	3.22%	5.00%	4.56%	6.00%	5.19%	7.77%	8.41%	9.23%
PNM Resources, Inc.	PNM	$1.16	$45.70	2.54%	2.61%	4.80%	4.10%	7.50%	5.47%	6.69%	8.07%	10.13%
Portland General Electric Company	POR	$1.45	$50.97	2.84%	2.91%	4.10%	4.90%	4.00%	4.33%	6.90%	7.24%	7.81%
Southern Company	SO	$2.40	$50.76	4.73%	4.81%	4.50%	2.16%	3.50%	3.39%	6.94%	8.19%	9.33%
WEC Energy Group, Inc.	WEC	$2.36	$77.19	3.06%	3.13%	4.40%	4.59%	6.00%	5.00%	7.52%	8.13%	9.15%
Xcel Energy Inc.	XEL	$1.62	$55.59	2.91%	3.00%	5.90%	6.60%	5.50%	6.00%	8.49%	9.00%	9.61%
PROXY GROUP MEAN				3.14%	3.22%	5.45%	5.61%	5.59%	5.56%	7.90%	8.79%	9.74%
PROXY GROUP MEDIAN				3.06%	3.14%	5.65%	5.57%	5.50%	5.56%	7.82%	8.90%	9.68%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of March 29, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model
90 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.35	$78.82	2.98%	3.07%	7.20%	6.00%	5.00%	6.07%	8.06%	9.14%	10.29%
Alliant Energy Corporation	LNT	$1.42	$44.67	3.18%	3.28%	6.00%	7.25%	6.50%	6.58%	9.27%	9.87%	10.54%
Ameren Corporation	AEE	$1.90	$69.17	2.75%	2.84%	6.80%	7.70%	6.50%	7.00%	9.34%	9.84%	10.55%
American Electric Power Company, Inc.	AEP	$2.68	$78.77	3.40%	3.49%	5.70%	5.57%	4.00%	5.09%	7.47%	8.58%	9.20%
Avangrid, Inc.	AGR	$1.76	$49.75	3.54%	3.71%	7.70%	9.20%	12.00%	9.63%	11.37%	13.34%	15.75%
Black Hills Corporation	BKH	$2.02	$67.55	2.99%	3.06%	4.80%	3.63%	6.50%	4.98%	6.67%	8.04%	9.59%
CMS Energy Corporation	CMS	$1.53	$52.29	2.93%	3.03%	6.40%	6.89%	7.00%	6.76%	9.42%	9.79%	10.03%
Consolidated Edison, Inc.	ED	$2.96	$79.82	3.71%	3.76%	2.00%	2.99%	3.00%	2.66%	5.75%	6.42%	6.76%
DTE Energy Company	DTE	$3.78	$117.89	3.21%	3.29%	6.00%	4.16%	5.00%	5.05%	7.43%	8.34%	9.30%
Duke Energy Corporation	DUK	$3.71	$88.13	4.21%	4.32%	5.00%	4.50%	5.50%	5.00%	8.80%	9.32%	9.83%
El Paso Electric Company	EE	$1.44	$53.97	2.67%	2.72%	4.10%	5.10%	3.00%	4.07%	5.71%	6.79%	7.84%
Evergy, Inc.	EVRG	$1.90	$57.58	3.30%	3.41%	6.70%	6.25%	NMF	6.48%	9.65%	9.88%	10.11%
Eversource Energy	ES	$2.14	$68.40	3.13%	3.22%	5.60%	5.88%	5.50%	5.66%	8.71%	8.88%	9.10%
Hawaiian Electric Industries, Inc.	HE	$1.28	$37.93	3.38%	3.47%	6.20%	7.80%	3.50%	5.83%	6.93%	9.31%	11.31%
NextEra Energy, Inc.	NEE	$5.00	$181.29	2.76%	2.87%	7.70%	7.46%	9.00%	8.05%	10.32%	10.92%	11.88%
NorthWestern Corporation	NWE	$2.30	$64.69	3.56%	3.60%	2.50%	2.74%	2.50%	2.58%	6.10%	6.18%	6.34%
OGE Energy Corp.	OGE	$1.46	$40.89	3.57%	3.67%	4.80%	NA	6.50%	5.65%	8.46%	9.32%	10.19%
Otter Tail Corporation	OTTR	$1.40	$49.07	2.85%	2.95%	7.00%	9.00%	5.00%	7.00%	7.92%	9.95%	11.98%
Pinnacle West Capital Corporation	PNW	$2.95	$89.80	3.29%	3.37%	5.00%	4.56%	6.00%	5.19%	7.92%	8.56%	9.38%
PNM Resources, Inc.	PNM	$1.16	$43.39	2.67%	2.75%	4.80%	4.10%	7.50%	5.47%	6.83%	8.21%	10.27%
Portland General Electric Company	POR	$1.45	$48.47	2.99%	3.06%	4.10%	4.90%	4.00%	4.33%	7.05%	7.39%	7.96%
Southern Company	SO	$2.40	$48.04	5.00%	5.08%	4.50%	2.16%	3.50%	3.39%	7.21%	8.47%	9.61%
WEC Energy Group, Inc.	WEC	$2.36	$73.39	3.22%	3.30%	4.40%	4.59%	6.00%	5.00%	7.69%	8.29%	9.31%
Xcel Energy Inc.	XEL	$1.62	$52.68	3.08%	3.17%	5.90%	6.60%	5.50%	6.00%	8.66%	9.17%	9.78%
PROXY GROUP MEAN				3.26%	3.35%	5.45%	5.61%	5.59%	5.56%	8.03%	8.92%	9.87%
PROXY GROUP MEDIAN				3.19%	3.29%	5.65%	5.57%	5.50%	5.56%	7.92%	9.01%	9.80%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of March 29, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] First Call Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.35	$77.59	3.03%	3.12%	7.20%	6.00%	5.00%	6.07%	8.10%	9.19%	10.34%
Alliant Energy Corporation	LNT	$1.42	$43.92	3.23%	3.34%	6.00%	7.25%	6.50%	6.58%	9.33%	9.92%	10.60%
Ameren Corporation	AEE	$1.90	$66.62	2.85%	2.95%	6.80%	7.70%	6.50%	7.00%	9.44%	9.95%	10.66%
American Electric Power Company, Inc.	AEP	$2.68	$75.38	3.56%	3.65%	5.70%	5.57%	4.00%	5.09%	7.63%	8.74%	9.36%
Avangrid, Inc.	AGR	$1.76	$49.50	3.56%	3.73%	7.70%	9.20%	12.00%	9.63%	11.39%	13.36%	15.77%
Black Hills Corporation	BKH	$2.02	$63.91	3.16%	3.24%	4.80%	3.63%	6.50%	4.98%	6.85%	8.22%	9.76%
CMS Energy Corporation	CMS	$1.53	$50.75	3.02%	3.12%	6.40%	6.89%	7.00%	6.76%	9.51%	9.88%	10.12%
Consolidated Edison, Inc.	ED	$2.96	$78.98	3.75%	3.80%	2.00%	2.99%	3.00%	2.66%	5.79%	6.46%	6.80%
DTE Energy Company	DTE	$3.78	$114.62	3.30%	3.38%	6.00%	4.16%	5.00%	5.05%	7.53%	8.43%	9.40%
Duke Energy Corporation	DUK	$3.71	$84.86	4.37%	4.48%	5.00%	4.50%	5.50%	5.00%	8.97%	9.48%	9.99%
El Paso Electric Company	EE	$1.44	$57.09	2.52%	2.57%	4.10%	5.10%	3.00%	4.07%	5.56%	6.64%	7.69%
Evergy, Inc.	EVRG	$1.90	$57.11	3.33%	3.43%	6.70%	6.25%	NMF	6.48%	9.68%	9.91%	10.14%
Eversource Energy	ES	$2.14	$65.25	3.28%	3.37%	5.60%	5.88%	5.50%	5.66%	8.87%	9.03%	9.26%
Hawaiian Electric Industries, Inc.	HE	$1.28	$36.80	3.48%	3.58%	6.20%	7.80%	3.50%	5.83%	7.04%	9.41%	11.41%
NextEra Energy, Inc.	NEE	$5.00	$176.25	2.84%	2.95%	7.70%	7.46%	9.00%	8.05%	10.40%	11.00%	11.96%
NorthWestern Corporation	NWE	$2.30	$62.22	3.70%	3.74%	2.50%	2.74%	2.50%	2.58%	6.24%	6.32%	6.49%
OGE Energy Corp.	OGE	$1.46	$38.84	3.76%	3.87%	4.80%	NA	6.50%	5.65%	8.65%	9.52%	10.38%
Otter Tail Corporation	OTTR	$1.40	$48.38	2.89%	3.00%	7.00%	9.00%	5.00%	7.00%	7.97%	10.00%	12.02%
Pinnacle West Capital Corporation	PNW	$2.95	$85.68	3.44%	3.53%	5.00%	4.56%	6.00%	5.19%	8.08%	8.72%	9.55%
PNM Resources, Inc.	PNM	$1.16	$41.36	2.80%	2.88%	4.80%	4.10%	7.50%	5.47%	6.96%	8.35%	10.41%
Portland General Electric Company	POR	$1.45	$47.17	3.07%	3.14%	4.10%	4.90%	4.00%	4.33%	7.14%	7.47%	8.05%
Southern Company	SO	$2.40	$46.81	5.13%	5.21%	4.50%	2.16%	3.50%	3.39%	7.34%	8.60%	9.74%
WEC Energy Group, Inc.	WEC	$2.36	$70.51	3.35%	3.43%	4.40%	4.59%	6.00%	5.00%	7.82%	8.43%	9.45%
Xcel Energy Inc.	XEL	$1.62	$50.31	3.22%	3.32%	5.90%	6.60%	5.50%	6.00%	8.81%	9.32%	9.93%
PROXY GROUP MEAN				3.36%	3.45%	5.45%	5.61%	5.59%	5.56%	8.13%	9.01%	9.97%
PROXY GROUP MEDIAN				3.29%	3.38%	5.65%	5.57%	5.50%	5.56%	8.02%	9.11%	9.96%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals indicated number of trading day average as of March 29, 2019
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: Yahoo! Finance
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

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Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (G) – 2

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

[1]	[2]	[3]
S&P 500 Est. Required Market Return	Current 30-Year Treasury (30-day average)	Implied Market Risk Premium
13.77%	2.99%	10.77%

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

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

[1]	[2]	[3]
S&P 500 Est. Required Market Return	Current 30-Year Treasury (30-day average)	Implied Market Risk Premium
16.40%	2.99%	13.41%

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

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Introduced as:
PEPCO _____ (G) – 3

Bloomberg and Value Line Beta Coefficients

Company	Ticker	[1] Bloomberg	[2] Value Line
ALLETE, Inc.	ALE	0.456	0.650
Alliant Energy Corporation	LNT	0.541	0.650
Ameren Corporation	AEE	0.449	0.600
American Electric Power Company, Inc.	AEP	0.502	0.550
Avangrid, Inc.	AGR	0.481	0.400
Black Hills Corporation	BKH	0.530	0.750
CMS Energy Corporation	CMS	0.476	0.550
Consolidated Edison, Inc.	ED	0.480	0.450
DTE Energy Company	DTE	0.505	0.550
Duke Energy Corporation	DUK	0.437	0.500
El Paso Electric Company	EE	0.504	0.650
Evergy, Inc.	EVRG	0.425	0.520
Eversource Energy	ES	0.582	0.600
Hawaiian Electric Industries, Inc.	HE	0.484	0.600
NextEra Energy, Inc.	NEE	0.561	0.600
NorthWestern Corporation	NWE	0.487	0.550
OGE Energy Corp.	OGE	0.555	0.850
Otter Tail Corporation	OTTR	0.527	0.700
Pinnacle West Capital Corporation	PNW	0.434	0.550
PNM Resources, Inc.	PNM	0.514	0.650
Portland General Electric Company	POR	0.470	0.600
Southern Company	SO	0.479	0.500
WEC Energy Group, Inc.	WEC	0.487	0.550
Xcel Energy Inc.	XEL	0.488	0.500
Mean		0.494	0.586

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line. Value Line does not report a Beta coefficient for Evergy, Inc. Therefore, the Beta coefficient for Evergy has been manually calculated according to Value Line's methodology.

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Introduced as:
PEPCO _____ (G) – 4

Capital Asset Pricing Model Results
Bloomberg and Value Line Derived Market Risk Premium

	[1]	[2]	[3]	[4]	[5]	[6]
					CAPM	
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg MRP	Value Line MRP
PROXY GROUP BLOOMBERG BETA COEFFICIENT						
Current 30-Year Treasury (30-day average) [7]	2.99%	0.494	10.77%	13.41%	8.31%	9.62%
Near-Term Projected 30-Year Treasury [8]	3.13%	0.494	10.77%	13.41%	8.45%	9.76%
Long-Term Projected 30-Year Treasury [9]	4.05%	0.494	10.77%	13.41%	9.37%	10.67%
Mean					8.71%	10.01%

					CAPM	
	Risk-Free Rate	Average Beta Coefficient	Bloomberg Market DCF Derived	Value Line Market DCF Derived	Bloomberg MRP	Value Line MRP
PROXY GROUP VALUE LINE AVERAGE BETA COEFFICIENT						
Current 30-Year Treasury (30-day average) [7]	2.99%	0.586	10.77%	13.41%	9.31%	10.85%
Near-Term Projected 30-Year Treasury [8]	3.13%	0.586	10.77%	13.41%	9.45%	11.00%
Long-Term Projected 30-Year Treasury [9]	4.05%	0.586	10.77%	13.41%	10.37%	11.91%
Mean					9.71%	11.25%

Notes:
[1] See Notes [7], [8], and [9]
[2] Source: PEPCO (G)-3
[3] Source: PEPCO (G)-2
[4] Source: PEPCO (G)-2
[5] Equals Col. [1] + (Col. [2] x Col. [3])
[6] Equals Col. [1] + (Col. [2] x Col. [4])
[7] Source: Bloomberg Professional
[8] Source: Blue Chip Financial Forecasts, Vol. 38, No. 4, April 1, 2019, at 2.
[9] Source: Blue Chip Financial Forecasts, Vol. 37, No. 12, December 1, 2018, at 14.

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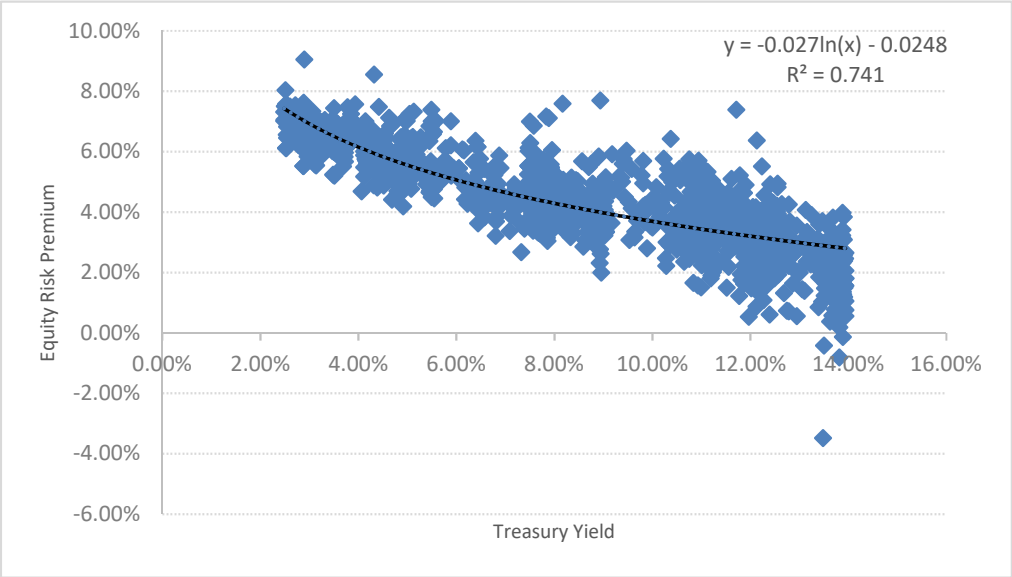
Introduced as:
PEPCO _____ (G) – 5

Bond Yield Plus Risk Premium

	[1] Constant	[2] Slope	[3] 30-Year Treasury Yield	[4] Risk Premium	[5] Return on Equity
Current	-2.48%	-2.68%	2.99%	6.93%	9.92%
Near Term Projected	-2.48%	-2.68%	3.13%	6.81%	9.94%
Long-Term Projected	-2.48%	-2.68%	4.05%	6.12%	10.17%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Source: Current = Bloomberg Professional.
[3] Near Term Projected = Blue Chip Financial Forecasts, Vol. 38, No. 4, April 1, 2019, at 2.
[3] Long Term Projected = Blue Chip Financial Forecasts, Vol. 37, No. 12, December 1, 2018, at 14.
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]

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Introduced as:
PEPCO _____ (G) – 6

Proxy Group Capital Structure

		% Common Equity								
Company	Ticker	2018Q3	2018Q2	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	Average
ALLETE, Inc.	ALE	58.50%	58.84%	63.09%	62.51%	61.03%	60.62%	60.28%	59.02%	60.49%
Alliant Energy Corporation	LNT	51.13%	51.00%	49.74%	49.77%	52.09%	51.23%	50.84%	50.73%	50.82%
Ameren Corporation	AEE	53.22%	52.01%	53.04%	52.65%	53.56%	53.11%	52.77%	52.62%	52.87%
American Electric Power Company, Inc.	AEP	48.68%	48.52%	48.60%	48.91%	48.46%	49.41%	49.61%	49.90%	49.01%
Avangrid, Inc.	AGR	56.13%	54.93%	56.55%	55.69%	53.88%	53.54%	55.66%	54.95%	55.17%
Black Hills Corporation	BKH	53.20%	53.82%	53.79%	54.40%	54.75%	53.84%	53.20%	52.81%	53.73%
CMS Energy Corporation	CMS	53.01%	52.86%	53.13%	52.25%	53.25%	52.97%	52.10%	51.24%	52.60%
Consolidated Edison, Inc.	ED	48.38%	48.73%	49.75%	49.23%	49.87%	49.19%	49.83%	49.39%	49.30%
DTE Energy Company	DTE	49.97%	49.23%	51.12%	51.02%	50.50%	50.63%	50.50%	50.50%	50.43%
Duke Energy Corporation	DUK	55.03%	54.94%	54.46%	54.30%	53.78%	54.62%	54.37%	54.66%	54.52%
El Paso Electric Company	EE	48.57%	47.32%	49.46%	49.95%	49.81%	48.01%	47.48%	47.73%	48.54%
Evergy, Inc.	EVRG	59.86%	58.51%	58.73%	58.62%	59.41%	58.74%	58.75%	59.28%	58.99%
Eversource Energy	ES	51.03%	50.14%	54.05%	54.60%	55.16%	54.82%	55.44%	55.51%	53.85%
Hawaiian Electric Industries, Inc.	HE	56.09%	55.78%	57.44%	57.42%	58.11%	57.76%	57.71%	57.70%	57.25%
NextEra Energy, Inc.	NEE	64.78%	60.84%	61.23%	59.93%	63.00%	62.78%	62.05%	62.65%	62.16%
NorthWestern Corporation	NWE	48.36%	48.41%	47.48%	49.89%	48.86%	48.61%	48.61%	48.13%	48.54%
OGE Energy Corp.	OGE	53.05%	54.25%	53.59%	53.36%	53.05%	52.75%	53.46%	56.09%	53.70%
Otter Tail Corporation	OTTR	53.49%	53.11%	52.67%	57.34%	57.24%	55.31%	55.31%	55.06%	54.94%
Pinnacle West Capital Corporation	PNW	53.68%	53.71%	53.18%	53.14%	53.05%	53.32%	53.20%	54.59%	53.48%
PNM Resources, Inc.	PNM	48.01%	46.68%	46.20%	46.06%	47.58%	46.89%	46.38%	46.01%	46.73%
Portland General Electric Company	POR	50.51%	50.29%	50.14%	49.80%	50.17%	50.32%	50.28%	49.82%	50.17%
Southern Company	SO	51.50%	50.31%	49.98%	47.67%	50.14%	49.99%	51.41%	51.10%	50.26%
WEC Energy Group, Inc.	WEC	58.30%	57.72%	61.62%	54.62%	55.82%	55.48%	54.80%	56.26%	56.83%
Xcel Energy Inc.	XEL	53.37%	53.63%	54.15%	53.95%	53.93%	54.37%	54.94%	54.37%	54.09%
Mean		53.24%	52.73%	53.47%	53.21%	53.60%	53.26%	53.29%	53.34%	53.27%

Operating Company Capital Structure

		% Common Equity								
Operating Company	Parent	2018Q3	2018Q2	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	Average
ALLETE (Minnesota Power)	ALE	60.43%	60.33%	60.38%	60.04%	59.73%	59.16%	58.71%	56.92%	59.46%
Superior Water, Light and Power Company	ALE	56.58%	57.34%	65.80%	64.99%	62.33%	62.08%	61.85%	61.12%	61.51%
Interstate Power and Light Company	LNT	49.64%	50.47%	49.92%	50.31%	51.79%	50.89%	50.23%	50.24%	50.44%
Wisconsin Power and Light Company	LNT	52.62%	51.52%	49.57%	49.23%	52.39%	51.56%	51.45%	51.22%	51.19%
Ameren Illinois Company	AEE	53.18%	52.74%	54.24%	53.38%	54.98%	54.55%	54.09%	53.44%	53.82%
Union Electric Company	AEE	53.26%	51.28%	51.84%	51.92%	52.14%	51.68%	51.45%	51.80%	51.92%
AEP Texas Central Company	AEP	NA	NA	NA	NA	NA	NA	NA	46.01%	46.01%
AEP Texas North Company	AEP	NA	NA	NA	NA	NA	NA	NA	43.29%	43.29%
AEP Texas Inc.	AEP	43.80%	43.20%	46.75%	45.14%	42.81%	49.46%	48.82%	NA	45.71%
Appalachian Power Company	AEP	49.30%	48.93%	49.35%	48.72%	48.30%	47.85%	48.17%	46.89%	48.44%
Indiana Michigan Power Company	AEP	44.53%	44.15%	46.64%	46.33%	46.65%	46.27%	49.54%	49.11%	46.65%
Kentucky Power Company	AEP	45.28%	44.89%	44.40%	43.52%	43.22%	43.30%	43.57%	43.45%	43.95%
Kingsport Power Company	AEP	50.71%	47.69%	47.28%	46.53%	45.88%	50.58%	48.98%	65.24%	50.36%
Ohio Power Company	AEP	56.85%	57.11%	52.91%	58.63%	57.64%	56.72%	56.75%	56.51%	56.64%
Public Service Company of Oklahoma	AEP	49.55%	48.59%	48.10%	48.50%	48.85%	48.26%	48.20%	48.47%	48.56%
Southwestern Electric Power Company	AEP	43.43%	47.91%	47.72%	48.52%	48.66%	48.14%	48.33%	45.95%	47.33%
Wheeling Power Company	AEP	54.70%	54.19%	54.27%	54.26%	54.13%	54.10%	54.10%	54.12%	54.23%
Central Maine Power Company	AGR	64.17%	63.53%	64.18%	63.82%	63.97%	63.27%	62.84%	62.39%	63.52%
New York State Electric & Gas Corporation	AGR	53.95%	50.99%	54.51%	53.30%	48.27%	50.24%	49.68%	48.84%	51.22%
Rochester Gas and Electric Corporation	AGR	48.16%	47.77%	50.80%	49.63%	48.94%	48.46%	55.25%	54.30%	50.42%
United Illuminating Company	AGR	58.23%	57.43%	56.70%	56.00%	54.35%	52.17%	54.88%	54.26%	55.50%
Black Hills Colorado Electric Utility Company, LP	BKH	53.04%	54.85%	54.68%	55.69%	54.96%	55.01%	53.08%	52.20%	54.19%
Black Hills Power, Inc.	BKH	53.51%	53.30%	53.22%	53.49%	56.14%	53.26%	53.24%	52.88%	53.63%
Cheyenne Light, Fuel and Power Company	BKH	53.04%	53.32%	53.46%	54.01%	53.16%	53.27%	53.29%	53.35%	53.36%
Consumers Energy Company	CMS	53.01%	52.86%	53.13%	52.25%	53.25%	52.97%	52.10%	51.24%	52.60%
Consolidated Edison Company of New York, Inc.	ED	48.33%	46.72%	48.66%	48.22%	49.47%	48.58%	49.65%	49.31%	48.62%
Orange and Rockland Utilities, Inc.	ED	48.44%	50.74%	50.83%	50.25%	50.27%	49.81%	50.00%	49.46%	49.98%
Rockland Electric Company	ED	NA	NA	NA	NA	NA	NA	NA	NA	NA
DTE Electric Company	DTE	49.97%	49.23%	51.12%	51.02%	50.50%	50.63%	50.50%	50.50%	50.43%
Duke Energy Carolinas, LLC	DUK	52.64%	52.10%	51.70%	52.98%	53.98%	53.49%	53.32%	52.81%	52.88%
Duke Energy Florida, LLC	DUK	49.65%	48.79%	49.92%	49.25%	49.46%	47.74%	46.95%	50.83%	49.07%
Duke Energy Indiana, LLC	DUK	52.79%	52.64%	52.54%	51.94%	51.71%	51.89%	52.15%	51.59%	52.16%
Duke Energy Kentucky, Inc.	DUK	56.58%	55.79%	53.72%	53.11%	50.69%	55.74%	55.43%	54.74%	54.48%
Duke Energy Ohio, Inc.	DUK	67.73%	67.10%	66.06%	66.24%	65.79%	65.38%	65.36%	66.39%	66.25%
Duke Energy Progress, LLC	DUK	50.76%	53.22%	52.82%	52.27%	51.06%	53.51%	52.99%	51.58%	52.28%
El Paso Electric Company	EE	48.57%	47.32%	49.46%	49.95%	49.81%	48.01%	47.48%	47.73%	48.54%
Kansas City Power & Light Company	EVRG	49.50%	48.88%	49.25%	49.15%	49.42%	48.47%	49.19%	49.61%	49.19%
Kansas Gas and Electric Company	EVRG	74.91%	74.45%	74.29%	74.18%	74.21%	73.69%	73.49%	73.37%	74.07%
KCP&L Greater Missouri Operations Company	EVRG	55.70%	52.03%	52.63%	52.40%	55.14%	54.57%	54.22%	54.47%	53.89%
Westar Energy (KPL)	EVRG	59.34%	58.68%	58.75%	58.74%	58.87%	58.22%	58.10%	59.68%	58.80%
Connecticut Light and Power Company	ES	54.49%	53.85%	50.40%	53.82%	53.49%	54.79%	54.51%	55.52%	53.86%
NSTAR Electric Company	ES	55.50%	54.51%	53.83%	53.85%	52.87%	52.73%	56.27%	56.10%	54.46%
Public Service Company of New Hampshire	ES	43.11%	42.06%	57.93%	57.30%	59.26%	57.05%	56.60%	56.31%	53.70%
Western Massachusetts Electric Company	ES	NA	NA	NA	53.43%	55.02%	54.71%	54.40%	54.11%	54.34%
Hawaii Electric Light Company, Inc.	HE	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hawaiian Electric Company, Inc.	HE	56.09%	55.78%	57.44%	57.42%	58.11%	57.76%	57.71%	57.70%	57.25%
Maui Electric Company, Limited	HE	NA	NA	NA	NA	NA	NA	NA	NA	NA
Florida Power & Light Company	NEE	64.78%	60.84%	61.23%	59.93%	63.00%	62.78%	62.05%	62.65%	62.16%
NorthWestern Corporation	NWE	48.36%	48.41%	47.48%	49.89%	48.86%	48.61%	48.61%	48.13%	48.54%
Oklahoma Gas and Electric Company	OGE	53.05%	54.25%	53.59%	53.36%	53.05%	52.75%	53.46%	56.09%	53.70%
Otter Tail Power Company	OTTR	53.49%	53.11%	52.67%	57.34%	57.24%	55.31%	55.31%	55.06%	54.94%
Arizona Public Service Company	PNW	53.68%	53.71%	53.18%	53.14%	53.05%	53.32%	53.20%	54.59%	53.48%
Public Service Company of New Mexico	PNM	48.01%	46.68%	46.20%	46.06%	47.58%	46.89%	46.38%	46.01%	46.73%
Portland General Electric Company	POR	50.51%	50.29%	50.14%	49.80%	50.17%	50.32%	50.28%	49.82%	50.17%
Alabama Power Company	SO	48.13%	47.51%	48.86%	47.07%	47.93%	47.25%	47.00%	46.97%	47.59%
Georgia Power Company	SO	57.27%	54.97%	53.81%	50.06%	50.35%	51.55%	50.36%	51.63%	52.50%
Gulf Power Company	SO	55.34%	54.90%	54.27%	54.19%	54.97%	54.41%	58.80%	56.16%	55.38%
Mississippi Power Company	SO	45.28%	43.87%	43.00%	39.34%	47.32%	46.76%	49.50%	49.62%	45.58%
Upper Michigan Energy Resources Corporation	WEC	55.08%	54.53%	70.04%	49.85%	NA	NA	NA	NA	57.37%
Wisconsin Electric Power Company	WEC	59.25%	59.09%	56.47%	55.94%	55.97%	55.76%	55.58%	56.74%	56.85%
Wisconsin Public Service Corporation	WEC	60.59%	59.53%	58.35%	58.06%	55.68%	55.21%	54.02%	55.78%	57.15%
Northern States Power Company - MN	XEL	52.64%	52.61%	52.59%	52.38%	52.22%	52.78%	52.62%	52.31%	52.52%
Northern States Power Company - WI	XEL	48.45%	53.85%	53.79%	53.36%	55.57%	55.22%	55.66%	54.93%	53.85%
Public Service Company of Colorado	XEL	56.08%	54.17%	56.67%	56.50%	55.64%	54.88%	57.00%	56.32%	55.91%
Southwestern Public Service Company	XEL	56.29%	53.88%	53.54%	53.55%	52.29%	54.61%	54.48%	53.93%	54.07%
Mean		53.24%	52.79%	53.51%	53.06%	53.26%	53.19%	53.41%	53.36%	53.01%

Source: S&P Global Market Intelligence

Proxy Group Capital Structure

		% Long-Term Debt								
Company	Ticker	2018Q3	2018Q2	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	Average
ALLETE, Inc.	ALE	41.50%	41.16%	36.91%	37.49%	38.97%	39.38%	39.72%	40.98%	39.51%
Alliant Energy Corporation	LNT	48.87%	49.00%	50.26%	50.23%	47.91%	48.77%	49.16%	49.27%	49.18%
Ameren Corporation	AEE	46.78%	47.99%	46.96%	47.35%	46.44%	46.89%	47.23%	47.38%	47.13%
American Electric Power Company, Inc.	AEP	51.32%	51.48%	51.40%	51.09%	51.54%	50.59%	50.39%	50.10%	50.99%
Avangrid, Inc.	AGR	43.87%	45.07%	43.45%	44.31%	46.12%	46.46%	44.34%	45.05%	44.83%
Black Hills Corporation	BKH	46.80%	46.18%	46.21%	45.60%	45.25%	46.16%	46.80%	47.19%	46.27%
CMS Energy Corporation	CMS	46.99%	47.14%	46.87%	47.75%	46.75%	47.03%	47.90%	48.76%	47.40%
Consolidated Edison, Inc.	ED	51.62%	51.27%	50.25%	50.77%	50.13%	50.81%	50.17%	50.61%	50.70%
DTE Energy Company	DTE	50.03%	50.77%	48.88%	48.98%	49.50%	49.37%	49.50%	49.50%	49.57%
Duke Energy Corporation	DUK	44.97%	45.06%	45.54%	45.70%	46.22%	45.38%	45.63%	45.34%	45.48%
El Paso Electric Company	EE	51.43%	52.68%	50.54%	50.05%	50.19%	51.99%	52.52%	52.27%	51.46%
Evergy, Inc.	EVRG	40.14%	41.49%	41.27%	41.38%	40.59%	41.26%	41.25%	40.72%	41.01%
Eversource Energy	ES	48.97%	49.86%	45.95%	45.40%	44.84%	45.18%	44.56%	44.49%	46.15%
Hawaiian Electric Industries, Inc.	HE	43.91%	44.22%	42.56%	42.58%	41.89%	42.24%	42.29%	42.30%	42.75%
NextEra Energy, Inc.	NEE	35.22%	39.16%	38.77%	40.07%	37.00%	37.22%	37.95%	37.35%	37.84%
NorthWestern Corporation	NWE	51.64%	51.59%	52.52%	50.11%	51.14%	51.39%	51.39%	51.87%	51.46%
OGE Energy Corp.	OGE	46.95%	45.75%	46.41%	46.64%	46.95%	47.25%	46.54%	43.91%	46.30%
Otter Tail Corporation	OTTR	46.51%	46.89%	47.33%	42.66%	42.76%	44.69%	44.69%	44.94%	45.06%
Pinnacle West Capital Corporation	PNW	46.32%	46.29%	46.82%	46.86%	46.95%	46.68%	46.80%	45.41%	46.52%
PNM Resources, Inc.	PNM	51.99%	53.32%	53.80%	53.94%	52.42%	53.11%	53.62%	53.99%	53.27%
Portland General Electric Company	POR	49.49%	49.71%	49.86%	50.20%	49.83%	49.68%	49.72%	50.18%	49.83%
Southern Company	SO	48.50%	49.69%	50.02%	52.33%	49.86%	50.01%	48.59%	48.90%	49.74%
WEC Energy Group, Inc.	WEC	41.70%	42.28%	38.38%	45.38%	44.18%	44.52%	45.20%	43.74%	43.17%
Xcel Energy Inc.	XEL	46.63%	46.37%	45.85%	46.05%	46.07%	45.63%	45.06%	45.63%	45.91%
Mean		46.76%	47.27%	46.53%	46.79%	46.40%	46.74%	46.71%	46.66%	46.73%

Operating Company Capital Structure

		% Long-Term Debt								
Operating Company	Parent	2018Q3	2018Q2	2018Q1	2017Q4	2017Q3	2017Q2	2017Q1	2016Q4	Average
ALLETE (Minnesota Power)	ALE	39.57%	39.67%	39.62%	39.96%	40.27%	40.84%	41.29%	43.08%	40.54%
Superior Water, Light and Power Company	ALE	43.42%	42.66%	34.20%	35.01%	37.67%	37.92%	38.15%	38.88%	38.49%
Interstate Power and Light Company	LNT	50.36%	49.53%	50.08%	49.69%	48.21%	49.11%	49.77%	49.76%	49.56%
Wisconsin Power and Light Company	LNT	47.38%	48.48%	50.43%	50.77%	47.61%	48.44%	48.55%	48.78%	48.81%
Ameren Illinois Company	AEE	46.82%	47.26%	45.76%	46.62%	45.02%	45.45%	45.91%	46.56%	46.18%
Union Electric Company	AEE	46.74%	48.72%	48.16%	48.08%	47.86%	48.32%	48.55%	48.20%	48.08%
AEP Texas Central Company	AEP	NA	NA	NA	NA	NA	NA	NA	53.99%	53.99%
AEP Texas North Company	AEP	NA	NA	NA	NA	NA	NA	NA	56.71%	56.71%
AEP Texas Inc.	AEP	56.20%	56.80%	53.25%	54.86%	57.19%	50.54%	51.18%	NA	54.29%
Appalachian Power Company	AEP	50.70%	51.07%	50.65%	51.28%	51.70%	52.15%	51.83%	53.11%	51.56%
Indiana Michigan Power Company	AEP	55.47%	55.85%	53.36%	53.67%	53.35%	53.73%	50.46%	50.89%	53.35%
Kentucky Power Company	AEP	54.72%	55.11%	55.60%	56.48%	56.78%	56.70%	56.43%	56.55%	56.05%
Kingsport Power Company	AEP	49.29%	52.31%	52.72%	53.47%	54.12%	49.42%	51.02%	34.76%	49.64%
Ohio Power Company	AEP	43.15%	42.89%	47.09%	41.37%	42.36%	43.28%	43.25%	43.49%	43.36%
Public Service Company of Oklahoma	AEP	50.45%	51.41%	51.90%	51.50%	51.15%	51.74%	51.80%	51.53%	51.44%
Southwestern Electric Power Company	AEP	56.57%	52.09%	52.28%	51.48%	51.34%	51.86%	51.67%	54.05%	52.67%
Wheeling Power Company	AEP	45.30%	45.81%	45.73%	45.74%	45.87%	45.90%	45.90%	45.88%	45.77%
Central Maine Power Company	AGR	35.83%	36.47%	35.82%	36.18%	36.03%	36.73%	37.16%	37.61%	36.48%
New York State Electric & Gas Corporation	AGR	46.05%	49.01%	45.49%	46.70%	51.73%	49.76%	50.32%	51.16%	48.78%
Rochester Gas and Electric Corporation	AGR	51.84%	52.23%	49.20%	50.37%	51.06%	51.54%	44.75%	45.70%	49.58%
United Illuminating Company	AGR	41.77%	42.57%	43.30%	44.00%	45.65%	47.83%	45.12%	45.74%	44.50%
Black Hills Colorado Electric Utility Company, LP	BKH	46.96%	45.15%	45.32%	44.31%	45.04%	44.99%	46.92%	47.80%	45.81%
Black Hills Power, Inc.	BKH	46.49%	46.70%	46.78%	46.51%	43.86%	46.74%	46.76%	47.12%	46.37%
Cheyenne Light, Fuel and Power Company	BKH	46.96%	46.68%	46.54%	45.99%	46.84%	46.73%	46.71%	46.65%	46.64%
Consumers Energy Company	CMS	46.99%	47.14%	46.87%	47.75%	46.75%	47.03%	47.90%	48.76%	47.40%
Consolidated Edison Company of New York, Inc.	ED	51.67%	53.28%	51.34%	51.78%	50.53%	51.42%	50.35%	50.69%	51.38%
Orange and Rockland Utilities, Inc.	ED	51.56%	49.26%	49.17%	49.75%	49.73%	50.19%	50.00%	50.54%	50.02%
Rockland Electric Company	ED	NA	NA	NA	NA	NA	NA	NA	NA	NA
DTE Electric Company	DTE	50.03%	50.77%	48.88%	48.98%	49.50%	49.37%	49.50%	49.50%	49.57%
Duke Energy Carolinas, LLC	DUK	47.36%	47.90%	48.30%	47.02%	46.02%	46.51%	46.68%	47.19%	47.12%
Duke Energy Florida, LLC	DUK	50.35%	51.21%	50.08%	50.75%	50.54%	52.26%	53.05%	49.17%	50.93%
Duke Energy Indiana, LLC	DUK	47.21%	47.36%	47.46%	48.06%	48.29%	48.11%	47.85%	48.41%	47.84%
Duke Energy Kentucky, Inc.	DUK	43.42%	44.21%	46.28%	46.89%	49.31%	44.26%	44.57%	45.26%	45.52%
Duke Energy Ohio, Inc.	DUK	32.27%	32.90%	33.94%	33.76%	34.21%	34.62%	34.64%	33.61%	33.75%
Duke Energy Progress, LLC	DUK	49.24%	46.78%	47.18%	47.73%	48.94%	46.49%	47.01%	48.42%	47.72%
El Paso Electric Company	EE	51.43%	52.68%	50.54%	50.05%	50.19%	51.99%	52.52%	52.27%	51.46%
Kansas City Power & Light Company	EVRG	50.50%	51.12%	50.75%	50.85%	50.58%	51.53%	50.81%	50.39%	50.81%
Kansas Gas and Electric Company	EVRG	25.09%	25.55%	25.71%	25.82%	25.79%	26.31%	26.51%	26.63%	25.93%
KCP&L Greater Missouri Operations Company	EVRG	44.30%	47.97%	47.37%	47.60%	44.86%	45.43%	45.78%	45.53%	46.11%
Westar Energy (KPL)	EVRG	40.66%	41.32%	41.25%	41.26%	41.13%	41.78%	41.90%	40.32%	41.20%
Connecticut Light and Power Company	ES	45.51%	46.15%	49.60%	46.18%	46.51%	45.21%	45.49%	44.48%	46.14%
NSTAR Electric Company	ES	44.50%	45.49%	46.17%	46.15%	47.13%	47.27%	43.73%	43.90%	45.54%
Public Service Company of New Hampshire	ES	56.89%	57.94%	42.07%	42.70%	40.74%	42.95%	43.40%	43.69%	46.30%
Western Massachusetts Electric Company	ES	NA	NA	NA	46.57%	44.98%	45.29%	45.60%	45.89%	45.66%
Hawaii Electric Light Company, Inc.	HE	NA	NA	NA	NA	NA	NA	NA	NA	NA
Hawaiian Electric Company, Inc.	HE	43.91%	44.22%	42.56%	42.58%	41.89%	42.24%	42.29%	42.30%	42.75%
Maui Electric Company, Limited	HE	NA	NA	NA	NA	NA	NA	NA	NA	NA
Florida Power & Light Company	NEE	35.22%	39.16%	38.77%	40.07%	37.00%	37.22%	37.95%	37.35%	37.84%
NorthWestern Corporation	NWE	51.64%	51.59%	52.52%	50.11%	51.14%	51.39%	51.39%	51.87%	51.46%
Oklahoma Gas and Electric Company	OGE	46.95%	45.75%	46.41%	46.64%	46.95%	47.25%	46.54%	43.91%	46.30%
Otter Tail Power Company	OTTR	46.51%	46.89%	47.33%	42.66%	42.76%	44.69%	44.69%	44.94%	45.06%
Arizona Public Service Company	PNW	46.32%	46.29%	46.82%	46.86%	46.95%	46.68%	46.80%	45.41%	46.52%
Public Service Company of New Mexico	PNM	51.99%	53.32%	53.80%	53.94%	52.42%	53.11%	53.62%	53.99%	53.27%
Portland General Electric Company	POR	49.49%	49.71%	49.86%	50.20%	49.83%	49.68%	49.72%	50.18%	49.83%
Alabama Power Company	SO	51.87%	52.49%	51.14%	52.93%	52.07%	52.75%	53.00%	53.03%	52.41%
Georgia Power Company	SO	42.73%	45.03%	46.19%	49.94%	49.65%	48.45%	49.64%	48.37%	47.50%
Gulf Power Company	SO	44.66%	45.10%	45.73%	45.81%	45.03%	45.59%	41.20%	43.84%	44.62%
Mississippi Power Company	SO	54.72%	56.13%	57.00%	60.66%	52.68%	53.24%	50.50%	50.38%	54.42%
Upper Michigan Energy Resources Corporation	WEC	44.92%	45.47%	29.96%	50.15%	NA	NA	NA	NA	42.63%
Wisconsin Electric Power Company	WEC	40.75%	40.91%	43.53%	44.06%	44.03%	44.24%	44.42%	43.26%	43.15%
Wisconsin Public Service Corporation	WEC	39.41%	40.47%	41.65%	41.94%	44.32%	44.79%	45.98%	44.22%	42.85%
Northern States Power Company - MN	XEL	47.36%	47.39%	47.41%	47.62%	47.78%	47.22%	47.38%	47.69%	47.48%
Northern States Power Company - WI	XEL	51.55%	46.15%	46.21%	46.64%	44.43%	44.78%	44.34%	45.07%	46.15%
Public Service Company of Colorado	XEL	43.92%	45.83%	43.33%	43.50%	44.36%	45.12%	43.00%	43.68%	44.09%
Southwestern Public Service Company	XEL	43.71%	46.12%	46.46%	46.45%	47.71%	45.39%	45.52%	46.07%	45.93%
Mean		46.76%	47.21%	46.49%	46.94%	46.74%	46.81%	46.59%	46.64%	46.99%

R.B. Hevert
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (G) – 7

DuPont Formula

Year	Profit Margin	Asset Turnover	Equity Multiplier	Return on Equity	Increase in Net Plant
2009	7.21%	52.65%	238.05%	8.42%	
2010	7.95%	52.32%	239.98%	9.24%	6.52%
2011	8.44%	50.80%	243.88%	9.62%	6.01%
2012	9.29%	44.96%	245.10%	9.57%	11.10%
2013	9.75%	44.18%	240.71%	9.72%	4.79%
2014	10.07%	42.09%	239.46%	9.59%	8.79%
2015	10.42%	36.54%	244.27%	9.04%	12.13%
2016	11.24%	34.52%	251.19%	9.40%	8.47%
2017	11.59%	34.12%	253.15%	9.59%	5.76%
2018	12.26%	36.90%	248.04%	10.30%	6.16%
Five -Year Projection	13.59%	32.42%	248.37%	10.28%	26.77%

		Net Profit	Revenue	Net Plant	Total Capital	Common Equity Ratio	Book Value per Share	Shares Outstanding	Reported Return on Com Equity	Profit Margin	Asset Turnover	Equity Multiplier	Calculated Return on Equity	Common Equity Check	ROE Check	Annual Increase in Net Plant
ALE	2009	$ 61.00	$ 759.10	$ 1,622.70	$ 1,625.30	57.20%	$ 26.41	35.20	6.60%	8.04%	46.78%	174.55%	6.56%	100.00%	99.42%	
	2010	75.30	907.00	1,805.60	1,747.60	55.80%	27.26	35.80	7.70%	8.30%	50.23%	185.16%	7.72%	100.08%	100.28%	11.3%
	2011	93.80	928.20	1,982.70	1,937.20	55.70%	28.78	37.50	8.70%	10.11%	46.81%	183.75%	8.69%	100.02%	99.92%	9.8%
	2012	97.10	961.20	2,347.60	2,134.60	56.30%	30.48	39.40	8.10%	10.10%	40.94%	195.34%	8.08%	99.93%	99.75%	18.4%
	2013	104.70	1,018.40	2,576.50	2,425.90	55.40%	32.44	41.40	7.80%	10.28%	39.53%	191.71%	7.79%	99.93%	99.88%	9.8%
	2014	124.80	1,136.80	3,286.40	2,882.20	55.80%	35.06	45.90	7.80%	10.98%	34.59%	204.34%	7.76%	100.06%	99.49%	27.6%
	2015	163.40	1,486.40	3,669.10	3,388.90	53.70%	37.07	49.10	9.00%	10.99%	40.51%	201.62%	8.98%	100.02%	99.76%	11.6%
	2016	155.30	1,339.70	3,741.20	3,263.40	58.00%	38.17	49.60	8.20%	11.59%	35.81%	197.66%	8.20%	100.02%	100.06%	2.0%
	2017	159.20	1,419.30	3,822.40	3,507.40	59.00%	40.47	51.10	7.70%	11.22%	37.13%	184.71%	7.69%	99.93%	99.91%	2.2%
	2018	174.10	1,498.60	3,904.40	3,584.30	60.10%	41.86	51.50	8.10%	11.62%	38.38%	181.25%	8.08%	100.08%	99.78%	2.1%
	2022-24	220.00	1,775.00	4,525.00	4,225.00	59.00%	48.25	51.50	9.00%	12.39%	39.23%	181.53%	8.83%	99.68%	98.06%	15.9%
LNT	2009	$ 208.60	$ 3,432.80	$ 6,203.00	$ 5,423.00	51.20%	$ 12.54	221.31	6.80%	6.08%	55.34%	223.40%	7.51%	99.95%	110.48%	
	2010	303.90	3,416.10	6,730.60	5,840.80	49.50%	13.05	221.79	9.90%	8.90%	50.75%	232.80%	10.51%	100.11%	106.17%	8.5%
	2011	304.40	3,665.30	7,037.10	5,921.20	50.90%	13.57	222.04	9.50%	8.30%	52.09%	233.49%	10.10%	99.97%	106.31%	4.6%
	2012	337.80	3,094.50	7,838.00	6,476.60	48.40%	14.12	221.97	10.30%	10.92%	39.48%	250.04%	10.78%	99.99%	104.62%	11.4%
	2013	382.10	3,276.80	7,147.30	6,461.00	50.80%	14.79	221.89	11.30%	11.66%	45.85%	217.76%	11.64%	99.99%	103.02%	-8.8%
	2014	385.50	3,350.30	6,442.00	7,257.20	47.50%	15.54	221.87	10.90%	11.51%	52.01%	186.88%	11.18%	100.02%	102.60%	-9.9%
	2015	380.70	3,253.60	8,970.20	7,246.30	51.40%	16.41	226.92	10.20%	11.70%	36.27%	240.84%	10.22%	99.98%	100.21%	39.2%
	2016	373.80	3,320.00	9,809.90	8,177.60	47.20%	16.96	227.67	9.70%	11.26%	33.84%	254.15%	9.68%	100.04%	99.84%	9.4%
	2017	455.90	3,382.20	10,797.90	8,192.80	51.00%	18.08	231.35	10.90%	13.48%	31.32%	258.43%	10.91%	100.11%	100.10%	10.1%
	2018	512.10	3,534.50	12,462.00	9,832.00	46.70%	19.43	236.06	11.20%	14.49%	28.36%	271.41%	11.15%	99.89%	99.58%	15.4%
	2022-24	695.00	3,990.00	17,000.00	12,000.00	48.00%	27.55	250.00	10.00%	17.42%	23.47%	295.14%	12.07%	119.57%	120.66%	36.4%
AEE	2009	$ 624.00	$ 7,090.00	$ 17,610.00	$ 15,991.00	49.10%	$ 33.08	237.40	7.80%	8.80%	40.26%	224.29%	7.95%	100.02%	101.89%	
	2010	669.00	7,638.00	17,853.00	15,185.00	50.90%	32.15	240.40	8.60%	8.76%	42.78%	230.98%	8.66%	100.00%	100.65%	1.4%
	2011	602.00	7,531.00	18,127.00	14,738.00	53.70%	32.64	242.60	7.50%	7.99%	41.55%	229.04%	7.61%	100.05%	101.42%	1.5%
	2012	589.00	6,828.00	16,096.00	13,384.00	49.40%	27.27	242.63	8.80%	8.63%	42.42%	243.45%	8.91%	100.07%	101.23%	-11.2%
	2013	518.00	5,838.00	16,205.00	12,190.00	53.70%	26.97	242.63	7.80%	8.87%	36.03%	247.55%	7.91%	99.96%	101.45%	0.7%
	2014	593.00	6,053.00	17,424.00	12,975.00	51.70%	27.67	242.63	8.70%	9.80%	34.74%	259.75%	8.84%	100.08%	101.61%	7.5%
	2015	585.00	6,098.00	18,799.00	13,968.00	49.70%	28.63	242.63	8.30%	9.59%	32.44%	270.80%	8.43%	100.06%	101.53%	7.9%
	2016	659.00	6,076.00	20,113.00	13,840.00	51.30%	29.27	242.63	9.20%	10.85%	30.21%	283.28%	9.28%	100.03%	100.89%	7.0%
	2017	683.00	6,177.00	21,466.00	14,420.00	49.80%	29.61	242.63	9.40%	11.06%	28.78%	298.92%	9.51%	100.04%	101.18%	6.7%
	2018	821.00	6,291.00	22,810.00	15,632.00	48.80%	31.21	244.50	10.70%	13.05%	27.58%	299.01%	10.76%	100.03%	100.58%	6.3%
	2022-24	1,080.00	7,500.00	29,300.00	20,600.00	49.50%	40.25	253.00	10.50%	14.40%	25.60%	287.34%	10.59%	99.87%	100.87%	28.5%
AEP	2009	$ 1,365.00	$ 13,489.00	$ 34,344.00	$ 28,958.00	45.40%	$ 27.49	478.05	10.40%	10.12%	39.28%	261.23%	10.38%	99.96%	99.83%	
	2010	1,248.00	14,427.00	35,674.00	29,184.00	46.70%	28.33	480.81	9.10%	8.65%	40.44%	261.75%	9.16%	99.94%	100.63%	3.9%
	2011	1,513.00	15,116.00	36,971.00	29,747.00	49.30%	30.33	483.42	10.30%	10.01%	40.89%	252.10%	10.32%	99.98%	100.16%	3.6%
	2012	1,443.00	14,945.00	38,763.00	30,823.00	49.40%	31.37	485.67	9.50%	9.66%	38.55%	254.57%	9.48%	100.06%	99.76%	4.8%
	2013	1,549.00	15,357.00	40,997.00	32,913.00	48.90%	32.98	487.78	9.60%	10.09%	37.46%	254.73%	9.62%	99.95%	100.25%	5.8%
	2014	1,634.00	17,020.00	44,117.00	33,001.00	51.00%	34.37	489.40	9.70%	9.60%	38.58%	262.13%	9.71%	99.94%	100.09%	7.6%
	2015	1,763.40	16,453.00	46,133.00	35,633.00	50.20%	36.44	491.05	9.90%	10.72%	35.66%	257.90%	9.86%	100.03%	99.58%	4.6%
	2016	2,073.60	16,380.00	45,639.00	34,775.00	50.00%	35.38	491.71	11.90%	12.66%	35.89%	262.48%	11.93%	100.05%	100.22%	-1.1%
	2017	1,783.20	15,425.00	50,262.00	37,707.00	48.50%	37.17	492.01	9.80%	11.56%	30.69%	274.84%	9.75%	100.00%	99.50%	10.1%
	2018	1,923.80	16,196.00	55,099.00	40,677.00	46.80%	38.58	493.25	10.10%	11.88%	29.39%	289.43%	10.11%	99.96%	100.06%	9.6%
	2022-24	2,585.00	18,500.00	77,300.00	51,400.00	48.50%	48.00	520.00	11.00%	13.97%	23.93%	310.08%	10.37%	100.12%	94.27%	40.3%
AGR	2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2011	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2012	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2013	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2014	424.00	4,594.00	17,099.00	14,956.00	83.20%	-	-	3.40%	9.23%	26.87%	137.41%	3.41%	-	100.22%	-
	2015	267.00	4,367.00	20,711.00	19,583.00	76.90%	48.74	308.86	1.80%	6.11%	21.09%	137.53%	1.77%	99.96%	98.50%	21.1%
	2016	611.00	6,018.00	21,548.00	19,619.00	77.00%	48.90	308.99	4.00%	10.15%	27.93%	142.64%	4.04%	100.02%	101.11%	4.0%
	2017	516.00	5,963.00	22,669.00	20,273.00	74.40%	48.79	309.01	3.40%	8.65%	26.30%	150.29%	3.42%	99.96%	100.62%	5.2%
	2022-24	1,100.00	7,250.00	31,000.00	27,200.00	61.50%	54.25	309.00	6.50%	15.17%	23.39%	185.32%	6.58%	100.21%	101.17%	36.8%
BKH	2009	$ 89.70	$ 1,269.60	$ 2,160.70	$ 2,100.70	51.60%	$ 27.84	38.97	8.30%	7.07%	58.76%	199.33%	8.28%	100.09%	99.70%	
	2010	64.60	1,307.30	2,495.40	2,286.30	48.10%	28.02	39.27	5.90%	4.94%	52.39%	226.91%	5.87%	100.06%	99.56%	15.5%
	2011	40.40	1,272.20	2,789.60	2,489.70	48.60%	27.53	43.92	3.30%	3.18%	45.61%	230.55%	3.34%	99.93%	101.18%	11.8%
	2012	86.90	1,173.90	2,742.70	2,171.40	56.80%	27.88	44.21	7.10%	7.40%	42.80%	222.38%	7.05%	99.94%	99.24%	-1.7%
	2013	115.80	1,275.90	2,990.30	2,704.70	48.40%	29.39	44.50	8.90%	9.08%	42.67%	228.43%	8.85%	99.91%	99.39%	9.0%
	2014	128.80	1,393.60	3,239.40	2,643.60	52.10%	30.80	44.67	9.40%	9.24%	43.02%	235.20%	9.35%	99.89%	99.48%	8.3%
	2015	128.30	1,304.60	3,259.10	3,332.70	44.00%	28.63	51.19	8.80%	9.83%	40.03%	222.25%	8.75%	99.94%	99.42%	0.6%
	2016	140.30	1,573.00	4,469.00	4,825.80	33.50%	30.25	53.38	8.70%	8.92%	35.20%	276.44%	8.68%	99.88%	99.75%	37.1%
	2017	186.50	1,680.30	4,541.40	4,818.40	35.50%	31.92	53.54	10.90%	11.10%	37.00%	265.50%	10.90%	99.91%	100.03%	1.6%
	2021-23	260.00	1,950.00	6,000.00	5,175.00	50.50%	42.75	61.00	10.00%	13.33%	32.50%	229.59%	9.95%	99.78%	99.49%	32.1%
CMS	2009	$ 231.00	$ 6,205.00	$ 9,682.00	$ 8,977.00	29.00%	$ 11.42	227.89	8.50%	3.72%	64.09%	371.91%	8.87%	99.97%	104.39%	
	2010	356.00	6,432.00	10,069.00	9,473.00	29.50%	11.19	249.60	12.50%	5.53%	63.88%	360.31%	12.74%	99.95%	101.91%	4.0%
	2011	384.00	6,503.00	10,633.00	9,279.00	32.60%	11.92	254.10	12.60%	5.90%	61.16%	351.51%	12.69%	100.13%	100.75%	5.6%
	2012	413.00	6,312.00	11,551.00	10,101.00	31.60%	12.09	264.10	12.90%	6.54%	54.64%	361.88%	12.94%	100.03%	100.30%	8.6%
	2013	454.00	6,566.00	12,246.00	10,730.00	32.20%	12.98	266.10	13.10%	6.91%	53.62%	354.44%	13.14%	99.97%	100.31%	6.0%
	2014	479.00	7,179.00	13,412.00	11,846.00	31.00%	13.34	275.20	13.00%	6.67%	53.53%	365.22%	13.04%	99.97%	100.34%	9.5%
	2015	525.00	6,456.00	14,705.00	12,534.00	31.40%	14.21	277.16	13.30%	8.13%	43.90%	373.63%	13.34%	100.07%	100.30%	9.6%
	2016	553.00	6,399.00	15,715.00	13,040.00	32.60%	15.23	279.21	13.00%	8.64%	40.72%	369.67%	13.01%	100.03%	100.07%	6.9%
	2017	610.00	6,583.00	16,761.00	13,692.00	32.40%	15.77	281.65	13.70%	9.27%	39.28%	377.82%	13.75%	100.12%	100.37%	6.7%
	2018	659.00	6,873.00	18,126.00	15,476.00	30.70%	16.78	283.37	13.80%	9.59%	37.92%	381.51%	13.87%	100.08%	100.51%	8.1%
	2022-24	1,015.00	8,000.00	23,800.00	20,000.00	36.50%	24.50	297.00	14.00%	12.69%	33.61%	326.03%	13.90%	99.68%	99.32%	31.3%
ED	2009	$ 868.00	$ 13,032.00	$ 22,464.00	$ 20,330.00	50.40%	$ 36.46	281.12	8.40%	6.66%	58.01%	219.24%	8.47%	100.03%	100.85%	
	2010	992.00	13,325.00	23,863.00	21,952.00	50.40%	37.93	291.62	8.90%	7.44%	55.84%	215.69%	8.97%	99.98%	100.74%	6.2%
	2011	1,062.00	12,938.00	25,093.00	21,794.00	52.50%	39.05	292.89	9.20%	8.21%	51.56%	219.31%	9.28%	99.96%	100.89%	5.2%
	2012	1,141.00	12,188.00	26,939.00	21,933.00	54.10%	40.53	292.87	9.60%	9.36%	45.24%	227.03%	9.62%	100.04%	100.17%	7.4%
	2013	1,157.00	12,381.00	28,436.00	22,735.00	53.90%	41.81	292.87	9.40%	9.34%	43.54%	232.05%	9.44%	99.92%	100.44%	5.6%
	2014	1,066.00	12,919.00	29,827.00	24,207.00	52.00%	42.94	292.88	8.50%	8.25%	43.31%	236.95%	8.47%	99.91%	99.63%	4.9%
	2015	1,193.00	12,554.00	32,209.00	25,058.00	52.10%	44.55	293.00	9.10%	9.50%	38.98%	246.71%	9.14%	99.98%	100.42%	8.0%
	2016	1,189.00	12,075.00	35,216.00	29,033.00	49.20%	46.88	305.00	8.30%	9.85%	34.29%	246.54%	8.32%	100.10%	100.29%	9.3%
	2017	1,266.00	12,033.00	37,600.00	30,149.00	51.10%	49.74	310.00	8.20%	10.52%	32.00%	244.06%	8.22%	100.09%	100.21%	6.8%
	2022-24	1,655.00	14,700.00	50,700.00	40,700.00	49.50%	60.50	332.00	8.50%	11.26%	28.99%	251.66%	8.21%	99.70%	96.65%	34.8%

		Net Profit	Revenue	Net Plant	Total Capital	Common Equity Ratio	Book Value per Share	Shares Outstanding	Reported Return on Com Equity	Profit Margin	Asset Turnover	Equity Multiplier	Calculated Return on Equity	Common Equity Check	ROE Check	Annual Increase in Net Plant
DTE	2009	$ 532.00	$ 8,014.00	$ 12,431.00	$ 13,648.00	46.00%	$ 37.96	165.40	8.50%	6.64%	64.47%	198.01%	8.47%	100.01%	99.69%	
	2010	630.00	8,557.00	12,992.00	13,811.00	48.70%	39.67	169.43	9.40%	7.36%	65.86%	193.16%	9.37%	99.93%	99.65%	4.5%
	2011	624.00	8,897.00	13,746.00	14,196.00	49.40%	41.41	169.25	8.90%	7.01%	64.72%	196.01%	8.90%	99.94%	99.98%	5.8%
	2012	666.00	8,791.00	14,684.00	14,387.00	51.20%	42.78	172.35	9.00%	7.58%	59.87%	199.34%	9.04%	100.09%	100.46%	6.8%
	2013	661.00	9,661.00	15,800.00	15,135.00	52.30%	44.73	177.09	8.30%	6.84%	61.15%	199.61%	8.35%	100.07%	100.61%	7.6%
	2014	905.00	12,301.00	16,820.00	16,670.00	50.00%	47.05	176.99	10.90%	7.36%	73.13%	201.80%	10.86%	99.91%	99.61%	6.5%
	2015	796.00	10,337.00	18,034.00	17,607.00	49.80%	48.88	179.47	9.10%	7.70%	57.32%	205.67%	9.08%	100.05%	99.76%	7.2%
	2016	868.00	10,630.00	19,730.00	20,280.00	44.40%	50.22	179.43	9.60%	8.17%	53.88%	219.12%	9.64%	100.07%	100.41%	9.4%
	2017	1,029.00	12,607.00	20,721.00	21,697.00	43.80%	53.03	179.39	10.80%	8.16%	60.84%	218.04%	10.83%	100.10%	100.26%	5.0%
	2018	1,120.00	14,212.00	21,650.00	22,371.00	45.80%	56.27	181.93	10.90%	7.88%	65.64%	211.30%	10.93%	99.91%	100.29%	4.5%
	2022-24	1,520.00	18,000.00	28,300.00	31,600.00	46.50%	73.50	200.00	10.50%	8.44%	63.60%	192.60%	10.34%	100.04%	98.52%	30.7%
DUK	2009	$ 1,461.00	$ 12,731.00	$ 37,950.00	$ 37,863.00	57.40%	$ 49.85	436.29	6.70%	11.48%	33.55%	174.62%	6.72%	100.07%	100.33%	
	2010	1,765.00	14,272.00	40,344.00	40,457.00	55.70%	50.84	442.96	7.80%	12.37%	35.38%	179.03%	7.83%	99.94%	100.42%	6.3%
	2011	1,839.00	14,529.00	42,661.00	41,451.00	54.90%	51.14	445.29	8.10%	12.66%	34.06%	187.47%	8.08%	100.07%	99.77%	5.7%
	2012	2,136.00	19,624.00	68,558.00	77,307.00	52.90%	58.04	704.00	5.20%	10.88%	28.62%	167.64%	5.22%	99.91%	100.44%	60.7%
	2013	2,813.00	24,598.00	69,490.00	79,482.00	52.00%	58.54	706.00	6.80%	11.44%	35.40%	168.13%	6.81%	100.00%	100.09%	1.4%
	2014	2,934.00	23,925.00	70,046.00	78,088.00	52.30%	57.81	707.00	7.20%	12.26%	34.16%	171.51%	7.18%	100.08%	99.78%	0.8%
	2015	2,854.00	23,459.00	75,709.00	77,222.00	51.40%	57.74	688.00	7.20%	12.17%	30.99%	190.74%	7.19%	100.08%	99.87%	8.1%
	2016	2,560.00	22,743.00	82,520.00	86,609.00	47.40%	58.62	700.00	6.20%	11.26%	27.56%	201.01%	6.24%	99.95%	100.58%	9.0%
	2017	2,963.00	23,565.00	86,391.00	90,774.00	46.00%	59.63	700.00	7.10%	12.57%	27.28%	206.89%	7.10%	99.96%	99.94%	4.7%
	2022-24	4,350.00	28,000.00	111,600.00	115,400.00	43.50%	67.00	750.00	8.50%	15.54%	25.09%	222.32%	8.67%	100.10%	101.95%	29.2%
EE	2009	$ 66.90	$ 828.00	$ 1,756.00	$ 1,527.70	47.30%	$ 16.45	43.92	9.30%	8.08%	47.15%	243.01%	9.26%	99.98%	99.55%	
	2010	90.30	877.30	1,865.80	1,660.10	48.80%	19.04	42.57	11.10%	10.29%	47.02%	230.31%	11.15%	100.05%	100.42%	6.3%
	2011	103.50	918.00	1,947.10	1,576.70	48.20%	19.03	39.96	13.60%	11.27%	47.15%	256.21%	13.62%	100.06%	100.14%	4.4%
	2012	90.80	852.90	2,102.30	1,824.50	45.20%	20.57	40.11	11.00%	10.65%	40.57%	254.92%	11.01%	100.05%	100.09%	8.0%
	2013	88.60	890.40	2,257.50	1,943.50	48.60%	23.44	40.27	9.40%	9.95%	39.44%	239.00%	9.38%	99.94%	99.79%	7.4%
	2014	91.40	917.50	2,488.40	2,118.40	46.50%	24.39	40.36	9.30%	9.96%	36.87%	252.62%	9.28%	99.93%	99.77%	10.2%
	2015	81.90	849.90	2,695.50	2,150.80	47.30%	25.13	40.44	8.10%	9.64%	31.53%	264.96%	8.05%	99.89%	99.39%	8.3%
	2016	96.80	886.90	2,821.20	2,269.90	47.30%	26.52	40.52	9.00%	10.91%	31.44%	262.76%	9.02%	100.09%	100.18%	4.7%
	2017	98.30	916.80	2,928.40	2,338.20	48.80%	28.14	40.58	8.60%	10.72%	31.31%	256.64%	8.61%	100.08%	100.17%	3.8%
	2021-23	115.00	1,000.00	3,600.00	3,025.00	44.50%	32.75	41.00	8.50%	11.50%	27.78%	267.43%	8.54%	99.75%	100.51%	22.9%
EVRG	2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2011	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2012	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2013	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2014	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2015	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2016	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2017	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	2018	535.80	4,275.90	18,952.00	16,716.00	60.00%	39.28	255.33	5.30%	12.53%	22.56%	188.96%	5.34%	100.00%	100.80%	
	2022-24	760.00	6,100.00	19,600.00	18,700.00	47.00%	41.50	212.00	8.50%	12.46%	31.12%	223.01%	8.65%	100.10%	101.73%	3.4%
ES	2009	$ 335.60	$ 5,439.40	$ 8,840.00	$ 8,629.50	41.50%	$ 20.37	175.62	9.20%	6.17%	61.53%	246.84%	9.37%	99.89%	101.86%	
	2010	377.80	4,898.20	9,567.70	8,741.80	43.60%	21.60	176.45	9.80%	7.71%	51.20%	251.03%	9.91%	100.00%	101.15%	8.2%
	2011	400.30	4,465.70	10,403.00	8,856.00	45.30%	22.65	177.16	9.80%	8.96%	42.93%	259.31%	9.98%	100.02%	101.82%	8.7%
	2012	533.00	6,273.80	16,605.00	16,675.00	55.40%	29.41	314.05	5.70%	8.50%	37.78%	179.75%	5.77%	99.98%	101.22%	59.6%
	2013	793.70	7,301.20	17,576.00	17,544.00	54.80%	30.49	315.27	8.20%	10.87%	41.54%	182.81%	8.26%	99.98%	100.68%	5.8%
	2014	827.10	7,741.90	18,647.00	18,738.00	53.20%	31.47	316.98	8.20%	10.68%	41.52%	187.06%	8.30%	100.07%	101.18%	6.1%
	2015	886.00	7,954.80	19,892.00	19,313.00	53.60%	32.64	317.19	8.50%	11.14%	39.99%	192.16%	8.56%	100.01%	100.69%	6.7%
	2016	949.80	7,639.10	21,351.00	19,697.00	54.40%	33.80	316.89	8.80%	12.43%	35.78%	199.26%	8.86%	99.96%	100.73%	7.3%
	2017	995.50	7,752.00	23,617.00	23,018.00	48.20%	34.99	316.89	8.90%	12.84%	32.82%	212.87%	8.97%	99.94%	100.82%	10.6%
	2022-24	1,355.00	9,350.00	33,600.00	31,700.00	43.50%	43.75	316.89	9.50%	14.49%	27.83%	243.66%	9.83%	100.54%	103.43%	42.3%
HE	2009	$ 84.90	$ 2,309.60	$ 3,088.60	$ 2,840.80	50.70%	$ 15.58	92.52	5.80%	3.68%	74.78%	214.44%	5.89%	100.08%	101.63%	
	2010	115.40	2,665.00	3,165.90	2,732.90	54.30%	15.67	94.69	7.70%	4.33%	84.18%	213.34%	7.78%	99.99%	100.99%	2.5%
	2011	140.10	3,242.30	3,334.50	2,841.30	53.90%	15.95	96.04	9.00%	4.32%	97.23%	217.73%	9.15%	100.02%	101.65%	5.3%
	2012	164.90	3,375.00	3,594.80	3,001.00	53.10%	16.28	97.93	10.20%	4.89%	93.89%	225.59%	10.35%	100.05%	101.45%	7.8%
	2013	163.40	3,238.50	3,858.90	3,142.90	55.00%	17.06	101.26	9.40%	5.05%	83.92%	223.24%	9.45%	99.94%	100.56%	7.3%
	2014	170.20	3,239.50	4,148.80	3,332.30	53.80%	17.47	102.57	9.40%	5.25%	78.08%	231.42%	9.49%	99.95%	101.00%	7.5%
	2015	161.80	2,603.00	4,377.70	3,473.50	55.50%	17.94	107.46	8.30%	6.22%	59.46%	227.08%	8.39%	100.00%	101.12%	5.5%
	2016	250.10	2,380.70	4,603.50	3,595.10	57.50%	19.03	108.58	12.00%	10.51%	51.71%	222.69%	12.10%	99.96%	100.82%	5.2%
	2017	180.60	2,555.60	5,025.90	3,765.50	55.70%	19.28	108.79	8.50%	7.07%	50.85%	239.63%	8.61%	100.00%	101.30%	9.2%
	2021-23	255.00	3,200.00	6,000.00	4,850.00	55.00%	23.75	113.00	9.50%	7.97%	53.33%	224.93%	9.56%	100.61%	100.63%	19.4%
NEE	2009	$ 1,615.00	$ 15,643.00	$ 36,078.00	$ 29,267.00	44.30%	$ 31.35	413.62	12.50%	10.32%	43.36%	278.27%	12.46%	100.01%	99.65%	
	2010	1,957.00	15,317.00	39,075.00	32,474.00	44.50%	34.36	420.86	13.50%	12.78%	39.20%	270.40%	13.54%	100.07%	100.31%	8.3%
	2011	2,021.00	15,341.00	42,490.00	35,753.00	41.80%	35.92	416.00	13.50%	13.17%	36.10%	284.31%	13.52%	99.99%	100.17%	8.7%
	2012	1,911.00	14,256.00	49,413.00	39,245.00	40.90%	37.90	424.00	11.90%	13.40%	28.85%	307.85%	11.91%	100.11%	100.05%	16.3%
	2013	2,062.00	15,136.00	52,720.00	42,009.00	42.90%	41.47	435.00	11.40%	13.62%	28.71%	292.53%	11.44%	100.10%	100.37%	6.7%
	2014	2,465.00	17,021.00	55,705.00	44,283.00	45.00%	44.96	443.00	12.40%	14.48%	30.56%	279.54%	12.37%	99.95%	99.76%	5.7%
	2015	2,752.00	17,486.00	61,386.00	49,255.00	45.80%	48.97	461.00	12.20%	15.74%	28.49%	272.12%	12.20%	100.07%	99.99%	10.2%
	2016	2,693.00	16,155.00	66,912.00	52,159.00	46.70%	52.01	468.00	11.10%	16.67%	24.14%	274.70%	11.06%	99.93%	99.60%	9.0%
	2017	3,074.00	17,195.00	72,416.00	59,671.00	47.30%	59.89	471.00	10.90%	17.88%	23.74%	256.57%	10.89%	99.94%	99.92%	8.2%
	2022-24	6,100.00	25,000.00	101,700.00	84,200.00	54.00%	85.00	535.00	13.50%	24.40%	24.58%	223.67%	13.42%	100.02%	99.38%	40.4%
NWE	2009	$ 73.40	$ 1,141.90	$ 1,964.10	$ 1,803.90	43.60%	$ 21.86	36.00	9.30%	6.43%	58.14%	249.73%	9.33%	100.06%	100.35%	
	2010	77.40	1,110.70	2,118.00	1,916.40	42.80%	22.64	36.23	9.40%	6.97%	52.44%	258.22%	9.44%	100.00%	100.39%	7.8%
	2011	92.60	1,117.30	2,213.30	1,797.10	47.80%	23.68	36.28	10.80%	8.29%	50.48%	257.66%	10.78%	100.01%	99.81%	4.5%
	2012	83.70	1,070.30	2,435.60	2,020.70	46.20%	25.09	37.22	9.00%	7.82%	43.94%	260.89%	8.97%	100.03%	99.62%	10.0%
	2013	94.00	1,154.50	2,690.10	2,215.70	46.50%	26.60	38.75	9.10%	8.14%	42.92%	261.10%	9.12%	100.04%	100.26%	10.4%
	2014	120.70	1,204.90	3,758.00	3,168.00	46.60%	31.50	46.91	8.20%	10.02%	32.06%	254.56%	8.18%	100.09%	99.71%	39.7%
	2015	138.40	1,214.30	4,059.50	3,408.60	46.90%	33.22	48.17	8.60%	11.40%	29.91%	253.94%	8.66%	100.10%	100.67%	8.0%
	2016	164.20	1,257.20	4,214.90	3,493.90	48.00%	34.68	48.33	9.80%	13.06%	29.83%	251.32%	9.79%	99.94%	99.91%	3.8%
	2017	162.70	1,305.70	4,358.30	3,614.50	49.80%	36.44	49.37	9.00%	12.46%	29.96%	242.12%	9.04%	99.95%	100.43%	3.4%
	2021-23	195.00	1,400.00	4,975.00	4,025.00	53.50%	42.50	51.00	9.00%	13.93%	28.14%	231.03%	9.06%	100.66%	100.62%	14.2%
OGE	2009	$ 258.30	$ 2,869.70	$ 5,911.60	$ 4,129.70	49.40%	$ 10.52	194.00	12.70%	9.00%	48.54%	289.77%	12.66%	100.04%	99.70%	
	2010	295.30	3,716.90	6,464.40	4,652.50	49.20%	11.73	195.20	12.90%	7.94%	57.50%	282.41%	12.90%	100.03%	100.01%	9.4%
	2011	342.90	3,915.90	7,474.00	5,300.40	48.40%	13.06	196.20	13.40%	8.76%	52.39%	291.34%	13.37%	99.88%	99.75%	15.6%
	2012	355.00	3,671.20	8,344.80	5,615.80	49.30%	14.00	197.60	12.80%	9.67%	43.99%	301.41%	12.82%	99.92%	100.18%	11.7%
	2013	387.60	2,867.70	6,672.80	5,337.20	56.90%	15.30	198.50	12.80%	13.52%	42.98%	219.73%	12.76%	100.01%	99.71%	-20.0%
	2014	395.80	2,453.10	6,979.90	5,999.70	54.10%	16.27	199.40	12.20%	16.13%	35.15%	215.04%	12.19%	99.95%	99.95%	4.6%
	2015	337.60	2,196.90	7,322.40	5,971.60	55.70%	16.66	199.70	10.20%	15.37%	30.00%	220.14%	10.15%	100.02%	99.51%	4.9%
	2016	338.20	2,259.20	7,696.20	5,849.60	58.90%	17.24	199.70	9.80%	14.97%	29.35%	223.38%	9.82%	99.92%	100.16%	5.1%
	2017	384.30	2,261.10	8,339.90	6,600.70	58.30%	19.28	199.70	10.00%	17.00%	27.11%	216.72%	9.99%	100.05%	99.86%	8.4%
	2018	425.50	2,270.30	8,643.80	6,902.00	58.00%	20.06	199.70	10.60%	18.74%	26.27%	215.92%	10.63%	100.07%	100.27%	3.6%
	2022-24	540.00	3,050.00	9,550.00	8,625.00	54.50%	23.50	199.70	11.50%	17.70%	31.94%	203.16%	11.49%	99.84%	99.89%	10.5%
OTTR	2009	$ 26.00	$ 1,039.50	$ 1,098.60	$ 1,124.40	59.80%	$ 18.78	35.81	3.80%	2.50%	94.62%	163.39%	3.87%	100.02%	101.76%	
	2010	13.60	1,119.10	1,108.70	1,083.30	58.40%	17.57	36.00	2.00%	1.22%	100.94%	175.25%	2.15%	99.98%	107.48%	0.9%
	2011	16.40	1,077.90	1,077.50	1,058.90	54.00%	15.83	36.10	2.70%	1.52%	100.04%	188.44%	2.87%	99.94%	106.23%	-2.8%
	2012	39.00	859.20	1,049.50	959.20	54.40%	14.43	36.17	7.30%	4.54%	81.87%	201.13%	7.47%	100.02%	102.38%	-2.6%
	2013	50.20	893.30	1,167.00	924.40	57.90%	14.75	36.27	9.30%	5.62%	76.55%	218.04%	9.38%	99.95%	100.85%	11.2%
	2014	56.90	799.30	1,268.50	1,071.30	53.50%	15.39	37.22	9.90%	7.12%	63.01%	221.32%	9.93%	99.94%	100.28%	8.7%
	2015	58.60	779.80	1,387.80	1,051.00	57.60%	15.98	37.86	9.70%	7.51%	56.19%	229.25%	9.68%	99.94%	99.79%	9.4%
	2016	62.00	803.50	1,477.20	1,175.40	57.00%	17.03	39.35	9.30%	7.72%	54.39%	220.48%	9.25%	100.02%	99.51%	6.4%
	2017	73.90	849.40	1,539.60	1,187.30	58.70%	17.62	39.56	10.60%	8.70%	55.17%	220.91%	10.60%	100.01%	100.03%	4.2%
	2018	82.30	916.40	1,581.10	1,318.90	55.30%	18.38	39.66	11.30%	8.98%	57.96%	216.78%	11.28%	99.95%	99.86%	2.7%
	2022-24	105.00	1,160.00	2,225.00	1,950.00	49.50%	23.25	41.75	10.50%	9.05%	52.13%	230.51%	10.88%	100.56%	103.60%	40.7%

		Net Profit	Revenue	Net Plant	Total Capital	Common Equity Ratio	Book Value per Share	Shares Outstanding	Reported Return on Com Equity	Profit Margin	Asset Turnover	Equity Multiplier	Calculated Return on Equity	Common Equity Check	ROE Check	Annual Increase in Net Plant
PNW	2009	$ 229.20	$ 3,297.10	$ 9,257.80	$ 6,686.60	49.60%	$ 32.69	101.43	6.90%	6.95%	35.61%	279.14%	6.91%	99.98%	100.16%	
	2010	330.40	3,263.60	9,578.80	6,729.10	54.70%	33.86	108.77	9.00%	10.12%	34.07%	260.24%	8.98%	100.06%	99.74%	3.5%
	2011	328.20	3,241.40	9,962.30	6,840.90	55.90%	34.98	109.25	8.60%	10.13%	32.54%	260.52%	8.58%	99.93%	99.80%	4.0%
	2012	387.40	3,301.80	10,396.00	7,171.90	55.40%	36.20	109.74	9.80%	11.73%	31.76%	261.65%	9.75%	99.98%	99.49%	4.4%
	2013	406.10	3,454.60	10,889.00	6,990.90	60.00%	38.07	110.18	9.70%	11.76%	31.73%	259.60%	9.68%	100.00%	99.81%	4.7%
	2014	397.60	3,491.60	11,194.00	7,398.70	59.00%	39.50	110.57	9.10%	11.39%	31.19%	256.44%	9.11%	100.05%	100.09%	2.8%
	2015	437.30	3,495.40	11,809.00	8,046.30	57.00%	41.30	110.98	9.50%	12.51%	29.60%	257.48%	9.53%	99.94%	100.37%	5.5%
	2016	442.00	3,498.70	12,714.00	8,825.40	54.40%	43.15	111.34	9.20%	12.63%	27.52%	264.82%	9.21%	100.07%	100.07%	7.7%
	2017	497.80	3,565.30	13,445.00	9,796.40	51.10%	44.80	111.75	9.90%	13.96%	26.52%	268.58%	9.94%	100.01%	100.45%	5.7%
	2021-23	660.00	4,500.00	16,125.00	11,225.00	54.50%	53.75	114.25	10.50%	14.67%	27.91%	263.58%	10.79%	100.38%	102.75%	19.9%
PNM	2009	$ 53.50	$ 1,647.70	$ 3,332.40	$ 3,214.90	51.00%	$ 18.90	86.67	3.20%	3.25%	49.44%	203.24%	3.26%	99.91%	101.97%	
	2010	80.00	1,673.50	3,444.40	3,100.30	49.20%	17.60	86.67	5.20%	4.78%	48.59%	225.81%	5.24%	100.00%	100.86%	3.4%
	2011	96.60	1,700.60	3,627.10	3,245.60	48.10%	19.62	79.65	6.10%	5.68%	46.89%	232.34%	6.19%	100.10%	101.44%	5.3%
	2012	105.60	1,342.40	3,746.50	3,277.90	48.70%	20.05	79.65	6.60%	7.87%	35.83%	234.69%	6.62%	100.04%	100.23%	3.3%
	2013	113.50	1,387.90	3,933.90	3,344.00	49.70%	20.87	79.65	6.80%	8.18%	35.28%	236.70%	6.83%	100.02%	100.43%	5.0%
	2014	116.30	1,435.90	4,270.00	3,437.10	51.90%	22.39	79.65	6.50%	8.10%	33.63%	239.37%	6.52%	99.97%	100.30%	8.5%
	2015	131.50	1,439.10	4,535.40	3,633.30	45.50%	20.78	79.65	7.90%	9.14%	31.73%	274.35%	7.95%	100.12%	100.69%	6.2%
	2016	132.40	1,363.00	4,904.70	3,806.80	44.00%	21.04	79.65	7.90%	9.71%	27.79%	292.82%	7.90%	100.05%	100.06%	8.1%
	2017	154.40	1,445.00	4,980.20	3,887.50	43.60%	21.28	79.65	9.10%	10.69%	29.01%	293.83%	9.11%	100.00%	100.10%	1.5%
	2021-23	225.00	1,700.00	6,025.00	5,250.00	42.00%	26.50	83.00	9.50%	13.24%	28.22%	273.24%	10.20%	99.75%	107.41%	21.0%
POR	2009	$ 95.00	$ 1,804.00	$ 3,858.00	$ 3,100.00	49.70%	$ 20.50	75.21	6.20%	5.27%	46.76%	250.41%	6.17%	100.07%	99.45%	
	2010	125.00	1,783.00	4,133.00	3,390.00	47.00%	21.14	75.32	7.90%	7.01%	43.14%	259.40%	7.85%	99.94%	99.31%	7.1%
	2011	147.00	1,813.00	4,285.00	3,298.00	50.40%	22.07	75.36	8.80%	8.11%	42.31%	257.79%	8.84%	100.06%	100.50%	3.7%
	2012	141.00	1,805.00	4,392.00	3,264.00	52.90%	22.87	75.56	8.20%	7.81%	41.10%	254.36%	8.17%	100.08%	99.59%	2.5%
	2013	137.00	1,810.00	4,880.00	3,735.00	48.70%	23.30	78.09	7.50%	7.57%	37.09%	268.29%	7.53%	100.03%	100.42%	11.1%
	2014	175.00	1,900.00	5,679.00	4,037.00	47.30%	24.43	78.23	9.20%	9.21%	33.46%	297.41%	9.16%	100.09%	99.62%	16.4%
	2015	172.00	1,898.00	6,012.00	4,329.00	52.20%	25.43	88.79	7.60%	9.06%	31.57%	266.05%	7.61%	99.92%	100.15%	5.9%
	2016	193.00	1,923.00	6,434.00	4,544.00	51.60%	26.35	88.95	8.20%	10.04%	29.89%	274.41%	8.23%	99.96%	100.38%	7.0%
	2017	204.00	2,009.00	6,741.00	4,842.00	49.90%	27.11	89.11	8.40%	10.15%	29.80%	279.00%	8.44%	99.98%	100.51%	4.8%
	2021-23	255.00	2,325.00	7,125.00	5,525.00	52.00%	32.00	90.00	9.00%	10.97%	32.63%	248.00%	8.88%	100.24%	98.62%	5.7%
SO	2009	$ 1,910.00	$ 15,743.00	$ 39,230.00	$ 34,091.00	43.60%	$ 18.15	819.65	12.40%	12.13%	40.13%	263.93%	12.85%	100.09%	103.63%	
	2010	2,040.00	17,456.00	42,002.00	35,438.00	45.70%	19.21	843.34	12.20%	11.69%	41.56%	259.35%	12.60%	100.03%	103.25%	7.1%
	2011	2,268.00	17,657.00	45,010.00	37,307.00	47.10%	20.32	865.13	12.50%	12.84%	39.23%	256.15%	12.91%	100.04%	103.26%	7.2%
	2012	2,415.00	16,537.00	48,390.00	38,653.00	47.30%	21.09	867.77	12.80%	14.60%	34.17%	264.67%	13.21%	100.10%	103.20%	7.5%
	2013	2,439.00	17,087.00	51,208.00	41,483.00	45.80%	21.43	887.09	12.50%	14.27%	33.37%	269.53%	12.84%	100.06%	102.70%	5.8%
	2014	2,567.00	18,467.00	54,868.00	42,142.00	47.30%	21.98	907.78	12.50%	13.90%	33.66%	275.26%	12.88%	100.10%	103.02%	7.1%
	2015	2,647.00	17,489.00	61,114.00	46,788.00	44.00%	22.59	911.72	12.60%	15.14%	28.62%	296.86%	12.86%	100.04%	102.05%	11.4%
	2016	2,757.00	19,896.00	78,446.00	69,359.00	35.70%	25.00	990.39	11.00%	13.86%	25.36%	316.81%	11.13%	99.99%	101.22%	28.4%
	2017	3,269.00	23,031.00	79,872.00	68,953.00	35.00%	23.98	1,007.60	13.40%	14.19%	28.83%	330.96%	13.55%	100.12%	101.09%	1.8%
	2022-24	4,180.00	30,650.00	91,900.00	79,700.00	40.00%	29.50	1,090.00	13.00%	13.64%	33.35%	288.27%	13.11%	100.86%	100.86%	15.1%
WEC	2009	$ 378.40	$ 4,127.90	$ 9,070.50	$ 7,473.10	47.70%	$ 15.26	233.82	10.60%	9.17%	45.51%	254.46%	10.62%	100.10%	100.14%	
	2010	455.60	4,202.50	9,601.50	7,764.50	49.00%	16.26	233.77	12.00%	10.84%	43.77%	252.37%	11.97%	99.91%	99.79%	5.9%
	2011	514.00	4,486.40	10,160.00	8,608.00	46.00%	17.20	230.49	12.90%	11.46%	44.16%	256.59%	12.98%	100.12%	100.63%	5.8%
	2012	547.50	4,246.40	10,572.00	8,619.30	48.00%	18.05	229.04	13.20%	12.89%	40.17%	255.53%	13.23%	99.93%	100.25%	4.1%
	2013	578.60	4,519.00	10,907.00	8,626.60	49.10%	18.73	225.96	13.60%	12.80%	41.43%	257.50%	13.66%	99.92%	100.44%	3.2%
	2014	589.50	4,997.10	11,258.00	8,636.50	51.20%	19.60	225.52	13.30%	11.80%	44.39%	254.60%	13.33%	99.96%	100.24%	3.2%
	2015	640.30	5,926.10	19,190.00	17,809.00	48.60%	27.42	315.68	7.40%	10.80%	30.88%	221.72%	7.40%	100.01%	99.97%	70.5%
	2016	940.20	7,472.30	19,916.00	18,118.00	49.30%	28.29	315.62	10.50%	12.58%	37.52%	222.97%	10.53%	99.96%	100.25%	3.8%
	2017	998.20	7,648.50	21,347.00	18,238.00	51.90%	29.98	315.57	10.50%	13.05%	35.83%	225.52%	10.55%	99.95%	100.43%	7.2%
	2018	1,060.50	7,679.50	22,001.00	19,813.00	49.40%	31.02	315.52	10.80%	13.81%	34.91%	224.78%	10.84%	100.00%	100.33%	3.1%
	2022-24	1,425.00	9,300.00	31,325.00	23,200.00	50.00%	36.75	315.50	12.50%	15.32%	29.69%	270.04%	12.28%	99.95%	98.28%	42.4%
XEL	2009	$ 685.50	$ 9,644.30	$ 18,508.00	$ 15,277.00	47.70%	$ 15.92	457.51	9.40%	7.11%	52.11%	253.98%	9.41%	99.95%	100.07%	
	2010	727.00	10,311.00	20,663.00	17,452.00	46.30%	16.76	482.33	8.90%	7.05%	49.90%	255.72%	9.00%	100.04%	101.09%	11.6%
	2011	841.40	10,655.00	22,353.00	17,331.00	48.90%	17.44	486.49	9.90%	7.90%	47.67%	263.76%	9.93%	100.11%	100.28%	8.2%
	2012	905.20	10,128.00	23,809.00	19,018.00	46.70%	18.19	487.96	10.20%	8.94%	42.54%	268.08%	10.19%	99.94%	99.92%	6.5%
	2013	948.20	10,915.00	26,122.00	20,477.00	46.70%	19.21	497.97	9.90%	8.69%	41.78%	273.16%	9.92%	100.03%	100.16%	9.7%
	2014	1,021.30	11,686.00	28,757.00	21,714.00	47.00%	20.20	505.73	10.00%	8.74%	40.64%	281.78%	10.01%	100.10%	100.07%	10.1%
	2015	1,063.60	11,024.00	31,206.00	23,092.00	45.90%	20.89	507.54	10.00%	9.65%	35.33%	294.42%	10.03%	100.03%	100.35%	8.5%
	2016	1,123.40	11,107.00	32,842.00	25,216.00	43.70%	21.73	507.22	10.20%	10.11%	33.82%	298.04%	10.19%	100.02%	99.95%	5.2%
	2017	1,171.00	11,404.00	34,329.00	25,975.00	44.10%	22.56	507.76	10.20%	10.27%	33.22%	299.69%	10.22%	100.00%	100.22%	4.5%
	2021-23	1,615.00	13,250.00	44,200.00	35,600.00	43.00%	28.50	533.00	10.50%	12.19%	29.98%	288.74%	10.55%	99.23%	100.48%	28.8%

R.B. Hevert
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (G) – 8

Change in Net Plant and Asset Turnover
Proxy Group - Annual Average

Year	Average Revenue/Net Plant	Average Change in Net Plant	Cumulative Change in Net Plant
2010	52.32%	6.52%	6.52%
2011	50.80%	6.01%	12.92%
2012	44.96%	11.10%	25.46%
2013	44.18%	4.79%	31.47%
2014	42.09%	8.79%	43.03%
2015	36.54%	12.13%	60.38%
2016	34.52%	8.47%	73.97%
2017	34.12%	5.76%	83.98%
2018	36.90%	6.16%	95.32%
3-5 Year Projection	32.42%	29.85%	153.62%

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.413013994
R Square	0.170580559
Adjusted R Square	0.166630943
Standard Error	0.091001201
Observations	212

ANOVA

	df	*SS*	*MS*	*F*
Regression	1	0.357658755	0.357658755	43.18914605
Residual	210	1.739055886	0.008281219	
Total	211	2.096714641		

	Coefficients	*Standard Error*	*t Stat*	*P-value*
Intercept	-0.008673043	0.00815222	-1.063887259	0.288601568
Change in Net Plant	-0.331943586	0.050509954	-6.57184495	3.85647E-10

Change in Net Plant and Asset Turnover
Proxy Group - Individual Company Results

Ticker	Year	Revenue	Net Plant	Revenue/Net Plant	Change in Net Plant	Change in Revenue/Net Plant
ALE	2009	$ 759.10	$ 1,622.70	46.78%		
ALE	2010	907.00	1,805.60	50.23%	11.27%	7.38%
ALE	2011	928.20	1,982.70	46.81%	9.81%	-6.80%
ALE	2012	961.20	2,347.60	40.94%	18.40%	-12.54%
ALE	2013	1,018.40	2,576.50	39.53%	9.75%	-3.46%
ALE	2014	1,136.80	3,286.40	34.59%	27.55%	-12.49%
ALE	2015	1,486.40	3,669.10	40.51%	11.64%	17.11%
ALE	2016	1,339.70	3,741.20	35.81%	1.97%	-11.61%
ALE	2017	1,419.30	3,822.40	37.13%	2.17%	3.69%
ALE	2018	1,498.60	3,904.40	38.38%	2.15%	3.37%
ALE	2022-24	1,775.00	4,525.00	39.23%	18.38%	5.64%
LNT	2009	$ 3,432.80	$ 6,203.00	55.34%		
LNT	2010	3,416.10	6,730.60	50.75%	8.51%	-8.29%
LNT	2011	3,665.30	7,037.10	52.09%	4.55%	2.62%
LNT	2012	3,094.50	7,838.00	39.48%	11.38%	-24.20%
LNT	2013	3,276.80	7,147.30	45.85%	-8.81%	16.12%
LNT	2014	3,350.30	6,442.00	52.01%	-9.87%	13.44%
LNT	2015	3,253.60	8,970.20	36.27%	39.25%	-30.26%
LNT	2016	3,320.00	9,809.90	33.84%	9.36%	-6.69%
LNT	2017	3,382.20	10,797.90	31.32%	10.07%	-7.45%
LNT	2018	3,534.50	12,462.00	28.36%	15.41%	-9.45%
LNT	2022-24	3,990.00	17,000.00	23.47%	57.44%	-25.07%
AEE	2009	$ 7,090.00	$ 17,610.00	40.26%		
AEE	2010	7,638.00	17,853.00	42.78%	1.38%	6.26%
AEE	2011	7,531.00	18,127.00	41.55%	1.53%	-2.89%
AEE	2012	6,828.00	16,096.00	42.42%	-11.20%	2.11%
AEE	2013	5,838.00	16,205.00	36.03%	0.68%	-15.07%
AEE	2014	6,053.00	17,424.00	34.74%	7.52%	-3.57%
AEE	2015	6,098.00	18,799.00	32.44%	7.89%	-6.63%
AEE	2016	6,076.00	20,113.00	30.21%	6.99%	-6.87%
AEE	2017	6,177.00	21,466.00	28.78%	6.73%	-4.75%
AEE	2018	6,291.00	22,810.00	27.58%	6.26%	-4.16%
AEE	2022-24	7,500.00	29,300.00	25.60%	36.49%	-11.05%
AEP	2009	$ 13,489.00	$ 34,344.00	39.28%		
AEP	2010	14,427.00	35,674.00	40.44%	3.87%	2.97%
AEP	2011	15,116.00	36,971.00	40.89%	3.64%	1.10%
AEP	2012	14,945.00	38,763.00	38.55%	4.85%	-5.70%
AEP	2013	15,357.00	40,997.00	37.46%	5.76%	-2.84%
AEP	2014	17,020.00	44,117.00	38.58%	7.61%	2.99%
AEP	2015	16,453.00	46,133.00	35.66%	4.57%	-7.56%
AEP	2016	16,380.00	45,639.00	35.89%	-1.07%	0.63%
AEP	2017	15,425.00	50,262.00	30.69%	10.13%	-14.49%
AEP	2018	16,196.00	55,099.00	29.39%	9.62%	-4.22%
AEP	2022-24	18,500.00	77,300.00	23.93%	53.79%	-22.02%
AGR	2009	-	-	-		
AGR	2010	-	-	-	-	-
AGR	2011	-	-	-	-	-
AGR	2012	-	-	-	-	-
AGR	2013	-	-	-	-	-
AGR	2014	4,594.00	17,099.00	26.87%	-	-
AGR	2015	4,367.00	20,711.00	21.09%	21.12%	-21.52%
AGR	2016	6,018.00	21,548.00	27.93%	4.04%	32.45%
AGR	2017	5,963.00	22,669.00	26.30%	5.20%	-5.81%
AGR	2022-24	7,250.00	31,000.00	23.39%	36.75%	-11.09%
BKH	2009	$ 1,269.60	$ 2,160.70	58.76%		
BKH	2010	1,307.30	2,495.40	52.39%	15.49%	-10.84%
BKH	2011	1,272.20	2,789.60	45.61%	11.79%	-12.95%
BKH	2012	1,173.90	2,742.70	42.80%	-1.68%	-6.15%
BKH	2013	1,275.90	2,990.30	42.67%	9.03%	-0.31%
BKH	2014	1,393.60	3,239.40	43.02%	8.33%	0.83%
BKH	2015	1,304.60	3,259.10	40.03%	0.61%	-6.95%
BKH	2016	1,573.00	4,469.00	35.20%	37.12%	-12.07%
BKH	2017	1,680.30	4,541.40	37.00%	1.62%	5.12%
BKH	2021-23	1,950.00	6,000.00	32.50%	32.12%	-12.16%

Change in Net Plant and Asset Turnover
Proxy Group - Individual Company Results

Ticker	Year	Revenue	Net Plant	Revenue/Net Plant	Change in Net Plant	Change in Revenue/Net Plant
CMS	2009	$ 6,205.00	$ 9,682.00	64.09%		
CMS	2010	6,432.00	10,069.00	63.88%	4.00%	-0.33%
CMS	2011	6,503.00	10,633.00	61.16%	5.60%	-4.26%
CMS	2012	6,312.00	11,551.00	54.64%	8.63%	-10.65%
CMS	2013	6,566.00	12,246.00	53.62%	6.02%	-1.88%
CMS	2014	7,179.00	13,412.00	53.53%	9.52%	-0.17%
CMS	2015	6,456.00	14,705.00	43.90%	9.64%	-17.98%
CMS	2016	6,399.00	15,715.00	40.72%	6.87%	-7.25%
CMS	2017	6,583.00	16,761.00	39.28%	6.66%	-3.54%
CMS	2018	6,873.00	18,126.00	37.92%	8.14%	-3.46%
CMS	2022-24	8,000.00	23,800.00	33.61%	42.00%	-14.42%
ED	2009	$ 13,032.00	$ 22,464.00	58.01%		
ED	2010	13,325.00	23,863.00	55.84%	6.23%	-3.75%
ED	2011	12,938.00	25,093.00	51.56%	5.15%	-7.66%
ED	2012	12,188.00	26,939.00	45.24%	7.36%	-12.25%
ED	2013	12,381.00	28,436.00	43.54%	5.56%	-3.76%
ED	2014	12,919.00	29,827.00	43.31%	4.89%	-0.52%
ED	2015	12,554.00	32,209.00	38.98%	7.99%	-10.01%
ED	2016	12,075.00	35,216.00	34.29%	9.34%	-12.03%
ED	2017	12,033.00	37,600.00	32.00%	6.77%	-6.67%
ED	2022-24	14,700.00	50,700.00	28.99%	34.84%	-9.40%
DTE	2009	$ 8,014.00	$ 12,431.00	64.47%		
DTE	2010	8,557.00	12,992.00	65.86%	4.51%	2.17%
DTE	2011	8,897.00	13,746.00	64.72%	5.80%	-1.73%
DTE	2012	8,791.00	14,684.00	59.87%	6.82%	-7.50%
DTE	2013	9,661.00	15,800.00	61.15%	7.60%	2.13%
DTE	2014	12,301.00	16,820.00	73.13%	6.46%	19.61%
DTE	2015	10,337.00	18,034.00	57.32%	7.22%	-21.62%
DTE	2016	10,630.00	19,730.00	53.88%	9.40%	-6.01%
DTE	2017	12,607.00	20,721.00	60.84%	5.02%	12.93%
DTE	2018	14,212.00	21,650.00	65.64%	4.48%	7.89%
DTE	2022-24	18,000.00	28,300.00	63.60%	36.58%	4.54%
DUK	2009	$ 12,731.00	$ 37,950.00	33.55%		
DUK	2010	14,272.00	40,344.00	35.38%	6.31%	5.45%
DUK	2011	14,529.00	42,661.00	34.06%	5.74%	-3.73%
DUK	2012	19,624.00	68,558.00	28.62%	60.70%	-15.95%
DUK	2013	24,598.00	69,490.00	35.40%	1.36%	23.67%
DUK	2014	23,925.00	70,046.00	34.16%	0.80%	-3.51%
DUK	2015	23,459.00	75,709.00	30.99%	8.08%	-9.28%
DUK	2016	22,743.00	82,520.00	27.56%	9.00%	-11.05%
DUK	2017	23,565.00	86,391.00	27.28%	4.69%	-1.03%
DUK	2022-24	28,000.00	111,600.00	25.09%	29.18%	-8.02%
EE	2009	$ 828.00	$ 1,756.00	47.15%		
EE	2010	877.30	1,865.80	47.02%	6.25%	-0.28%
EE	2011	918.00	1,947.10	47.15%	4.36%	0.27%
EE	2012	852.90	2,102.30	40.57%	7.97%	-13.95%
EE	2013	890.40	2,257.50	39.44%	7.38%	-2.78%
EE	2014	917.50	2,488.40	36.87%	10.23%	-6.52%
EE	2015	849.90	2,695.50	31.53%	8.32%	-14.48%
EE	2016	886.90	2,821.20	31.44%	4.66%	-0.30%
EE	2017	916.80	2,928.40	31.31%	3.80%	-0.41%
EE	2021-23	1,000.00	3,600.00	27.78%	22.93%	-11.27%
EVRG	2009	-	-	-		
EVRG	2010	-	-	-	-	-
EVRG	2011	-	-	-	-	-
EVRG	2012	-	-	-	-	-
EVRG	2013	-	-	-	-	-
EVRG	2014	-	-	-	-	-
EVRG	2015	-	-	-	-	-
EVRG	2016	-	-	-	-	-
EVRG	2017	-	-	-	-	-
EVRG	2018	4,275.90	18,952.00	22.56%	-	-
EVRG	2022-24	6,100.00	19,600.00	31.12%	3.42%	37.94%

Change in Net Plant and Asset Turnover
Proxy Group - Individual Company Results

Ticker	Year	Revenue	Net Plant	Revenue/Net Plant	Change in Net Plant	Change in Revenue/Net Plant
ES	2009	$ 5,439.40	$ 8,840.00	61.53%		
ES	2010	4,898.20	9,567.70	51.20%	8.23%	-16.80%
ES	2011	4,465.70	10,403.00	42.93%	8.73%	-16.15%
ES	2012	6,273.80	16,605.00	37.78%	59.62%	-11.98%
ES	2013	7,301.20	17,576.00	41.54%	5.85%	9.95%
ES	2014	7,741.90	18,647.00	41.52%	6.09%	-0.05%
ES	2015	7,954.80	19,892.00	39.99%	6.68%	-3.68%
ES	2016	7,639.10	21,351.00	35.78%	7.33%	-10.53%
ES	2017	7,752.00	23,617.00	32.82%	10.61%	-8.26%
ES	2022-24	9,350.00	33,600.00	27.83%	42.27%	-15.22%
HE	2009	$ 2,309.60	$ 3,088.60	74.78%		
HE	2010	2,665.00	3,165.90	84.18%	2.50%	12.57%
HE	2011	3,242.30	3,334.50	97.23%	5.33%	15.51%
HE	2012	3,375.00	3,594.80	93.89%	7.81%	-3.44%
HE	2013	3,238.50	3,858.90	83.92%	7.35%	-10.61%
HE	2014	3,239.50	4,148.80	78.08%	7.51%	-6.96%
HE	2015	2,603.00	4,377.70	59.46%	5.52%	-23.85%
HE	2016	2,380.70	4,603.50	51.71%	5.16%	-13.03%
HE	2017	2,555.60	5,025.90	50.85%	9.18%	-1.68%
HE	2021-23	3,200.00	6,000.00	53.33%	19.38%	4.89%
NEE	2009	$ 15,643.00	$ 36,078.00	43.36%		
NEE	2010	15,317.00	39,075.00	39.20%	8.31%	-9.59%
NEE	2011	15,341.00	42,490.00	36.10%	8.74%	-7.89%
NEE	2012	14,256.00	49,413.00	28.85%	16.29%	-20.09%
NEE	2013	15,136.00	52,720.00	28.71%	6.69%	-0.49%
NEE	2014	17,021.00	55,705.00	30.56%	5.66%	6.43%
NEE	2015	17,486.00	61,386.00	28.49%	10.20%	-6.78%
NEE	2016	16,155.00	66,912.00	24.14%	9.00%	-15.24%
NEE	2017	17,195.00	72,416.00	23.74%	8.23%	-1.65%
NEE	2022-24	25,000.00	101,700.00	24.58%	40.44%	3.53%
NWE	2009	$ 1,141.90	$ 1,964.10	58.14%		
NWE	2010	1,110.70	2,118.00	52.44%	7.84%	-9.80%
NWE	2011	1,117.30	2,213.30	50.48%	4.50%	-3.74%
NWE	2012	1,070.30	2,435.60	43.94%	10.04%	-12.95%
NWE	2013	1,154.50	2,690.10	42.92%	10.45%	-2.34%
NWE	2014	1,204.90	3,758.00	32.06%	39.70%	-25.29%
NWE	2015	1,214.30	4,059.50	29.91%	8.02%	-6.70%
NWE	2016	1,257.20	4,214.90	29.83%	3.83%	-0.28%
NWE	2017	1,305.70	4,358.30	29.96%	3.40%	0.44%
NWE	2021-23	1,400.00	4,975.00	28.14%	14.15%	-6.07%
OGE	2009	$ 2,869.70	$ 5,911.60	48.54%		
OGE	2010	3,716.90	6,464.40	57.50%	9.35%	18.45%
OGE	2011	3,915.90	7,474.00	52.39%	15.62%	-8.88%
OGE	2012	3,671.20	8,344.80	43.99%	11.65%	-16.03%
OGE	2013	2,867.70	6,672.80	42.98%	-20.04%	-2.31%
OGE	2014	2,453.10	6,979.90	35.15%	4.60%	-18.22%
OGE	2015	2,196.90	7,322.40	30.00%	4.91%	-14.63%
OGE	2016	2,259.20	7,696.20	29.35%	5.10%	-2.16%
OGE	2017	2,261.10	8,339.90	27.11%	8.36%	-7.64%
OGE	2018	2,270.30	8,643.80	26.27%	3.64%	-3.12%
OGE	2022-24	3,050.00	9,550.00	31.94%	14.51%	17.80%
OTTR	2009	$ 1,039.50	$ 1,098.60	94.62%		
OTTR	2010	1,119.10	1,108.70	100.94%	0.92%	6.68%
OTTR	2011	1,077.90	1,077.50	100.04%	-2.81%	-0.89%
OTTR	2012	859.20	1,049.50	81.87%	-2.60%	-18.16%
OTTR	2013	893.30	1,167.00	76.55%	11.20%	-6.50%
OTTR	2014	799.30	1,268.50	63.01%	8.70%	-17.68%
OTTR	2015	779.80	1,387.80	56.19%	9.40%	-10.83%
OTTR	2016	803.50	1,477.20	54.39%	6.44%	-3.20%
OTTR	2017	849.40	1,539.60	55.17%	4.22%	1.43%
OTTR	2018	916.40	1,581.10	57.96%	2.70%	5.06%
OTTR	2022-24	1,160.00	2,225.00	52.13%	44.52%	-5.50%

Change in Net Plant and Asset Turnover
Proxy Group - Individual Company Results

Ticker	Year	Revenue	Net Plant	Revenue/Net Plant	Change in Net Plant	Change in Revenue/Net Plant
PNW	2009	$ 3,297.10	$ 9,257.80	35.61%		
PNW	2010	3,263.60	9,578.80	34.07%	3.47%	-4.33%
PNW	2011	3,241.40	9,962.30	32.54%	4.00%	-4.50%
PNW	2012	3,301.80	10,396.00	31.76%	4.35%	-2.39%
PNW	2013	3,454.60	10,889.00	31.73%	4.74%	-0.11%
PNW	2014	3,491.60	11,194.00	31.19%	2.80%	-1.68%
PNW	2015	3,495.40	11,809.00	29.60%	5.49%	-5.10%
PNW	2016	3,498.70	12,714.00	27.52%	7.66%	-7.03%
PNW	2017	3,565.30	13,445.00	26.52%	5.75%	-3.64%
PNW	2021-23	4,500.00	16,125.00	27.91%	19.93%	5.24%
PNM	2009	$ 1,647.70	$ 3,332.40	49.44%		
PNM	2010	1,673.50	3,444.40	48.59%	3.36%	-1.74%
PNM	2011	1,700.60	3,627.10	46.89%	5.30%	-3.50%
PNM	2012	1,342.40	3,746.50	35.83%	3.29%	-23.58%
PNM	2013	1,387.90	3,933.90	35.28%	5.00%	-1.54%
PNM	2014	1,435.90	4,270.00	33.63%	8.54%	-4.68%
PNM	2015	1,439.10	4,535.40	31.73%	6.22%	-5.64%
PNM	2016	1,363.00	4,904.70	27.79%	8.14%	-12.42%
PNM	2017	1,445.00	4,980.20	29.01%	1.54%	4.41%
PNM	2021-23	1,700.00	6,025.00	28.22%	20.98%	-2.75%
POR	2009	$ 1,804.00	$ 3,858.00	46.76%		
POR	2010	1,783.00	4,133.00	43.14%	7.13%	-7.74%
POR	2011	1,813.00	4,285.00	42.31%	3.68%	-1.92%
POR	2012	1,805.00	4,392.00	41.10%	2.50%	-2.87%
POR	2013	1,810.00	4,880.00	37.09%	11.11%	-9.75%
POR	2014	1,900.00	5,679.00	33.46%	16.37%	-9.80%
POR	2015	1,898.00	6,012.00	31.57%	5.86%	-5.64%
POR	2016	1,923.00	6,434.00	29.89%	7.02%	-5.33%
POR	2017	2,009.00	6,741.00	29.80%	4.77%	-0.29%
POR	2021-23	2,325.00	7,125.00	32.63%	5.70%	9.49%
SO	2009	$ 15,743.00	$ 39,230.00	40.13%		
SO	2010	17,456.00	42,002.00	41.56%	7.07%	3.56%
SO	2011	17,657.00	45,010.00	39.23%	7.16%	-5.61%
SO	2012	16,537.00	48,390.00	34.17%	7.51%	-12.88%
SO	2013	17,087.00	51,208.00	33.37%	5.82%	-2.36%
SO	2014	18,467.00	54,868.00	33.66%	7.15%	0.87%
SO	2015	17,489.00	61,114.00	28.62%	11.38%	-14.97%
SO	2016	19,896.00	78,446.00	25.36%	28.36%	-11.37%
SO	2017	23,031.00	79,872.00	28.83%	1.82%	13.69%
SO	2022-24	30,650.00	91,900.00	33.35%	15.06%	15.66%
WEC	2009	$ 4,127.90	$ 9,070.50	45.51%		
WEC	2010	4,202.50	9,601.50	43.77%	5.85%	-3.82%
WEC	2011	4,486.40	10,160.00	44.16%	5.82%	0.89%
WEC	2012	4,246.40	10,572.00	40.17%	4.06%	-9.04%
WEC	2013	4,519.00	10,907.00	41.43%	3.17%	3.15%
WEC	2014	4,997.10	11,258.00	44.39%	3.22%	7.13%
WEC	2015	5,926.10	19,190.00	30.88%	70.46%	-30.43%
WEC	2016	7,472.30	19,916.00	37.52%	3.78%	21.49%
WEC	2017	7,648.50	21,347.00	35.83%	7.19%	-4.50%
WEC	2018	7,679.50	22,001.00	34.91%	3.06%	-2.58%
WEC	2022-24	9,300.00	31,325.00	29.69%	46.74%	-17.14%
XEL	2009	$ 9,644.30	$ 18,508.00	52.11%		
XEL	2010	10,311.00	20,663.00	49.90%	11.64%	-4.24%
XEL	2011	10,655.00	22,353.00	47.67%	8.18%	-4.48%
XEL	2012	10,128.00	23,809.00	42.54%	6.51%	-10.76%
XEL	2013	10,915.00	26,122.00	41.78%	9.71%	-1.77%
XEL	2014	11,686.00	28,757.00	40.64%	10.09%	-2.75%
XEL	2015	11,024.00	31,206.00	35.33%	8.52%	-13.07%
XEL	2016	11,107.00	32,842.00	33.82%	5.24%	-4.27%
XEL	2017	11,404.00	34,329.00	33.22%	4.53%	-1.77%
XEL	2021-23	13,250.00	44,200.00	29.98%	28.75%	-9.76%

R.B. Hevert
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (G) – 9

Summary of Adjustment Clauses & Alternative Regulation/Incentive Plans

			Adjustment Clauses						
Company	Parent	State	Fuel/ Purchased Power	Decoupling (F/P) [1]	New Capital Investment [2]	Energy Efficiency [3]	Renewables & RPS [4]	Environmental [5]	Other [6]
ALLETE (Minnesota Power)	ALE	Minnesota	✓			✓	✓	✓	✓
Superior Water, Light and Power Company	ALE	Wisconsin	✓						✓
Interstate Power and Light Company	LNT	Iowa	✓			✓	✓	✓	✓
Wisconsin Power and Light Company	LNT	Wisconsin	✓						✓
Ameren Illinois Company	AEE	Illinois	✓		✓	✓	✓	✓	✓
Union Electric Company	AEE	Missouri	✓	P		✓		✓	✓
Southwestern Electric Power Company	AEP	Arkansas	✓	P	✓	✓		✓	✓
Indiana Michigan Power Company	AEP	Indiana	✓	P	✓	✓	✓	✓	✓
Kentucky Power Company	AEP	Kentucky	✓	P	✓	✓		✓	✓
Southwestern Electric Power Company	AEP	Louisiana	✓	P	✓	✓		✓	✓
Indiana Michigan Power Company	AEP	Michigan	✓	P		✓	✓	✓	✓
Ohio Power Company	AEP	Ohio	✓	P	✓	✓	✓		✓
Public Service Company of Oklahoma	AEP	Oklahoma	✓	P		✓			✓
Kingsport Power Company	AEP	Tennessee	✓		✓				✓
AEP Texas Central Company	AEP	Texas	NA		✓	✓		✓	✓
AEP Texas North Company	AEP	Texas	NA		✓	✓			✓
Southwestern Electric Power Company	AEP	Texas	✓		✓	✓	✓		✓
Appalachian Power Company	AEP	Virginia	✓		✓	✓	✓	✓	✓
Appalachian Power / Wheeling Power	AEP	West Virginia	✓		✓	✓			✓
United Illuminating Company	AGR	Connecticut	✓	F		✓	✓	✓	✓
Central Maine Power Company	AGR	Maine	✓	F					✓
New York State Electric & Gas Corporation	AGR	New York	✓	F		✓	✓		✓
Rochester Gas and Electric Corporation	AGR	New York	✓	F		✓	✓		✓
Black Hills Colorado Electric Utility Company, LP	BKH	Colorado	✓		✓	✓	✓		✓
Black Hills Power, Inc.	BKH	South Dakota	✓	P	✓	✓		✓	✓
Black Hills Power, Inc.	BKH	Wyoming	✓						✓
Cheyenne Light, Fuel and Power Company	BKH	Wyoming	✓	P		✓			✓
Consumers Energy Company	CMS	Michigan	✓			✓	✓		✓
Rockland Electric Company	ED	New Jersey	✓		✓	✓	✓		✓
Consolidated Edison Company of New York, Inc.	ED	New York	✓	F	✓	✓	✓	✓	✓
Orange and Rockland Utilities, Inc.	ED	New York	✓	F	✓	✓	✓		✓
DTE Electric Company	DTE	Michigan	✓			✓	✓	✓	✓
Duke Energy Florida, LLC	DUK	Florida	✓		✓	✓		✓	✓
Duke Energy Indiana, LLC	DUK	Indiana	✓	P	✓	✓	✓	✓	✓
Duke Energy Kentucky, Inc.	DUK	Kentucky	✓	P		✓		✓	✓
Duke Energy Carolinas, LLC	DUK	North Carolina	✓	P		✓	✓	✓	✓
Duke Energy Progress, LLC	DUK	North Carolina	✓	P	✓	✓	✓	✓	✓
Duke Energy Ohio, Inc.	DUK	Ohio	✓	P	✓	✓	✓		✓
Duke Energy Carolinas, LLC	DUK	South Carolina	✓	P		✓	✓	✓	✓
Duke Energy Progress, LLC	DUK	South Carolina	✓	P		✓	✓	✓	✓
El Paso Electric Company	EE	New Mexico	✓			✓			✓
El Paso Electric Company	EE	Texas	✓			✓			✓
Kansas City Power & Light Company	EVRG	Kansas	✓			✓		✓	✓
Kansas City Power & Light Company	EVRG	Missouri	✓	P		✓		✓	✓
KCP&L Greater Missouri Operations Company	EVRG	Missouri	✓			✓	✓	✓	✓
Westar Energy (KPL)	EVRG	Kansas	✓	P		✓		✓	✓
Connecticut Light and Power Company	ES	Connecticut	✓	F	✓	✓		✓	✓
NSTAR Electric Company	ES	Massachusetts	✓	F	✓	✓	✓		✓
Western Massachusetts Electric Company	ES	Massachusetts	✓	F	✓	✓	✓		✓
Public Service Company of New Hampshire	ES	New Hampshire	✓	P	✓	✓			✓
Hawaii Electric Light Company, Inc.	HE	Hawaii	✓	F	✓	✓	✓		✓
Hawaiian Electric Company, Inc.	HE	Hawaii	✓	F	✓	✓	✓		✓
Maui Electric Company, Limited	HE	Hawaii	✓	F	✓	✓	✓		✓
Florida Power & Light Company	NEE	Florida	✓			✓		✓	✓
Gulf Power Company	NEE	Florida	✓			✓		✓	✓
NorthWestern Energy	NWE	Montana	✓			✓			✓
NorthWestern Energy	NWE	South Dakota	✓					✓	✓
Oklahoma Gas and Electric Company	OGE	Arkansas	✓	P	✓	✓		✓	✓
Oklahoma Gas and Electric Company	OGE	Oklahoma	✓	P		✓			✓
Otter Tail Power Company	OTTR	Minnesota	✓		✓	✓	✓	✓	✓
Otter Tail Power Company	OTTR	North Dakota	✓		✓		✓	✓	✓
Otter Tail Power Company	OTTR	South Dakota	✓		✓	✓		✓	✓
Arizona Public Service Company	PNW	Arizona	✓	P		✓	✓	✓	✓
Public Service Company of New Mexico	PNM	New Mexico	✓			✓	✓		✓
Texas-New Mexico Power Company	PNM	Texas	NA		✓	✓			✓
Portland General Electric Company	POR	Oregon	✓	P		✓	✓	✓	✓
Alabama Power Company	SO	Alabama	✓		✓			✓	✓
Georgia Power Company	SO	Georgia	✓		✓	✓		✓	✓
Mississippi Power Company	SO	Mississippi	✓	P	✓	✓	✓	✓	✓
Upper Michigan Energy Resources Corp	WEC	Michigan	✓			✓	✓		✓
Wisconsin Electric Power	WEC	Wisconsin	✓						✓
Wisconsin Public Service Company	WEC	Wisconsin	✓						✓
Public Service Company of Colorado	XEL	Colorado	✓		✓	✓	✓	✓	✓
Northern States Power Company - WI	XEL	Michigan	✓			✓			✓
Northern States Power Company - MN	XEL	Minnesota	✓	F	✓	✓	✓	✓	✓
Southwestern Public Service Company	XEL	New Mexico	✓			✓	✓		✓
Northern States Power Company - MN	XEL	North Dakota	✓		✓		✓		✓
Northern States Power Company - MN	XEL	South Dakota	✓	P	✓	✓		✓	✓
Southwestern Public Service Company	XEL	Texas	✓		✓	✓			✓
Northern States Power Company - WI	XEL	Wisconsin	✓						✓
			77	39	41	70	40	42	80
			96%	49%	51%	88%	50%	53%	100%

Notes:

A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category. Texas T&D utilities do not have retail obligation, thus do not need a purchased power clause.

[1] Full or partial decoupling (such as Straight-Fixed Variable rate design, weather normalization clauses, and recovery of lost revenues as a result of Energy Efficiency programs).

[2] Includes recovery of costs related to targeted new generation projects, infrastructure replacement, system integrity/hardening, Smart Grid, AMI metering, and other capital expenditures.

[3] Utility-sponsored conservation, energy efficiency, load control, or other demand side management programs.

[4] Recovers costs associated with renewable energy projects, Distributed Energy Resources, REC purchases, net metering, RPS expense, and renewable PPAs.

[5] EPA upgrade costs, emissions control & allowance purchase costs, nuclear/coal plant decommissioning, and other costs to comply with state and federal environmental mandates.

[6] Pension expenses, bad debt costs, storm costs, vegetation management, RTO/Transmission Expense, capacity costs, transmission costs, government & franchise fees and taxes, economic development, and low income programs.

Sources: *Alternative Regulation/Incentive Plans: A State-by-State Overview* , November 19, 2013; Regulatory Research Associates, *Adjustment Clauses: A State-by-State Overview* , September 28, 2018; Regulatory Research Associates, *Rate Freezes: Their historical context and prevalence today* , October 15, 2018; ACEEE Utility Business Model Database; Regulatory Research Associates *Commission Profiles* ; SEC Form 10-Ks; Company Tariffs.

Summary of Adjustment Clauses & Alternative Regulation/Incentive Plans

			Alternative Regulation / Incentive Plans								
Company	Parent	State	Formula-Based Rates	Performance Based Ratemaking [7]	CWIP Allowed in Rate Base (L/F)	Forward Test Year	Price Freeze/ Cap	Earnings Sharing	Formula-Based ROE	Service Quality/ Performance	Merger Savings
ALLETE (Minnesota Power)	ALE	Minnesota			L	✓					
Superior Water, Light and Power Company	ALE	Wisconsin			L	✓					
Interstate Power and Light Company	LNT	Iowa		✓			✓				
Wisconsin Power and Light Company	LNT	Wisconsin		✓	L	✓	✓	✓			
Ameren Illinois Company	AEE	Illinois	✓		L			✓	✓	✓	
Union Electric Company	AEE	Missouri									
Southwestern Electric Power Company	AEP	Arkansas									
Indiana Michigan Power Company	AEP	Indiana			F	✓					
Kentucky Power Company	AEP	Kentucky		✓	F						
Southwestern Electric Power Company	AEP	Louisiana	✓		L		✓	✓			
Indiana Michigan Power Company	AEP	Michigan			L	✓					
Ohio Power Company	AEP	Ohio		✓	F		✓	✓			
Public Service Company of Oklahoma	AEP	Oklahoma		✓	F						
Kingsport Power Company	AEP	Tennessee			F	✓					
AEP Texas Central Company	AEP	Texas			L						
AEP Texas North Company	AEP	Texas			L						
Southwestern Electric Power Company	AEP	Texas			L						
Appalachian Power Company	AEP	Virginia		✓	F	✓		✓	✓	✓	
Appalachian Power / Wheeling Power	AEP	West Virginia			L						
United Illuminating Company	AGR	Connecticut		✓				✓			
Central Maine Power Company	AGR	Maine						✓			
New York State Electric & Gas Corporation	AGR	New York		✓			✓	✓			
Rochester Gas and Electric Corporation	AGR	New York		✓			✓	✓			
Black Hills Colorado Electric Utility Company, LP	BKH	Colorado		✓	F						
Black Hills Power, Inc.	BKH	South Dakota		✓							
Black Hills Power, Inc.	BKH	Wyoming		✓							
Cheyenne Light, Fuel and Power Company	BKH	Wyoming									
Consumers Energy Company	CMS	Michigan			L	✓					
Rockland Electric Company	ED	New Jersey									
Consolidated Edison Company of New York, Inc.	ED	New York		✓		✓	✓	✓			
Orange and Rockland Utilities, Inc.	ED	New York		✓		✓	✓	✓			
DTE Electric Company	DTE	Michigan			L	✓					
Duke Energy Florida, LLC	DUK	Florida		✓		✓	✓				
Duke Energy Indiana, LLC	DUK	Indiana			F		✓				
Duke Energy Kentucky, Inc.	DUK	Kentucky			F	✓					
Duke Energy Carolinas, LLC	DUK	North Carolina					✓				
Duke Energy Progress, LLC	DUK	North Carolina		✓							
Duke Energy Ohio, Inc.	DUK	Ohio						✓			
Duke Energy Carolinas, LLC	DUK	South Carolina					✓				
Duke Energy Progress, LLC	DUK	South Carolina									
El Paso Electric Company	EE	New Mexico									
El Paso Electric Company	EE	Texas									
Kansas City Power & Light Company	EVRG	Kansas			F		✓			✓	
Kansas City Power & Light Company	EVRG	Missouri									
KCP&L Greater Missouri Operations Company	EVRG	Missouri									
Westar Energy (KPL)	EVRG	Kansas			F		✓				✓
Connecticut Light and Power Company	ES	Connecticut		✓		✓	✓	✓			
NSTAR Electric Company	ES	Massachusetts		✓				✓		✓	
Western Massachusetts Electric Company	ES	Massachusetts		✓				✓		✓	
Public Service Company of New Hampshire	ES	New Hampshire		✓			✓	✓			
Hawaii Electric Light Company, Inc.	HE	Hawaii		✓		✓		✓			
Hawaiian Electric Company, Inc.	HE	Hawaii		✓		✓		✓			
Maui Electric Company, Limited	HE	Hawaii		✓		✓		✓			
Florida Power & Light Company	NEE	Florida		✓	F	✓	✓				
Gulf Power Company	NEE	Florida			F	✓	✓				
NorthWestern Energy	NWE	Montana				✓					
NorthWestern Energy	NWE	South Dakota		✓	L		✓				
Oklahoma Gas and Electric Company	OGE	Arkansas	✓								
Oklahoma Gas and Electric Company	OGE	Oklahoma		✓	F						
Otter Tail Power Company	OTTR	Minnesota			L						
Otter Tail Power Company	OTTR	North Dakota			F	✓					
Otter Tail Power Company	OTTR	South Dakota			L						
Arizona Public Service Company	PNW	Arizona		✓			✓				
Public Service Company of New Mexico	PNM	New Mexico		✓	F	✓		✓			
Texas-New Mexico Power Company	PNM	Texas			L						
Portland General Electric Company	POR	Oregon				✓					
Alabama Power Company	SO	Alabama	✓	✓							
Georgia Power Company	SO	Georgia		✓	L	✓	✓	✓			
Mississippi Power Company	SO	Mississippi	✓	✓	F	✓			✓	✓	
Upper Michigan Energy Resources Corp	WEC	Michigan			L	✓					
Wisconsin Electric Power	WEC	Wisconsin		✓	L	✓	✓	✓			
Wisconsin Public Service Company	WEC	Wisconsin		✓	L	✓		✓			
Public Service Company of Colorado	XEL	Colorado		✓	L		✓	✓			
Northern States Power Company - WI	XEL	Michigan			L	✓					
Northern States Power Company - MN	XEL	Minnesota		✓	L	✓					
Southwestern Public Service Company	XEL	New Mexico			F		✓				
Northern States Power Company - MN	XEL	North Dakota		✓	F			✓			
Northern States Power Company - MN	XEL	South Dakota		✓	L		✓				
Southwestern Public Service Company	XEL	Texas			L		✓				
Northern States Power Company - WI	XEL	Wisconsin			L	✓		✓			
			5	37	45	31	26	26	3	6	1
			6%	46%	56%	39%	33%	33%	4%	8%	1%

Notes:
A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category. Texas T&D utilities do not have retail obligation, thus do not need a purchased power clause.

[7] Includes multiyear rate plans.

Sources: *Alternative Regulation/Incentive Plans: A State-by-State Overview,* November 19, 2013; Regulatory Research Associates, *Adjustment Clauses: A State-by-State Overview*, September 28, 2018; Regulatory Research Associates, *Rate Freezes: Their historical context and prevalence today*, October 15, 2018; ACEEE Utility Business Model Database; Regulatory Research Associates *Commission Profiles*; SEC Form 10-Ks; Company Tariffs.

R.B. Hevert
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
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MANAGEMENT CONSULTANTS

Resume of:

Robert B. Hevert, Partner
Rates, Regulation & Planning Practice Leader

Summary

Bob Hevert is a financial and economic consultant with more than 30 years of broad experience in the energy and utility industries. He has an extensive background in the areas of corporate finance, mergers and acquisitions, project finance, asset and business unit valuation, rate and regulatory matters, energy market assessment, and corporate strategic planning. He has provided expert testimony on a wide range of financial, strategic, and economic matters on more than 250 occasions at the state, provincial, and federal levels.

Prior to joining ScottMadden, Bob served as managing partner at Sussex Economic Advisors, LLC. Throughout the course of his career, he has worked with numerous leading energy companies and financial institutions throughout North America. He has provided expert testimony and support of litigation in various regulatory proceedings on a variety of energy and economic issues. Bob earned a B.S. in business and economics from the University of Delaware and an M.B.A. with a concentration in finance from the University of Massachusetts at Amherst. Bob also holds the Chartered Financial Analyst designation.

Areas of Specialization

- Regulation and rates
- Utilities
- Fossil/hydro generation
- Markets and RTOs
- Nuclear generation
- Mergers and acquisitions
- Regulatory strategy and rate case support
- Capital project planning
- Strategic and business planning

Recent Expert Testimony Submission/Appearance

- Federal Energy Regulatory Commission – Return on Equity
- New Jersey Board of Public Utilities – Merger Approval
- New Mexico Public Regulation Commission – Cost of Capital and Financial Integrity
- United States District Court – PURPA and FERC Regulations
- Alberta Utilities Commission – Return on Equity and Capital Structure

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies, the Alberta Utilities Commission, and the Federal Energy Regulatory Commission
- For an independent electric transmission provider in Texas, prepared an expert report on the economic damages with respect to failure to meet guaranteed completion dates. The report was filed as part of an arbitration proceeding and included a review of the ratemaking implications of economic damages
- Advised the board of directors of a publicly traded electric and natural gas combination utility on dividend policy issues, earnings payout trends and related capital market considerations
- Assisted a publicly traded utility with a strategic buy-side evaluation of a gas utility with more than $1 billion in assets. The assignment included operational performance benchmarking, calculation of merger synergies, risk analysis, and review of the regulatory implications of the transaction
- Provided testimony before the Arkansas Public Service Commission in support of the acquisition of SourceGas LLC by Black Hills Corporation. The testimony addressed certain balance sheet capitalization and credit rating issues
- For the State of Maine Public Utility Commission, prepared a report that summarized the Northeast and Atlantic Canada natural gas power markets and analyzed the potential benefits and costs associated with natural gas pipeline expansions. The independent report was filed at the Maine Public Utility Commission

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MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Regulatory Commission of Alaska				
Cook Inlet Natural Gas Storage Alaska, LLC	06/18	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. U-18-043	Return on Equity
ENSTAR Natural Gas Company	06/16	ENSTAR Natural Gas Company	Matter No. TA 285-4	Return on Equity
ENSTAR Natural Gas Company	08/14	ENSTAR Natural Gas Company	Matter No. TA 262-4	Return on Equity
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc., and FortisAlberta Inc.	10/17	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc., and FortisAlberta Inc.	2018 General Cost of Capital, Proceeding ID. 22570	Rate of Return
EPCOR Energy Alberta G.P. Inc.	01/17	EPCOR Energy Alberta G.P. Inc.	Proceeding 22357	Energy Price Setting Plan
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	02/16	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2016 General Cost of Capital, Proceeding ID. 20622	Rate of Return
Arizona Corporation Commission				
Southwest Gas Corporation	05/19	Southwest Gas Corporation	Docket No. G-01551A-19-0055	Return on Equity
Southwest Gas Corporation	05/16	Southwest Gas Corporation	Docket No. G-01551A-16-0107	Return on Equity
Southwest Gas Corporation	11/10	Southwest Gas Corporation	Docket No. G-01551A-10-0458	Return on Equity
Arkansas Public Service Commission				
Southwestern Electric Power Company	02/19	Southwestern Electric Power Company	Docket No. 19-008-U	Return on Equity
Oklahoma Gas and Electric Company	09/16	Oklahoma Gas and Electric Company	Docket No. 16-052-U	Return on Equity
SourceGas Arkansas, Inc.	12/15	SourceGas Arkansas, Inc.	Docket No. 15-078-U	Response to Direct Testimony by Arkansas Attorney General related to Compliance Issues
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	11/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 15-098-U	Return on Equity
SourceGas Arkansas, Inc.	04/15	SourceGas Arkansas, Inc.	Docket No. 15-011-U	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	01/07	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas	Docket No. 06-161-U	Return on Equity
California Public Utilities Commission				
Southwest Gas Corporation	12/12	Southwest Gas Corporation	Docket No. A-12-12-024	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Return on Equity
Xcel Energy, Inc.	03/15	Public Service Company of Colorado	Docket No. 15AL-0135G	Return on Equity (gas)

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MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Xcel Energy, Inc.	06/14	Public Service Company of Colorado	Docket No. 14AL-0660E	Return on Equity (electric)
Xcel Energy, Inc.	12/12	Public Service Company of Colorado	Docket No. 12AL-1268G	Return on Equity (gas)
Xcel Energy, Inc.	11/11	Public Service Company of Colorado	Docket No. 11AL-947E	Return on Equity (electric)
Xcel Energy, Inc.	12/10	Public Service Company of Colorado	Docket No. 10AL-963G	Return on Equity (electric)
Atmos Energy Corporation	07/09	Atmos Energy Colorado-Kansas Division	Docket No. 09AL-507G	Return on Equity (gas)
Xcel Energy, Inc.	12/06	Public Service Company of Colorado	Docket No. 06S-656G	Return on Equity (gas)
Xcel Energy, Inc.	04/06	Public Service Company of Colorado	Docket No. 06S-234EG	Return on Equity (electric)
Xcel Energy, Inc.	08/05	Public Service Company of Colorado	Docket No. 05S-369ST	Return on Equity (steam)
Xcel Energy, Inc.	05/05	Public Service Company of Colorado	Docket No. 05S-246G	Return on Equity (gas)
Connecticut Public Utilities Regulatory Authority				
Connecticut Light and Power Company	11/17	Connecticut Light and Power Company	Docket No. 17-10-46	Return on Equity
Connecticut Light and Power Company	06/14	Connecticut Light and Power Company	Docket No. 14-05-06	Return on Equity
Southern Connecticut Gas Company	09/08	Southern Connecticut Gas Company	Docket No. 08-08-17	Return on Equity
Southern Connecticut Gas Company	12/07	Southern Connecticut Gas Company	Docket No. 05-03-17PH02	Return on Equity
Connecticut Natural Gas Corporation	12/07	Connecticut Natural Gas Corporation	Docket No. 06-03-04PH02	Return on Equity
Council of the City of New Orleans				
Entergy New Orleans, LLC	09/18	Entergy New Orleans, LLC	Docket No. UD-18-07	Return on Equity
Delaware Public Service Commission				
Delmarva Power & Light Company	08/17	Delmarva Power & Light Company	Docket No. 17-0977 (Electric)	Return on Equity
Delmarva Power & Light Company	08/17	Delmarva Power & Light Company	Docket No. 17-0978 (Gas)	Return on Equity
Delmarva Power & Light Company	05/16	Delmarva Power & Light Company	Case No. 16-649 (Electric)	Return on Equity
Delmarva Power & Light Company	05/16	Delmarva Power & Light Company	Case No. 16-650 (Gas)	Return on Equity
Delmarva Power & Light Company	03/13	Delmarva Power & Light Company	Case No. 13-115	Return on Equity
Delmarva Power & Light Company	12/12	Delmarva Power & Light Company	Case No. 12-546	Return on Equity
Delmarva Power & Light Company	03/12	Delmarva Power & Light Company	Case No. 11-528	Return on Equity
District of Columbia Public Service Commission				
Potomac Electric Power Company	12/17	Potomac Electric Power Company	Formal Case No. 1150	Return on Equity
Potomac Electric Power Company	06/16	Potomac Electric Power Company	Formal Case No. 1139	Return on Equity
Washington Gas Light Company	02/16	Washington Gas Light Company	Formal Case No. 1137	Return on Equity

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Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Potomac Electric Power Company	03/13	Potomac Electric Power Company	Formal Case No. 1103-2013-E	Return on Equity
Potomac Electric Power Company	07/11	Potomac Electric Power Company	Formal Case No. 1087	Return on Equity
Federal Energy Regulatory Commission				
Sabine Pipeline, LLC	09/15	Sabine Pipeline, LLC	Docket No. RP15-1322-000	Return on Equity
NextEra Energy Transmission West, LLC	07/15	NextEra Energy Transmission West, LLC	Docket No. ER15-2239-000	Return on Equity
Maritimes & Northeast Pipeline, LLC	05/15	Maritimes & Northeast Pipeline, LLC	Docket No. RP15-1026-000	Return on Equity
Public Service Company of New Mexico	12/12	Public Service Company of New Mexico	Docket No. ER13-685-000	Return on Equity
Public Service Company of New Mexico	10/10	Public Service Company of New Mexico	Docket No. ER11-1915-000	Return on Equity
Portland Natural Gas Transmission System	05/10	Portland Natural Gas Transmission System	Docket No. RP10-729-000	Return on Equity
Florida Gas Transmission Company, LLC	10/09	Florida Gas Transmission Company, LLC	Docket No. RP10-21-000	Return on Equity
Maritimes and Northeast Pipeline, LLC	07/09	Maritimes and Northeast Pipeline, LLC	Docket No. RP09-809-000	Return on Equity
Spectra Energy	02/08	Saltville Gas Storage	Docket No. RP08-257-000	Return on Equity
Panhandle Energy Pipelines	08/07	Panhandle Energy Pipelines	Docket No. PL07-2-000	Response to draft policy statement regarding inclusion of MLPs in proxy groups for determination of gas pipeline ROEs
Southwest Gas Storage Company	08/07	Southwest Gas Storage Company	Docket No. RP07-541-000	Return on Equity
Southwest Gas Storage Company	06/07	Southwest Gas Storage Company	Docket No. RP07-34-000	Return on Equity
Sea Robin Pipeline LLC	06/07	Sea Robin Pipeline LLC	Docket No. RP07-513-000	Return on Equity
Transwestern Pipeline Company	09/06	Transwestern Pipeline Company	Docket No. RP06-614-000	Return on Equity
GPU International and Aquila	11/00	GPU International	Docket No. EC01-24-000	Market Power Study
Florida Public Service Commission				
Florida Power & Light Company	03/16	Florida Power & Light Company	Docket No. 160021-EI	Return on Equity
Tampa Electric Company	04/13	Tampa Electric Company	Docket No. 130040-EI	Return on Equity
Georgia Public Service Commission				
Atlanta Gas Light Company	05/10	Atlanta Gas Light Company	Docket No. 31647-U	Return on Equity
Hawaii Public Utilities Commission				
Hawai'i Electric Light Company, Inc.	12/18	Hawai'i Electric Light Company, Inc.	Docket No. 2018-0368	Return on Equity
Maui Electric Company, Limited	10/17	Maui Electric Company, Limited	Docket No. 2017-0150	Return on Equity

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Testimony Listing of:
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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Hawaiian Electric Company, Inc.	12/16	Hawaiian Electric Company, Inc.	Docket No. 2016-0328	Return on Equity
Hawai'i Electric Light Company, Inc.	09/16	Hawai'i Electric Light Company, Inc.	Docket No. 2015-0170	Return on Equity
Maui Electric Company, Limited	12/14	Maui Electric Company, Limited	Docket No. 2014-0318	Return on Equity
Hawaiian Electric Company, Inc.	06/14	Hawaiian Electric Company, Inc.	Docket No. 2013-0373	Return on Equity
Hawai'i Electric Light Company, Inc.	08/12	Hawai'i Electric Light Company, Inc.	Docket No. 2012-0099	Return on Equity
Illinois Commerce Commission				
Ameren Illinois Company d/b/a Ameren Illinois	01/18	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 18-0463	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/15	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 15-0142	Return on Equity
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	04/14	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	Docket No. 14-0371	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	01/13	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 13-0192	Return on Equity
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0279	Return on Equity (electric)
Ameren Illinois Company d/b/a Ameren Illinois	02/11	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 11-0282	Return on Equity (gas)
Indiana Utility Regulatory Commission				
Indiana Michigan Power Company	7/17	Indiana Michigan Power Company	Cause No. 44967	Return on Equity
Duke Energy Indiana, Inc.	12/15	Duke Energy Indiana, Inc.	Cause No. 44720	Return on Equity
Duke Energy Indiana, Inc.	12/14	Duke Energy Indiana, Inc.	Cause No. 44526	Return on Equity
Northern Indiana Public Service Company	05/09	Northern Indiana Public Service Company	Cause No. 43894	Assessment of Valuation Approaches
Kansas Corporation Commission				
Empire District Electric Company	02/19	Empire District Electric Company	Docket No. 19-EPDE-223-RTS	Return on Equity
Empire District Electric Company	12/18	Empire District Electric Company	Docket No. 19-EPDE-223-RTS	Alternative Ratemaking Mechanisms
Kansas City Power & Light Company	05/18	Kansas City Power & Light Company	Docket No. 18-KCPE-480-RTS	Return on Equity
Westar Energy	02/18	Westar Energy	Docket No. 18-WSEE-328-RTS	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Great Plains Energy, Inc. and Kansas City Power & Light Company	01/17	Great Plains Energy, Inc. and Kansas City Power & Light Company	Docket No. 16-KCPE-593-ACQ	Response to Direct Testimony by Commission Staff related to the ratemaking capital structure processes
Kansas City Power & Light Company	01/15	Kansas City Power & Light Company	Docket No. 15-KCPE-116-RTS	Return on Equity
Maine Public Utilities Commission				
Northern Utilities, Inc.	05/17	Northern Utilities, Inc.	Docket No. 2017-00065	Return on Equity
Central Maine Power Company	06/11	Central Maine Power Company	Docket No. 2010-327	Response to Bench Analysis provided by Commission Staff relating to the Company's credit and collections processes
Maryland Public Service Commission				
Washington Gas Light Company	04/19	Washington Gas Light Company	Case No. 9605	Return on Equity
Potomac Electric Power Company	01/19	Potomac Electric Power Company	Case No. 9602	Return on Equity
Washington Gas Light Company	05/18	Washington Gas Light Company	Case No. 9481	Return on Equity
Potomac Electric Power Company	01/18	Potomac Electric Power Company	Case No. 9472	Return on Equity
Delmarva Power & Light Company	07/17	Delmarva Power & Light Company	Case No. 9455	Return on Equity
Potomac Electric Power Company	03/17	Potomac Electric Power Company	Case No. 9443	Return on Equity
Delmarva Power & Light Company	06/16	Delmarva Power & Light Company	Case No. 9424	Return on Equity
Potomac Electric Power Company	06/16	Potomac Electric Power Company	Case No. 9418	Return on Equity
Potomac Electric Power Company	12/13	Potomac Electric Power Company	Case No. 9336	Return on Equity
Delmarva Power & Light Company	03/13	Delmarva Power & Light Company	Case No. 9317	Return on Equity
Potomac Electric Power Company	11/12	Potomac Electric Power Company	Case No. 9311	Return on Equity
Potomac Electric Power Company	12/11	Potomac Electric Power Company	Case No. 9286	Return on Equity
Delmarva Power & Light Company	12/11	Delmarva Power & Light Company	Case No. 9285	Return on Equity
Delmarva Power & Light Company	12/10	Delmarva Power & Light Company	Case No. 9249	Return on Equity

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Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Massachusetts Department of Public Utilities				
NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company & Nantucket Electric Company, d/b/a National Grid; and Fitchburg Gas and Electric Light Company, d/b/a Unitil	02/19	NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company & Nantucket Electric Company, d/b/a National Grid; and Fitchburg Gas and Electric Light Company, d/b/a Unitil	DPU 18-64/DPU 18-65/DPU 18-66	Response to Direct Testimony by Attorney General Witness regarding Remuneration Rate Section 83D
National Grid	11/18	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 18-150	Return on Equity
NSTAR Electric Company d/b/a Eversource Energy	11/18	NSTAR Electric Company d/b/a Eversource Energy	DPU 18-76/DPU 18-77/DPU 18-78	Response to Direct Testimony by Attorney General Witness regarding Remuneration Rate Section 83C
Boston Gas Company, Colonial Gas Company each d/b/a National Grid	11/17	Boston Gas Company, Colonial Gas Company each d/b/a National Grid	DPU 17-170	Return on Equity
NSTAR Electric Company Western and Massachusetts Electric Company each d/b/a Eversource Energy	01/17	NSTAR Electric Company Western Massachusetts Electric Company each d/b/a Eversource Energy	DPU 17-05	Return on Equity
National Grid	11/15	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 15-155	Return on Equity
Fitchburg Gas and Electric Light Company d/b/a Unitil	06/15	Fitchburg Gas and Electric Light Company d/b/a Unitil	DPU 15-80	Return on Equity
NSTAR Gas Company	12/14	NSTAR Gas Company	DPU 14-150	Return on Equity
Fitchburg Gas and Electric Light Company d/b/a Unitil	07/13	Fitchburg Gas and Electric Light Company d/b/a Unitil	DPU 13-90	Return on Equity
Bay State Gas Company d/b/a Columbia Gas of Massachusetts	04/12	Bay State Gas Company d/b/a Columbia Gas of Massachusetts	DPU 12-25	Capital Cost Recovery
National Grid	08/09	Massachusetts Electric Company d/b/a National Grid	DPU 09-39	Revenue Decoupling and Return on Equity
National Grid	08/09	Massachusetts Electric Company and Nantucket Electric Company d/b/a National Grid	DPU 09-38	Return on Equity – Solar Generation

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Testimony Listing of:
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Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Bay State Gas Company	04/09	Bay State Gas Company	DPU 09-30	Return on Equity
NSTAR Electric	09/04	NSTAR Electric	DTE 04-85	Divestiture of Power Purchase Agreement
NSTAR Electric	08/04	NSTAR Electric	DTE 04-78	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-68	Divestiture of Power Purchase Agreement
NSTAR Electric	07/04	NSTAR Electric	DTE 04-61	Divestiture of Power Purchase Agreement
NSTAR Electric	06/04	NSTAR Electric	DTE 04-60	Divestiture of Power Purchase Agreement
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Bay State Gas Company	01/93	Bay State Gas Company	DPU 93-14	Divestiture of Shelf Registration
Bay State Gas Company	01/91	Bay State Gas Company	DPU 91-25	Divestiture of Shelf Registration
Michigan Public Service Commission				
Indiana Michigan Power Company	05/17	Indiana Michigan Power Company	Case No. U-18370	Return on Equity
Minnesota Public Utilities Commission				
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/17	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-17-285	Return on Equity
ALLETE, Inc., d/b/a Minnesota Power Inc.	11/16	ALLETE, Inc., d/b/a Minnesota Power Inc.	Docket No. E015/GR-16-664	Return on Equity
Otter Tail Power Corporation	02/16	Otter Tail Power Company	Docket No. E017/GR-15-1033	Return on Equity
Minnesota Energy Resources Corporation	09/15	Minnesota Energy Resources Corporation	Docket No. G-011/GR-15-736	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-15-424	Return on Equity
Xcel Energy, Inc.	11/13	Northern States Power Company	Docket No. E002/GR-13-868	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	08/13	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-13-316	Return on Equity
Xcel Energy, Inc.	11/12	Northern States Power Company	Docket No. E002/GR-12-961	Return on Equity
Otter Tail Power Corporation	04/10	Otter Tail Power Company	Docket No. E-017/GR-10-239	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Minnesota Power a division of ALLETE, Inc.	11/09	Minnesota Power	Docket No. E-015/GR-09-1151	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas	11/08	CenterPoint Energy Minnesota Gas	Docket No. G-008/GR-08-1075	Return on Equity
Otter Tail Power Corporation	10/07	Otter Tail Power Company	Docket No. E-017/GR-07-1178	Return on Equity
Xcel Energy, Inc.	11/05	Northern States Power Company -Minnesota	Docket No. E-002/GR-05-1428	Return on Equity (electric)
Xcel Energy, Inc.	09/04	Northern States Power Company - Minnesota	Docket No. G-002/GR-04-1511	Return on Equity (gas)
Mississippi Public Service Commission				
CenterPoint Energy Resources, Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Mississippi Gas	07/09	CenterPoint Energy Mississippi Gas	Docket No. 09-UN-334	Return on Equity
Missouri Public Service Commission				
Union Electric Company d/b/a Ameren Missouri	12/18	Union Electric Company d/b/a Ameren Missouri	Case No. GR-2019-0077	Return on Equity
KCP&L Greater Missouri Operations Company	01/18	KCP&L Greater Missouri Operations Company	Case No. ER-2018-0146	Return on Equity
Kansas City Power & Light Company	01/18	Kansas City Power & Light Company	Case No. ER-2018-0145	Return on Equity
Laclede Gas Company and Missouri Gas Energy	11/17	Laclede Gas Company and Missouri Gas Energy	Case No. GR-2017-0215 Case No. GR-2017-0216	Goodwill Adjustment on Capital Structure
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a/ Liberty Utilities	09/17	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a/ Liberty Utilities	Case No. GR-2018-0013	New Ratemaking Mechanisms
Union Electric Company d/b/a Ameren Missouri	07/16	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2016-0179	Return on Equity (electric)
Kansas City Power & Light Company	07/16	Kansas City Power & Light Company	Case No. ER-2016-0285	Return on Equity (electric)
Kansas City Power & Light Company	02/16	Kansas City Power & Light Company	Case No. ER-2016-0156	Return on Equity (electric)
Kansas City Power & Light Company	10/14	Kansas City Power & Light Company	Case No. ER-2014-0370	Return on Equity (electric)
Union Electric Company d/b/a Ameren Missouri	07/14	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2014-0258	Return on Equity (electric)
Union Electric Company d/b/a Ameren Missouri	06/14	Union Electric Company d/b/a Ameren Missouri	Case No. EC-2014-0223	Return on Equity (electric)
Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	02/14	Liberty Utilities (Midstates Natural Gas) Corp. d/b/a Liberty Utilities	Case No. GR-2014-0152	Return on Equity

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Laclede Gas Company	12/12	Laclede Gas Company	Case No. GR-2013-0171	Return on Equity
Union Electric Company d/b/a Ameren Missouri	02/12	Union Electric Company d/b/a Ameren Missouri	Case No. ER-2012-0166	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	09/10	Union Electric Company d/b/a AmerenUE	Case No. ER-2011-0028	Return on Equity (electric)
Union Electric Company d/b/a AmerenUE	06/10	Union Electric Company d/b/a AmerenUE	Case No. GR-2010-0363	Return on Equity (gas)
Montana Public Service Commission				
Northwestern Corporation	09/12	Northwestern Corporation d/b/a Northwestern Energy	Docket No. D2012.9.94	Return on Equity (gas)
Nevada Public Utilities Commission				
Southwest Gas Corporation	05/18	Southwest Gas Corporation	Docket No. 18-05031	Return on Equity (gas)
Southwest Gas Corporation	04/12	Southwest Gas Corporation	Docket No. 12-04005	Return on Equity (gas)
Nevada Power Company	06/11	Nevada Power Company	Docket No. 11-06006	Return on Equity (electric)
New Hampshire Public Utilities Commission				
Northern Utilities, Inc.	06/17	Northern Utilities, Inc.	Docket No. DG 17-070	Return on Equity
Liberty Utilities d/b/a EnergyNorth Natural Gas	04/17	Liberty Utilities d/b/a EnergyNorth Natural Gas	Docket No. DG 17-048	Return on Equity
Unitil Energy Systems, Inc.	04/16	Unitil Energy Systems, Inc.	Docket No. DE 16-384	Return on Equity
Liberty Utilities d/b/a Granite State Electric Company	04/16	Liberty Utilities d/b/a Granite State Electric Company	Docket No. DE 16-383	Return on Equity
Liberty Utilities d/b/a EnergyNorth Natural Gas	08/14	Liberty Utilities d/b/a EnergyNorth Natural Gas	Docket No. DG 14-180	Return on Equity
Liberty Utilities d/b/a Granite State Electric Company	03/13	Liberty Utilities d/b/a Granite State Electric Company	Docket No. DE 13-063	Return on Equity
EnergyNorth Natural Gas d/b/a National Grid NH	02/10	EnergyNorth Natural Gas d/b/a National Grid NH	Docket No. DG 10-017	Return on Equity
Unitil Energy Systems, Inc., EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	08/08	Unitil Energy Systems, Inc., EnergyNorth Natural Gas, Inc. d/b/a National Grid NH, Granite State Electric Company d/b/a National Grid, and Northern Utilities, Inc. – New Hampshire Division	Docket No. DG 07-072	Carrying Charge Rate on Cash Working Capital

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
New Jersey Board of Public Utilities				
Elizabethtown Gas Company	04/19	Elizabethtown Gas Company	Docket No. GR19040486	Return on Equity
Atlantic City Electric Company	10/18	Atlantic City Electric Company	Docket No. EO18020196	Return on Equity
Atlantic City Electric Company	08/18	Atlantic City Electric Company	Docket No. ER18080925	Return on Equity
Atlantic City Electric Company	06/18	Atlantic City Electric Company	Docket No. ER18060638	Return on Equity
Atlantic City Electric Company	03/17	Atlantic City Electric Company	Docket No. ER17030308	Return on Equity
Pivotal Utility Holdings, Inc.	08/16	Elizabethtown Gas	Docket No. GR16090826	Return on Equity
The Southern Company; AGL Resources Inc.; AMS Corp. and Pivotal Holdings, Inc. d/b/a Elizabethtown Gas	04/16	The Southern Company; AGL Resources Inc.; AMS Corp. and Pivotal Holdings, Inc. d/b/a Elizabethtown Gas	BPU Docket No. GM15101196	Merger Approval
Atlantic City Electric Company	03/16	Atlantic City Electric Company	Docket No. ER16030252	Return on Equity
Pepco Holdings, Inc.	03/14	Atlantic City Electric Company	Docket No. ER14030245	Return on Equity
Orange and Rockland Utilities	11/13	Rockland Electric Company	Docket No. ER13111135	Return on Equity
Atlantic City Electric Company	12/12	Atlantic City Electric Company	Docket No. ER12121071	Return on Equity
Atlantic City Electric Company	08/11	Atlantic City Electric Company	Docket No. ER11080469	Return on Equity
Pepco Holdings, Inc.	09/06	Atlantic City Electric Company	Docket No. EM06090638	Divestiture and Valuation of Electric Generating Assets
Pepco Holdings, Inc.	12/05	Atlantic City Electric Company	Docket No. EM05121058	Market Value of Electric Generation Assets; Auction
Conectiv	06/03	Atlantic City Electric Company	Docket No. EO03020091	Market Value of Electric Generation Assets; Auction Process
New Mexico Public Regulation Commission				
Public Service Company of New Mexico	12/16	Public Service Company of New Mexico	Case No. 16-00276-UT	Return on Equity (electric)
Public Service Company of New Mexico	08/15	Public Service Company of New Mexico	Case No. 15-00261-UT	Return on Equity (electric)
Public Service Company of New Mexico	12/14	Public Service Company of New Mexico	Case No. 14-00332-UT	Return on Equity (electric)
Public Service Company of New Mexico	12/14	Public Service Company of New Mexico	Case No. 13-00390-UT	Cost of Capital and Financial Integrity
Southwestern Public Service Company	02/11	Southwestern Public Service Company	Case No. 10-00395-UT	Return on Equity (electric)
Public Service Company of New Mexico	06/10	Public Service Company of New Mexico	Case No. 10-00086-UT	Return on Equity (electric)

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SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Public Service Company of New Mexico	09/08	Public Service Company of New Mexico	Case No. 08-00273-UT	Return on Equity (electric)
Xcel Energy, Inc.	07/07	Southwestern Public Service Company	Case No. 07-00319-UT	Return on Equity (electric)
New York State Public Service Commission				
Consolidated Edison Company of New York, Inc.	01/15	Consolidated Edison Company of New York, Inc.	Case No. 15-E-0050	Return on Equity (electric)
Orange and Rockland Utilities, Inc.	11/14	Orange and Rockland Utilities, Inc.	Case Nos. 14-E-0493 and 14-G-0494	Return on Equity (electric and gas)
Consolidated Edison Company of New York, Inc.	01/13	Consolidated Edison Company of New York, Inc.	Case No. 13-E-0030	Return on Equity (electric)
Niagara Mohawk Corporation d/b/a National Grid for Electric Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Electric Service	Case No. 12-E-0201	Return on Equity (electric)
Niagara Mohawk Corporation d/b/a National Grid for Gas Service	04/12	Niagara Mohawk Corporation d/b/a National Grid for Gas Service	Case No. 12-G-0202	Return on Equity (gas)
Orange and Rockland Utilities, Inc.	07/11	Orange and Rockland Utilities, Inc.	Case No. 11-E-0408	Return on Equity (electric)
Orange and Rockland Utilities, Inc.	07/10	Orange and Rockland Utilities, Inc.	Case No. 10-E-0362	Return on Equity (electric)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-G-0795	Return on Equity (gas)
Consolidated Edison Company of New York, Inc.	11/09	Consolidated Edison Company of New York, Inc.	Case No. 09-S-0794	Return on Equity (steam)
Niagara Mohawk Power Corporation	07/01	Niagara Mohawk Power Corporation	Case No. 01-E-1046	Power Purchase and Sale Agreement; Standard Offer Service Agreement
North Carolina Utilities Commission				
Piedmont Natural Gas Company, Inc.	04/19	Piedmont Natural Gas Company, Inc.	Docket No. G-9, Sub 743	Return on Equity
Virginia Electric and Power Company d/b/a Dominion North Carolina Power	03/19	Virginia Electric and Power Company d/b/a Dominion North Carolina Power	Docket No. E-22, Sub 562	Return on Equity
Duke Energy Carolinas, LLC	08/17	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1146	Return on Equity
Duke Energy Progress, LLC	06/17	Duke Energy Progress, LLC	Docket No. E-2, Sub 1142	Return on Equity
Public Service Company of North Carolina, Inc.	03/16	Public Service Company of North Carolina, Inc.	Docket No. G-5, Sub 565	Return on Equity
Dominion North Carolina Power	03/16	Dominion North Carolina Power	Docket No. E-22, Sub 532	Return on Equity

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MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Duke Energy Carolinas, LLC	02/13	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1026	Return on Equity
Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	10/12	Carolina Power & Light Company d/b/a Progress Energy Carolinas, Inc.	Docket No. E-2, Sub 1023	Return on Equity
Virginia Electric and Power Company d/b/a Dominion North Carolina Power	03/12	Virginia Electric and Power Company d/b/a Dominion North Carolina Power	Docket No. E-22, Sub 479	Return on Equity
Duke Energy Carolinas, LLC	07/11	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 989	Return on Equity
North Dakota Public Service Commission				
Otter Tail Power Company	11/17	Otter Tail Power Company	Docket No. 17-398	Return on Equity (electric)
Otter Tail Power Company	11/08	Otter Tail Power Company	Docket No. 08-862	Return on Equity (electric)
Oklahoma Corporation Commission				
Empire District Electric Company	03/19	Empire District Electric Company	Cause No. PUD201800133	Return on Equity
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/16	CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	Cause No. PUD201600094	Return on Equity
Oklahoma Gas & Electric Company	12/15	Oklahoma Gas & Electric Company	Cause No. PUD201500273	Return on Equity
Public Service Company of Oklahoma	07/15	Public Service Company of Oklahoma	Cause No. PUD201500208	Return on Equity
Oklahoma Gas & Electric Company	07/11	Oklahoma Gas & Electric Company	Cause No. PUD201100087	Return on Equity
CenterPoint Energy Resources Corp., d/b/a CenterPoint Energy Oklahoma Gas	03/09	CenterPoint Energy Oklahoma Gas	Cause No. PUD200900055	Return on Equity
Pennsylvania Public Utility Commission				
Pike County Light & Power Company	01/14	Pike County Light & Power Company	Docket No. R-2013-2397237	Return on Equity (electric & gas)
Veolia Energy Philadelphia, Inc.	12/13	Veolia Energy Philadelphia, Inc.	Docket No. R-2013-2386293	Return on Equity (steam)
Rhode Island Public Utilities Commission				
The Narragansett Electric Company d/b/a National Grid	02/19	The Narragansett Electric Company d/b/a National Grid	Docket No. 4929	Support for financial remuneration under new power purchase agreement
The Narragansett Electric Company d/b/a National Grid	11/17	The Narragansett Electric Company d/b/a National Grid	Docket No. 4770	Return on Equity (electric & gas)
The Narragansett Electric Company d/b/a National Grid	04/12	The Narragansett Electric Company d/b/a National Grid	Docket No. 4323	Return on Equity (electric & gas)

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MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
National Grid RI – Gas	08/08	National Grid RI – Gas	Docket No. 3943	Revenue Decoupling and Return on Equity
South Carolina Public Service Commission				
Duke Energy Carolinas, LLC	11/18	Duke Energy Carolinas, LLC	Docket No. 2018-319-E	Return on Equity
Duke Energy Progress, LLC	11/18	Duke Energy Progress, LLC	Docket No. 2018-318-E	Return on Equity
South Carolina Electric & Gas	08/18	South Carolina Electric & Gas	Docket No. 2017-370-E	Return on Equity
South Carolina Electric & Gas	12/17	South Carolina Electric & Gas	Docket No. 2017-305-E	Return on Equity
Duke Energy Progress, LLC	07/16	Duke Energy Progress, LLC	Docket No. 2016-227-E	Return on Equity
Duke Energy Carolinas, LLC	03/13	Duke Energy Carolinas, LLC	Docket No. 2013-59-E	Return on Equity
South Carolina Electric & Gas	06/12	South Carolina Electric & Gas	Docket No. 2012-218-E	Return on Equity
Duke Energy Carolinas, LLC	08/11	Duke Energy Carolinas, LLC	Docket No. 2011-271-E	Return on Equity
South Carolina Electric & Gas	03/10	South Carolina Electric & Gas	Docket No. 2009-489-E	Return on Equity
South Dakota Public Utilities Commission				
Otter Tail Power Company	04/18	Otter Tail Power Company	Docket No. EL18-021	Return on Equity (electric)
Otter Tail Power Company	08/10	Otter Tail Power Company	Docket No. EL10-011	Return on Equity (electric)
Northern States Power Company	06/09	South Dakota Division of Northern States Power	Docket No. EL09-009	Return on Equity (electric)
Otter Tail Power Company	10/08	Otter Tail Power Company	Docket No. EL08-030	Return on Equity (electric)
Texas Public Utility Commission				
CenterPoint Energy Houston Electric LLC	04/19	CenterPoint Energy Houston Electric LLC	Docket No. 49421	Return on Equity
Texas-New Mexico Power Company	05/18	Texas-New Mexico Power Company	Docket No. 48401	Return on Equity
Entergy Texas, Inc.	05/18	Entergy Texas, Inc.	Docket No. 48371	Return on Equity
Southwestern Public Service Company	08/17	Southwestern Public Service Company	Docket No. 47527	Return on Equity
Oncor Electric Delivery Company, LLC	03/17	Oncor Electric Delivery Company, LLC	Docket No. 46957	Return on Equity
El Paso Electric Company	02/17	El Paso Electric Company	Docket No. 46831	Return on Equity
Southwestern Electric Power Company	12/16	Southwestern Electric Power Company	Docket No. 46449	Return on Equity (electric)
Sharyland Utilities, L.P.	04/16	Sharyland Utilities, L.P.	Docket No. 45414	Return on Equity
Southwestern Public Service Company	02/16	Southwestern Public Service Company	Docket No. 44524	Return on Equity (electric)
Wind Energy Transmission Texas, LLC	05/15	Wind Energy Transmission Texas, LLC	Docket No. 44746	Return on Equity

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MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Cross Texas Transmission	12/14	Cross Texas Transmission	Docket No. 43950	Return on Equity
Southwestern Public Service Company	12/14	Southwestern Public Service Company	Docket No. 43695	Return on Equity (electric)
Sharyland Utilities, L.P.	05/13	Sharyland Utilities, L.P.	Docket No. 41474	Return on Equity
Wind Energy Texas Transmission, LLC	08/12	Wind Energy Texas Transmission, LLC	Docket No. 40606	Return on Equity
Southwestern Electric Power Company	07/12	Southwestern Electric Power Company	Docket No. 40443	Return on Equity
Oncor Electric Delivery Company, LLC	01/11	Oncor Electric Delivery Company, LLC	Docket No. 38929	Return on Equity
Texas-New Mexico Power Company	08/10	Texas-New Mexico Power Company	Docket No. 38480	Return on Equity (electric)
CenterPoint Energy Houston Electric LLC	06/10	CenterPoint Energy Houston Electric LLC	Docket No. 38339	Return on Equity
Xcel Energy, Inc.	05/10	Southwestern Public Service Company	Docket No. 38147	Return on Equity (electric)
Texas-New Mexico Power Company	08/08	Texas-New Mexico Power Company	Docket No. 36025	Return on Equity (electric)
Xcel Energy, Inc.	05/06	Southwestern Public Service Company	Docket No. 32766	Return on Equity (electric)
Texas Railroad Commission				
Atmos Energy Corporation – Mid-Tex Division	10/18	Atmos Energy Corporation – Mid-Tex Division	GUD 10779	Return on Equity
Atmos Energy Corporation – West Texas Division	06/18	Atmos Energy Corporation – West Texas Division	GUD 10743	Return on Equity
Atmos Energy Corporation – Mid-Texas Division	06/18	Atmos Energy Corporation – Mid-Texas Division	GUD 10742	Return on Equity
CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	11/17	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	GUD 10669	Return on Equity
Atmos Pipeline - Texas	01/17	Atmos Pipeline - Texas	GUD 10580	Return on Equity
CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	12/16	CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Entex And CenterPoint Energy Texas Gas	GUD 10567	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	03/15	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10432	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/12	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10182	Return on Equity

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MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Atmos Energy Corporation – West Texas Division	06/12	Atmos Energy Corporation – West Texas Division	GUD 10174	Return on Equity
Atmos Energy Corporation – Mid-Texas Division	06/12	Atmos Energy Corporation – Mid-Texas Division	GUD 10170	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	12/10	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 10038	Return on Equity
Atmos Pipeline – Texas	09/10	Atmos Pipeline - Texas	GUD 10000	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	07/09	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Entex and CenterPoint Energy Texas Gas	GUD 9902	Return on Equity
CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	03/08	CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Texas Gas	GUD 9791	Return on Equity
Utah Public Service Commission				
Questar Gas Company	12/07	Questar Gas Company	Docket No. 07-057-13	Return on Equity
Vermont Public Service Board				
Central Vermont Public Service Corporation; Green Mountain Power	02/12	Central Vermont Public Service Corporation; Green Mountain Power	Docket No. 7770	Merger Policy
Central Vermont Public Service Corporation	12/10	Central Vermont Public Service Corporation	Docket No. 7627	Return on Equity (electric)
Green Mountain Power	04/06	Green Mountain Power	Docket Nos. 7175 and 7176	Return on Equity (electric)
Vermont Gas Systems, Inc.	12/05	Vermont Gas Systems	Docket Nos. 7109 and 7160	Return on Equity (gas)
Virginia State Corporation Commission				
Virginia Electric and Power Company	03/19	Virginia Electric and Power Company	Case No. PUR-2019-00050	Return on Equity
Virginia Electric and Power Company	03/17	Virginia Electric and Power Company	Case No. PUR-2017-00038	Return on Equity
Virginia Natural Gas, Inc.	03/17	Virginia Natural Gas, Inc.	Case No. PUE-2016-00143	Return on Equity
Virginia Electric and Power Company	10/16	Virginia Electric and Power Company	Case No. PUE-2016-00112; PUE-2016-00113; PUE-2016-00136	Return on Equity
Washington Gas Light Company	06/16	Washington Gas Light Company	Case No. PUE-2016-00001	Return on Equity

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MANAGEMENT CONSULTANTS

Testimony Listing of:
Robert B. Hevert, Partner
Rates, Regulation and Planning Practice Leader

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Virginia Electric and Power Company	06/16	Virginia Electric and Power Company	Case Nos. PUE-2016-00063; PUE-2016-00062; PUE-2016-00061; PUE-2016-00060; PUE-2016-00059	Return on Equity
Virginia Electric and Power Company	12/15	Virginia Electric and Power Company	Case Nos. PUE-2015-00058; PUE-2015-00059; PUE-2015-00060; PUE-2015-00061; PUE-2015-00075; PUE-2015-00089; PUE-2015-00102; PUE-2015-00104	Return on Equity
Virginia Electric and Power Company	03/15	Virginia Electric and Power Company	Case No. PUE-2015-00027	Return on Equity
Virginia Electric and Power Company	03/13	Virginia Electric and Power Company	Case No. PUE-2013-00020	Return on Equity
Virginia Natural Gas, Inc.	02/11	Virginia Natural Gas, Inc.	Case No. PUE-2010-00142	Capital Structure
Columbia Gas of Virginia, Inc.	06/06	Columbia Gas of Virginia, Inc.	Case No. PUE-2005-00098	Merger Synergies
Dominion Resources	10/01	Virginia Electric and Power Company	Case No. PUE000584	Corporate Structure and Electric Generation Strategy

Expert Reports

United States District Court, District of South Carolina, Columbia Division				
South Carolina Electric & Gas Company	07/18	South Carolina Electric & Gas Company	Case No. 3:18-CV-01795-JMC	Return on Equity
United States District Court, Western District of Texas, Austin Division				
Southwestern Public Service Company	02/12	Southwestern Public Service Company	C.A. No. A-09-CA-917-SS	PURPA and FERC regulations
American Arbitration Association				
Confidential Client	11/14	Confidential Client	Confidential	Economic harm related to failure to perform

J.E. Giese
Direct Testimony
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (H)

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VI. MRP 10

EXECUTIVE SUMMARY- JULIE E. GIESE

This testimony supports the accounting books and records of Potomac Electric Power Company (Pepco or the Company) as well as the Company's costing and accounting procedures. It also addresses certain accounting related filing requirements in: (i) Order No. 17424, as modified in Order No. 17539 from Formal Case No. 1103; and (ii) Order No. 18148 from Formal Case No. 1119.

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF JULIE E. GIESE
FORMAL CASE NO. 1156

I. INTRODUCTION

Q1. Please state your name and position.

A1. My name is Julie E. Giese. I serve as Director of Accounting, Pepco Holdings LLC (PHI). I am testifying on behalf of Pepco.

Q2. What are your responsibilities in your role as Director of Accounting?

A2. I am responsible for specific accounting-related projects as well as PHI accounting close, reporting, and control activities for PHI's utility operations, which include Pepco.

Q3. Please state your education background and professional qualifications.

A3. I received my Bachelor of Science in Accounting from Towson University. I am a Certified Public Accountant. I have held various financial accounting and managerial positions at Constellation, Exelon Generation, and Baltimore Gas and Electric Company since 2010. In April 2016, I assumed my current position at PHI. Prior to joining Exelon/Constellation, I was an auditor with PricewaterhouseCoopers for eight years.

Q4. Have you previously testified before the Public Service Commission of the District of Columbia (Commission)?

A4. Yes, I submitted testimony with respect to the Company's accounting and costing procedures and certain accounting-related filing requirements before the Commission in Formal Case No. 1150.

Q5. What is the purpose of your Direct Testimony in this proceeding?

A5. The purpose of my Direct Testimony is to support:

I. The accounting books and records of Pepco;

II. The Company's costing and accounting procedures, which are the basis for the actual amounts recorded in Pepco's books and records for the six months ended December 31, 2018, the actual test period amounts used by Company Witness Ziminsky in determining the Company's revenue requirements;

III. Certain accounting-related filing requirements in Order No. 17424, as modified in Order No. 17539 from Formal Case No. 1103; and

IV. Certain accounting-related filing requirements in Order No. 18148 from Formal Case No. 1119 (Approval of Merger).[1]

This testimony and accompanying exhibits were prepared by me or under my direct supervision and control. The sources for my testimony are Company records, public documents, and my personal knowledge and expertise.

Q6. What portion of the Company's filing does your Direct Testimony support?

A6. This testimony supports both the Multiyear Rate Plan (MRP) and the traditional test period compliance filing.

[1] *In The Matter of the Joint Application of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC and New Special Purpose Entity, LLC for Authorization and Approval of Proposed Merger Transaction*, Formal Case No. 1119, Order No. 18148, at P 1 (March 23, 2016) ("Merger Order"). The Commission subsequently issued Order No. 18160 (April 4, 2016) correcting certain errors in the Merger Order and in Attachment B to the Merger Order (the "Merger Commitments"). References herein to the Merger Order and the Merger Commitments are to Order No. 18148 and Attachment B to Order No. 18148, respectively, as corrected by Order No. 18160.

II. PEPCO'S BOOKS AND RECORDS

Q7. Does the Company maintain its books and records in accordance with the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts and Generally Accepted Accounting Principles (GAAP)?

A7. Yes.

Q8. Are the Company's books and records audited by an independent accounting firm?

A8. Yes. PricewaterhouseCoopers LLP (PwC) audited the Company's financial statements included in Pepco's 2018 FERC Form No. 1 and the 2018 Exelon 10-K. Copies of the audit reports issued by PwC related to the 10-K financial statements and the 2018 FERC Form 1 are attached as PEPCO (H)-1. PwC concluded that the Company's financial statements conform with GAAP and the requirements of the FERC's Uniform System of Accounts in all material respects.

III. PHI's COSTING AND ACCOUNTING PROCEDURES

Q9. Please briefly discuss the Company's accounting structure associated with services that are provided by PHI Service Company (PHISCO) and Exelon Business Services Company (BSC).

A9. PHI segregates costs by providing services through separate operating subsidiaries. PHISCO is a wholly-owned subsidiary of PHI that provides a variety of shared support services at cost, including legal, finance, engineering, distribution and transmission planning, asset management, and power procurement, to PHI and its operating subsidiaries, including Pepco. PHISCO provides these support services in compliance with a service agreement. BSC is a business services subsidiary of Exelon

that provides a variety of corporate governance shared support services such as human resources, security, corporate strategy and development, information technology, corporate communications, and supply at cost to Exelon operating subsidiaries, including Pepco. As with PHISCO, BSC provides these shared services pursuant to a service agreement. Additional discussion of the PHISCO and BSC services provided to Pepco is in the Direct Testimony of Company Witness Barnett.

Q10. Briefly discuss the Company's cost accounting approach.

A10. The underlying principle of both PHI's and Exelon's costing approach is the use of a fully distributed cost alignment methodology (full costing). The full costing philosophy is based on the premise that both direct and indirect costs are identified and charged for goods and services. The costs of goods and services include direct costs, such as labor and materials, and indirect costs, such as benefits and other related expenses. Full costing aids in ensuring indirect costs follow the same accounting path as direct costs when billed to affiliates.

Q11. Has the Company filed a copy of its Cost Allocation Manual (CAM) with this Commission?

A11. Yes. Pursuant to Rule 3904.1 of the Commission's Affiliate Transactions Code of Conduct, 15 D.C.M.R. § 3904.1, the Company's last annual filing of the CAM was April 30, 2019. The CAM filed in April 2019 listed the corporate services that are provided by BSC and PHISCO along with the associated allocation ratios. The CAM included a copy of the service agreement of PHISCO as well as the General Services Agreement (GSA) between BSC and its affiliates, which includes Pepco.

Q12. Have there been independent examinations of the Company's CAM and in particular, PHISCO and BSC?

A12. Yes. Prior to the merger with Exelon in March 2016, PHI's CAM and affiliate transactions, including charges from PHISCO, were routinely examined by independent firms. PEPCO (H)-2 is a listing of the independent reports of the Company's CAM and/or PHISCO charging and allocation of costs since 2008. Since the merger, seven independent attestation reports of the Company's CAM and affiliate transactions have been issued, all of which included BSC charges. These reports are also identified in PEPCO (H)-2.

Q13. Have these completed independent examinations revealed any material or substantive issues with the calculation of PHISCO and BSC charges?

A13. No. In each of the examinations prior to the merger, the auditors found the PHISCO allocations and charges to be consistent with the CAM and the PHISCO Service Agreement. Additionally, in the seven examinations issued since the merger, which included BSC charges, the auditors found the allocations and charges to be consistent with the CAM and the GSA and the PHISCO Service Agreement, as applicable.

IV. ACCOUNTING REQUIREMENTS FROM ORDER NO. 17424 IN FORMAL CASE NO. 1103

Q14. Can you briefly summarize the accounting requirements from Order No. 17424 in Formal Case No. 1103, as modified in Order No. 17539?

A14. Yes. In Paragraph 374 of Order No. 17424, which was issued prior to the merger with Exelon, the Commission indicated that Pepco "should supply more information concerning the PHISCO costs that are direct-charged and allocated to Pepco DC when it files a rate case." To this end, the Commission directed the Company to include with its 21-day compliance filing in its next rate case the following: 1) an updated CAM; 2) an updated service agreement; 3) an exhibit that breaks out and separately states the PHISCO costs that are directly assigned and allocated to Pepco DC.

Q15. Regarding Paragraph 374 of Order No. 17424, as modified in Order No. 17539, has the Company addressed the first two requirements – providing an updated CAM and service agreement?

A15. Yes. As previously discussed in my Direct Testimony, the Company's last annual filing of the CAM was on April 30, 2019. The CAM included copies of the PHISCO Service Agreement as well as the GSA.

Q16. Can you please restate the third requirement from Paragraph 374 of Order No. 17424, as modified in Order No. 17539?

A16. Yes. In Paragraph 374 of Order No. 17424 the Commission indicated that Pepco was to provide an exhibit which "should include: (a) the total amount of direct-charged costs and the total amount of allocated costs to Pepco DC during the test year

and the prior four fiscal years; (b) the total amount of direct-charged and allocated costs to Pepco DC included in Pepco DC rate base during the test year and the prior four fiscal years; (c) the total amount included in Pepco DC O&M expense during the test year and prior four fiscal years; (d) a detailed description of any changes or modifications to the service agreement between PHISCO and Pepco since the previous rate case; and (e) a detailed description of any changes to the CAM and methods of allocating costs from PHISCO to Pepco since the previous rate case."

Q17. Has the Company provided an exhibit that addresses the information in parts (a) through (c) discussed above?

A17. Yes, Pepco will include with its 21-day compliance filing a schedule providing the cost information specified in parts (a) through (c) of Paragraph 374 of Order No. 17424. The schedule will include both the PHISCO and the BSC direct and allocated costs requested.

Q18. Please address parts (d) through (e) discussed above?

A18. With regards to part (d), there have been no changes or modifications to the GSA or the PHISCO Service Agreement since Formal Case No. 1150, Pepco's last base rate case. Similarly, with regards to part (e), there have been no changes to the CAM or the methods of allocating costs from BSC or PHISCO to Pepco since Formal Case No. 1150.

V. ACCOUNTING REQUIREMENTS FROM ORDER NO. 18148 IN FORMAL CASE NO. 1119 (APPROVAL OF EXELON MERGER)

Q19. Can you briefly summarize your testimony regarding accounting requirements from the Merger Commitments referred to in Attachment B to Order No. 18148?

A19. Yes, I will specifically address Merger Commitments 31, 34, 38, and 39.[2]

Q20. Please discuss the requirements you are addressing under Merger Commitment 31.

A20. Merger Commitment 31 provides:

> In each of Pepco's base rate cases filed within five (5) years after closing of the Merger, Pepco shall provide in addition to the information otherwise required to be provided with Pepco's 21-day compliance filing, the following information with respect to charges to Pepco from Exelon, EBSC or any other affiliate that supplies service to Pepco after the Merger:
>
> (a) The Cost Allocation Manual(s) in effect and used to allocate costs to Pepco and Pepco's District of Columbia operations;
>
> (b) The service agreement(s) in effect between Pepco and Exelon, EBSC, and any other affiliate that charges costs to Pepco;
>
> (c) An exhibit separately stating the costs that are directly assigned or allocated to Pepco and Pepco's District of Columbia operations for the test year and for each year post-Merger, by entity charging the costs, including:
>
> (i) Total amount of direct charged costs and total amount of allocated costs to Pepco and to Pepco's District of Columbia operation;
>
> (ii) Total amount of direct charged costs and total amount of allocated costs included in Pepco's rate base and in Pepco's rate base for the District of Columbia; and
>
> (iii) Total amount of direct charged costs and total amount of allocated costs included in Pepco's operating and maintenance expenses and in Pepco's operating and maintenance expenses for the District of Columbia.

[2] *See* Merger Order, Attachment B at Paragraphs 31, 34, 38 and 39.

Consistent with the Commission's directive, the required information will be submitted with Pepco's 21-day compliance filing. The costs included in the exhibit required by item (c) will be reported as costs included as additions to Pepco's rate base consistent with the directive on reporting these costs issued in Order No. 17539, which modified the Commission's directive in Order No. 17424.

Q21. Please discuss the requirements you are addressing under Merger Commitment 34.

A21. Merger Commitment 34 states:

> EBSC costs shall be directly charged whenever practicable and possible. In its next base rate proceeding, Pepco will file testimony addressing EBSC charges and the bases for such charges. Pepco's testimony will also explain any changes in allocation procedures that have been adopted since its last base rate proceeding."

With respect to the Company's cost accounting approach, both PHI and Exelon use a fully distributed cost alignment methodology (full costing). Under its cost principles contained in the GSA, Exelon prioritizes the use of direct billings where practicable and possible. From July 1, 2018 through December 31, 2018, Pepco received $10.6 million of direct charges from BSC associated with a variety of direct support in areas such as Finance, Human Resources, Legal, IT and Supply. The BSC allocation methodologies are described in the GSA.

Q22. Please discuss the requirements you are addressing under Merger Commitment 38.

A22. Under Merger Commitment 38: "for assets that EBSC acquires for use by Pepco, the same capitalization/expense policies shall apply to those assets that are applicable under the Commission's standards for assets acquired directly by Pepco." From July 1, 2018 to the present date, the assets acquired by BSC for use by Pepco

have been recorded in Pepco's books and records and have followed the applicable accounting policy for Pepco. Both BSC and Pepco policies comply with FERC and GAAP guidance.

Q23. Please discuss the requirements you are addressing under Merger Commitment 39.

A23. Merger Commitment 39 states: "for depreciable assets that EBSC acquires for use by Pepco, the depreciation expense charged to Pepco by EBSC shall reflect the same depreciable lives and methods required by the Commission for similar assets acquired directly by Pepco. In no event shall depreciable lives on plant acquired by EBSC be shorter than those approved by the Commission for similar property acquired directly by Pepco." Some differences in depreciable lives between the two Companies exist, primarily related to IT equipment. Please see the Direct Testimony of Company Witness Ziminsky for a discussion of the Company's proposed ratemaking adjustment (RMA) 32 which conforms the EBSC depreciation lives to align with those used by Pepco.

VI. MRP

Q24. Would the Commission's adoption of the MRP change the Company's CAM?

A24. No.

Q25. Does this conclude your Direct Testimony?

A25. Yes, it does.

J.E. Giese
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (H) – 1

Report of Independent Auditors

To the Board of Directors of Potomac Electric Power Company:

We have audited the accompanying financial statements of Potomac Electric Power Company (the "Company"), which comprise the comparative balance sheets as of December 31, 2018 and December 31, 2017, and the related statements of income, of retained earnings and of cash flows for the years then ended, included on pages 110 through 123.39 of the accompanying Federal Energy Regulatory Commission Form 1.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases described in Note1. Management is also responsible for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on the financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Potomac Electric Power Company as of December 31, 2018 and December 31, 2017, and the results of its operations and its cash flows for the years then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases described in Note 1.

Basis of Accounting

We draw attention to Note 1 of the financial statements, which describes the basis of accounting. As described in Note 1 to the financial statements, the financial statements are prepared by Potomac Electric Power Company on the basis of the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than accounting principles generally accepted in the United States of America, to meet the requirements of the Federal Energy Regulatory Commission. Our opinion is not modified with respect to this matter.

Restriction of Use

This report is intended solely for the information and use of the Board of Directors and Management of Potomac Electric Power Company and the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

PricewaterhouseCoopers LLP

Washington, D.C.
April 2, 2019

pwc

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Potomac Electric Power Company

Opinion on the Financial Statements

We have audited the financial statements, including the related notes, as listed in the index appearing under Item 15(a)(7)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(7)(ii), of Potomac Electric Power Company (the "Company") (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

Washington, DC
February 8, 2019

We have served as the Company's auditor since at least 1993. We have not been able to determine the specific year we began serving as auditor of the Company.

PricewaterhouseCoopers LLP, 600 13th Street, Washington, DC 20005
T: (202) 414 1000, F: (202) 414 1301, www.pwc.com/us

J.E. Giese
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (H) – 2

Pepco Holdings LLC
Cost Allocation Manual
Service Company
Independent Examinations

Jurisdiction	Auditor	Period
Delaware Public Service Commission	PricewaterhouseCoopers LLP (PwC)	12me December 2010 12me December 2013 12me December 2016
New Jersey Board Of Public Utilities	Overland Consulting	2005-2008
Maryland Public Service Commission	PwC	12me September 2008 12me June 2009 12me September 2010 12me June 2011 12me June 2012 12me December 2012 12me June 2013 12me December 2014 12me June 2015 12me March 2016 12me December 2016 12me August 2017 12 me September 2018
Public Service Commission of the District of Columbia		
	KPMG	2007-2008
	Liberty Consultants	2009-2011
	PwC (Code of Conduct)	12me December 2015 12me December 2017
Federal Energy Regulatory Commission (FERC)		
	FERC Division of Audit Staff	2008-2009

IN THE MATTER OF THE APPLICATION OF POTOMAC ELECTRIC POWER COMPANY FOR AUTHORITY TO IMPLEMENT A MULTIYEAR RATE PLAN FOR ELECTRIC DISTRIBUTION SERVICE IN THE DISTRICT OF COLUMBIA	**)**	**Formal Case No. 1156**

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

VOLUME V

DIRECT TESTIMONIES AND EXHIBITS OF

Mr. Bryan L. Clark

B.L. Clark
Direct Testimony
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (I)

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EXECUTIVE - BRYAN L. CLARK

PEPCO DISTRICT OF COLUMBIA CAPITAL CONSTRUCTION SUMMARY

Pepco DC 2019 - 2023 Capital Budget[1] (Dollars in Millions)					
Distribution Construction	**2019**	**2020**	**2021**	**2022**	**2023**
Customer Driven	$84.6	$78.9	$76.2	$76.6	$74.8
Reliability[2]	171.9	167.8	175.0	224.3	204.2
Load	65.2	49.3	54.4	54.7	32.6
TOTAL	$321.7	$296.0	$305.6	$355.6	$311.6

SUMMARY OF DISTRIBUTION CATEGORIES

Distribution Categories	General Scope of Work
Customer Driven	Projects required by customers, including connecting them to the distribution system, and work performed at the direction of government agencies, such as electric plant relocations that support highway construction projects.
Reliability	Projects to increase and maintain the reliability of the distribution system and electric facilities, including supporting communications facilities that provide service to the Company's customers. These projects include replacement of existing infrastructure, upgrades to reduce outages and improve system performance, and cost of emergency replacement of failed equipment during storms and other events.
Load	Load projects are proactive additions or upgrades to the system in order to meet all levels of customer load in advance of those load conditions developing on the system. Load projects ensure that the system continues to meet design criteria. This category of work does not include projects that are solely for the connection of new customers to the electric system.

Potomac Electric Power Company (Pepco or the Company) is presenting its Distribution Construction Program that includes customer driven, reliability, and load projects with 2018 actual costs of $287,000,000 and forecast capital costs for 2019 in the amount of

[1] Please note that Pepco is providing its five-year budget and forecast, consistent with previous rate cases and Commission directives. However, the MRP proposed by the Company in this case is for the years 2020-2022.

[2] The reliability budget includes budgeted capital emergency expenditures and the District of Columbia Powerline Undergrounding (DC PLUG) initiave expenses.

$321,700,000. Additionally, Pepco seeks adoption of its forecast for capital expenditures in 2020-2022, which are $296,000,000, $305,600,000, and $355,600,000, respectively. The capital expenses described in my testimony are intended to support the capital construction and maintenance of customer-driven, reliability, and load projects. This testimony provides an overview of the Company's distribution program as well as Pepco's key strategic initiatives.

The testimony also addresses certain performance incentive mechanisms (PIMs). These PIMs include operational targets for the System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI), and a policy PIM focused on Distributed Energy Resources (DER) interconnection review timeframes for Approval to Install (ATI).

Finally, this testimony discusses certain ratemaking adjustments concerning reliability construction projects, DC PLUG-related costs, the Frederick Douglass Memorial Bridge project, and the benefit of these construction projects to customers.

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF BRYAN L. CLARK
FORMAL CASE NO. 1156

I. INTRODUCTION AND QUALIFICATIONS

A. Witness Qualifications

Q1. Please state your name and position.

A1. My name is Bryan L. Clark and I am Director of Gas Operations for Delmarva Power, and previously served as Director of Strategy at Pepco Holdings, LLC (PHI). I am testifying on behalf of Pepco.

Q2. What were your responsibilities in your role as Director of Strategy?

A2. I led a planning and analysis team focused on grid modernization within the Regulatory group of PHI, which includes Pepco, Atlantic City Electric Company, and Delmarva Power & Light Company (Delmarva Power). This team is responsible for the evolution of policy and technology that will enable grid modernization and the development of the electric distribution system as a platform for the safe and reliable exchange of energy related services for PHI's customers. The Strategy team also serves in a lead role to assemble, analyze, and produce numerous regulatory compliance reporting requirements associated with the operations and engineering functions of the PHI utilities, including Pepco.

Q3. Could you please describe your educational and professional background and experience?

A3. I earned an Associate of Applied Science Degree in Electronics Engineering from Delaware Technical & Community College, a Bachelor of Science Degree in Engineering from the University of Delaware, and a Master's in Business Administration from Wilmington University. I joined Delmarva Power at the Indian River Generating Station, progressing from the role of plant equipment operator to operations supervisor and subsequently serving as a project engineer and system operator in Delmarva Power's Electric System Operations Division. I have held several management positions, including Manager of Asset Performance and Reliability, Distribution Control Center Manager, and Process Manager of Reliability. In 2016, I was promoted to the position of Director of Engineering. In 2018, I transitioned into the role of Director of Utility of the Future and was subsequently named Director of Strategy in 2019.

I have served as an Adjunct Professor of Electric System Operations Technology at Bismarck State University. I serve on the Engineering Technology Industrial Advisory Board at the University of Maryland - Eastern Shore and the Engineering Technology Advisory Board at Delaware Technical & Community College.

Q4. Have you previously testified before the Public Service Commission of the District of Columbia (Commission)?

A4. Yes. I submitted testimony in Formal Case No. 1150, Pepco's most recent base rate case and also in Formal Case Nos. 1130 and 1155, Pepco's Application for Approval of Its Transportation Electrification Program.

B. Purpose of Testimony

Q5. What is the purpose of your Direct Testimony in this proceeding?

A5. My Direct Testimony will be supporting both the traditional test period compliance filing and the Multiyear Rate Plan (MRP), and I will discuss the following:

- Pepco's strong reliability performance, including the Company's progress in meeting the reliability standards contained within the Electricity Quality of Service Standards (EQSS)[3] as modified and made more stringent by Order No. 18148 in Formal Case No. 1119[4] and the reliability progress achieved through the Company's construction program;
- The contents and overview of the Construction Report and Pepco's capital construction program;
- Key initiatives to modernize and optimize the distribution system and how these initiatives have and will benefit Pepco's customers;

[3] District of Columbia Municipal Regulations (DCMR) Title 15, Chapter 36, Electricity Quality of Service Standards, (§3603).

[4] *In The Matter of the Joint Application of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC and New Special Purpose Entity, LLC for Authorization and Approval of Proposed Merger Transaction*, Formal Case No. 1119, Order No. 18148, at P 54 (March 23, 2016) ("Merger Order"). The Commission subsequently issued Order No. 18160 (April 4, 2016) correcting certain errors in the Merger Order and in Attachment B to the Merger Order (the "Merger Commitments"). References herein to the Merger Order and the Merger Commitments are to Order No. 18148 and Attachment B to Order No. 18148, respectively, as corrected by Order No. 18160.

- Operational and policy-based Performance Incentive Mechanisms (PIMs) regarding reliability and distributed energy resources (DER) as part of the Company's MRP; and
- Ratemaking Adjustments (RMAs) 1-3, 4 and 28, as presented in Company Witness Ziminsky's Direct Testimony.

This testimony and accompanying exhibits were prepared by me or under my supervision and control. The sources for my testimony are Company records, public documents, and my personal knowledge and experience.

Q6. Are you sponsoring any exhibits in this proceeding?

A6. Yes. I am sponsoring PEPCO (I)-1, which provides the directives in accordance with the Commission's directive in Formal Case No. 1103, Order No. 17424.[5] I am also sponsoring PEPCO (I)-2, which provides the detailed project sheets. Finally, I am also sponsoring PEPCO (I)-3, which contains the complete listing of all distribution-related expenditures that are projected to close to plant between 2019 and 2022.

II. PEPCO'S DISTRICT OF COLUMBIA RELIABILITY PERFORMANCE

Q7. Please describe Pepco's reliability performance requirements in the District of Columbia pursuant to the EQSS and Merger Commitments.

A7. In a Notice of Final Rulemaking, published February 24, 2012, the Commission established EQSS that became effective January 1, 2013. In addition, the Company's reliability standards were made more stringent by the Commission in the Merger

[5] *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution*, Formal Case No. 1103, Order No. 17424 (March 26, 2014) (Order No. 17424) at ¶537-39.

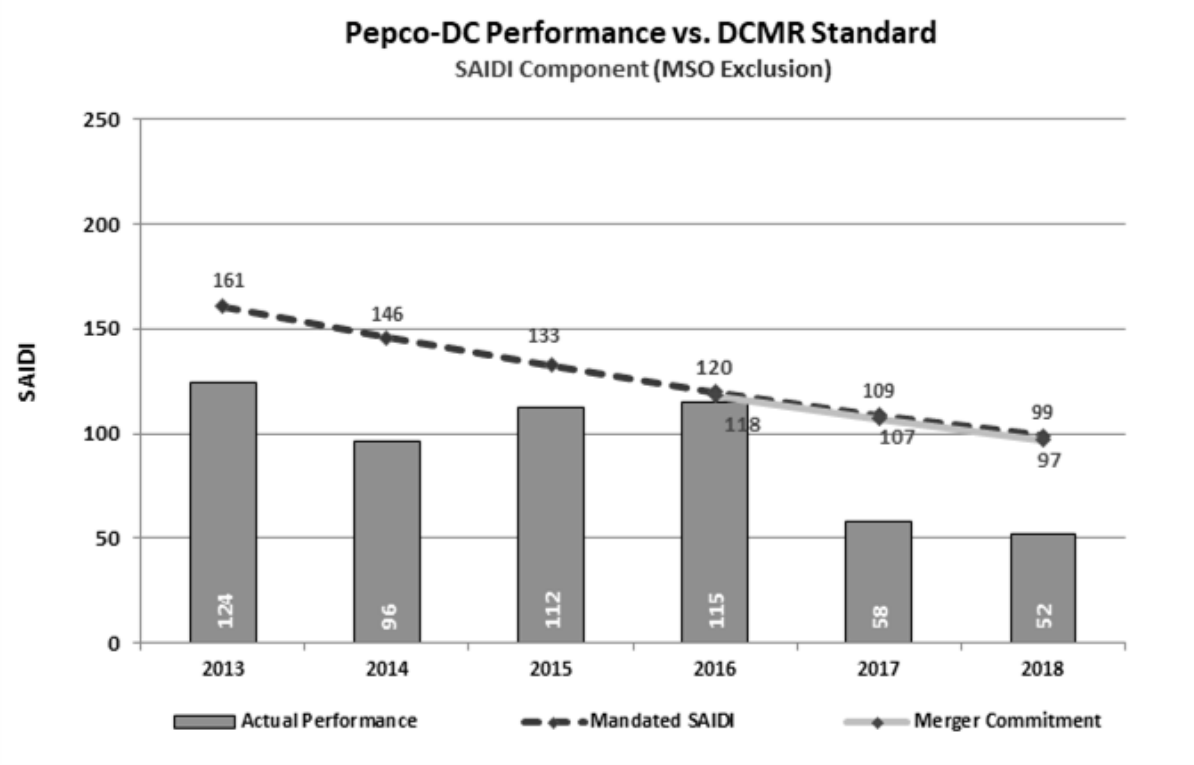
Order.[6] For years 2017 and 2018, consistent with its construction program, Pepco made appropriate investments in order to meet these reliability standards.

Q8. What were the reliability performance results?

A8. As reflected in Figure 1 and Figure 2, the Company has met these standards in 2017 and 2018. Between 2013 and 2018, Pepco's SAIDI level has improved from 124 to 52 minutes (58% improvement). Over the same period, Pepco's SAIFI level has improved from .88 to .53 interruptions (40% improvement). The data included in Figure 1 and Figure 2 reflect the current exclusion criterion that defines an excludable event within the District of Columbia (Major Service Outage or MSO).

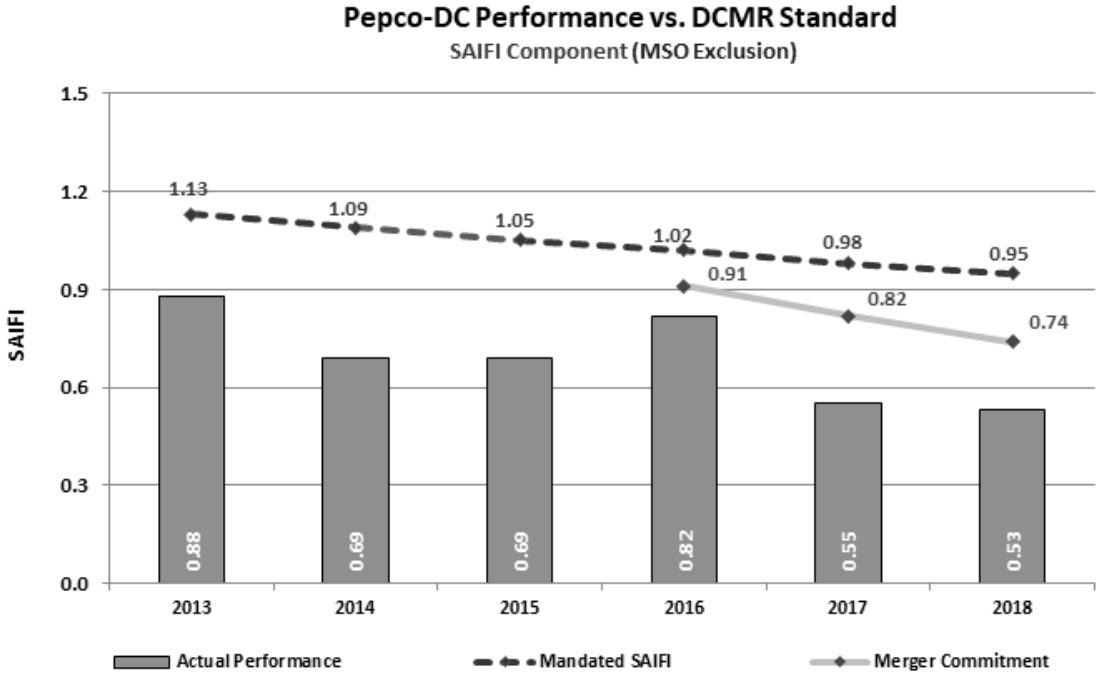
[6] Merger Order at ¶ 54.

Figure 1: Pepco DC Performance vs. DCMR Standard and Merger Commitment[7]



[7] SAIDI (System Average Interruption Duration Index) is the average time customers are interrupted. SAIDI is mathematically equal to the sum of customer interruption hours divided by total number of customers served. 2018 data represents trailing 12-months data ending December 31, 2018.

Figure 2: Pepco DC Performance vs. DCMR Standard and Merger Commitment[8]



Q9. What should customers expect from Pepco's reliability construction program going forward?

A9. Pepco's SAIDI and SAIFI reliability performance has continued to improve as a result of Pepco's reliability construction program; however, reliability improvements resulting from the construction program are not linear, as shown in Figures 1 and 2, and year-over-year results will not always see the magnitude in gains witnessed over the last several years due to the improvements that have already been achieved, which will make future reliability advances more difficult to attain. Rather, the projects in the plan are designed to continue to maintain and improve the material condition of the Pepco distribution system, resulting in better reliability performance under both blue

[8] SAIFI (System Average Interruption Frequency Index) is the average frequency of sustained interruptions per customer. SAIFI is mathematically equal to the sum of number of customer interruptions divided by total number of customers served. The 2018 data represents trailing 12-months data ending December 31, 2018.

sky and severe weather conditions. Continued investments in reliability construction are required to maintain the trend towards improvement and to assure adequate planning margin or contingency reserve to successfully achieve future reliability standards and commitments. Therefore, to achieve the reliability performance standards to which the Company has committed, continued investment in reliability initiatives is required, and Pepco must make the appropriate investments within the spending caps put in place on reliability spending in Order No. 18148.

Q10. If MSOs are excluded from the SAIDI and SAIFI statistics in Figures 1 and 2, are these results still impacted by weather events?

A10. Yes, not all weather events reach the level of a major event that is excludable by the regulations.[9] While the Company may experience small or intermediate storms that do not reach the level required to be classified as an MSO, the impact of those storms is included in the Company's reliability performance under the EQSS. The ability to endure significant weather events while triggering fewer MSOs to exclude serves as evidence of the increased resiliency and improved reliability resulting from Pepco's construction program.

Q11. Do you attribute any of the Company's improved reliability performance to the Exelon practices it has adopted?

A11. Yes. While reliability performance is impacted by many variables, a prime example of a practice gained from Exelon and contributor to the reliability improvement from 2017 to present is Pepco's adoption of the Exelon practice of completing as much identified maintenance and planned reliability work as possible

[9] 15 DCMR 3699.1.

before the summer. In this way, the system is better prepared for the high loads and heavy storms often experienced in July and August in the District of Columbia, thereby improving reliability performance for the year.

Another Exelon philosophy that Pepco has adopted is to "Restore then Repair," which emphasizes restoring as many customers experiencing an outage as possible through temporary means and then turning to the longer-term repairs, thereby reducing the number of customers experiencing an extended outage.

Additionally, the Company's adoption of Exelon's approach to managing both planned and corrective work on the system has added rigor and oversight to the successful execution of capital projects and system maintenance. This approach to work management has four goals:

1. Prioritize, schedule, plan, and execute work efficiently and safely;
2. Optimize resources from the crews in the field to our employees managing the work in the office;
3. Improve reliability and customer satisfaction through better prioritization of work performed; and
4. Add structure and rigor to the work performed via the new Work Management teams in each utility.

Work management helps Pepco to screen, plan, and schedule more effectively. This process also proactively identifies barriers and risks to ensure work is being done safely. It stages materials, so they are ready when needed during a project. It keeps the focus on completing full designs that can be successfully executed in the field without unnecessary delays.

Finally, Pepco has adopted the peer group concept. Because Exelon organizationally structures each of its electric utilities according to a standardized template, leaders at all levels at each of the utilities are able to socialize operational and engineering challenges encountered as well as collaboratively solve problems via Exelon's peer network. The peer network serves as a conduit for information sharing and continuous improvement.

Q12. Has the Company observed mutual assistance or supply chain procurement benefits as a result of access to Exelon resources?

A12. Yes. Pepco has benefitted from the availability of mutual assistance resources through the Exelon family of companies during major weather events and used these resources in the MSO that occurred in March 2018, Winter Storm Riley. These internal mutual assistance resources, which are available to Pepco when needed, are dispatched sooner than traditional external mutual assistance resources, reducing outage times. Specifically, there were a total of 131 Exelon-affiliated mutual assistance field personnel utilized by Pepco during the Winter Storm Riley restoration. These internal mutual assistance resources benefit from having the same procedures, such as "lock out tag out," across all Exelon companies, reducing the time needed to prepare the crews to go into the field and improving crew safety. Further, the availability of Exelon mutual assistance resources reduces the significant financial commitment necessary to acquire and pre-stage resources for an impending or anticipated major weather event and is especially cost-effective if a forecasted event does not materialize.

III. OVERVIEW OF PEPCO DISTRICT OF COLUMBIA DISTRIBUTION CONSTRUCTION PROGRAM

A. Overview of Pepco's Distribution Construction Report

Q13. Please describe Pepco's District of Columbia distribution construction program.

A13. The Company's distribution construction program is described and discussed in detail in the Construction Report (PEPCO (I)-1 to (I)-3). The construction program is Pepco's plan to focus on: (1) providing service to new customers; (2) improving reliability for all customers; (3) expanding the distribution system to supply the increasing electrical demands within the District of Columbia; and (4) replacing aging infrastructure to prevent and minimize failures and extended outages.

Q14. What is the Construction Report?

A14. The Construction Report provides information on the Company's distribution construction program in the format described and in the categories required by Order Nos. 16930 and 17424 and in similar fashion to the Construction Reports filed by the Company in Formal Case Nos. 1139 and 1150. For the convenience of parties to this case, Pepco plans to hold a Technical Conference to further discuss the Construction Report and answer questions that parties may have.

The Construction Report describes Pepco's distribution construction program for the District of Columbia, including projects for the years 2018-2023. Each section of the report includes project descriptions and actual expenditures for 2018 as well as projected costs for 2019-2023. Finally, the Construction Report includes overviews for major substation projects currently under construction or planned based on current infrastructure replacement plans and load forecasts. These projects are included to

demonstrate the Company's orderly but flexible approach to meeting system needs. The report is arranged into the following sections and includes project identifiers:[10]

- Procedural Background - explains the Commission directives defining the Construction Report;
- Introduction - explains the Construction Report's structure and contents, the Company's project development process, and the Company's approach to reliability benefits and projections;
- Section A: Load Growth - provides an overview of load growth projects;
- Section B: Distribution Automation - provides an overview of distribution automation projects;
- Section C: Feeder and Substation Reliability - provides an overview of feeder and substation reliability projects;
- Section D: Emergency Restoration - provides an overview of emergency replacement projects;
- Section E: 4 kV to 13 kV Conversion - provides an overview of projects related to the conversion of parts of the distribution system in the District of Columbia from 4 kV to 13 kV and the maintenance of the remaining 4 kV system;
- Section F: Customer Driven - provides an overview of projects that respond to customer integration demands and that maintain the capabilities of

[10] In previous reports, Pepco has provided additional project "identifiers," or Work Breakdown Structure (WBS) numbers, which was a unique number associated with the system in which the project was maintained. In the attached Construction Report, Pepco is providing what is referred to as an ITN number, which is similar to the WBS number from previous reports. The ITN number is being used for this testimony because Pepco has begun using a new system to maintain its project budgets.

Pepco's distribution system as customer-sited technologies and facilities are introduced;

- Section G: Other Projects - provides an overview of projects that typically support the safe and reliable operation of the distribution system in the District (*i.e.*, communications, security and facilities) and covers the expenses associated with retiring facilities that have exceeded their useful life or are used to track net- positive capital inflows to Pepco over the period for which cost recovery is sought, among others;
- Feeder Reliability Improvement Report - illustrates how Pepco's Feeder Improvement and Distribution Automation programs have improved reliability performance, as directed by Order No. 17424;
- PEPCO (I)-2, Project Schedules – provides historical expenditures since January 2018, as well as planned future expenditures for all projects with scheduled expenditures in 2019 and projected expenditures from 2020 through 2023 as of January 2019 and an overview of the projects, including scope and need; and
- PEPCO (I)-3 is a complete listing of all distribution-related expenditures that are projected to close to plant between 2019 and 2022.

Q15. Please provide the Pepco 2018 construction budget and the 2019 through 2023 projections.

A15. **Table 1**

Pepco DC Capital Construction: 2018 Actual; 2019 Budget and 2020-2023 Projections (Dollars in Millions)						
Distribution Construction	**Actual**	**Five Year Projections**				
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
Customer Driven	$ 93.6	$ 84.6	$ 78.9	$ 76.2	$ 76.6	$ 74.8
Reliability	$ 121.9	$ 171.9	$ 167.8	$ 175.0	$ 224.3	$ 204.2
Load	$ 71.5	$ 65.2	$ 49.3	$ 54.4	$ 54.7	$ 32.6
TOTAL	$ 287.0	$ 321.7	$ 296.0	$ 305.6	$ 355.6	$ 311.6

B. Reliability Projects

Q16. Please explain the types of planned work under the Reliability Programs grouping in Table 1:

A16. Planned reliability work includes:

- **Feeders and Lines:** Distribution line work has consistently improved reliability performance and is the largest reliability segment in the reliability construction program. This work includes installing and replacing reclosers, switches, conductors, animal guards, lightning arrestors, and other equipment necessary to improve feeder reliability performance. Examples of feeder and lines projects include Pepco's Comprehensive Feeder Program,[11] which identifies feeders for which remediation will improve system reliability measures by addressing equipment, vegetation, weather, and animal-caused interruptions, and the upgrades for Multiple Device Operations,[12] which remediates protective devices that have

[11] *See* Construction Report, PEPCO (I)-2, at 146.
[12] *Id.*, at 145.

operated more than three times in the previous 12 months and addresses small groups of customers who are experiencing repeat outages.

- **Substation Equipment Replacement:** This work provides gains in longer-term performance and reduces outages that could have a significant impact on customers and system performance. This work includes projects, such as the replacement of deteriorating equipment at the Fort Slocum Substation.[13]

  Transformers and Protectors: Similar to substation work, reliability replacement of network transformers and protectors reduces high customer-impact outages.[14]

- **4kV to 13kV Conversions:** This is a long-term program to replace aging equipment and meet increased load requirements that provides increased reliability for customers served from the 4kV system, such as the G Street Substation conversion project.[15]

- **Distribution Automation:** This program improves reliability by installing advanced control systems across the distribution system in order to automatically identify and isolate faults and restore service to customers more quickly.

- **Area Plan:** The area plan is an initiative to improve the reliability of smaller portions of the system, such as a neighborhood or other "pocket" of the system, that lag system-level reliability performance by improving reliability at one or more substations and their associated feeders serving

[13] *Id.*, at 44.
[14] *Id.*, at 161.
[15] *Id.*, at 155.

that area rather than focusing on improving the performance of individual feeders.

Finally, the emergency and storm restoration program budget is established to recognize the costs of construction involved in restoration due to unpredictable events and storms that are not classified as MSOs.

Q17. Please discuss Customers Experiencing Multiple Interruptions (CEMI).

A17. CEMI is a metric to measure the percentage of the Company's customers who have experienced "*n*" (or, any number) or more interruptions in a 12-month period.[16] As shown in Figures 3 and 4, as Pepco's SAIFI and SAIDI indices have been improving since 2016, CEMI has followed a similar pattern (see Figure 3). In addition, historically under SAIDI/SAIFI reporting, all neighborhoods on a feeder are listed as part of a feeder event; under CEMI tracking and use of AMI meters, only those customers actually impacted are listed. See Figure 4. Outages can impact feeders in specific 'pockets' or neighborhoods. Just because a feeder of concern goes through a specific neighborhood does not mean the problems exist in that neighborhood. In Figure 4, for example, Neighborhood 3 is impacted but Neighborhoods 1 and 2 are not, even though they are served by the same feeder.

[16] Per IEEE Std 1366-2012, the Customers Experiencing Multiple Interruptions Index (CEMI*n*) indicates the ratio of individual customers experiencing *n* or more sustained interruptions to the total number of customers served.

Figure 3: CEMI-4

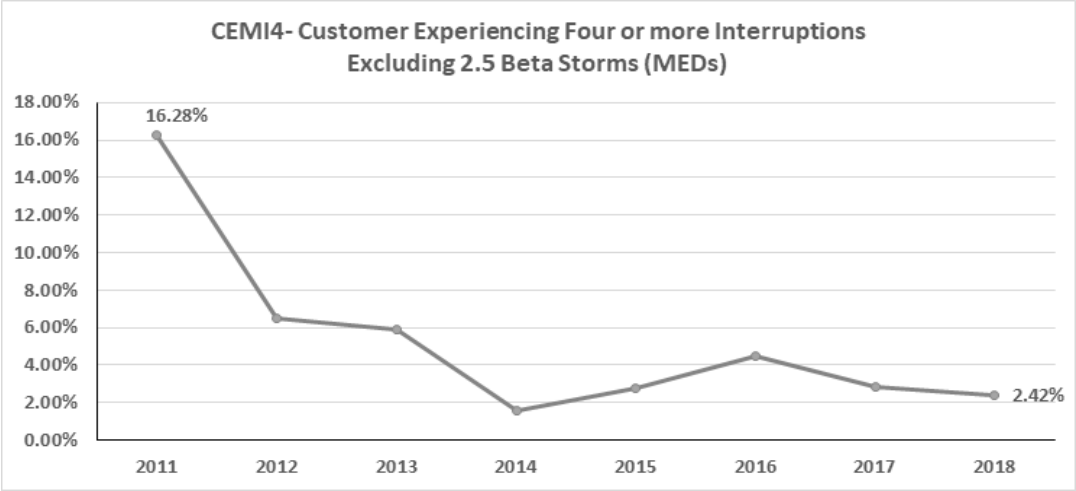
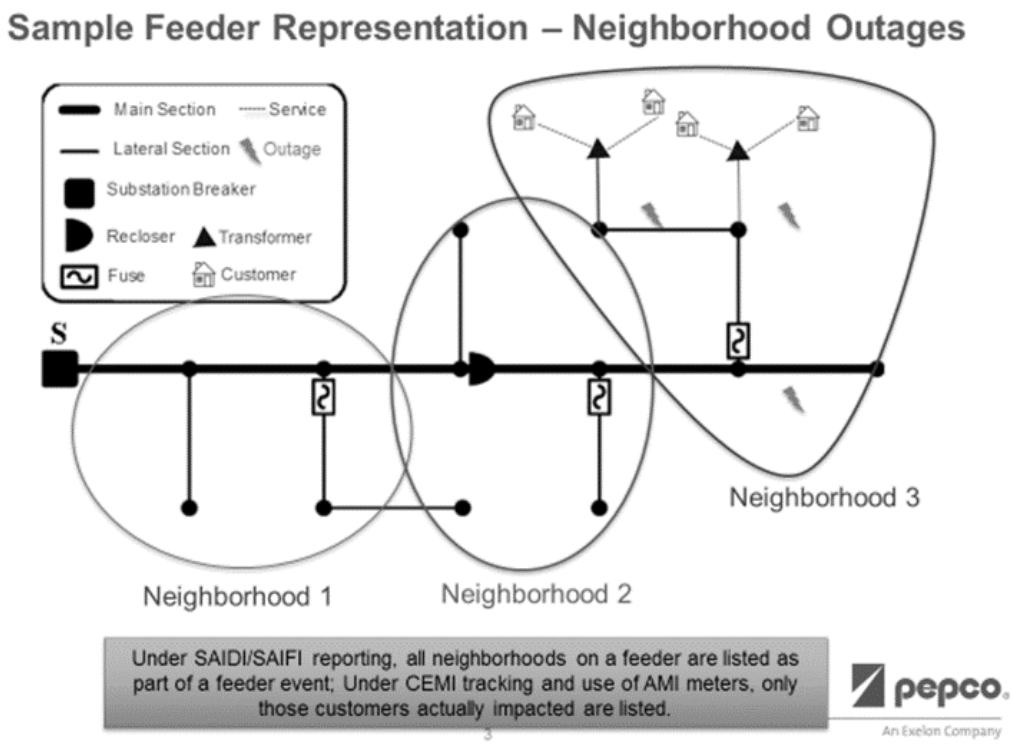


Figure 4: Neighborhood Outages



Q18. What is Pepco doing to specifically address customers who experience multiple outages?

A18. As part of the Company's ongoing efforts to address these pockets of underperforming areas, Pepco has implemented challenge sessions of large outages affecting 1,000 customers or more to be self-critical on performance and proposed remediation plans. Also, the Company will track CEMI performance using linear and geospatial analytics to identify the poor pockets of neighborhood reliability, targeting those neighborhoods that have seen multiple interruptions.

The Company realizes that service interruptions, particularly repetitive interruptions to individual or groups of customers, can be disruptive and impactful. Therefore, Pepco continues to focus on CEMI reduction as a key driver of improved reliability and customer satisfaction.

Q19. What are Distribution Automation (DA) technologies?

A19. Types of DA technologies include:

1. Automatic Sectionalizing and Restoration (ASR) schemes;
2. Other Non-ASR switch additions (Switches and Automatic Circuit Reclosers (ACRs or reclosers));
3. Other automation projects to add visibility and control (substations, capacitor banks, and automation equipment replacement);
4. Network transformer protector RMS; and
5. DA communication and control infrastructure build-out and integration.

Q20. Why is the Company proposing to continue to deploy DA technologies?

A20. Pepco recognizes the benefits of deploying smart grid technology to improve infrastructure reliability, enhance the customer experience, and provide better operational flexibility and control over the grid. DA is one aspect of Pepco's larger smart grid implementation. Pepco's DA approach is comprised of installing advanced control systems and devices across the distribution system to automatically identify and isolate faults in real time and restore service to customers.

Q21. What type of DA is the Company planning to deploy and what are the benefits to customers?

A21. Pepco continues to deploy DA technologies in the District of Columbia, such as ACRs. The simplest benefit of reclosers is using local coordinated protection settings to automatically clear temporary faults or isolate sections of a feeder during sustained faults. Further, using Pepco's AMI communications infrastructure, reclosers that have telecom capability can provide remote visibility and control to the system operator. Finally, reclosers with both local protection settings and that are telecom enabled can be made part of an ASR scheme. ASR schemes isolate faulted lines and restore feeders by reclosing source breakers and supplying power from backup tie sources. This results in a significant reduction of the number of customers affected by a sustained outage.

Q22. Is Pepco deploying other advanced technologies on its District of Columbia distribution system that also provide benefit to customers?

A22. Yes, Pepco is also continuing its process of deploying Network Remote Monitoring System (RMS) for each of the 47 networks in its District of Columbia

LVAC system. The network RMS system is an advanced remote control and monitoring system installed on underground network transformers. Before RMS was installed on the system, the Company could not monitor the performance of transformers or perform any operations remotely. Therefore, to take an action on a network transformer, the Company dispatched a crew that manually inspected the transformer or manually performed switching activities. With the installation of RMS, the system operators are now able to take emergency actions remotely to open low voltage switches on a transformer if they observe an overload occurring or have a report of a network event such as a transformer fire. The remote capability allows for more immediate action and can avoid the cost of sending a crew to open the switch. In addition, when one or more feeders is out of service, RMS allows the system operators to observe the loading on every transformer in a network group and know immediately if any one transformer is not operating as expected or is overloaded. When such an occurrence is observed, the operator has the ability to remotely open the low voltage switch at the point of the overload before the transformer fails.

Q23. Are all distribution construction expenditures that are being requested in the Company's rate recovery request included within the Construction Report?

A23. Yes. In Order No. 17424, the Commission directed Pepco to "include a complete list of all the Company's distribution construction projects for which any rate recovery is sought in its Construction Program Report."[17]

[17] Order No. 17424 at ¶520.

C. Key Strategic Planning Initiatives

Q24. What were the Strategy team's key projects and initiatives in the District in 2018?

A24. In 2018, consistent with the mission of the Company and the District's policy goals, many of which are included in the recently enacted "Clean Energy DC Omnibus Amendment Act of 2018," Pepco undertook or proposed several key projects and initiatives. For example, Pepco proposed to implement a Transportation Electrification Program (TE Program) consisting of 13 separate offerings for Plug-In Vehicle (PIV) charging in the District of Columbia. On April 12, 2019, the Commission issued Order No. 19898, accepting some of the Company's offerings for the TE Program and requiring further analysis and reporting. While this order is under reconsideration, Pepco is eager to facilitate the District's policy goals and foster a widespread and accessible electric transportation charging infrastructure. This will be achieved by implementing grid-integrated rates, partnering with entities and institutions seeking to deploy charging infrastructure, coordinating with District agencies and other stakeholders to discuss policy concerns, leveraging and providing new opportunities for competitive equipment and service providers, and allowing Pepco's customers to charge their vehicles using 100% renewable energy.

Pepco has fully participated in the Formal Case No. 1130 Modernizing the Energy Distribution System for Increased Sustainability (MEDSIS) proceeding since its inception. Since June of 2018, Pepco has participated in all six of the MEDSIS working groups led by the Smart Electric Power Association (SEPA), the Commission's MEDSIS consultant, and Pepco has made numerous presentations

regarding its system data, system planning, technology implementation and has made its subject matter experts available for stakeholder questions.

Q25. Please describe your team's key initiatives for 2019.

A25. Along with ongoing initiatives described in the previous question, in January of 2019, in the MEDSIS stakeholder working group meetings, Pepco proposed a progressive Distribution System Planning for Non-Wires Alternatives (DSP NWA) process. Through the DSP NWA process, Pepco would issue Requests for Information regarding load-impacting factors, such as future real estate developments and DER implementation, to further refine its load forecast, issue a load constraints report identifying future system needs, and issue RFIs and RFPs for non-wires solutions to address those system constraints.[18] This new process will benefit customers by providing a transparent, structured process that considers NWAs when planning for capacity projects.

Q26. Please describe your team's key initiatives for 2020-2022.

A26. The Company is planning to support several other high-level initiatives, including the implementation of battery storage; collaborating with stakeholders in the development of public purpose microgrids and other resiliency hubs within the city; the deployment of electric vehicle charging infrastructure across the city; continuing the deployment of community solar projects; advancing the Company's efforts in the areas of energy efficiency and demand response; implementing new uses of AMI technology; and modernizing the distribution grid to enable advanced command and

[18] The MEDSIS recommendations still have to be adopted by the Commission before implementation of this proposal would occur.

control systems supporting the transition of the grid to a platform for the provision of advanced energy and information services.

Q27. How do these initiatives benefit customers?

A27. These initiatives benefit customers by contributing to the Company's continuous reliability improvements, providing energy savings, improving customer satisfaction, achieving greater utilization of the grid, and expanding the use of DERs on the system. These initiatives also support greater integration of renewable energy and battery storage, electric vehicle deployment, and resilience strategies.

Q28. Please discuss AMI and how its data is used for DER analysis.

A28. AMI enables future technologies and provides both the Company and customers with more information about electricity usage and empowers customers to make better-informed decisions about their energy usage. Through a web-based suite of energy-management tools (EMTs), customers can better understand their electricity consumption. AMI technology also provides the Company more detailed information about how energy is used on the system. The Company is also using the system data supplied by AMI to detect overloads at the system, subsystem, and component levels in its planning process. This practice allows Pepco to identify potential outages before they happen. Additionally, AMI data is also used to optimize the integration of DERs into the grid and enables the Company to produce and maintain detailed hosting capacity maps.

The DER Planning and Analytics group maintains models of each Pepco feeder in a program called DEW (Distributed Energy Workstation). These models rely on accurate data for the best possible representation of the true operation of the feeder.

This includes geographic information from GIS, equipment characteristics and settings, and load data. AMI load data is currently aggregated with other load sources, including primary meter customer loads and consumption billing data for non-AMI customers, into a single database called the Load/Gen database. This database creates hourly load profiles for each customer, which can then be applied to our model for time-series study. The end-use models allow the Company to run power flow studies at different time points to determine the impact of proposed DER systems. The AMI load data is vital in determining these critical time points, such as peak and minimum daytime load, at which the model will be analyzed.

Q29. Please discuss the DER data that AMI provides to the Company.

A29. AMI provides the Company with the following data for Customer Loads:

- More accurate load data in power flow models - DER analytics depends on the output of power flow. Traditional power flow is done with SCADA data (one value for the complete feeder) with that load spread across the feeder. Using AMI data and DER output data, a much more accurate analysis of the feeder and critical time points can be accomplished.
- Minimum daytime load study for residential customers - A data analytics study of 1,000 residential customers was conducted to determine the proper minimum customer load to use when performing secondary voltage rise analysis and service transformer loading. AMI data allowed the Company to perform this study.
- Net load versus native (gross) load for customers with DERs - Utilizing AMI data (net load) and back-cast solar output, the analytics program is

able to determine native load (if no solar existed) as well as the net load, with solar included on the circuit. This is very important in studying both conditions to insure the reliability of the system.

- Secondary voltage rise analysis and monitoring new DERs - It is beneficial to have AMI voltage data from the past year, especially where a new system is being added to a service transformer with one or more systems. The voltage data allows Pepco to identify any customer who may be having high voltage as a result of the addition of a DER.
- Ability to identify incorrect phasing or other GIS errors - Through comparing modeled feeder voltages with measured voltages captured from AMI, it is possible to find where facilities or service transformers should be connected in the GIS record to a different phase. This helps improve the accuracy of data.
- Transformer load management – The AMI data is used to determine if service transformers are overloaded and for how many hours of the year or, on the other hand, if they are under utilized.

IV. DISCUSSION OF OPERATIONAL AND POLICY PERFORMANCE INCENTIVE MECHANISMS (PIMS)

Q30. Are you sponsoring any of the Company's PIMs in your testimony?

A30. Yes. I am sponsoring three PIMs: two focused on achieving operational goals, SAIDI and SAIFI (Reliability PIMs). I am also sponsoring a policy-related PIM addressing DER interconnection review timeframes.

Q31. Please describe the Reliability PIMs in the Company's MRP proposal.

A31. Pepco's MRP includes two Reliability PIMs to address metrics for SAIDI and SAIFI. The Company also proposes a "tracking-only" metric for CEMI-4.

Q32. Please describe Pepco's current EQSS requirement as it relates to SAIFI.

A32. Under the EQSS, Pepco's SAIFI (excluding MSOs) target for 2019 is 0.92. If Pepco fails to meet this target, the Company is subject to potential penalties under the EQSS.[19]

Q33. Please describe Pepco's merger commitment with respect to SAIFI.

A33. In Order No. 18148, Pepco became subject to Merger Commitment 54, which mandates SAIFI, excluding MSO, performance of 0.58 in 2020.[20] If Pepco does not meet this performance level, it must pay a non-compliance payment to the MEDSIS Pilot Project Fund Subaccount.[21] The commitment does not extend beyond 2020.

Q34. Please describe Pepco's proposed PIM related to SAIFI.

A34. Pepco is proposing a SAIFI PIM starting with 2021 performance, extending the Merger Commitment 54 performance standard of 0.58 beyond 2020, with a deadband (explained below) of plus or minus 0.08 around that performance level.

Q35. Why is Pepco's proposed SAIFI target appropriate?

A35. Pepco's Merger Commitment 54 expires in 2020, and, barring this PIM or any other Commission action, Pepco's performance standards will revert to the EQSS level. The 0.58 SAIFI level equates to first decile performance and is consistent with Pepco's goals to improve and maintain its reliability performance in the District of Columbia.

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[19] 15 DCMR §3603.
[20] Merger Order at ¶ 54.
[21] *Id.*

Q36. Please describe Pepco's current EQSS requirement as it relates to SAIDI.

A36. Under the EQSS, Pepco's SAIDI (excluding MSOs) target for 2019 is 89 minutes. If Pepco fails to meet this target, the Company is subject to potential penalties under the EQSS.[22]

Q37. Please describe Pepco's merger commitment with respect to SAIDI.

A37. Merger Commitment 54 also mandates SAIDI, excluding MSO, performance of 79 minutes in 2020. If Pepco does not meet this performance level, it must pay a non-compliance payment to the MEDSIS Pilot Project Fund Subaccount.[23] The commitment does not go beyond 2020.

Q38. Please describe Pepco's proposed PIM related to SAIDI.

A38. Pepco is proposing a SAIDI PIM starting with 2021 performance, with target performance based on Pepco's average of its best three years of SAIDI performance during the last five years (which equates to 69 minutes), with a deadband of plus or minus 10 minutes around that performance level.

Q39. Why is Pepco's proposed SAIDI target appropriate?

A39. Pepco's merger commitment expires in 2020, and, barring this PIM or further Commission action, Pepco's performance standards will revert to the EQSS level. The proposed 69-minute SAIDI level equates to first-quartile performance, is a significant increase over Pepco's Merger Commitment, and is consistent with Pepco's goals to improve and maintain its reliability performance in the District of Columbia.

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[22] 15 DCMR §3603.
[23] Merger Order at ¶ 54.

Q40. How did Pepco develop its proposed deadbands for SAIFI and SAIDI?

A40. Pepco is proposing to use deadbands in its PIMs for SAIFI and SAIDI. Pepco's proposed SAIFI and SAIDI deadband is based on the concept of a planning margin. The planning margin includes three factors that are generally challenging to plan for but are ultimately impactful when they do occur. These three factors are: (1) non-MSO storms; (2) underground network events; and (3) a transmission and substation event. Any or all of these three possible occurrences could potentially impact the system within one year with otherwise normal reliability results, causing increased SAIFI and SAIDI results that would not be excludable through the MSO standards.

To develop the planning margin for non-MSO storms, Pepco reviewed storm impacts for the previous five years (2013-2017), identified the peak storm customer interruptions (CI) and customer minutes of interruptions (CMI) over that period, and used this data to determine the SAIFI and SAIDI impacts to build into the planning margin.

To develop the planning margin for an underground network event, Pepco reviewed these types of events over the previous five years. Pepco then looked at the most impactful event over that period and used that event's data in its planning margin analysis.

To develop the planning margin for a transmission and substation event, Pepco reviewed these types of events over the previous five years. Pepco then looked at the most impactful event over that period and used that event's data in its planning margin analysis.

Please see the Table 2 for the calculation of the planning margin for SAIFI and SAIDI.

Table 2: Planning Margin Factors for SAIFI and SAIDI

Planning Margin Factor	CI	CMI	SAIFI	SAIDI
2018 vs. 2013-2017 Peak minor Storm CI and CMI	11,115	3,419,488	0.04	11.68
One Network Event (7/15/2016 Florida Ave)	5,305	3,864,841	0.02	13.21
One Transmission Event (4/19/2013 loss of #2 bus due to stuck breaker on 15711 Benning)	7,741	632,716	0.03	2.16
Total	**24,161**	**7,917,045**	0.08	27.05

For SAIFI, Pepco added the 0.08 planning margin to its 0.58 target to come to a high deadband of 0.66. To arrive at the low deadband, Pepco simply reduced the SAIFI target by 0.08 to 0.50.

For SAIDI, Pepco added the 27-minute planning margin to its 2018 actual performance of 52 minutes to arrive at a high deadband of 79 minutes - 10 minutes greater than the 69 minute target. To arrive at the low deadband, Pepco reduced its target by the same 10 minutes.

Q41. How did the Company arrive at this particular deadband for the SAIFI and SAIDI PIMs?

A41. The deadbands establish margins around the proposed PIMs' target values within which no penalty or reward would be provided to the Company. The Company reviewed the last five years of performance and developed targets, based heavily upon the planning margin process, with normalization to account for typical variations in performance metrics from year to year.

Q42. What has Pepco's historical SAIFI and SAIDI performance been in the District?

A42. Please see Table 3.

Table 3: Pepco's Historical SAIFI AND SAIDI Performance (DC)

Year	SAIFI	SAIDI
2013	0.88	124
2014	0.69	96
2015	0.69	112
2016	0.82	115
2017	0.55	58
2018	0.53	52

Q43. How do the SAIFI and SAIDI PIMs benefit customers?

A43. These PIMs benefit customers by better aligning Pepco's financial performance with customer expectations and Commission directives regarding strong reliability performance. Under these PIMs, Pepco will be penalized for performance below the deadband and rewarded for exemplary performance better than the deadband. If Pepco performs near the target level within the deadband, no reward or penalty would occur. Penalties and rewards under this PIM would be automatic, as opposed to penalties under the EQSS, which are discretionary.[24]

Q44. How will the Company report on its SAIFI and SAIDI performance in the context of its proposed PIM?

A44. As discussed in Company Witness Wolverton's Direct Testimony, Pepco will include a report on its performance for proposed PIM target levels in its Annual Reconciliation Filing made around May of each year.

[24] Pepco would ask the Commission to take any automatic PIM penalties under consideration when assessing potential EQSS penalties for non-compliant performance.

Q45. What does the Company propose will happen to these PIMs at the conclusion of the MRP period?

A45. The Company proposes that the PIMs be re-evaluated and re-established in its next MRP.

Q46. What is CEMI-4?

A46. CEMI stands for Customers Experiencing Multiple Interruptions and is expressed as a percentage. CEMI-4 is defined as customers experiencing four or more interruptions over a 12-month period. In 2018, Pepco's CEMI-4 was 2.42%, which means that 2.42% of Pepco's District of Columbia customers experienced four or more interruptions during 2018 (excluding IEEE-excluded events).

CEMI can be viewed as a measure of "neighborhood reliability," as it can be useful to identify small groupings of customers that are experiencing multiple outages in a given period. Improvements in CEMI often require the utility to address issues that may only impact a small subset of customers.

Q47. Does Pepco currently track and report on CEMI?

A47. Yes, as part of its Annual Consolidated Report, Pepco provides CEMI statistics. However, there are currently no performance targets or requirements in the District with respect to CEMI.

Q48. What has been Pepco's historical CEMI-4 (based on IEEE exclusions) in the District?

A48. Please see Table 4.

Table 4: Pepco's Historical CEMI-4 Performance (DC)

Year	CEMI-4
2013	5.93%
2014	1.57%
2015	2.77%
2016	4.46%
2017	2.80%
2018	2.42%

Q49. What is Pepco proposing with respect to CEMI-4?

A49. As noted in Company Witness McGowan's testimony, is it not uncommon for utilities in jurisdictions that have implemented performance-based ratemaking to introduce "tracking-only" metrics to be considered for future PIMs with financial penalties and/or rewards. Pepco is proposing that it track and report annually on CEMI-4 (based on IEEE exclusions) performance in the District of Columbia during the course of its MRP, for evaluation at a later time for a PIM.

As Pepco's system-wide SAIFI and SAIDI have improved, its CEMI-4 improvement has been less linear. Pepco is implementing certain new tools in 2019 that will specifically address CEMI. Those new tools include: a daily CEMI alerts flag when a customer has a second outage for the year, a CEMI dashboard, reporting and tracking of CEMI performance by ward/neighborhood, and the establishment of a formal, budgeted CEMI program.

Q50. How will this CEMI-4 tracking metric benefit customers?

A50. As previously discussed, CEMI-4 is a good measure of neighborhood reliability. Developing a formal tracking metric around CEMI-4 is a first step toward developing a formal PIM related to CEMI in the future, which would better align Pepco's financial performance with its operational performance in a key Commission goal of neighborhood reliability.

Q51. What is Pepco's role in DER interconnections in the District?

A51. When customers choose to install DER at their location, they must submit an interconnection request to Pepco. The Commission has established a process and timeline for the various size interconnections that are requested. In January 2019, the Commission established new rules in this area, reducing the timeline for certain steps in the interconnection process. See the Table 5 for a summary of those changes.

Table 5: New Rules for DER Interconnection Process

	Level 1 - Old Rules	**Level 1 - New Rules (NOPR)**
Level 1 Size	0-10 kW	0-20 kW
1 – Completeness Review	10 days	5 days
2 – Approval to Install (ATI)	15 days	5 days
3 - Authorization to Operate	20 days	20 days

Q52. Please summarize the key changes in the table above.

A52. The most labor-intensive step in the interconnection process for Pepco is the Approval to Install (ATI). This step is where Pepco must complete an engineering analysis of the interconnection application and ultimately deny or authorize the request

to interconnect. As can be seen, the size of Level 1 interconnection requests has been increased from 10kW to 20kW, and the time to complete the ATI has been decreased from 15 days to five days.

Q53. How has Pepco performed compared to these timelines for Level 1 ATI?

A53. Under the 15-day timeline, Pepco was able to complete approximately 98% of ATI's on time. Under the new five-day timeline, Pepco's performance, 46.62%, would not have been as good using 2018 data. Pepco will need to improve significantly to meet the Commission's new timelines for Level 1 ATI.

Q54. Does Pepco currently report on its interconnection applications in the District of Columbia?

A54. Yes. Pepco files quarterly reports in Formal Case No. 1050 as well as an annual report in the same docket.

Q55. Is Pepco proposing a PIM with respect to the DER interconnection timeline?

A55. Yes. Pepco is proposing to establish a PIM in this area. The specific metric Pepco is proposing is the "average number of days for Level 1 ATI." For instance, if Pepco had three Level 1 ATI requests, and Request #1 was completed in four days, Request #2 was completed in six days, and Request #3 was completed in eight days – the average would be six days (4+6+8=18 / 3 = 6 days). Pepco is proposing that its target for this metric be five days, consistent with the Commission's new rule. Pepco is also proposing a deadband of plus or minus 0.5 days around the five-day target (i.e., 4.5 - 5.5 days).

Q56. How does this PIM benefit customers?

A56. This PIM aligns Pepco's financial performance with the District of Columbia's energy policy goals to reduce carbon emissions and increase local generation.[25] The more streamlined the interconnection process is, the easier it will be for residents and businesses in the District of Columbia to install DER. Under this PIM, Pepco will be penalized for performance worse than the deadband and rewarded for exemplary performance better than the deadband. If Pepco performs near the target level within the deadband, no reward or penalty would occur. Penalties and rewards under this PIM would be automatic and based strictly on the Company's performance.

Q57. How will the Company report on its Level 1 Average ATI performance in the context of its proposed PIM?

A57. As discussed in Company Witness Wolverton's Direct Testimony, Pepco will include a report on its performance against proposed PIM target levels in its Annual Reconciliation Filing made around May of each year.

Q58. What does the Company propose happen to this PIM at the conclusion of the MRP period?

A58. As noted earlier, the Company proposes that all of the PIMs be re-evaluated and re-established in its next MRP.

[25] Clean Energy DC Omnibus Act of 2018, D.C. Law L22-0257.

V. TRADITIONAL TEST PERIOD COMPLIANCE FILING RATEMAKING ADJUSTMENTS

Q59. In his Direct Testimony, Company Witness Ziminsky discusses RMAs 1-3, which reflect the revenue requirement associated with reliability construction projects. Is the Company seeking recovery of all investments related to reliability projects?

A59. No. For RMAs 1 through 3, the Company only reflects reliability investments that will actually be made by the hearing date in the instant proceeding.[26] These RMAs do not include all of the capital investments that are planned to occur during the post-test year periods.

Q60. In his Direct Testimony, Company Witness Ziminsky discusses RMA 4, which reflects the removal of DC PLUG-related costs. Is the Company seeking recovery of all investments related to DC PLUG?

A60. No, as explained in the direct testimony of Company Witness Ziminsky, the Company is removing from the cost of service all Electric Company Infrastructure Improvement Costs that are eligible for recovery through the Underground Project Charge, as authorized by the Electric Company Infrastructure Improvement Financing Act of 2014, as amended.

Q61. Please describe the Frederick Douglass Memorial Bridge project.

A61. As part of the South Capitol Street Corridor Project, the District Department of Transportation (DDOT) is replacing the current Frederick Douglass Memorial Bridge. As discussed by Company Witness Ziminsky, Pepco will be constructing two eight-

[13] RMA 1 reflects the reliability projects placed in service during the 12 months ending June 30, 2019. RMA 2 reflects the reliability projects closed to EPIS during the period from July 1, 2019 through December 31, 2019. RMA 3 reflects the impact of reliability projects in Construction Work in Progress (CWIP) as of December 31, 2019 and that are forecasted to be placed into service from January 1, 202, to June 30, 2020.

way subtransmission duct banks and cable through the newly replaced bridge and then installing cable. The work is scheduled for completion by October 2021. Costs associated with this project are included in the Construction Report and are addressed in RMA 28, which is included in the Direct Testimony of Company Witness Ziminisky.

Q62. Why are the construction projects in these RMAs needed and how do they benefit customers?

A62. These additions to electric plant are needed in order for Pepco to maintain and improve the Company's reliability performance, meet or exceed the Commission-approved SAIDI and SAIFI commitments, improve customer satisfaction, and continue to modernize the grid. These reliability investments produce no new distribution electric revenue from load growth and support the ongoing safe and reliable electric service to existing distribution customers. Reliability projects benefit existing customers, and customers realize these benefits as soon as the facilities are made operational, which can be before the facilities are moved to plant in service from an accounting view. In these situations, customers immediately see improved system performance during all weather conditions, including storms, and fewer outages overall.

VI. CONCLUSION

Q63. Does this complete your Direct Testimony?

A63. Yes, it does.

B.L. Clark
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (I) – 1

District of Columbia
Distribution Construction Program Report

Potomac Electric Power Company

May 30, 2019

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PEPCO (I)-2: Capital Project Budgets and Descriptions (Allocated Projects)

List of Acronyms

ACR	Automatic Circuit Reclosers
AMI	Advanced Metering Infrastructure
ARRA	American Recovery and Reinvestment Act
ASR	Automatic Sectionalizing and Restoration
CEMI	Customers Experiencing Multiple Interruptions
CI	Customer Interruptions
CMI	Customer Minutes of Interruptions
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DC PLUG	District of Columbia Power Line Undergrounding
DCPR	District of Columbia Distribution Construction Program Report
DDOT	District Department of Transportation
DOE	Department of Energy
ECA	Equipment Condition Assessment
EMS	Energy Management System
EQSS	Electricity Quality of Service Standards
EV	Electric Vehicle
FDS	Fault Detection System
LVAC	Low Voltage Alternating Current
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
O&M	Operations and Maintenance
OMS	Outage Management System
Pepco	Potomac Electric Power Company
PNB	Prospective New Business (report)
PV	Photovoltaic
RCM	Reliability Centered Maintenance
RMS	Remote Monitoring System
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SGIG	Smart Grid Investment Grant
VVR	Variable Voltage Regulation
WBS	Work Breakdown Structure
WMIS	Work Management Information System
WR	Work Request

Procedural Background

On March 8, 2013, Potomac Electric Power Company ("Pepco" or the "Company") filed an application with the Public Service Commission of the District of Columbia ("Commission") requesting authority to increase existing distribution service rates and charges for electric service in the District of Columbia (Formal Case No. 1103). Filed alongside its application was Pepco's first Construction Program Report describing its construction plan in the District of Columbia.

In Order No. 17424, the Commission found that the report Pepco submitted was in compliance with its prior Order No. 16930 (P 519), but with modifications directed by Order No. 17424. The modifications directed by the Commission were as follows:

A. A complete list of all of Pepco's distribution construction projects for which rate recovery is being sought (P 520).
B. A more detailed tracking of the reliability improvements achieved from Pepco's feeder improvement work (P 553).
C. A new stand-alone chapter on the outage performance of the groups of feeders included in ASR schemes, including both the outages when ASR operates and when it does not. Included in this would be feeder-by-feeder outage data for each feeder included in any of Pepco's feeder improvement programs. This reporting would start with those feeders worked on in 2012. Future reports would track the performance of these "Class of 2012" feeders for five years, along with succeeding "classes" in the future. (P 554).
D. A description of how Pepco has evaluated alternative methodologies to improve its ability to predict reliability improvements in terms of SAIDI (System Average Interruption Duration Index) and SAIFI (System Average Interruption Frequency Index) (P 537).
E. A description of how the Demand Response program in the District is factored into its load forecast which is used to determine the need and timing for certain construction projects. (P 538)
F. A more detailed justification for the transformer remote monitoring system (RMS) investments being made (P 539).
G. Feeder-by-feeder outage data for each feeder included in any of Pepco's feeder improvement programs (P 554).

The following table maps the above requirements to the content in this report that fulfills them:

Order Requirement	**Location in this Report**
A	PEPCO (I)-2
B	Chapter 3 (3.9.1 & 3.9.2) Chapter 8 (8.2 and 8.3)
C	Chapter 8
D	Chapter 3 (3.9.1)
E	Chapter 1 (1.4.2)
F	Chapter 2 (2.1.5, 2.5.2, 2.7.3 and 2.9.2)
G	Chapter 8 (8.3)

After Pepco's most recent litigated rate case, in Order No. 18846 (Formal Case No. 1139), the Commission noted that no party contended that Pepco's Distribution Construction Program report failed to comply with Commission directives, and the Commission found that the report was in compliance with Order Nos. 16930 and 17424. The following report follows the same organizational structure as that filed in Formal Case No. 1139 and Formal Case No. 1150. Please note that project budgets are now reflected in PEPCO (I)-2.

Introduction

Pepco submits its District of Columbia Distribution Construction Program Report ("DCPR," "Report," or "Construction Report") in compliance with the above-referenced requirements. The DCPR has been structured to adhere to the Commission's reporting requirements and directives. The DCPR provides the Commission with detailed data that demonstrates the need and value of the capital construction program undertaken by Pepco. This capital construction program is focused on providing service to new customers as well as improving reliability for all customers, expanding the distribution system to supply the increasing electrical demands within the District of Columbia and replacing aging infrastructure to prevent and minimize failures and extended customer outages. The work proposed within the DCPR addresses the entire distribution system including overhead, underground, and substation facilities. This Report groups similar activities together, discusses factors that are common to all programs, and includes a detailed planning report that presents information on each specific project.

This Report is organized into chapters that identify capital projects carried out to fulfill the Company's responsibility to serve all customers by maintaining the safe and reliable operation of the distribution system in the District of Columbia and an eighth chapter containing the Feeder Reliability Improvement Report. Pepco is seeking cost recovery for projects that have already been completed and closed to plant in service for projects between January 1, 2018 and June 30, 2019 (and post-test year additions), as well as projects scheduled to be in-service during the Multiyear Rate Period. This Report provides detailed information for all projects with cost recovery being requested in this proceeding and for all other projects that have funds budgeted in 2019. Projects included in the Report that have expenditures planned for 2019 will also reflect the budgeted amounts between 2019 and 2023. The eight chapters discussing the capital projects include:

1. Load Growth – provides an overview of load growth projects.
2. Distribution Automation – provides an overview of distribution automation projects.
3. Feeder and Substation Reliability – provides an overview of feeder and substation reliability projects.
4. Emergency Restoration – provides an overview of damage and emergency replacement projects.
5. 4kV to 13kV System Work – provides an overview of projects related to the conversion of parts of the distribution system in the District of Columbia from 4kV to 13kV and the maintenance of the remaining 4kV system.
6. Customer-Driven Projects – provides an overview of projects that respond to customer requests for new services, relocation of facilities due to street modifications and other activities directly supporting requests from individual customers.
7. Other Projects – provides an overview of projects that typically support the safe and reliable operation of the distribution system in the District (*i.e.,* communications, security and facilities) and work associated with the replacement or upgrades associated with IT equipment and systems.

8. Feeder Reliability Improvement Report – provides a report on the outage performance of groups of feeders included in ASR schemes as well as feeder-by-feeder outage data for each feeder included in any of Pepco's feeder improvement programs.

The chapters above are developed around a particular theme or project type. However, certain types of projects fall across multiple chapters. Communication projects are a good example of this as some communications projects are tied to Distribution Automation (DA), some to new substations being built to address load growth, and the remainder done as part of projects not associated with a particular chapter and, therefore, are included in the Other Projects chapter.

A separate attachment to the DCPR is:

- **PEPCO (I)-2: Capital Project Forms** – includes budgets and details for all distribution-related capital-funded construction work carried out between between January 1, 2018 and June 30, 2019 (and post-test year additions), as well as projects scheduled to be in-service during the Multiyear Rate Period and included in this Report for each project shows the WBS code,[1] project scope, justification, costs, and alternatives where appropriate, among other information.

Project Budget Development Process

On an annual basis, Pepco approves its capital construction budget construction plan for each project Investment Tracking Number (ITN)[2] to be worked on during the current year and its four-year construction forecast for all projects anticipated to be required throughout the five-year planning horizon. Similarly, on an annual basis Pepco approves its O&M budget for the coming year. Pepco implements these budgets throughout the year making capital investments and incurring expenses that are necessary for the ongoing provision of safe and reliable electric distribution service. Forecasts for a future year can vary from one budget to the next for certain projects, particularly for programmatic or recurring projects, as Pepco evaluates the needs of the distribution system over time and refines its work plans. For example, there will be more uncertainty surrounding the 2023 forecast for a program developed as part of the 2019 budget process as compared to the 2023 forecast for the same project made as part of the 2022 budget process. Also, some projects included in this Report have net negative cash flows which, in most cases, reflect adjustments made to the project once it is closed.

Pepco uses estimating techniques for the capital budgeting process that develops the five-year plan at the ITN project level. PHI systems include predefined units define scopes of work, and all costs, including overhead costs that are to be included in the cost estimate, as well as the associated FERC accounts, are included. In addition, PHI systems account for ordering materials and provide advance forecasts of construction labor requirements. Annual budgets are established and approved at the ITN level and work is released for construction at a detailed EPS project level.

[1] Pepco has historically used a WBS code to identify projects, and this Report will continue to do so. However, due to system conversion, in places Pepco will also begin to use an "ITN" code, which is the code used by the new system.
[2] As stated in the prior footnote, these projects were previously referred to by using "WBS" codes.

PHI financial management systems are regularly updated to reflect current labor rates and labor-hours required to perform individual units of work. Material costs are based on current system average costs for each specific material item at the time that the design is performed and together produce estimated costs that are reflective of the expected actual costs to perform the work. Accordingly, actual costs incurred may vary from these estimates.

Source of Funds

Pepco receives equity contributions from its parent company and issues debt in the capital markets to fund the operations and construction program. The Company uses permanent financing in the form of long-term debt and common equity to finance its construction expenditures. The Company has several alternatives to raising debt, however, it has traditionally issued first mortgage secured debt, which generally has the lowest cost of financing. Short-term commercial paper can also be used to temporarily fund construction expenditures and working capital until long-term debt is secured.

When considering the mix of debt and equity for Pepco, it is important for Pepco to maintain its capital structure at a level that supports its current credit ratings. Maintaining strong credit ratings is particularly important today given Pepco's continued plans to invest significantly in the system's reliability.

Approach to Reliability Benefits and Projections

Pepco uses a statistical approach to analyze the reliability benefits resulting from reliability enhancement projects that have been carried out (which includes feeder improvement programs, vegetation management and maintenance, as well as distribution automation projects). This approach uses the observed, historical benefits from similar past projects to project the impacts of planned future reliability improvement projects in meeting regulatory requirements, and the PHI-Exelon Merger Commitments. The projects covered in the DCPR have been planned in conjunction with this reliability projections approach to determine the projects' projected reliability benefits.

1. Load Growth

1.1. Overview of Projects

Planning for future load growth starts with the development of load growth projections. Short-term, summer-peak forecasts are developed for three years to allow adequate time to complete routine 4kV and 13kV construction work. Long range forecasting (4 to 10 years) is used to develop advanced plans for large 4kV and 13kV construction projects that require more than two or three years to complete, to identify the need for additional supply capacity at existing substations and for new substation capacity, to develop routine and advance plans for 34.5kV to 230kV construction work, and to identify future capital projects in the construction budget forecast process. This process provides the time needed to purchase land, obtain zoning modifications, file with the Commission a Notice of Construction (NOC) when transmission-level supply lines or new distribution substations are required, perform appropriate outreach to the community, and secure the necessary permits for large projects. It also identifies the need for long lead-time equipment, such as station transformers and underground cables which can take up to two years to design and secure manufacturing capacity. The time required to perform the advanced engineering and design work, review alternatives, and develop conceptual building designs can exceed three years and therefore requires commitments to be made up to six years before the required in-service dates so that the new facilities can obtain necessary approvals and be constructed in time to serve new load or prevent a reliability violation from occurring. This time period also allows for any redesign that is required in the permitting approval process.

Forecasting begins with the comparison of the firm capacity rating of each feeder and substation to the actual summer historical loads for these facilities on a two-year cycle. Actual new customer loads from customer-submitted class of service forms, other available development reports, planned changes in feeder configuration, historical load growth, current and projected additions of distributed energy systems and emergency transfer capacity are also analyzed. The individual feeder and network feeder group loads for each year are calculated and aggregated to produce the non-coincident substation load predictions for each year of the ten-year plan. The ten-year plan is developed in conjunction with the PJM ten-year forecast so that the projected growth in total system load is consistent with the development of the transmission system serving the District of Columbia.

Pepco's projects to address load growth generally fall into the following categories:

- <u>Feeder Extensions, Rearrangements, and Upgrades</u> – these projects, on overhead and underground distribution feeders, are (1) standalone projects to address shorter term (1 to 3 years) reliability, capacity and emergency transfer needs, (2) a series of interrelated modifications to the distribution system that allow for the deferral of larger longer-term needs such as new substations, or (3) projects to maintain system performance within required levels, generally in the form of additional capacitors, regulators or other devices needed to manage system voltages within allowed limits. These projects are smaller, in a

relative sense, and can be done if enough normal and emergency capacity is available on the feeders and at the substation involved.

- Substation and Subtransmission Capacity Additions – when substation capacity is projected to exceed its firm capacity, planners look for cost-effective ways to increase capacity at existing substations. This can include replacement of the most limiting device, replacement or upgrading of the substation transformer and/or supply line, or the transfer of existing load to an adjacent substation to make additional capacity available at the limited substation.
- New Substations – when substation capacity becomes limited at several adjacent substations and there is no opportunity to increase capacity at existing substations or transfer load between substations, a new substation must be built. Capacity limitations are governed by the emergency rating of the combined electric equipment within the station that includes the station power transformer, switchgear and feeders so that the emergency operating limit for all of the equipment together do not exceed the emergency load rating under any planned operating condition.
- 4kV conversion projects – Due to the age and condition of the 4kV system the Company has a long-term plan to convert all of the remaining 4kV system to 13kV and ultimately retire the entire 4 kV system. The timing of these conversion projects is dictated by either increased loads that are projected to exceed the capacity of the 4kV feeders or by reliability concerns due to the condition of the equipment and increased outages. A conversion project requires the construction of a new 13kV feeder from an existing substation along with replacement of all associated equipment and transformers so that the customers can be moved from the 4kV feeder to the newly constructed 13kV feeder.

Please note that since 4kV conversion projects address aging infrastructure reliability issues but also serve to increase capacity, these projects are covered along with other 4kV work in the chapter entitled “4kV to 13kV System Work” and are not discussed in this load growth chapter of the DCPR.

Project budgets included in this load growth group are reflected in PEPCO (I)-2.

Past Loadings

Based on actual loads, the District of Columbia in total has seen overall negative load growth from 2013 to 2018. However, selected individual neighborhoods within the District of Columbia are the centers for economic development and are growing rapidly. This growth in individual areas is the driver for load relief projects in the District of Columbia. Where possible, Pepco addresses this load growth with lower cost measures such as shifting loads from circuits with higher levels of projected load to those with lower levels of load. This type of work is done each year on a continuous basis, and provides Pepco with the opportunity to meet growing capacity requirements in a cost effective manner. However, such measures do not always suffice, and eventually more involved options such as substation upgrades and additions become the only technically viable options.

The individual neighborhoods that have experienced, or are projected to experience, more pronounced growth include:

- Washington Navy Yard/Southwest (Ward 6)
- Columbia Heights (Ward 1)
- Eckington (Ward 5)
- Mt. Vernon Square (Wards 2 and 6)/Convention Center and NoMa (Wards 5 and 6)
- St. Elizabeths and Columbian Quarter (Ward 8)

Table 1 shows past actual peak loadings by ward in the District of Columbia.

Table 1: Historical District of Columbia Load by Ward

Historical District of Columbia Loads										
Loads in Mega-Volt-Amperes (MVA)										
Ward 1	**Sub. Number**		**2013**	**2014**	**2015**	**2016**	**2017**	**2018**		
	10		103.0	135.4	135.7	143.0	125.6	127.1		
	13 (4.33kV)		11.0	10.0	9.4	9.9	3.1	2.5		
	13		33.0	32.5	31.7	33.0	31.9	34.3		
	25		43.5	40.1	39.1	44.0	50.2	51.0		
	Subtotal - Ward 1		**190.5**	**218.0**	**215.9**	**229.9**	**210.8**	**214.9**	Avg. Trend =	2.44%
Ward 2	**Sub. Number**		**2013**	**2014**	**2015**	**2016**	**2017**	**2018**		
	2		166.5	159.1	151.7	154.1	147.6	146.9		
	12		111.6	104.8	105.9	106.6	104.2	102.5		
	18		142.1	129.7	126.9	134.3	128.3	126.0		
	21		38.5	36.5	36.4	36.3	37.1	39.9		
	52		178.9	177.4	175.9	175.8	157.0	154.7		
	74		48.6	48.1	43.8	43.3	41.0	41.8		
	124		105.5	103.2	99.7	101.5	98.5	96.2		
	197		123.6	120.5	116.5	117.5	112.4	107.2		
	Subtotal - Ward 2		**915.3**	**879.3**	**856.8**	**869.4**	**826.1**	**815.2**	Avg. Trend =	-2.29%
Ward 3	**Sub. Number**		**2013**	**2014**	**2015**	**2016**	**2017**	**2018**		
	38		52.6	46.1	46.3	47.3	37.5	36.7		
	38 (4.33kV)		3.5	3.9	0.0	0.0	0.0	0.0		
	77		73.3	67.0	70.0	68.7	64.3	64.9		
	93 (4.33kV)		4.6	4.0	3.2	5.4	3.0	3.4		
	129		163.8	150.2	151.5	162.1	159.3	162.7		
	145 (4.33kV)		2.7	2.8	2.5	3.1	2.4	2.6		
	146 (4.33kV)		4.2	4.0	3.6	5.8	5.4	4.8		
	Subtotal - Ward 3		**304.7**	**278.0**	**277.1**	**292.4**	**271.9**	**275.1**	Avg. Trend =	-2.02%
Ward 4	**Sub. Number**		**2013**	**2014**	**2015**	**2016**	**2017**	**2018**		
	27		38.3	36.6	31.4	34.1	34.1	36.4		
	190		87.5	80.7	84.0	88.9	89.0	87.3		
	Subtotal - Ward 4		**125.8**	**117.3**	**115.4**	**123.0**	**123.1**	**123.7**	Avg. Trend =	-0.34%

Historical District of Columbia Loads

Loads in Mega-Volt-Amperes (MVA)

Ward 5	**Sub. Number**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**		
	133	129.6	99.1	97.0	108.2	101.8	106.2		
	212	79.7	79.9	79.5	83.9	106.9	116.2		
	Subtotal - Ward 5	**209.3**	**179.0**	**176.5**	**192.1**	**208.7**	**222.4**	Avg. Trend =	1.22%
Ward 6	**Sub. Number**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**		
	Sta. 'B'	124.9	118.7	110.7	119.3	123.1	56.5		
	33	17.0	16.3	16.5	17.1	16.4	16.1		
	117	111.2	108.5	104.1	112.7	104.5	101.4		
	161	113.2	109.5	114.7	112.3	108.5	107.1		
	223	0.0	0.0	0.0	0.0	0.0	78.0		
	Subtotal - Ward 6	**366.3**	**353.0**	**346.0**	**361.4**	**352.5**	**359.1**	Avg. Trend =	-0.40%
Ward 7	**Sub. Number**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**		
	7	165.9	160.7	160.2	158.5	159.7	162.3		
	Subtotal - Ward 7	**165.9**	**160.7**	**160.2**	**158.5**	**159.7**	**162.3**	Avg. Trend =	-0.44%
Ward 8	**Sub. Number**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**		
	8 (4.33kV)	1.6	1.5	1.5	1.6	1.2	0.9		
	8	32.2	25.8	25.9	27.6	17.5	22.5		
	136	77.4	80.6	80.3	89.5	91.2	93.4		
	168	20.9	21.6	19.3	20.7	20.6	20.5		
	Subtotal - Ward 8	**132.1**	**129.5**	**127.0**	**139.4**	**130.5**	**137.3**	Avg. Trend =	0.78%
	DC TOTAL	**2409.9**	**2314.8**	**2274.9**	**2366.1**	**2283.3**	**2310.0**	Avg. Trend =	-0.84%

Notes: All substations supply 13.8kV of primary power unless otherwise noted.
Loads shown are actual readings taken during peak summer conditions.
Totals shown are the sum of undiversified peak loads and are not meant to be used as official Pepco system peak loads.
Trends shown are based on the straight line regression of the loads and include transfers amongst the substations.

1.2. Forecast Loadings

Figure 1 shows the forecasted substation peak load of the District of Columbia as a whole over the next 10-years and Table 2 shows the forecasted loads for each ward within the District of Columbia.

Figure 1: Forecasted District of Columbia Substation Peak Load

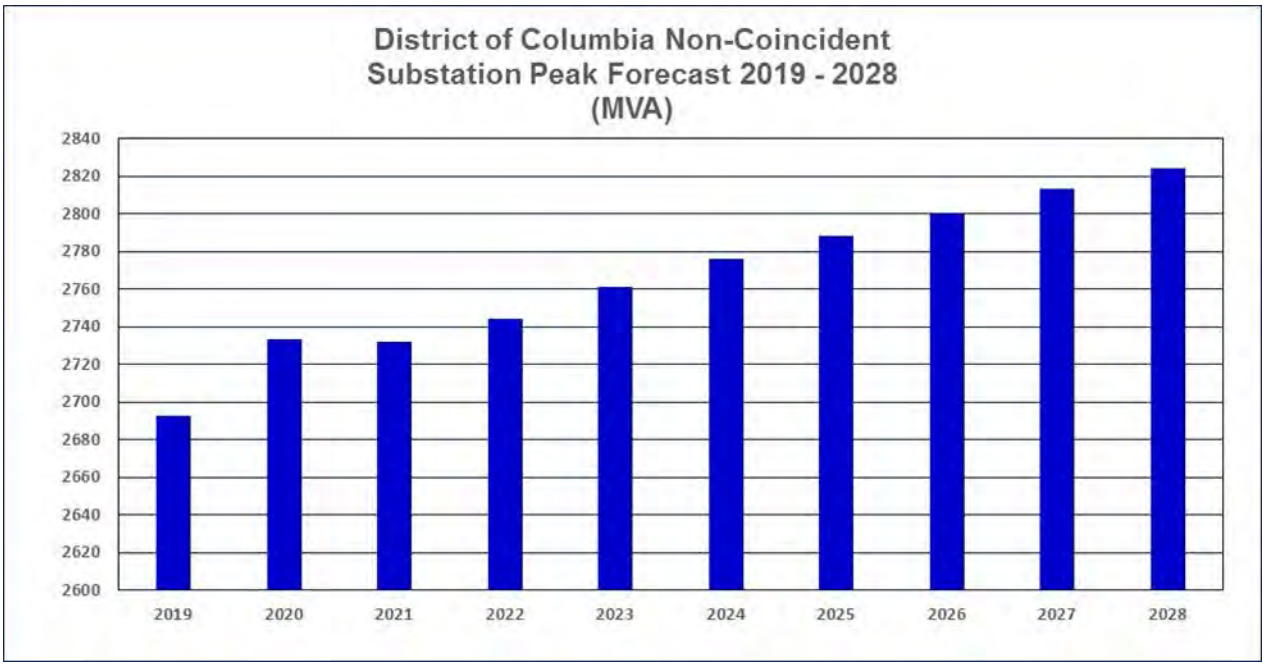


Table 2: Forecasted District of Columbia Load by Ward

Forecasted District of Columbia Loads												
Loads in Mega-Volt-Amperes (MVA)												
Ward 1	**Sub. Number**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
	10	162.3	165.2	163.0	163.2	163.6	163.9	164.1	164.5	164.7	165.1	
	13 (4.33kV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	13	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	25	57.6	57.6	56.9	56.9	56.9	56.9	56.8	56.8	56.8	56.7	
	Subtotal - Ward 1	**219.9**	**222.8**	**219.9**	**220.1**	**220.5**	**220.8**	**220.9**	**221.3**	**221.5**	**221.8**	
											Avg. Trend =	0.10%
Ward 2	**Sub. Number**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
	2	178.9	178.9	178.4	178.5	178.6	178.6	178.7	178.8	178.9	178.9	
	12	120.7	120.9	120.6	120.7	120.8	120.8	120.9	121.0	121.1	121.1	
	18	152.4	156.1	156.5	157.1	157.7	158.3	158.9	159.5	160.1	160.7	
	21	41.7	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	
	52	193.2	194.7	194.7	195.2	195.6	196.1	196.5	197.0	197.4	197.9	
	74	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	
	124	112.6	113.1	113.0	113.1	113.2	113.3	113.4	113.5	113.6	113.7	
	197	127.3	127.8	127.9	128.1	128.3	128.5	128.7	128.9	129.1	129.3	
	Subtotal - Ward 2	**973.5**	**981.4**	**981.0**	**982.6**	**984.1**	**985.5**	**987.0**	**988.6**	**990.1**	**991.5**	
											Avg. Trend =	0.20%
Ward 3	**Sub. Number**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
	38	48.0	48.9	48.2	48.2	48.2	48.2	48.3	48.3	48.3	48.3	
	38 (4.33kV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	77	75.6	75.8	74.0	74.1	74.2	74.3	74.4	74.5	74.5	74.6	
	93 (4.33kV)	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	
	129	180.0	180.4	178.5	178.5	178.6	178.6	178.7	178.7	178.7	178.8	
	145 (4.33kV)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	
	146 (4.33kV)	5.6	5.6	5.6	5.6	5.5	5.5	5.5	5.5	5.5	5.5	
	Subtotal - Ward 3	**315.7**	**317.2**	**312.8**	**312.9**	**313.0**	**313.1**	**313.4**	**313.5**	**313.5**	**313.7**	
											Avg. Trend =	-0.07%
Ward 4	**Sub. Number**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
	27	31.4	31.4	30.4	30.3	30.3	30.2	30.2	30.1	30.1	30.0	
	190	121.9	124.8	121.6	121.5	121.4	121.3	121.2	121.2	121.1	121.0	
	Subtotal - Ward 4	**153.3**	**156.2**	**152.0**	**151.8**	**151.7**	**151.5**	**151.4**	**151.3**	**151.2**	**151.0**	
											Avg. Trend =	-0.17%

Forecasted District of Columbia Loads												
Loads in Mega-Volt-Amperes (MVA)												
Ward 5	**Sub. Number**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
	133	115.4	122.8	119.6	109.8	109.4	108.9	108.4	108.0	107.6	107.3	
	212	149.3	157.4	175.0	190.0	199.7	208.4	213.0	218.3	224.3	228.3	
	Subtotal - Ward 5	**264.7**	**280.2**	**294.6**	**299.8**	**309.1**	**317.3**	**321.4**	**326.3**	**331.9**	**335.6**	
											Avg. Trend =	2.67%
Ward 6	**Sub. Number**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
	Sta. 'B'	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	
	33	18.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	117	119.5	119.5	119.4	119.5	119.6	119.7	119.7	119.8	119.9	120.0	
	161	116.3	116.1	116.7	117.3	118.2	118.8	120.8	121.7	122.6	123.1	
	223	143.5	163.5	166.4	169.8	173.2	176.6	180.1	183.5	186.9	190.4	
	Subtotal - Ward 6	**428.4**	**430.1**	**433.5**	**437.6**	**442.0**	**446.1**	**451.6**	**456.0**	**460.4**	**464.5**	
											Avg. Trend =	0.90%
Ward 7	**Sub. Number**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
	7	175.2	178.0	172.8	172.5	172.1	171.7	171.4	171.0	170.7	170.4	
	Subtotal - Ward 7	**175.2**	**178.0**	**172.8**	**172.5**	**172.1**	**171.7**	**171.4**	**171.0**	**170.7**	**170.4**	
											Avg. Trend =	-0.31%
Ward 8	**Sub. Number**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	
	8 (4.33 kV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	8 (13.8 kV)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
	136	138.9	144.2	143.6	145.1	146.7	148.3	149.9	151.5	153.1	154.7	
	168	23.1	23.1	22.2	22.1	21.9	21.7	21.5	21.3	21.1	21.0	
	Subtotal - Ward 8	**162.0**	**167.3**	**165.8**	**167.2**	**168.6**	**170.0**	**171.4**	**172.8**	**174.2**	**175.7**	
											Avg. Trend =	0.91%
	DC TOTAL	**2692.7**	**2733.2**	**2732.4**	**2744.5**	**2761.1**	**2776.0**	**2788.5**	**2800.8**	**2813.5**	**2824.2**	
											Avg. Trend =	0.53%
	Notes: All substations supply 13.8kV of primary power unless otherwise noted.											
	Totals shown are the sum of undiversified peak loads and are not meant to be used											
	as official Pepco system peak loads.											
	Totals shown for first two years include planned transfers, the last eight years do not show planned transfers.											

There are also neighborhoods where Pepco forecasts above average load growth, and these include the Mt. Vernon Square/Convention Center neighborhood , NoMa , the Washington Navy Yard/Southwest neighborhood.

The sum of historical substation loads displayed in the Historical District of Columbia Loads table indicate that peak loads overall have been decreasing since 2011. The reductions can partially be attributed to the effects of energy conservation particularly from new construction, Pepco's Direct Load Control program and distributed energy resource interconnections. However, a large component of peak load reduction is due to cooler temperatures during the summers of 2012 through 2018 as compared to 2011 temperatures. Year 2011 was considered an extreme weather year and the loads in that year have served as the basis for the load forecast since then. The planning process must take into consideration the extreme weather years and understand how the loads expected to be realized during those years will be served by the distribution system.

1.3. Identified Need

This section will cover the following items:

1) Pepco's distribution planning process, which identifies the need for load relief projects.
2) Pepco's load forecasting process, which incorporates many factors, including the effect of demand response and energy efficiency programs, and distributed energy.

The specific needs driving many of the smaller load relief projects can be found in the supporting information within PEPCO (I)-2.

1.3.1. Pepco's Distribution Planning Process

Load growth projects are undertaken in order to meet the forecasted capacity needs of customers in the District of Columbia. By their very nature, these projects must be committed to and constructed in advance of the predicted electric system load growth occurring. Because of the significant time that it takes to develop, engineer, design, plan, permit, construct, and commission some load-growth projects, Pepco must begin the process years in advance in order to ensure the reliability of the electric system.

Pepco creates an annual plan for Pepco's existing and future electric system needs that will provide reliable electric service to customers and support load growth in a cost-effective manner. In order to accomplish this mission, Pepco continuously analyzes the adequacy of its electric system to meet demand for energy on its system and to plan for future growth. Moreover, the Company maintains engineering and operating criteria that are used in the analysis of its system and to provide a basis for rational and orderly changes to the electric system. The three major components of system planning criteria are (1) maintaining appropriate voltage and reactive support, (2) operating within maximum ratings of facilities, and (3) increasing the reliability of the electric system. For example, voltage on a nominal 120 volt system must be maintained between 114 and 126 volts under normal conditions and between 108 and 126 volts under contingency conditions as per the requirements of ANSI Standards 84.1. Ratings of facilities include normal, emergency, and short-term emergency ratings on all facilities including feeders, power transformers, circuit breakers, for both summer and winter periods. In terms of reliability, the data that are reviewed and tracked include historical and forecasted load vs. capacity of the feeders, feeder groups, and substations as well as age, condition and operational performance of system equipment.

1.4. Justification

A detailed justification for each project can be found in PEPCO (I)-2. This section, however, will provide a justification for the major load relief projects being proposed between 2019 and 2026 in the District of Columbia.

Please note that all data presented below is based on current information and engineering analysis for similar types of projects that have been completed in recent years, and may be revised as the Company completes final designs, fully evaluates site conditions, satisfies permitting and zoning requirements and receives final contract and equipment bids. This information could impact both the costs and timing of a project. Costs presented reflect forecasts based on approved budgets, and include related distribution, real estate, and permitting costs. In addition, each project's required in-service date is continuously being reviewed and may change as detailed designs are completed and revisions occur in the timing of new customer projects or coordination with other projects that require revising the scheduled in-service dates. Although the actual need date can be advanced or delayed, the primary need for these projects does not significantly change enough such that the project can be cancelled in its entirety.

Table 3 reflects Pepco's planned substation additions and enhancements for the District of Columbia with their anticipated in service dates. These project costs reflect the total current budgets including real estate acquisition costs, transmission supply where applicable as well as all distribution-related cost.

Table 3: Pepco Substation Additions and Enhancements in the District of Columbia

#	Project Cost	Project Description	Projected In-Service Date	Areas Served
1	**$149.9 million**	**Harrison Sub. (Formerly Northwest Sub.)** – Upgrade substation to replace aging infrastructure.	Dec. 2019	Friendship Heights, Chevy Chase
2	**$143.0 million**	**Mt. Vernon Square Sub.** – Build new substation to relieve predicted network overloads.	June 2023	NoMa, Mt. Vernon Triangle, Shaw
3	**$180.0 million**	**Harvard Sub. –** Upgrade Harvard as a new 230/13 kV substation to retire existing Harvard and Champlain substations.	June 2023	Columbia Heights, Adams Morgan
4	**$123.0 million**	**Champlain Sub. –** Upgrade Champlain as a new 230/69/34 kV substation to resupply downtown distribution substations.	June 2026	Downtown

1.4.1. Justification of Substation Additions and Enhancements

The new Harrison Sub. upgrade is being proposed to replace aging infrastructure and in order to meet area load growth. The new substation at Mt. Vernon Square is needed to provide capacity to the redeveloping Mt. Vernon Triangle and Shaw areas. The capacity improvements at Harvard Sub. are needed to replace aging infrastructure at Harvard Sub. and Champlain Sub., and to create capacity to serve the growing Columbia Heights area. The new upgraded substation at Champlain will be used to re-supply existing L Street, F Street, and Georgetown substations with new solid dielectric feeders. Pepco has also projected capacity constraints and, thus, a potential need for a load-driven substation in the 2026-2028 timeframe in the St. Elizabeth's and Columbian Quarter area of Ward 8. Future ACRs will discuss this project in more detail and as its load continues to develop.

1. **Upgrade Harrison Sub. 38 (**2019 Aging Infrastructure Project)

The upgraded Harrison Sub. 38 will be a 138 kV / 13 kV substation with an ultimate capacity of 150 MVA. All 13 kV load currently supplied from Harrison Sub. 38 will be temporarily supplied from temporary equipment to be assembled on the site next to Harrison Sub. 38. This will allow the existing substation to be de-energized so that the station can be upgraded on the site of the existing station. Once construction is finished, all circuits will be transferred from the temporary equipment and the temporary equipment will be removed from the property.

Load Growth Projections:

Facility: Harrison Sub. 38

Summer Summer Rating = 56.0 MVA

	2018 History	2019 Anticipated	2020 Anticipated	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated
Net Load Forecast (MVA)	39.7	48.0	48.9	48.2	48.2	48.2	48.2	48.3	48.3	48.3	48.3
Cumulative DER Impacts since 2011	1.5	1.6	1.8	2.5	2.6	2.6	2.7	2.7	2.7	2.8	2.8

Note: Loads shown include the net effects of converting and transferring the 4 kV load off of Harrison Sub. 38 to other area substations. Also 2018 historical loads shown include the temporary transfers to neighboring substations to prevent the temporary substation from exceeding its firm capacity.

Magnitude of Load: Approximately 49 MVA of load will initially be served from the upgraded Harrison Sub. 38. Approximately 70% of the load is in the District of Columbia. Additional load will be transferred from neighboring substations in the following years in order to provide capacity for future growth in those areas.

Identified Need: Project is needed to improve reliability by meeting load growth and replacing aging infrastructure.

Justification: The main building at Harrison Sub. 38 was constructed in 1940 and has had various additions over time. Harrison Sub. 38 – 13 kV substation is anticipated to exceed its firm capacity in the summer of 2025. The transformers are 47 to 60 years old. Transformer 1 has been assessed as impaired and will need eventual replacement. The switchgear is a double bus configuration and in need of replacement based on its assessed condition. Some of the switches are 52 years old with only a 500 MVA rating. This substation is already "landlocked", meaning that there is only access from the front or from a 12-foot driveway. Given that there is no additional space for new equipment, there is no realistic way that the existing equipment inside Harrison Sub. 38 can be upgraded without first removing it.

The existing 4 kV substations at Harrison Sub. 38 also needed replacement. Transformer 6 has been assessed as impaired and needs eventual replacement. Pepco completed work to convert and re-route existing 4 kV feeders in order to retire the 34/4 kV and 13/4 kV substations at Harrison Sub. 38 to eliminate the need to build a new 4 kV substation on the Harrison substation property.

Total Planned Capital Investment (Includes A & G): $149.9 million. The estimate for Harrison substation has been increased to reflect construction bids received, and the construction of a temporary substation.

In-service Date: December 2019

Current Status: In-service date delayed now to December 2019, which is a change from the 2018 ACR. The initial delay was caused by 34kV joint failures experienced when constructing the temporary substation, and delays in receiving the building permits for the upgraded substation. The latest delay is caused by the logistics of working in the “North Yard”. This area includes the transformer and termination bays, 138kV manholes, station service transformer, backup generator, amongst several other above and below grade items. The temporary substation was completed in the first quarter of 2017 and upgrades on the existing substation began in the first quarter of 2017.

Alternative: An alternative to upgrading the Harrison Sub. 38 would be to extend 17 feeders from Little Falls Sub. 77 and transfer all load from Harrison Sub. 38 to that substation.

The total cost of completing this alternative is also estimated to be approximately $107 million and would leave Little Falls Sub. 77 without any spare substation bus feeder positions for future use. Also, it is predicted that Little Falls Sub. 77 will exceed its firm capacity in 2021 if this alternative work is completed, requiring the construction of a new substation at that time.

2. Construct New Mt. Vernon Square Area Substation (2023 Load Relief Project)

Overview: This project consists of constructing a new 230/13 kV substation with an ultimate capacity of 210 MVA near Mt. Vernon Square. It is currently planned to initially have three 230/13

kV transformers for a firm capacity of 144 MVA. This substation will provide distribution capacity to the rapidly redeveloping area in and around the Mt. Vernon Triangle. Initially, approximately 57.0 MVA of load would be transferred from the Northeast Sub. 212 Southwest LVAC Network Group and Tenth Street Sub. 52 radial distribution in 2023.

Load Projections:

Facility: Northeast Sub. 212 Southwest LVAC Group

Summer Summer Rating = 50.0 MVA

	2018 History	2019 Anticipated	2020 Anticipated	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated
Net Load Forecast (MVA)	33.9	41.6	43.4	47.5	49.2	53.4	56.3	57.5	59.0	61.5	63.0
Cumulative DER Impacts since 2011	0.5	0.6	0.6	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4

Facility: Northeast Sub. 212

Summer Summer Rating = 214.0 MVA

	2018 History	2019 Anticipated	2020 Anticipated	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated
Net Load Forecast (MVA)	128.5	149.3	157.4	175.0	190.0	199.7	208.4	213.0	218.3	224.3	228.3
Cumulative DER Impacts since 2011	1.6	1.8	2.0	3.2	3.3	3.3	3.4	3.5	3.6	3.7	3.7

Magnitude of Load: Initially, approximately 57.0 MVA of load would be transferred from the Northeast Sub. 212 Southwest LVAC Network Group and Tenth Street Sub. 52 radial distribution in 2023.

Justification: The new Mt. Vernon Square Area Substation will provide relief to the Northeast Sub. 212 Southwest LVAC Network Group, which is expected to exceed its firm capacity in 2023 by approximately 7%, due to space limitations in the streets around the Northeast substation, no new feeder groups can be extended to relieve these overloads.

Over approximately 140 MVA of long-term growth is expected to come into service in the Mt. Vernon Triangle, NoMa, and Capitol Crossing areas over the next 8 years. This currently includes over 15,000 apartment type residential units, 1,300 hotel rooms, 2.5 million square feet of retail space and 6.5 million square feet of office space.

Total Planned Capital Investment (Includes A & G): $143.0 million

Current Status: In design stages.

In-service Date: June 2023.

Alternative: An alternative to constructing Mount Vernon Substation in 2023 is to delay the construction of the facility until 2024. To facilitate this, a series of cascading load transfers are required to relieve Northeast Sub. 212 using Florida Avenue Sub. 10. This alternative is not practical due to load proximity. The feeders being extended from Florida Avenue Sub. 10 will be less reliable due to length and would reduce area operating flexibility as Florida Avenue Sub. 10 and the other area substations will all be loaded near their full capacity.

Multiple sites were evaluated for locating the proposed Mt. Vernon Square Sub. An alternative substation location was investigated along New York Avenue in Northeast DC. It was determined that the primary amount of development and load center of the new substation was in the Mt. Vernon Triangle area. Several sites were investigated in the Mt. Vernon Triangle area but alternatives were rejected as too expensive or not offering required access to the nearby streets.

3. **Upgrade Harvard Sub. 13** (2023 Aging Infrastructure Project)

Overview: This project consists of removing the current 34kV/13kV substation at Harvard Sub. 13 and upgrading to a new 230/13kV substation with an ultimate Firm Capacity of 210 MVA. It will initially have three 230/13kV transformers resulting in a Firm Capacity of 140 MVA. The upgraded Harvard Sub. 13 will serve all 13kV load supplied from the existing Harvard Sub. 13 and will provide capacity to enable the transfer of load from Florida Avenue Sub. 10 and partial load from Champlain Sub. 25. The remaining load of Champlain Sub. 25 will be transferred to Florida Avenue Sub. 10, allowing for the retirement of that facility as a distribution substation. The upgraded Harvard Sub. 13 will also provide capacity for future load growth in the Columbia Heights and Adams Morgan areas.

NOTE: Changes to the original plan for transferring all load of Champlain Sub. 25 to new Harvard Sub. 13 are due to feeder routing limitations discovered during field investigations.

Load Growth Projections:

Summer Rating = 42.0 MVA

	2018 History	2019 Anticipated	2020 Anticipated	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated
Net Load Forecast (MVA)	37.4	36.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cumulative DER Impacts since 2011	2.7	3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Magnitude of Load: Approximately 37 MVA of load is predicted to be supplied from the existing Harvard Sub. 13 in 2019 when construction of the new substation is scheduled to begin. During construction of the new Harvard substation, all load currently supplied by the existing Harvard Sub. 13 will be transferred temporarily to nearby substations. After the upgraded Harvard Sub. 13 is put into service, partial load from Florida Avenue Sub. 10 and Champlain Sub. 25 will be

transferred to it. The remaining load supplied from Champlain Sub. 25 will be transferred to Florida Avenue Sub. 10, allowing for the retirement of the Champlain distribution substation.

Identified Need: This project is needed to retire aging infrastructure including Harvard Sub. 13 13 kV substation originally constructed in 1907, the 34 kV supplies to Harvard Sub. 13 from Buzzard Point Sta. "B", constructed around 1960, and Champlain Sub. 25 13 kV substation, constructed around 1954. This upgraded substation will also supply capacity to the growing Columbia Heights and Adams Morgan areas.

Justification: Harvard Substation 13 was initially built in 1907 with the substation having undergone several refurbishments with the latest taking place in the mid-1960s. The 34kV supplies to Harvard Substation 13 were constructed in the 1940s. The last incarnation of Champlain Substation 25 was put into service in the mid-1950s although some portions of the site are likely older. Neither substation meets Pepco's current standard for fault current withstand and are configured in a non-standard way which could lead to longer restoration times for failures experienced inside the substation. In addition, completion of this project along with the project to resupply L Street Sub. 21 (Downtown 34-69kV Resupply) and the retirements of Anacostia Sub. 8 and Navy Yard Sub. 33 will enable the retirement of Buzzard Point Sta. B 13/34 kV substation. The upgraded Harvard substation will provide capacity to accommodate projected load growth in the Columbia Heights area.

Total Planned Capital Investment (Includes A & G): $180.0 million (overall estimated cost of project increased due to inclusion of historic landmark nomination, demolition and civil engineering costs).

Current Status: In design stage

In-service Date: June 2023

Alternative: An alternative would be to maintain the Harvard and Champlain substations, replacing the switchgear in each substation. This was not considered a viable option as the switchgear would have to be demolished rather than removed because it is concrete encased. In addition, if this station is maintained, the 34 kV transformers at Harvard and Buzzard Point as well as the 34 kV supply feeders would have to be replaced. Even with these replacements, there would be little increase in capacity for future load growth.

4. **Upgrade Champlain Sub. 25 to 230/69/34 kV substation** (2026 Aging Infrastructure Project)

Overview: This project consists of removing the current 69 kV/13 kV substation at Champlain Sub. 25 and upgrading to a new 230 kV / 69 kV / 34 kV substation with an ultimate capacity of around 570 MVA. It will have three 230 kV/69 kV transformers and four 69/34 kV transformers. From the upgraded Champlain Sub. 25, four new 69 kV supplies will be extended to serve F Street Sub. 74 and Georgetown Sub. 12 and 34 kV supplies will be extended to serve L Street Sub. 21. The

supply feeder replacements for F Street Sub. 74 and Georgetown Sub. 12 are recommended so the existing, aged, fluid self-contained 69 kV supplies from Potomac River Sta. C can be retired. These feeders have increasing maintenance issues over the past several years. The new 34 kV supply feeders to L Street Sub. 21 from Champlain are recommended to retire the existing 34 kV feeders from Buzzard Point which restrict the firm capacity available at L Street Sub. 21.

Load Growth Projections:

Facility: F St. Sub. 74

Summer Summer Rating = 82.0 MVA

	2018 History	2019 Anticipated	2020 Anticipated	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated
Net Load Forecast (MVA)	45.9	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7	46.7
Cumulative DER Impacts since 2011	0.0	0.0	0.0	1.5	1.7	2.0	2.2	2.4	2.6	2.8	3.0

Facility: Georgetown Sub. 12

Summer Summer Rating = 132.0 MVA

	2018 History	2019 Anticipated	2020 Anticipated	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated
Net Load Forecast (MVA)	120.8	120.7	120.9	120.6	120.7	120.8	120.8	120.9	121.0	121.1	121.1
Cumulative DER Impacts since 2011	2.3	2.6	2.9	3.1	3.1	3.1	3.1	3.2	3.2	3.2	3.2

Facility: L St. Sub. 21

Summer Summer Rating = 62.0 MVA

	2018 History	2019 Anticipated	2020 Anticipated	2021 Anticipated	2022 Anticipated	2023 Anticipated	2024 Anticipated	2025 Anticipated	2026 Anticipated	2027 Anticipated	2028 Anticipated
Net Load Forecast (MVA)	39.7	41.7	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2	43.2
Cumulative DER Impacts since 2011	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4

Magnitude of Load: Approximately 211 MVA of load will be served from the upgraded Champlain Sub. 25 as the existing F Street Sub. 74, Georgetown Sub. 12 and L Street Sub. 21 will all be supplied from new 69 kV and 34 kV feeders extended from Champlain.

Identified Need: This project is needed to retire aging 69 kV supply feeders to Georgetown Sub. 12 and F Street Sub. 74 and the aging 34 kV supply feeders to L Street Sub. 21.

Justification: These feeders are all over thirty years old. The 69 kV supply feeders are “self-contained” type cables, meaning that there is fluid contained inside the cable jacket for cooling purposes. There have been an increasing number of maintenance problems with this cable which require extended time and resources to resolve due to limited material availability and few

contractors with expertise repairing this type of cable system. This increases customer outage risk as the feeder needs to be taken out of service for extended periods of time while repairs are made.

The new 34 kV supplies to L Street Sub. 21 will replace the solid dielectric and gas filled cables that are at least 30 years old. In addition, resupplying L Street will allow for the retirement of Buzzard Point 13 kV and 34 kV substations, the former of which was originally built in the 1930's as a generating station. Another benefit of replacing the feeders is that the firm capacity at L Street will significantly increase.

Total Planned Capital Investment (Includes A & G): $123.0 million. The increase in cost is due to the inclusion of costs associated with Takoma Sub. 500MVA phase shifters.

Current Status: In the early design stages.

In-service Date: June 2026

Alternative: The alternative would be to replace the 69 kV and 34 kV cables in kind with new solid dielectric from Potomac River and Buzzard Point. These extensions are far longer than they would be from the proposed new Champlain substation. Also, in the case of the 34 kV feeders from L Street Sub. 21, the Buzzard 34 kV and 13 kV substations would have to be rebuilt which is not cost efficient as L Street would be the only load to be supplied by Buzzard Point 13 kV and 34 kV once all other proposed work to transfer load from Buzzard Point 13 kV and 34 kV is completed.

1.5. Total Cost

For information on the total cost of each load growth project, see the tables included in the Overview of Projects above and refer to the project write-ups in PEPCO (I)-2.

1.6. Work Schedule

For information on the schedule of each load growth project, see PEPCO (I)-2.

1.7. Status

For information on the current status of each ongoing load growth project, see PEPCO (I)-2.

1.8. Benefit-Cost Analysis

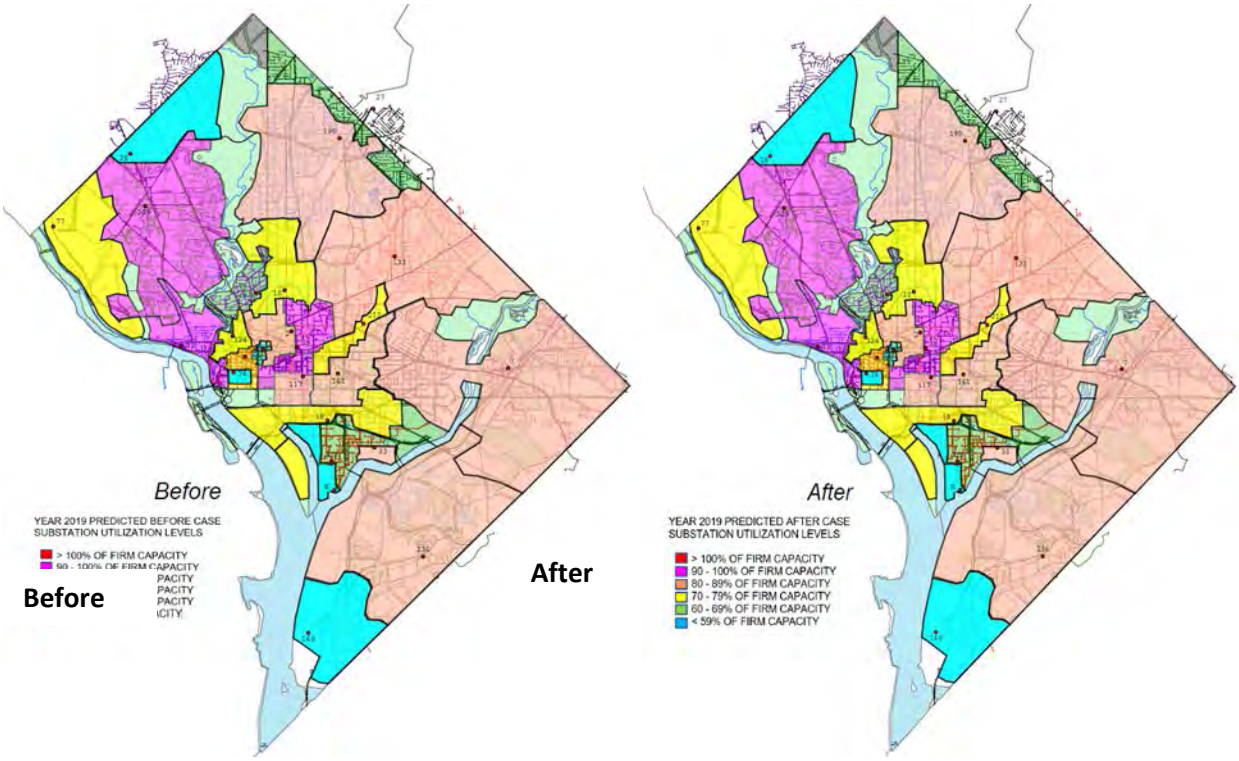
The graphic below on the left shows that without the planned work, several substations will be overloaded and will increase the risk that during peak load conditions there will be insufficient capacity to support the load within the areas served by these substations. If this situation did

develop, the only alternative would be to implement rotating load shedding.

The benefit-to-cost analysis for electric system deployment is focused on supplying capacity at peak load time without exceeding design criteria. The loading within each substation is a balance between attempting to operate a facility at near capacity for optimal use of the facility and performing at a lower capacity level that allows for increased utilization of excess capacity during operational emergencies. These operational and utilization factors are taken into consideration when forecasts are developed and evaluation of the rate of development within each region is analyzed.

The projects recommended are designed to relieve the immediate planning criteria violations and also allow for additional growth for a reasonable period of time after the work has been completed. Figure 2 demonstrates that this goal will be achieved upon completion of the 2019 work plan and that there is growth potential for all planning districts within the District of Columbia.

Figure 2: 2019 Predicted "Before" and "After" Substation Utilization Levels



1.9. Alternatives

A detailed description of the alternatives considered for each project may be found in the project description forms in PEPCO (I)-2.

It is notable, however, that there has been increased interest from stakeholders in recent years in the concept of pursuing new technology solutions in lieu of traditional utility investments to meet capacity needs, as well as other electric system needs. Such solutions can include various types of distributed energy resources (DERs), microgrids, and notably, battery storage. In essence, battery storage is capable of peak shaving or clipping the peak for the few hours of the year when the system facilities are expected to exceed their maximum loading. While system peaks occur only a few hours and days throughout the year, current technology and engineering practice requires that the system be designed to meet maximum demand.

1.10. Priorities

As noted in the Overview of Projects section above, there are four general types of projects to address load growth in the District of Columbia. System capacity needs on the system are prioritized to address the most pressing and immediate forecasted needs by conducting feeder (*i.e.* extensions, rearrangements, conversions and upgrades) or substation (*i.e.* capacity additions) work. The addition of new substations is considered when the long-term capacity needs of the system dictates it.

1.11. Source of Funds

For information on the source of funds for Load Growth projects, refer to the Source of Funds section at the beginning of this Report.

1.12. Related Government Action

Not Applicable.

2. Distribution Automation

2.1. Overview of Projects

Pepco recognizes the benefits of deploying smart grid technology to improve infrastructure reliability, enhance the customer experience, and provide better operational flexibility and control over the grid. Distribution Automation (DA) is one aspect of Pepco's larger smart grid implementation strategy. Pepco's DA approach is comprised of installing advanced control systems and devices across the distribution system to automatically identify and isolate faults in real time and restore service to customers. These systems and devices serve the following functions:

- Fault identification and isolation: DA can isolate faulted sections of the distribution infrastructure to minimize customer impact during outage events;
- Service restoration: DA can significantly reduce the duration of outages experienced by customers through automated isolation of faulted areas and restoration of customers unaffected by the fault.
- System/Data management: DA can provide accurate and real-time information regarding the overall integrity of the distribution system, which allows for targeted and timely deployment of system restoration measures.
- Control: DA can provide expanded control of field equipment outside of the substation and increased monitoring points spread across the entire distribution system. These control and monitoring points allow for real time operation of the system and increased awareness of loads and status of individual segments of the distribution grid.

Types of DA projects include:

1. Automatic Sectionalizing and Restoration (ASR) schemes;
2. Other Non-ASR switch additions (Switches and Automatic Circuit Reclosers(ACRs));
3. Other automation projects to add visibility and control (substations, capacitor banks, and automation equipment replacement);
4. Network transformer protector RMS; and
5. DA communication & control infrastructure build-out and integration.

Project budgets included in the DA group are reflected in PEPCO (I)-2.

2.1.1. <u>Automatic Sectionalization and Restoration Schemes</u>

ASR Schemes improve system reliability by automatically isolating faults and restoring unaffected portions of feeders by using advanced sensors, controls, and communications systems. Sensors detect faults as they occur in the system. Control systems reconfigure the distribution system by operating switches and other isolation devices, such as automatic circuit reclosers (ACRs) to isolate the faulted sections. Loads served on unaffected sections are automatically switched over to neighboring feeders. ASR schemes resupply customers from alternate sources and shorten

restoration times. An ASR scheme's "self-healing" design quickly identifies the faulted section, thereby reducing the time to dispatch restoration crews, and eliminating sustained outages for customers served from unfaulted portions of the feeder.

2.1.2. Candidate Feeder Selection and ASR Scheme Design

To identify candidate feeders for these schemes, Pepco begins with an evaluation of the performance history of individual substation breakers, substation circuit breakers, and ACRs downstream on circuits. Specifically, Pepco identifies feeders with three or more lockouts over the most recent two-year period. These feeders are ordered in priority by ones that carry more load than others (*e.g.,* 13kV feeders carry four to five times more load than 4kV feeders). Table lists the candidate feeders for ASR scheme development, and Table *4* shows the list of deployed ASR schemes.

ASR schemes are then developed by grouping candidate feeders based on their proximity to other qualifying feeders. This grouping produces synergies using the same substation equipment to control multiple feeders. Pepco prioritizes ASR schemes based on achievable reliability improvement and cost.

In order to increase work efficiency and accelerate the implementation of ASR schemes, Pepco revised its DA feeder selection criteria to focus on feeder lockouts and reliability performance at a substation level rather than individual feeder level. The new selection process prioritizes those feeders that have poorer historical reliability and those feeders that are supplied from substations which are DA ready. This alternate candidate feeder selection process allows Pepco to address the feeders that can be more easily incorporated into ASR schemes by looking at the degree of automation at their source substations. Once these are completed, ASR schemes are added to the feeders supplied from the prioritized substations that need to be made DA ready. This process results in adding ASR to feeders that do not meet the three outage criteria, and has the advantage of preparing these same feeders from future outage.

Table 4 ASR Selected Feeders – 01/01/2014-12/31/2016 Feeder Lockout Statistics

Substation	Feeder Number	In-service	# of Lockouts (Exc MEDs)	# of Lockouts (Inc MEDs)
Takoma	15198	2019 Planned	0	0
Takoma	15264	2019 Planned	3	3
Green Meadows	14289	2019 Planned	3	3
Green Meadows	14296	2019 Planned	0	0
Grant Ave	14979	2019 Planned	4	4
Ft. Slocum 190	15001	2019 Planned	2	2
Ft. Slocum 190	15003	2019 Planned	0	0
Ft. Slocum 190	15006	2019 Planned	1	1
Ft. Slocum 190	15011	2019 Planned	5	5
Ft. Slocum 190	15012	2019 Planned	0	0

Ft. Slocum 190	15015	2019 Planned	2	2
Ft. Slocum 190	15016	2019 Planned	0	0
Ft. Slocum 190	15021	2019 Planned	2	2
Ft. Slocum 190	15197	2019 Planned	0	0
Green Meadows	14297	2019 Planned	1	1
Ft. Slocum 190	15013	2019 Planned	1	1
Ft. Slocum 190	15018	2019 Planned	0	0
Benning	15701	2019 Planned	2	2
12th & Irving	14001	2019 Planned	1	1
12th & Irving	14005	2019 Planned	3	3
12th & Irving	14008	2019 Planned	4	4
12th & Irving	14009	2019 Planned	2	2
12th & Irving	14014	2019 Planned	5	5
12th & Irving	14016	2019 Planned	4	5
12th & Irving	14017	2019 Planned	0	0
12th & Irving	14022	2019 Planned	1	1
12th & Irving	14023	2019 Planned	1	1
12th & Irving	14093	2019 Planned	2	2

2.1.3. Other Non-ASR Distribution Automation Switch Additions

Non-ASR switch additions consists of projects that deploy remotely operated switches and stand-alone ACRs, which may be incorporated into future ASR schemes. ACRs and remotely operated switches on feeders allow for more capability to isolate the faulted portion of the feeder and return more customers to service sooner. ACRs activate to isolate downstream faults, which serves to limit the number customers affected during outage events. The remote control capability of these devices allows the System Operator to perform switching without the need to dispatch field crews, thus reducing customer outage time and related costs.

Currently, ACRs are deployed based on the feeder-level lockout histories and high SAIFI performance. The long-term goal for ACR deployments is to identify where the ACRs should be combined into an ASR scheme to realize the maximum reliability benefits including, but not limited to, limiting exposure of outages to 500 customers on a single blue-sky event, on average. In order to perform this work, a feeder must have sufficient ties and sufficient ACRs to form an ASR Scheme. The installation of an ASR scheme and the installation of ACRs will help Pepco towards achieving its reliability improvements objectives, but not all feeders require having an ACR scheme installed on them.

2.1.4. Other Substation Automation Projects

Other substation automation projects include adding automation equipment (*e.g.,* remotely operated relays, monitors, and additional communications equipment) to provide Pepco system

operators increased visibility into the Pepco distribution system.

In accordance with the Long Range Study 4kV Distribution System 2007, areas with little or no load growth can in most instances continue to be served by the 4kV system. Those 4kV substations without SCADA controls are being upgraded to allow substation breakers and transformers to be monitored, and remotely controlled and operated. Monitoring of these substation conditions, along with the remote operations capabilities, can improve the reliability of the substations, and can potentially reduce outage restoration times. The construction at Fifty-Third St. Sub 48 was completed in 2018, and the construction at Chesapeakse Street Sub 181 is still ongoing with the targeted completion of 1Q 2019. The engineering for Fort Dupont Sub 58, Ft. Davis Sub 100, Seat Pleasant Sub 30, Texas Ave Sub 111 has been completed and engineering for Mac Arthur Sub 152 is in progress.

Capacitor automation enables the Pepco distribution system to function more efficiently resulting in reduced line losses by allowing the system to be operated at a power factor closer to unity. In addition, the ability to coordinate capacitor bank operations will enable better reactive power control via Conservation Voltage Reduction (CVR) and Variable Voltage Regulation (VVR) events in the future, if appropriate. This may reduce the overall power needs from the transmission and distribution networks. Increased control and management of distribution line equipment is needed to support growth in DER. Voltage control is a key component for advanced grid operations and for future distribution management systems. 49 capacitor bank controllers and radios are currently deployed in Pepco DC (9 deployed in 2015, 20 deployed in 2016 and 13 deployed in 2017, 7 were deployed in 2018). The number of additional capacitor banks to be deployed beyond 2018 will be determined at a later date.

2.1.5. Network Transformer/Protector Remote Monitoring System (RMS)

Pepco has been deploying RMS to monitor transformers and network protectors on the LVAC network system. Pepco's first RMS system was supported by US DOE funding and was placed in service in 2013. The RMS is a communication and control system that is fully integrated into the Pepco Energy Management System (EMS), and provides the system operators and maintenance personnel with:

- Up-to-date feedback on operational (and configurational) status of the network
- Real-time data needed to monitor the health of the asset (*e.g.*, transformer oil temperature, phase voltages and currents, loading, and power factor).

The RMS system is comprised of the following components:

- Sensors to monitor the network transformer, network protectors, and other electrical components (*i.e.*, voltage, current, transformer loading)
- Sensors to monitor physical conditions (*i.e.*, temperature, oil and water levels, pressure)
- Network transformer protectors with two-way communications capabilities to allow Pepco

system operators to remotely operate them
- Communications pathway (*i.e.*, antenna which are flush with manhole slabs, and fiber connections back to the control room)
- Data storage and control screens

RMS deployment is prioritized towards the higher loaded LVAC networks to maximize customer and operating benefits and to reduce risks for system operations. Subsequent deployment of RMS is being accomplished in an incremental fashion, thus allowing Pepco to gain efficiencies in design. The addition of RMS has benefits to the operation and restoration of the system as well as its maintenance.

2.1.6. Integration of Distribution Automation with Existing Systems and Building of a Communication Infrastructure

In order for DA to function correctly, substations must first be equipped with the proper equipment to allow for remote monitoring and control. The ten 13kV substations located within the District of Columbia or substations that serve District of Columbia customers that have already been equipped with upgraded Smart Relays and enhanced Remote Telemetry Units (RTUs) for improved visibility and control at these locations are listed below. Additional information provided by these relays will allow for more effective and efficient operation and will support the operation of the ASR system being installed at each location.

- 12th & Irving Substation
- Benning Substation
- Fort Slocum Substation
- Harrison Substation
- Van Ness Substation
- Takoma Substation (located in MD but serves some DC customers)
- Tuxedo Substation (located in MD but serves some DC customers)

The overall smart grid network and infrastructure design includes a fiber-optic/microwave network (UOFPOF25D), a wireless broadband network, and a wireless mesh network (UORPOBR1D, UORPORBSB). The wireless mesh network builds upon the wireless mesh network installed for the AMI system and only requires additional radios at the DA device (reclosers and switches) in order to communicate with the network.

DA equipment communicates via Pepco's wireless mesh communications network, on a private network from a broadband provider, or on a newly established private broadband network. Pepco has constructed and continues to expand its fiber optic network which is used for communications between substations, and between substations and the control centers.

For the DA to function properly, all deployed equipment (*i.e.*, remotely operated switches, automatic circuit reclosers) must be able to communicate with the Pepco control center and system operators. Thus, any design of DA must integrate with existing or developing systems,

such as the EMS, Outage Management System (OMS) and consider interfacing with other smart grid systems such as the AMI or Direct Load Control devices. These and other key linkages are mapped out and considered in all DA design plans. As DA equipment is deployed, the associated telecommunications infrastructure and equipment are designed, engineered, and deployed to ensure proper DA function.

Pepco uses various communications technologies and networks to meet the various communication needs of the different DA installations. For example, DA systems require fast acting switching operations (recloser operations can occur on the time scale of milliseconds), which requires information to travel and be updated in similar time frames. Other systems (*e.g.* video monitoring) have their own dedicated channels. Other information such as smart meter data (*e.g.*, voltage and consumption) are updated on the order of tens of minutes, which can be accommodated on a slower radio mesh networks.

Fiber optic systems are used primarily to handle the traffic with either high bandwidth and / or low latency requirements, such as remote control and remote monitoring of equipment (*e.g.* SCADA, ASR schemes, stand-alone ACRs, as well as certain security monitoring systems for substations). There is a degree of redundancy, as fiber connected Multiprotocol Label Switching (MPLS) routers have redundant paths for data flow. Applications and systems that do not require low latency or high volume data transfers (*e.g.* AMI meters), the broadband radio networks are used. The meshed radio networks can also re-route traffic to provide alternate paths for the data to flow.

As Pepco has gained experience with DA, the communications (bandwidth and speed) requirements have increased. Some of the originally planned wireless communications networks which were used to collect data at relatively long intervals (sometimes once a day communications between the devices and data management / analysis centers) are becoming obsolete. Similarly, as more devices are monitored and controlled through SCADA, existing fiber optics needed to be expanded. Communications infrastructure projects carried out since 2013 include the upgrading and replacement of obsolete fiber optics systems (PROMx), as well as the associated protection systems (*e.g.* firewalls).

2.2. Past Loadings

Not Applicable

2.3. Forecast Loadings

Not Applicable

2.4. Identified Need

For information on the identified need of each distribution automation project, see the project write-ups in PEPCO (I)-2.

2.5. Justification

The following sections discuss the justification for each distribution automation project. In addition, see the project write-ups in PEPCO (I)-2.

2.5.1. Distribution Automation (ASR Schemes and Non-ASR Switch Deployments)

The justification for DA is improved service reliability by reducing the impact of large feeder outages. In 2016, ASR schemes within the District of Columbia saved a total of 2,185 customer interruptions (CI). Stand-alone ACRs which are not a part of ASR schemes saved a total of 12,289 CI.

In 2017 to end of September, ASR schemes within the District of Columbia have saved a total of 2,913 customer interruptions (CI) in total. Stand-alone ACRs which are not a part of ASR schemes have saved a total of 14,589 CI.

In 2018, ASR schemes within the District of Columbia saved a total of 3,276 customer interruptions (CI). Stand-alone ACRs which are not a part of ASR schemes saved a total of 19,858 CI.

2.5.2. Other Automation Projects (4kV Automation and Capacitor Bank Automation)

4kV substation automation has enabled the Pepco system operators to monitor and control the 4kV substations remotely, which avoids sending out crews to those substations to operate the breakers and relays. The ability to monitor loading of these substations may prevent overloading outages and truck rolls to perform switching operations and can potentially shorten outage restoration times and reduce costs.

For instance, the ability to automate capacitor banks enables Pepco to conduct CVR during peak days to reduce overall energy consumption and perform VVR to better control the reactive power

on the distribution grid. Both CVR and VVR are key components of grid modernization that will allow the distribution system to function more efficiently and reduce the overall peak demand on both the distribution and transmission system. These innovations potentially will allow Pepco to delay future capacity upgrade projects.

Network RMS gives Pepco System Operators and Engineers more situational awareness by providing real-time load and environmental information, as well as transformer condition information and remote control capabilities. The real-time control and monitoring capabilities gained from Network RMS will allow System Operators to attend swiftly to emergencies when any transformer needs to be isolated from the network. The system will also provide operators real-time information on the status of a protector breaker (if open or closed) the number of times and the frequency that protectors are operating, which can be useful in detecting transformers going on and off the network. The analysis of trends in the underground network and can be useful in asset and maintenance strategy and the detection of operating conditions that could lead to protector or transformer failure before a failure occurs.

Telecommunication linkage between DA devices (*i.e.*, 69kV remotely operated switches, ACRs, network transformers, sensors, relays and others) and the control room is a critical component of the modern Pepco distribution grid. Without the communications system and its linkages, remote monitoring and operations of equipment would not be possible, thus reducing the situational awareness of the Pepco system operators, and potentially delaying restoration times due to the need to dispatch crews to operate equipment on-site (rather than remotely).

2.6. Total Original Cost

For information on the total cost of each distribution project, see the tables included in the Overview of Projects above and refer to the project write-ups in PEPCO (I)-2.

2.7. Work Schedule

For information on the work schedule of each distribution automation project, see the project write-ups in PEPCO (I)-2.

2.7.1. <u>Distribution Automation Schedule and Progress</u>

To date, 3 ASR schemes have been successfully deployed. See *Table 5* for a list of deployed DA Schemes in the District of Columbia.

Table 5 DA Schemes Deployed in District of Columbia

Scheme Name	kV	Subs	Feeders	In Service Date	Current Status
Benning-Tuxedo	13	2	14717 15705 15706 15707 15709 15710 15130	10/3/2012	In-service
12th & Irving-Fort Slocum	13	4	14007 14015 15009 15010 15014	8/8/2013	In-service
2017 expansion in 12th & Irving	13	2	14006 14200	Q4 2017	In Service
Harrison-Van Ness	13	3	14136 14133 14135 14765 14767 14768 14890 14896 14900 15801 15943	8/25/2013	In-service
2017 expansion in Van Ness	13	1	14132	2017Q4	In-Service
Takoma (Van Ness ASR Scheme and MC4 Scheme in Maryland)	13	1	15199 15200	6/2016 Q4 2017	In-service

2.7.2. <u>Other Non-ASR Switch Additions Schedule and Progress</u>

In addition to ACRs that are installed as part of an ASR scheme, individual ACRs are installed to improve reliability on individual feeders, including those identified by Pepco as Least Performing. Each ACR will isolate faults and reduce the number of customers that are exposed to faults or feeder lockouts. If, at a later date, the feeder with ACR(s) installed is added to an ASR scheme, the existing ACRs can be added into the scheme and produce additional reliability benefits by being able to restore automatically sections of a feeder that is not involved in the fault. Table 6 lists the number of ACRs that have been installed since 2013 and the current number of ACRs planned to be installed in the future.

Table 6: ACR Deployed in District of Columbia

	2013	2014	2015	2016	2017	2018	2019 - 2020
# of Stand-alone ACR Deployed	21	23	20	21	65	75	Up to 10 per year

2.7.3. Network Transformer Protector Remote Monitoring System Schedule and Progress

Pepco completed the installation, testing, and integration of the network transformer/protector RMS on 50 network transformer/protectors in the Buzzard Point Network (in Southeast District of Columbia, completed in 2014). Prior to installing the RMS system, the network transformers are inspected and replaced if justified by their poor condition or need for higher capacity.

The Buzzard Point Network (in the Southeast District of Columbia) RMS equipment installation, testing, and integration into EMS was completed in 2014. The development of the RMS system and the initial installation at Buzzard Point were part of the Department of Energy's (DOE) American Recovery and Reinvestment Act (ARRA) Smart Grid Investment Grant (SGIG) that Pepco received. The installations in the Northeast Network and the Substation 18 Central Network are part of Pepco's long-term plan to install RMS in all of its 49 networks, which contain approximately 4,000 transformers. See Table 7 for status of deployed and planned RMS monitoring equipment installation and EMS integration.

Table 7: RMS Deployment in Pepco DC

Network	**In Service Date**	**Planned number of transformers with RMS installed**	**EMS Integrated**	**Current Status**
Buzzard Point Southeast	12/31/2014	53	53	In-service.
Substation 212 South	2/28/2018	80	80	In-service.
Substation 212 Southeast	3/4/2015	49	49	In-service.
Substation 18 Central	3/15/2016	72	72	In-service.
Substation 7 Northwest	5/30/2017	75	75	In-service.
Substation 161 South	3/9/2018	86	86	In-service.
Substation 25 Central	5/30/2019	60	56	EMS Integration in progress.
Substation 52 West	5/30/2019	79	63	EMS Integration in progress.
Substation 52 South	6/30/2019	59	6	EMS Integration in progress.
Buzzard Point West	6/30/2019	2	0	EMS Integration in progress.
Totals		615	540	

2.7.4. Distribution Automation Communication & Control Infrastructure Build-Out and Integration Schedule and Progress

The telecommunications and integration projects details are available in the project write-ups in PEPCO (I)-2. Since the telecommunications and controls integration is a crucial part of DA, the timelines for these projects are considered and accounted for when DA system are deployed.

2.8. Status

For the status of each distribution automation project, see the project write-ups in PEPCO (I)-2.

2.9. Benefit-Cost Analysis

2.9.1. ASR Scheme and Non-ASR Switch Benefits

An overview of the ASR scheme and non-ASR switch benefits is included in the Feeder Reliability Improvement Report, which is included as a separate chapter in this Report as required by Order No. 17424.

2.9.2. RMS Operational and Restoration Benefits

RMS monitors will provide increased visibility and control capability for system operators to remotely open or close the network transformer protectors through two-way communications. Load, voltage, protector status, and equipment condition data are recorded for study and operating purposes and for increased ability to schedule maintenance of this equipment. RMS will provide operational data to evaluate the performance of the transformer and protector and allow opening the protector to disconnect network load from the transformer without the need to wait for a crew to manually operate the protector. This will provide benefits during emergencies when there is a need to very quickly isolate a transformer from the network.

The operational benefits from RMS can be classified into the following categories:

1) *Improved Network Outage Restorations* – During network failures, RMS can provide visibility into transformer loading. This visibility allows operators to immediately “see” overloads and prevent equipment damage. Further, during network restoration, RMS allows operators to remotely view the status of network transformers to determine if they are in service and operating correctly a process that would have to be performed manually, thereby reducing restoration times.

2) *Remote Operator Blocking* - Often, during periods of light load, or as a result of other equipment such as a substation reactor failing, a network protector may be prone to “pumping.” Pumping occurs when the load conditions are on the borderline of the protector being open or closed. During periods like this, the operators have the ability to remotely block a protector open, thus preventing unnecessary operations and prolonging

the life of the equipment. This remote blocking capability has other added benefits. Operators have the ability to transfer feeder load at network spot locations during emergency conditions, as well as to remotely isolate a network secondary bus during an emergency. This improves operational efficiency, reduces the risk of feeder overloads during contingency operations and increases worker safety.

Since the activation of the RMS system, the remote blocking capability to address protector pumping issues is used on a regular basis, approximately two to four times per month across all of the monitors deployed under the DOE initiative. This action will extend the life of the protectors by avoiding excessive wear and tear. This capability also allows for maintenance of the protector to be performed based on known operating conditions and not just time based intervals.

3) *Network Status and Load Monitoring*- RMS gives Pepco's System Operations the ability to see the status of a network protector via different views on their control terminals. This enables Pepco's dispatchers to send crews to the location of the failed network protector (identified using the data sent by RMS and presented on their screens), rather than sending out Pepco's field crews to locate a malfunctioning protector that is locked closed during a feeder outage. These views can also reveal whether opposite protectors are closed at critical customer facilities prior to switching out feeders, thus preventing momentary blinks (*i.e.* momentary outages lasting a few seconds) in service.

   Network RMS provides real-time load information to engineers and planners, who can use this information to make better decisions regarding load growth and system configuration. Also, if the system identifies a pumping protector, the load information can be examined to determine relay settings that will prevent the pumping.

   Pepco's Distribution Planning Department has used load readings taken from RMS to improve short-term analysis of the system. Transformer loadings and status are analyzed at varying load levels to determine where there are issues with excess network protector operations and what settings can be applied to the network protectors in order to reduce the number of operations.

   Reverse power flow can be identified by the RMS so that no flow is allowed to go from the secondary to primary side of the transformer. This will become more valuable as the number of solar systems on the network system increases and monitoring of protector status will be critical for the safe operation of the network. Network systems today are designed for one way power flow from the primary to the secondary side of the transformer. Local generation in the form of solar can produce new flow patterns and cause adverse operation and performance of network protectors.

4) *Protector Fail Alarms* - If a relay issues a command to open or close and the desired command is not carried out by the protector breaker, the relay will issue a "protector fail" alarm to the control center. This helps to quickly and efficiently identify failed protectors or blown fuses before they can cause more serious problems.

5) *Remote Setting Updates* - Pepco has the ability to set alarms for specific transformer load values. For example, if a transformer reaches 90-percent load, the network RMS application will notify System Operations so that it can closely monitor the load, prevent overloads and work with Distribution Planning to schedule transformer replacement or other improvements.

To date, RMS has identified one transformer that was loaded at close to 100% during contingency and is being monitored for any upward trends that would require replacement.

6) *Network Grid Solar Penetration* – As the level of solar installation increases the need for RMS increases significantly. Only with a monitoring system can a dispatcher monitor the flow of current into a transformer and know the status of the protector. The installation of PV systems on the LVAC system are generally large (200 to 400 Kw) and can very quickly cause reverse flow into the protector and cause the protector to open. This can result in a large commercial building operating in contingency modes for extended period of times and places the customers served by the system to be at risk of unplanned outages. The RMS system is required to allow for higher penetration of PV while at the same time maintaining the reliability of all aspects of the network system.

7) *Real-time measurement and monitoring*:

- Phase Currents (A, B and C phases)
- Network, Transformer secondary Voltages at the network protector
- Phasing voltages at the network protector (across the open breaker)
- Transformer Loading in Amps
- Power (Watts, VARs, VA)
- Power Factor
- Phase Angles
- Status of the protector (open or close)
- Number of Network Protector Cycles (number of protector operations over a specified timeframe, check if the Network Protector is cycling due to load conditions or pumping rapidly due to malfunction)
- Transformer temperature and oil level
- Pressure at the network protector
- Water levels in the vault

2.9.3. RMS Maintenance Benefits

From a maintenance perspective, RMS monitors provide up-to-date data on the operations as well as conditions (such as number of protector operations), which is used to determine when a particular monitored asset will need to be maintained. This performance-based asset maintenance strategy allows Pepco to perform maintenance activities on an as-needed basis rather than on a time-based interval (whether or not the asset needs to be maintained).

Approximately $19.56 million has been spent on RMS deployments between 2013 and 2018. Approximately $3.98 million is budgeted for 2019, and an additional $14.73 million is budgeted between 2020 and 2023.

2.9.4. Distribution Automation Communication & Control Infrastructure Build-Out and Integration Benefits

DA work not associated with RMS is not possible without the completion of a communications network that allows the equipment to communicate with the operational systems and the system operators. The cumulative impact of the communication infrastructure can be thought of as the sum of the individual benefits covered under the DA chapter.

Approximately $2.9 million has been spent on communications and integration projects between 2015 and 2018. Approximately $450 thousand is budgeted for 2019, and an additional $1.98 million is budgeted between 2020 and 2023.

2.10. Alternatives

For information of identified alternatives to DA projects, see the project write-ups in PEPCO (I)-2.

2.11. Priorities

Prioritization of candidate feeders and DA selection criteria is covered in section 2.1.2 of this Report.

2.12. Source of Funds

In addition to the funds secured as described in the Source of Funds section at the beginning of this Report, certain costs incurred as part of DA projects are covered using DOE funding.

2.12.1. DOE Funding

In late 2009, Pepco was awarded a DOE SGIG to match its DA spending based on its comprehensive smart grid strategy to help fund the advancement of DA as one aspect of Pepco's larger smart grid implementation. The DOE SGIG provided reimbursement of approximately 50% of the costs for the projects included under the grant. In accordance with the grant, all DOE-funded projects, with the exception of DORPBR1D (AMI Communications Meter to Pole Pepco - DC), were completed by 2013. All DA projects have been fully-funded by Pepco since 2013. Note that the expenditures reflected in PEPCO (I)-2 include related expenditures due to ledger adjustments and project closures completed post DOE project completions.

3. Feeder and Substation Reliability

3.1. Overview of Projects

Projects undertaken for reliability within the District of Columbia generally occupy two broad areas of focus - feeder reliability projects and substation reliability projects. The purpose of reliability-driven projects at Pepco is to improve reliability in portions of the system that are aging, not performing as expected, or to maintain reliability through emergency restoration efforts during storms.

Projects initiated to improve reliability typically occur on existing infrastructure that is deemed capable of handling forecasted loads but which has exhibited less than desirable reliability performance in the recent past. These projects typically address past performance issues or emergent trends in a particular asset's performance or condition. These trends are developed by tracking the number of interruptions and the duration of outages. In addition, evaluation of the number and type of equipment failures will also produce trends when failures are the result of equipment outages or failures.

Reliability projects intended to maintain reliability are those where infrastructure exhibits a degraded physical condition or has reached an advanced age. These projects replace infrastructure proactively prior to repeated failure, typically addressing known condition-based risks in a class of assets that threaten the future reliability and stability of the system. Inspection-based assessment produces a history of performance on feeders and selected pieces of equipment (*e.g.*, network transformer inspections identify rusting of transformers, oil analysis trends development of gases within power transformers, etc.)

Projects undertaken to improve and maintain reliability can be projects that are specific to a single asset, such as the replacement of a large impaired transformer, or programmatic in nature, addressing a class of assets in a sustained programmed approach such as the Worst Performing Feeder Program. The aggregate impact of both types of projects should result in sustained or improved levels of reliability across the distribution system in the District of Columbia.

Elements of the distribution system that are deemed to be unable to serve forecast loads or maintain acceptable voltage profiles are identified and addressed as load projects (Chapter 1 of this Report), while emergency repairs to distribution system infrastructure is covered under the Emergency chapter (Chapter 4) of this Report.

3.1.1. Feeder Reliability

Reliability Performance Feeders

The Reliability Performance Feeders project group consists of projects designed to address feeder reliability in response to historic performance in order to improve reliability. These projects are planned in nature and are primarily driven by the recent past performance of a feeder. The

focus of these projects is to address negative performance trends and return a feeder's performance to acceptable levels.

In the case of performance-based selection criteria, historic outage data are collected from the OMS for analysis. These data are used to compute reliability indices such as SAIFI and SAIDI at various levels in the distribution system. The indices serve as an indicator of a system's or subsystem's overall performance over time and allow comparison of the relative impacts subsystems and feeders have on overall system reliability indices. Those feeders and/or subsystems displaying the historic performance that most affects the system reliability indices are selected for reliability improvement projects.

Budgets for these Reliability Performance Feeder Projects are reflected in PEPCO (I)-2. The following are examples of Pepco's major Reliability Performance Feeder Projects:

UDLPRM4BF PSC Priority Circuit Improvement

The PSC Priority Circuit Feeder Improvements program, also known as the Worst Performing Feeder Program, is conducted in order to comply with the Priority Feeders Reliability Standards established under 15 D.C.M.R. § 3603. Under this program the least reliable 2% of distribution feeders over the past year in the District of Columbia, subject to certain exclusions, are identified, analyzed and prioritized for remediation. Corrective action is initiated on the identified feeders to improve individual and overall distribution feeder reliability thereby reducing the number and duration of outages for the customers supplied from these feeders.

UDLPRM63D Pepco DC Feeder Reliability Improvement

The Pepco DC Feeder Reliability Improvement program, also referred to as the Comprehensive Feeder Program, is intended to identify the feeders that are not going to be remediated under the Worst Performing Feeder Program, whose remediation will improve system reliability measures by addressing equipment, vegetation, weather, and animal caused interruptions. These feeders if left unattended would likely advance to become a priority feeder in future years. The program is an essential means by which Pepco addresses feeders that are low performing, have a high number of customer interruptions, or experience long outage durations in order to improve reliability for the customers supplied from these feeders, improve system reliability and provide additional measures in order to meet the SAIFI and SAIDI targets in the District of Columbia.

UDLPRM4BQX Benning: Upgrades for Multi Device Operations

Replace or upgrade protective devices that have operated more than 3 times in the previous 12 months. This program addresses small groups of customers that are experiencing repeat outages. Once a device is identified corrective action is taken to reduce or prevent future operations of the device (fuse, reclosers) and reduce the number and frequency of outages that the customers are experiencing.

Proactive Replacement Feeders

The Proactive Replacement Feeders project group consists of projects designed to maintain feeder reliability in response to concerns about the age and condition of an individual or class of feeders. These are annual, programmatic projects which typically identify candidate feeders as part of inspections and a forward-looking analysis that considers the likelihood of failure in the future due to the asset's age and condition. Such projects result from the need to replace targeted assets through a planned effort.

Inspections, including visual and infrared, are performed on overhead and ground-level facilities to identify equipment conditions that may lead to future failures resulting in outages. These conditions are prioritized and selected for remediation in proactive reliability projects or corrected as part of planned maintenance programs. Additionally, assets can be reviewed for inclusion in proactive replacement programs based on a history of failures attributable to a condition inherent across the asset class that is likely to result in additional outage.

Pepco generally creates tentative plans under each project based on condition, however system emergencies and issues identified during inspections can alter the timing of the projects. Budgets for Proactive Replacement Feeders are reflected in PEPCO (I)-2.

3.1.2. Substation Reliability

Substation Equipment Proactive Replacements

Substation reliability equipment projects generally consist of planned projects to replace or purchase spare equipment for large, high-cost, long-lead-time primary components within substations.

Substation reliability is maintained by keeping both the primary and redundant assets in good working condition. Therefore, condition and criticality of assets predominantly drives substation reliability programs. This concept is known as Reliability Centered Maintenance (RCM), the principles of which dictate that predictive maintenance activities serve to identify failing assets prior to failure.

Substation assets are inspected under various inspection programs, including visual, infra-red, and oil sampling where applicable. Based on observed condition and potential system risk, assets are cleared for normal duty, scheduled for closer monitoring, scheduled for maintenance, selected for immediate replacement, or added to prioritized programmatic replacement programs. Pepco's Equipment Condition Assessment (ECA) process is the vehicle used to identify substation assets for reliability-driven replacement. The ECA process cooperatively analyzes major equipment condition, makes major repair and replacement decisions utilizing various subject matter experts, and through consensus prioritizes candidates for replacement on a quarterly basis. However, in the event of some external drivers such as weather events, these replacements may also be triggered by historic performance of a component. The ECA process does not assess the condition of entire substations.

These projects are heavily driven by Pepco's need to manage contingency risk and do not necessarily result from benefit-cost analysis. The selection of substation reliability projects differs somewhat from feeder performance improvement project selection. Many projects in substation reliability do not directly translate to improvements in outage frequency and duration. This is because the utility's obligation to serve requires substation design criteria which provides redundancy and risk management. Although substation component failures are rare in comparison to feeder components, the loss of a critical substation asset could result in long-term outages affecting thousands of customers. The provision of redundant components, backup sources, and minimization of single points of failure in substation designs reduces this risk and generally allows Pepco to perform routine maintenance and upgrades without the need for planned customer outages. Spares are selected and stocked based on broad usefulness and compatibility with Pepco's existing system and the need to execute a "plug-and-play" solution in emergency conditions. This redundancy also allows Pepco to manage contingencies and continue service despite the loss of a major substation component.

Equipment replacements are usually in-kind or upgrades depending on component availability at the time. System emergencies can alter the timing or prioritization of these projects.

Projects included in the Substation Equipment Proactive Replacement and Spare Purchase Projects group are reflected in PEPCO (I)-2. Pepco generally creates tentative plans under each project based on condition, however system emergencies can alter the timing of these projects.

Substation Supporting Infrastructure Replacements

These projects include the planned replacement of the supporting infrastructure and monitoring equipment and upgrades to facilities in substations. These projects are annual in nature, and Pepco generally creates tentative plans under each project based on condition. System emergencies can alter the timing of these projects. Work performed within these projects are generally in response to failed or failing equipment that needs to be replaced to maintain the overall reliability of the substation and all feeders and customers served by that station.

Budgets and details of Substation Supporting Infrastructure Replacements are reflected in PEPCO (I)-2.

3.2. Past Loadings

3.2.1. Feeder Reliability

Not Applicable.

3.2.2. Substation Reliability

Not Applicable.

3.3. Forecast Loadings

3.3.1. Feeder Reliability

Not Applicable.

3.3.2. Substation Reliability

Not Applicable.

3.4. Identified Need

3.4.1. Feeder Reliability

For information on the identified need for each feeder reliability project, see the project write-ups in PEPCO (I)-2.

3.4.2. Substation Reliability

For information on the identified need of each substation reliability project, see the project write-ups in PEPCO (I)-2.

3.5. Justification

3.5.1. Feeder Reliability

After targets for reliability improvement are identified via statistical analysis or conditional assessment, Pepco takes a two-stage approach to reliability improvement. Reliability projects are first focused on outage prevention and then outage mitigation. Preventing an outage is the primary focus of many reliability projects because this approach reduces both frequency- and duration-based reliability indices and offers the best overall customer experience. Mitigation-focused reliability projects reduce the impacts of an outage by limiting the number of customers affected through sectionalization (via addition of isolation devices on the feeder) and/or limit the duration of an outage through reduced troubleshooting time or automated isolation and restoration schemes. Reliability projects can consist of a multitude of actions aimed at improvement of the reliability on a feeder. In fact, the varied types of outage causes recorded on a feeder over time indicate that there is usually no single best fix for outages at the feeder level but, rather, a mix of remedial activities aimed at gaining the most effective portfolio of solutions on a particular feeder. Additionally, reliability projects can include the addition of monitoring/control systems and devices to feeders that allow Pepco to monitor and redirect the flow of power in real time as well as identify trending issues or locate faults remotely, leading to a reduction in outage frequency and duration.

Depending on the observed issues on a feeder, Pepco has developed standard approaches to remediation. For instance, if a feeder exhibits a propensity for tree-associated outages, in addition to vegetation management, Pepco engineers can elect to replace the bare primary conductor with coated wire that is more resistant to faults caused by tree limbs along sections of the line where tree problems typically occur. If a feeder is frequently subject to animal outages, entire sections of the line could be retrofitted with animal guards and wire covers that would reduce or eliminate future faults caused by animals climbing along the lines. If a section of a feeder served by underground residential cable begins to exhibit frequent cable faults, Pepco can choose to programmatically replace the entire area of underground cable based on the trend in cable outages for the area and the observed condition of the cable.

For information on the justification for each feeder reliability project, see the project write-ups in PEPCO (I)-2.

3.5.2. Substation Reliability

Generally, substation reliability projects cannot be translated into measurable or forecasted SAIDI or SAIFI benefits. The presence of redundant systems within substations reduces or eliminates the direct threat to customer reliability from the loss of a single asset. However, the failure of such

assets reduces the redundancy of the supply to feeders and elevates the risk of large-scale customer outages if another failure was to occur. Given the high potential for customer impacts and the long replacement cycle of major substation assets, Pepco takes steps to replace these assets proactively based on condition assessment and the desire to manage contingency risk and maintain system reliability.

For information on the justification for each substation reliability project, see the project write-ups in PEPCO (I)-2.

3.6. Total Original Cost

3.6.1. Feeder Reliability

For information on the total cost of each feeder reliability project, see the Overview of Projects above and the project write-ups in PEPCO (I)-2.

3.6.2. Substation Reliability

For information on the total cost of each substation reliability project, see the tables included in the Overview of Projects above and refer to the project write-ups in PEPCO (I)-2.

3.7. Work Schedule

3.7.1. Feeder Reliability

For information on the work schedule of each feeder reliability project, see the project write-ups in PEPCO (I)-2.

3.7.2. Substation Reliability

For information on the work schedule of each substation reliability project, see the project write-ups in PEPCO (I)-2.

3.8. Status

3.8.1. Feeder Reliability

For the status of each feeder reliability project, see the project write-ups in PEPCO (I)-2.

3.8.2. Substation Reliability

For the status of each substation reliability project, see the project write-ups in PEPCO (I)-2.

3.9. Benefit-Cost Analysis

3.9.1. Feeder Reliability

The method Pepco currently uses to evaluate benefits for an electric distribution feeder is to measure its improvement in reliability performance. This comparison is made between the feeder's historical reliability performance before corrective action is taken to the reliability performance after the corrective work has been completed. The following figures show the improvement in both overall system performance and in the Priority Feeder and Comprehensive Reliability feeders where work was performed during 2016. In all cases, improvement is shown year over year, and customers are experiencing fewer outages and shorter duration when outages do occur. These results indicate that the Feeder Improvement Program is working and realizing positive results. In the following Figure 3, the year showing the "class" of feeder is the year that the feeder was selected as a Priority Feeder.

Figure 3: District of Columbia Historical SAIFI Performance

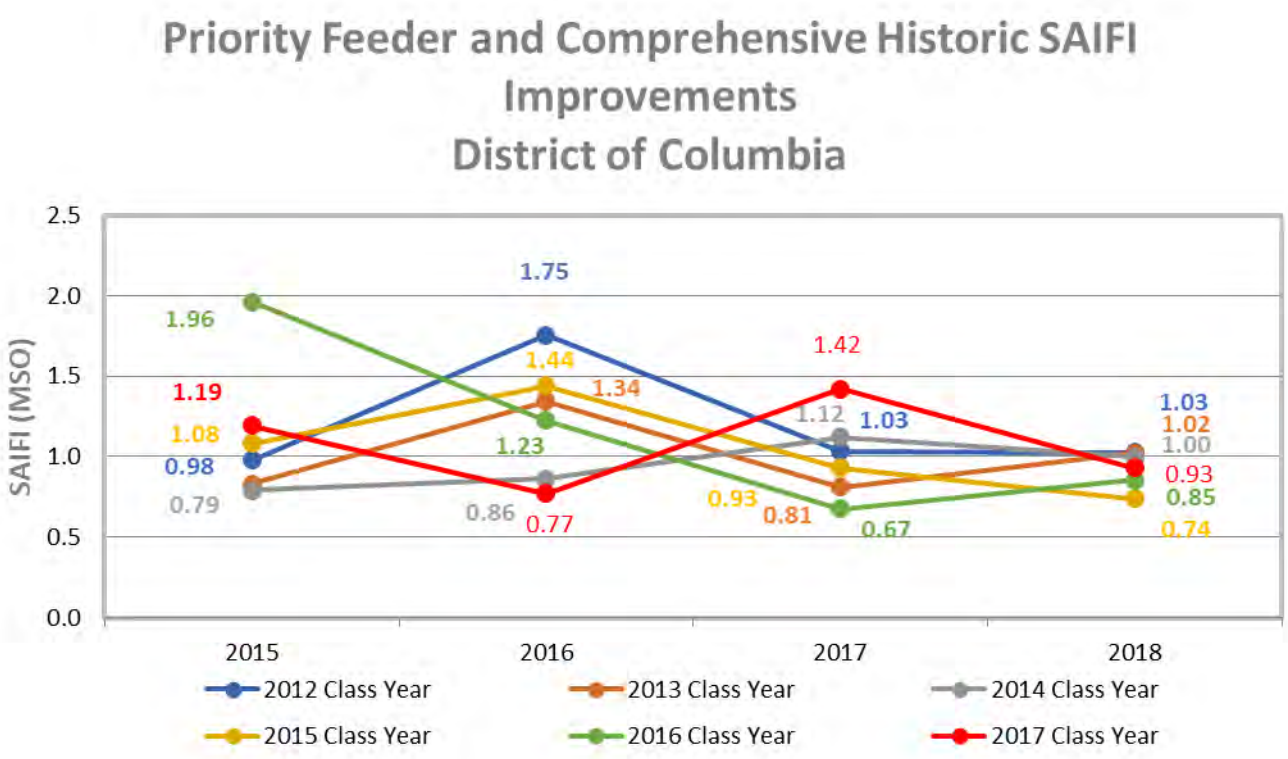


Figure 4: District of Columbia System SAIFI Performance and Projections

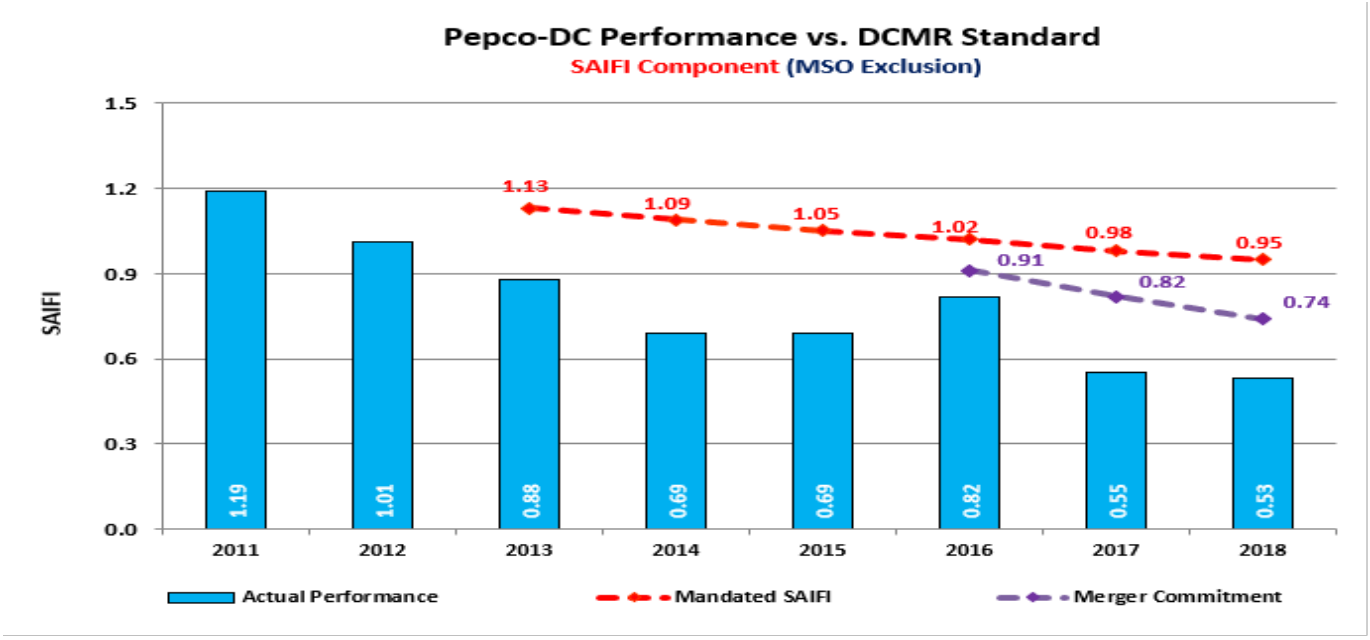


Figure 5: District of Columbia Historical SAIDI Performance

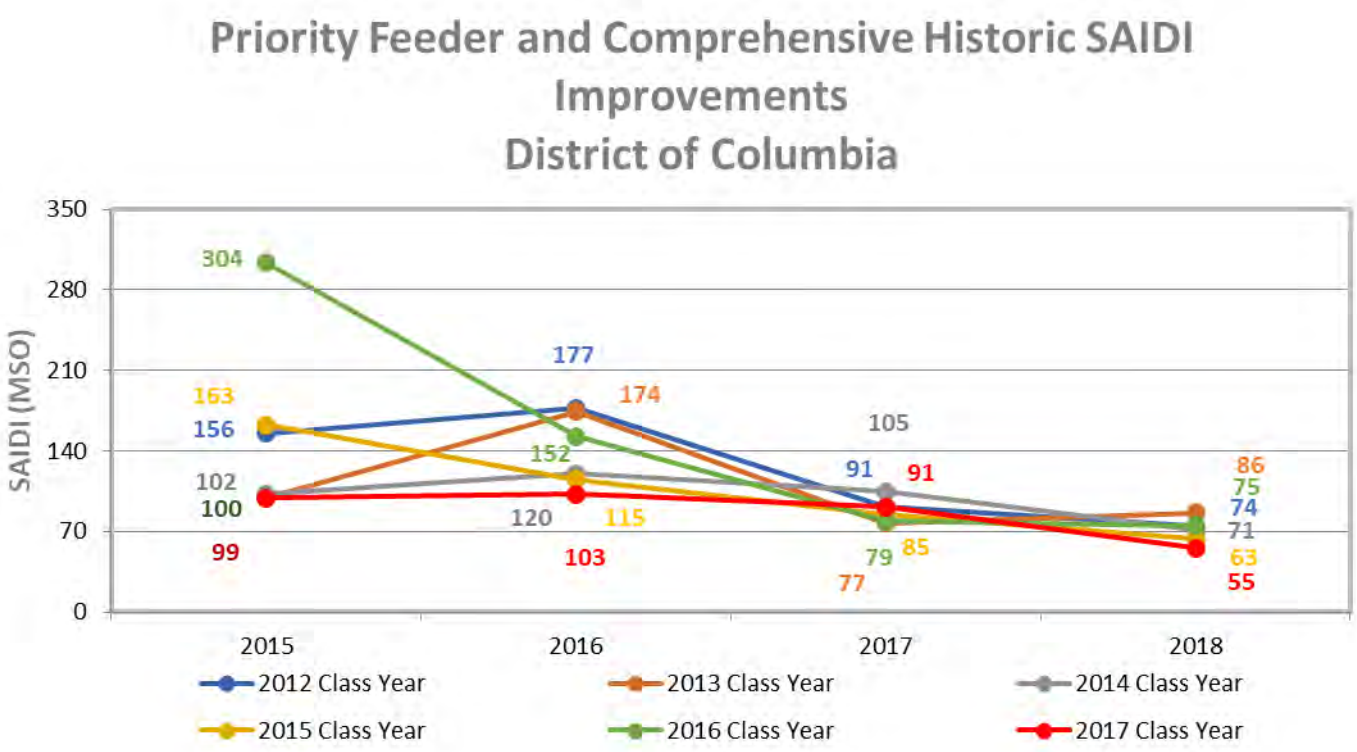
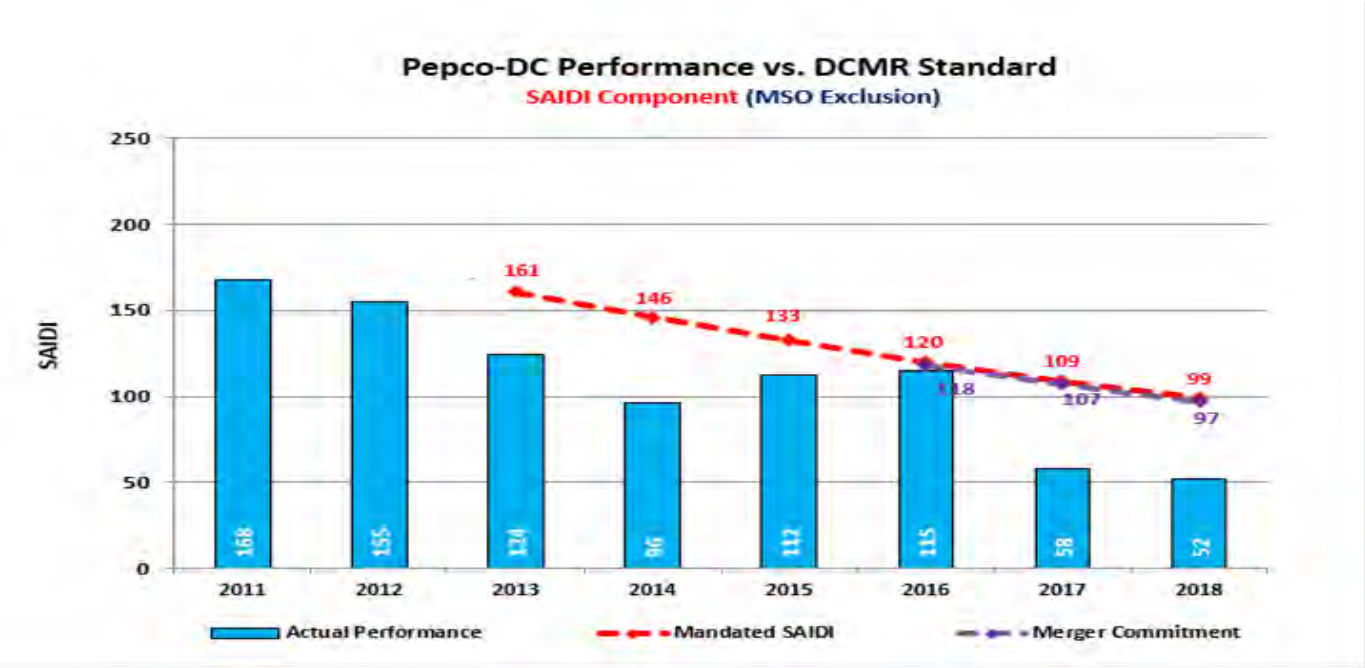


Figure 6: District of Columbia System SAIDI Performance and Projections



Pepco has employed a statistical modeling approach to project and evaluate the expected reliability performance of the electric system based on the impacts of prior reliability enhancement projects. This method uses historical, observed improvements resulting from feeder improvement and DA projects to project the impacts of planned work in these categories against the regulatory reliability targets as well as the PHI-Exelon Merger Commitments. The forecasted results are illustrated in Figure *7* and Figure 8, and reflect that the reliability improvement programs modeled at current planned expenditures levels over the next five years are generally on track to achieve both EQSS goals and Merger Commitments for each year, including up through 2022. Additional SAIDI (and SAIFI) process improvements may also be needed to assure achievement of the regulatory and Merger Commitment goals towards the end of the five-year period, which is typical when attempting to project out over a five year period for system performance. Pepco plans to re-evaluate the statistical approach to project reliability benefits to ensure that the approach is aligned with the Exelon corporate approach to develop reliability projections and Pepco is fully committed to comply with its Merger Commitments.

Figure 7: Pepco DC SAIFI Projections 2018-2022

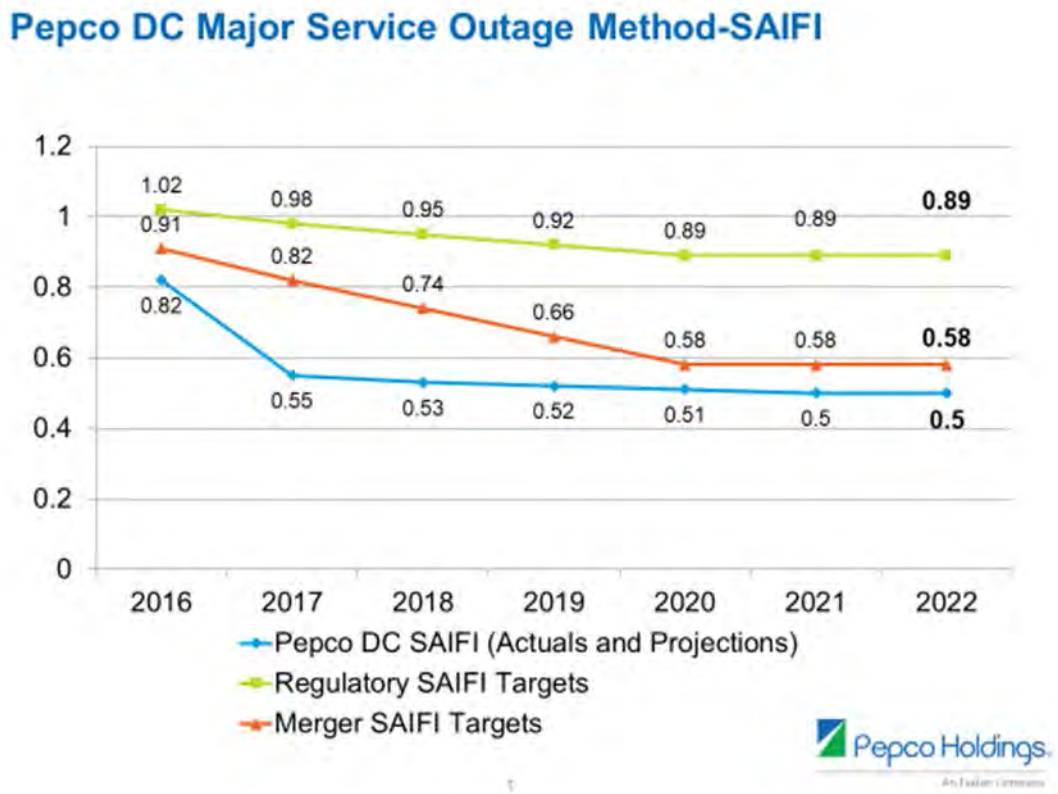
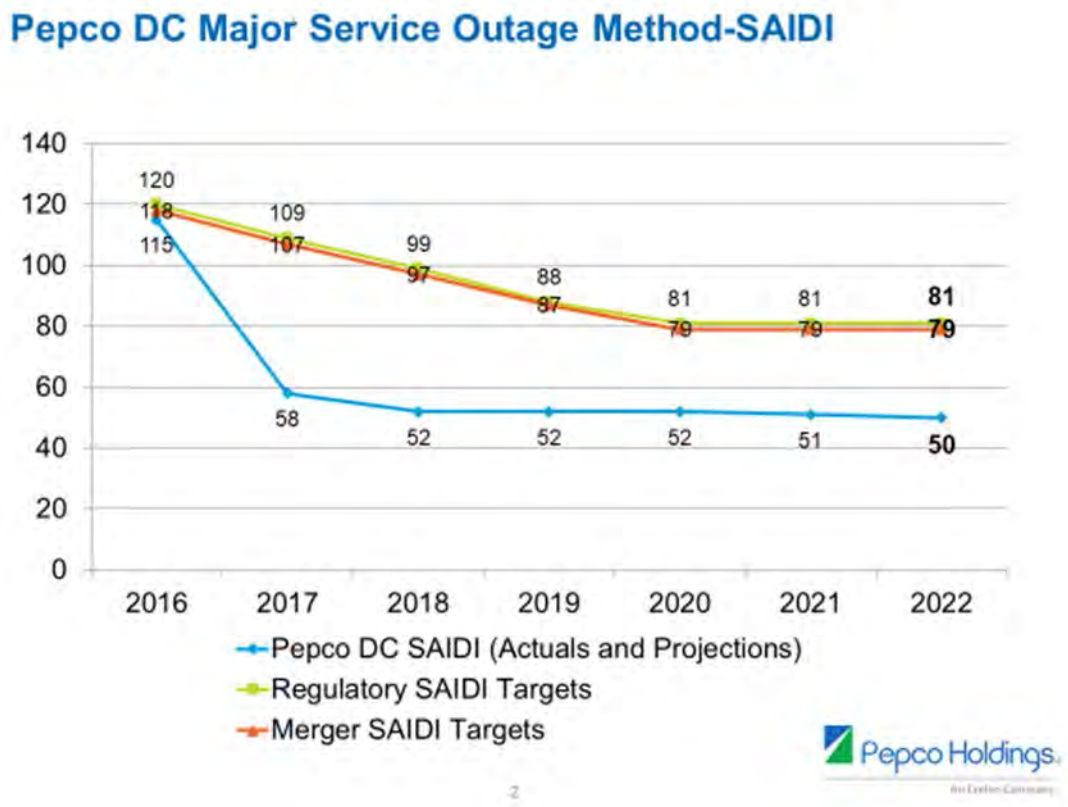


Figure 8: Pepco DC SAIDI Projections 2018-2022



The statistical approach to project future reliability metrics was not designed to be comprehensive in nature and does not model all feeder reliability initiatives underway. For example, the projects designed to replace aging infrastructure will provide reliability benefits but they are not modelled since the prediction of future failures cannot be based on past performance of the equipment such as cables and switchgear.

3.9.2. <u>Substation Reliability</u>

The benefit of the substation reliability program is three-fold: 1) it strives to identify and address failing equipment in a proactive manner in order to replace critical equipment prior to a failure, 2) the procurement of spare critical equipment under the program increases the likelihood that the loss of a critical piece of equipment can be addressed in a timely manner, and 3) repairs are made to substation facilities in order to adequately protect the infrastructure that is housed within them.

The replacement of failing or damaged equipment is considered high-priority work, especially when the loss of the equipment can result in customer outages. Pepco uses spare equipment, when available, to replace the failing equipment. Spares are selected and stocked based on broad usefulness and compatibility with Pepco's existing system and the need to execute a "plug-and-play" solution in emergency conditions. As such, evaluation of cost versus benefits in these

scenarios is not practical. The necessity of these projects speaks clearly to the need to quickly and safely restore power to customers and to reduce system risk. Although the standard design for Pepco substations is for “n-2 contingencies,” or to withstand the loss of two supply lines or transformer with no loss of load, however failure of a third piece of equipment would place the station into a situation in which customer outages would likely occur. This risk is mitigated by the use of spare equipment to replace the failing or damaged equipment. The risk of a substation outage would impact thousands of customers and could extend for prolonged periods of time if new equipment had to be purchased. In addition, acquiring and storing spare and replacement equipment ahead of time is the longer-term lowest-cost option because Pepco is able to bid and procure the equipment in a normal competitive bid process. Obtaining equipment at the time of a failure results in paying a premium price, limits availability of equipment, and results in long lead times to procure the equipment.

3.10. Alternatives

3.10.1. Feeder Reliability

For information regarding identified alternatives to feeder reliability projects, see the project write-ups in PEPCO (I)-2.

3.10.2. Substation Reliability

Alternatives for substation reliability projects are typically limited to replacement of the equipment given the unique nature of the infrastructure.

For information of identified alternatives to each substation reliability project, see the project write-ups in PEPCO (I)-2.

3.11. Priorities

3.11.1. Feeder Reliability

As noted in the Overview of Projects, Pepco considers two types of feeder reliability projects: Reliability Performance Feeders and Proactive Replacement Feeders. The Overview of Projects section for each type of project identifies the priorities for addressing reliability for the respective feeder reliability categories, namely performance-based reliability issues for Reliability Performance Feeders and condition-based reliability issues for Proactive Replacement Feeders. Refer to the Overview of Projects for a detailed discussion about the feeder selection criteria used to prioritize feeders selected under each type of program.

3.11.2. Substation Reliability

As noted in the Overview of Projects section for Substation Reliability above, Pepco uses RCM to identify failing assets prior to failure. The condition and criticality of the failing assets is considered as part of the ECA process when prioritizing the replacement of substation equipment. Refer to the Overview of Projects section for details around the RCM and ECA processes used to prioritize substation reliability projects.

3.12. Source of Funds

3.12.1. Feeder Reliability

Refer to the Source of Funds section at the beginning of this Report.

3.12.2. Substation Reliability

Refer to the Source of Funds section at the beginning of this Report.

3.13. Related Government Action

EQSS Standards

The majority of the projects described herein are being performed according to the timeline required to meet and exceed the Commission's EQSS standards,[3] as modified by the Merger Commitments approved in Order No. 18148. These stringent reliability standards require Pepco to pursue more aggressive schedules and scopes for required reliability work to enable Pepco to meet the more stringent standards.

3.13.1. Feeder Reliability

The Commission's reliability standards, including those related to Merger Commitments, are the only government action impacting feeder reliability projects.[4]

3.13.2. Substation Reliability

The Commission's reliability standards and Merger Commitments, given the impact of substations on overall reliability, is the only government action impacting substation reliability projects.

[3] Formal Case No. 982, *In the Matter of the Investigation of the Potomac Electric Power Company Regarding Interruption to Electric Energy Service* ("F.C. No. 982"); and F. C. No. 1002, *In the Matter of the Joint Application of Pepco and the New RC, Inc. for Authorization and Approval of Merger Transaction, Notice of Final Rulemaking* dated February 24, 2012, §3603.11

[4] DC PLUG is not subject to the instant proceeding and has been excluded from this report.

4. Emergency Restoration

4.1. Overview of Projects

Projects included in the Emergency Restoration category provide Pepco with the backup equipment and response services required to expediently respond to the existence of conditions in which customers are out of service or portions of the electric system are at an unusually high risk due to the distribution system being in a contingency configuration or when temporary repairs exist after a storm or similar event. Outages or risks that would be addressed by these projects may be caused by severe weather, external factors (such as vehicle accidents, dig-ins, or vandalism), or unexpected component failures. When outages occur as a result of these events, the larger grid's reliability is compromised, often requiring emergency replacement of portions of the electric infrastructure.

Pepco has created these projects for such situations, and the annual budgets are based on historic expenditures. In some cases, particularly for large substation-based components, Pepco strategically stocks spare components that have long lead times for procurement, such as substation breakers or transformers. If called upon, the spare components inventory is later replaced under these project budgets in preparation for future events.

Pepco generally replaces damaged equipment with spare components. Spares are selected and stocked based on broad usefulness and compatibility with Pepco's existing system, offering the most flexibility to deliver solutions under emergency conditions. Details and budgets for Emergency Restoration projects are reflected in PEPCO (I)-2. Past Loadings

Not Applicable

4.2. Forecast Loadings

Not Applicable

4.3. Identified Need

For information on the identified need for each Emergency Restoration project, see the write-up in PEPCO (I)-2.

4.4. Justification

For information on the justification for each Emergency Restoration project, see the write-up in PEPCO (I)-2.

4.5. Total Original Cost

For information on the total cost of each Emergency Restoration project, see the Overview of Projects above and the write-up in PEPCO (I)-2.

4.6. Work Schedule

Emergency Restoration projects are typically done in response to unforeseen events on an as-needed basis. As such, the work schedule for these projects is determined by need rather than scheduled in advance. That said, any detail on the work schedule for each Emergency Restoration project that can be scheduled is included in the write-up in PEPCO (I)-2.

4.7. Status

For information on the status of each Emergency Restoration project, see the write-up in PEPCO (I)-2.

4.8. Benefit-Cost Analysis

Pepco's primary obligation is to serve Pepco customers, manage personnel and public safety, and minimize risk to the system. As a result, replacing failed or damaged equipment is considered the highest priority work, especially when the failure or damage results in customer outages. The cost of not performing this work would result in indefinitely extended outages or widespread damage to customer and Pepco equipment and potentially present a hazardous situation. The benefits of these projects include the reduced risk of extended outages as well as the ability to better forecast emergency response budgets. The need to quickly and safely restore power and minimize system risks themselves speak clearly to the necessity of these projects and the Company's obligation to provide a safe and reliable distribution system.

4.9. Alternatives

For information on the identified alternatives to Emergency Restoration projects, see the write-up in PEPCO (I)-2.

4.10. Priorities

Priorities of each Emergency Restoration project are considered high, and these projects are needed to ensure the restoration work can be accomplished.

4.11. Source of Funds

For information on the source of funds for each Emergency Restoration project, refer to the Source of Funds section at the beginning of this Report.

4.12. Related Government Action

Not Applicable.

5. 4kV to 13kV System Work

5.1. Overview of Projects

This chapter covers projects related to the conversion of parts of the distribution system in the District of Columbia from 4kV to 13kV and the maintenance of the remaining 4kV system. While the 4kV system has provided an effective and reliable supply to Pepco customers for many years, the 4kV system is an aging, lower-capacity distribution system supplying power to various neighborhoods in the District of Columbia. This system, which today provides capacity for 135 megawatts of load through the District of Columbia, was once the main system of supply to distribution customers in and around the District of Columbia. However, beginning in the 1970's parts of this system were retired in surrounding Prince George's and Montgomery counties as these areas began growing and becoming more dense. Subsequently, beginning in the 1990's, Pepco began retiring portions of the 4kV system in the District of Columbia in areas where there was high growth, where the system was isolated with no backup and where it was determined to be economically beneficial in the longer-term to convert the 4kV rather than maintain it by replacing aging infrastructure as it reached its useful end of life. Conversely, portions of the 4kV, particularly in Northeast and Northwest DC, have maintained reliable operations and have been updated and maintained, and it is Pepco's plan to maintain these portions of the 4kV distribution system into the future. Generally the overhead constructed 4kV system has the greatest potential for continued operation and by replacing substation transformers will continue to provide reliable service. The underground constructed system has little potential for upgrades to prolong the life of the cable system and will require complete replacement and conversion to 13kV operations. These projects are prioritized based on reaching full capacity and future load growth or on operational performance. In all cases, routine replacement and upgrades are performed until the individual systems are replaced.

While it is Pepco's intention to continue to operate the portions of the 4kV system for as long as feasible given the condition of equipment and expected loading, portions of the system can no longer provide capacity for load density needed and require upgrade, while other portions of the system will require replacement in the short-term due to their condition. Moreover, portions of the system are sufficient for continued operations, but require incremental investments to improve reliability. Table 9 provides relevant statistics for the 4kV system over time.

Table 9: Evolution of the Pepco DC 4kV Distribution System

Pepco DC 4kV Distribution Statistics				
Year	Capacity (Approx. MW)	Substations	Transformers	Feeders
1997	-	39	70	-
2007	170	31	52	144
2016	135	27	45	112
2025	100	19	26	66

Allowing for load growth, under current projections, approximately 100 megawatts will remain on the 4kV distribution system in the year 2025. This 4kV load will be located primarily in Wards 3, 7 and 8 where the load is served by substations that have either multiple transformers or are networked together through the feeder primaries. These 4kV areas in Wards 3, 7 and 8 are reliable due to the shortness of the feeders and the availability of ready backup. Areas of low-planned load growth will be maintained and not converted. In these cases, the work will involve upgrading of substation transformer equipment and other supporting equipment.

Accordingly, Pepco conducts a variety of projects on the 4kV system, generally falling into the following categories:

- Load Relief – sections of the 4kV system that can no longer meet the capacity needs are retired and customers are reconnected to new 13kV distribution equipment
- Reliability – sections of the 4kV system that can no longer reliably provide service to customers are retired and customers are reconnected to new 13kV distribution equipment
- Support of Continued Operations – where appropriate, Pepco installs new equipment on the existing 4kV system to enhance its reliable and continued operation

Details of 4kV Voltage Conversion projects undertaken by Pepco since 2016 to address load relief, reliability and support of continued operations on the 4kV distribution system are reflected in PEPCO (I)-2.

5.2. Past Loadings

Not Applicable

5.3. Forecast Loadings

Not Applicable

5.4. Identified Need

For information on the identified need for each 4kV Voltage Conversion project, see the project write-ups in PEPCO (I)-2.

5.5. Justification

The justifications for individual projects may be found in the project write-ups in PEPCO (I)-2. Overall, however, the projects that Pepco undertakes on the 4kV system are guided by the detailed and comprehensive Long Range Study 4kV Distribution System 2007.

The Long Range Study 4kV Distribution System 2007 is a highly detailed analytical assessment of the 4kV system and all of its individual components. As part of this study, Pepco conducted a detailed in-the-field assessment of transformers, breakers, and cables supplying power to customers in the system. This evaluation led to the creation of the following recommendations:

1. Maintain current operations at substations not requiring immediate work, but reduce loadings whenever possible through 4kV-to-13kV conversions or installing 13kV-to-4kV step down transformers;
2. Retire single supply 4kV substations with no network feeder back-up, and substations with reliability issues through either 4kV-to-13kV conversions or installing 13kV-to-4kV step down transformers;
3. Closely monitor and maintain the health of 4kV substations that are not slated for immediate retirement; and
4. Salvage usable 4kV breakers and transformers from converted substations and reuse them on other parts of the 4kV system, as required.

5.6. Total Original Cost

For information on the total cost of each 4kV to 13kV System Work project, see the tables included in the Overview of Projects above and refer to the project write-ups in PEPCO (I)-2.

5.7. Work Schedule

For information on the work schedule for each 4kV to 13kV System Work project, see the project write-ups in PEPCO (I)-2.

5.8. Status

For information on the status of each 4kV to 13kV System Work project, see the project write-ups in PEPCO (I)-2.

5.9. Benefit-Cost Analysis

As noted in the Overview of Projects above, the 4kV system in the District of Columbia is aging and comprised of low capacity feeders. The analytical assessment conducted as part of the Long Range Study 4kV Distribution System 2007 determined that upgrading the system to 13kV is the most cost-effective approach to maintain service where load growth and reliability issues arise.

5.10. Alternatives

For information on the identified alternatives to 4kV to 13kV System Work projects, see PEPCO (I)-2.

5.11. Priorities

As noted in the Overview of Projects above, Pepco prioritizes conversion of the 4kV system that can no longer provide capacity to meet growing load density and when aging equipment (*i.e.*, transformers, breakers and cables supplying power to customers) requires replacement, or is needed to support continued operations.

5.12. Source of Funds

For information on the source of funds for each 4kV to 13kV System Work project, refer to the Source of Funds section at the beginning of this Report.

5.13. Related Government Action

Not Applicable.

6. Customer-Driven Projects

6.1. Overview of Projects

Customer-driven projects are performed in response to customer requests used to cover a broad project type as they occur throughout the service territory. For example a Customer-driven project might be relocation of Company facilities due to street modification being performed by the District of Columbia Department of Transportation. In these cases Pepco occupies the street right of way by permit and is required to relocate our facilities upon request but at our cost. In order to have the necessary budgets in place, Pepco uses a six-year historical average of customer additions, analysis of current industry trends, and an analysis of new loads based on prospective new business.

As businesses, public entities, and individuals move into and expand within the District of Columbia, Pepco must accommodate the customer needs by upgrading infrastructure and providing new services in both existing and new locations. As a result, Pepco budgets for projects that respond to customer requests and maintains the capabilities of Pepco's distribution system as customer-sited technologies and facilities are introduced. These projects are meant to integrate customers into the system, and are separate from projects meant to respond to load growth at existing customer sites and the aggregate impact of load growth in regions of the District of Columbia that require system upgrades beyond the point of interconnection – the latter types of projects are reflected in the Load category.

Depending on the technical criteria of a customer request, and according to the Tariff, customers requesting customer-driven projects may be required to pay for some or all of the costs associated with modifications to Pepco infrastructure. The budgets established by Pepco are the net anticipated expenditures after taking into consideration historical levels of contributions in aid of construction.

Details of Customer Driven projects are reflected in PEPCO (I)-2.

6.2. Past Loadings

Not Applicable

6.3. Forecast Loadings

Not Applicable

6.4. Identified Need

For information on the identified need for each Customer-driven project, see the project write-up

in PEPCO (I)-2.

6.5. Justification

For information on the justification for each Customer-driven project, see the project write-up in PEPCO (I)-2.

6.6. Total Original Cost

For information on the total cost of each Customer-driven project, see the tables in the Overview of Projects above and the project write-up in PEPCO (I)-2.

6.7. Work Schedule

For information on the work schedule for each Customer-driven project, see the project write-up in PEPCO (I)-2.

6.8. Status

For information on the status of each Customer-driven project, see the project write-up in PEPCO (I)-2.

6.9. Benefit-Cost Analysis

Not Applicable

6.10. Alternatives

For information on the identified alternatives to Customer-driven project, see the project write-up in PEPCO (I)-2.

6.11. Priorities

Not Applicable

6.12. Source of Funds

For information on the source of funds for each Customer-driven project, refer to the Source of Funds section at the beginning of this Report.

6.13. Related Government Action

Not Applicable.

7. Other Projects

7.1. Overview of Projects

There are eight categories of projects captured under the Other Projects chapter. They include:

- Communications,
- Substation Retirements,
    - Benning Retirement,
- DC Power Line Undergrounding Program,
- Security,
- Facilities,
- Accruals,
- Subtransmission, and
- Miscellaneous.

These are projects that support the entire electric system and, as such, are allocated across the Pepco service area as well as between transmission and distribution accounts. They also support the safe and reliable operation of the distribution system in the District of Columbia (*i.e.*, communications, security and facilities), cover the expenses associated with retiring facilities that have exceeded their useful life, and include costs allocated to Pepco in the District of Columbia for subtransmission projects conducted under Maryland WBS codes, among others.

7.1.1. Communications Projects

These projects include expansion of the fiber optic communication system, installation of communication system to support new substation projects, upgrades to and the replacement of communications equipment such as radios, and systems used by Pepco's various distribution automation systems to transmit data, establish controls of distributed equipment, or monitor field sensors. Details of Communications projects are reflected in PEPCO (I)-2.

7.1.2. Substation Retirements

These projects include the planned retirements of existing substations that are no longer needed to serve load in the District of Columbia or are retired due to new substations coming online. These substation retirement projects typically occur on an as-needed basis based on system need.

Details of projects associated with the retirement of substations are reflected in PEPCO (I)-2.

7.1.3. Security

These projects are undertaken to ensure the physical security of the Pepco distribution system in the District of Columbia. Details of the projects included in this group are reflected in PEPCO (I)-2.

7.1.4. Facilities

These projects are carried out to maintain and construct non-substation facilities, purchase equipment and supplies (*i.e.*, office furniture and Vehicle Resources Management tools) for employees, and implement green and electric vehicle (EV) initiatives. Details of projects included in this group are reflected in PEPCO (I)-2.

7.1.5. Accrual Projects

These projects are financial accrual accounts for new load and reliability projects. These accruals reflect a timing difference as to when the Company is responsible for an expense and when the actual expenditures are made. These expenditures normally result due to the difference in the timing of contractor payments or material delivery and when an invoice is actually paid. Over a period of months these accruals and expenditures will balance. Details of projects included in this group are reflected in PEPCO (I)-2.

7.1.6. Pepco Maryland Projects with Expenditures Allocated to Pepco DC

The allocated projects are mainly related to the 69kV subtransmission systems, but also includes shared facilities, IT and communications related projects. The allocations of expenditures for these projects are reflected in PEPCO (I)-3 and (I)-2 for allocated projects.

7.1.7. Miscellaneous

These are a collection of projects that do not closely align with the other categories included in this Report. Details of the projects included in this group are reflected in PEPCO (I)-2.

7.2. Past Loadings

Not Applicable

7.3. Forecast Loadings

Not Applicable

7.4. Identified Need

For information on the identified need for each Other project, see PEPCO (I)-2.

7.5. Justification

For information on the justification for each Other project, see PEPCO (I)-2.

7.6. Total Original Cost

For information on the total cost of each Other project, see the tables included in the Overview of Projects above and the project write-ups in PEPCO (I)-2.

7.7. Work Schedule

For information on the work schedule for each Other project, see PEPCO (I)-2.

7.8. Status

For information on the status of each Other project, see PEPCO (I)-2.

7.9. Benefit-Cost Analysis

Not Applicable

7.10. Alternatives

For information on the identified alternatives to each Other project, see PEPCO (I)-2.

7.11. Priorities

Not Applicable

7.12. Source of Funds

For information on the source of funds for each Other project, refer to the Source of Funds section at the beginning of this Report.

7.13. Related Government Action

Not Applicable.

8. Feeder Reliability Improvement Report

The Commission has directed Pepco to report on the outage performance of groups of feeders included in ASR schemes, including both the outages when and ASR operates and when it does not. Furthermore, the Commission requested feeder-by-feeder outage data for each feeder included in any of Pepco's feeder improvement programs. The Commission stated that this reporting should start with those feeders worked on in 2012, and future reports should track the performance of these "Class of 2012" feeders for five years, along with succeeding "classes" in the future.

8.1. ASR Scheme and Non-ASR Switch Benefits

Pepco began using ASRs in 2008 after completion of a pilot in its Maryland service area. Based on the experience in Maryland, Pepco engineered and deployed ASR schemes in the District of Columbia. Pepco activated its first ASR scheme in the District in 2012. As of December 2018, there are 26 feeders organized into 3 DC ASR schemes, plus 2 feeders belonging to a Maryland scheme but serving DC customers. This gives a total of 28 feeders that serve the District of Columbia. Table 10 provides a listing of all ASR feeders deployed in the District of Columbia.

Table 10: ASR Schemes Deployed in District of Columbia

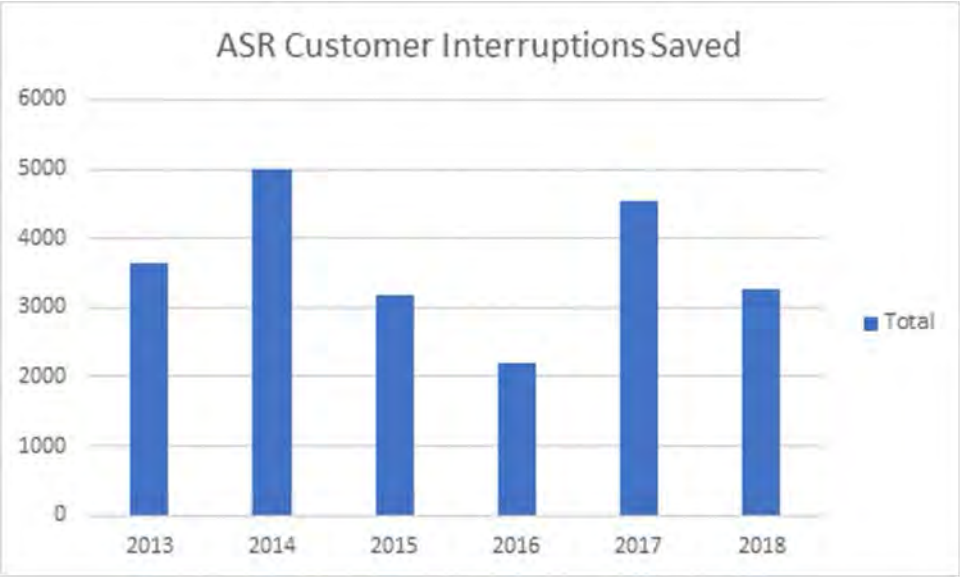
Scheme Name	kV	Subs	Feeders	In Service Date	Current Status
Benning-Tuxedo	13	2	14717 15705 15706 15707 15709 15710 15130	10/3/2012	In-service
12th & Irving-Fort Slocum	13	4	14007 14015 15009 15010 15014	8/8/2013	In-service
2017 expansion in 12th & Irving	13	2	14006 14200	Q4 2017	In Service
Harrison-Van Ness	13	3	14136 14133 14135 14765 14767 14768 14890 14896 14900 15801 15943	8/25/2013	In-service
2017 expansion in Van Ness	13	1	14132	2017Q4	In-Service
Takoma (Van Ness ASR Scheme and MC4 Scheme in Maryland)	13	1	15199 15200	6/2016 Q4 2017	In-service

Since activation of the first ASR scheme in 2012, ASR schemes deployed in the District of Columbia have allowed for the avoidance of approximately 22,000 customer interruptions. The following two pages contain six figures showing the impact of ASR schemes on reliability on the Pepco system.

- Figure 9 shows the number of customer interruptions that were saved associated with the ASR schemes activated from 2013-2018.

Benefits of the ASR schemes are based on calculations of outages avoided measured in terms of CI and CMI. For example, without an ASR scheme, customers upstream of a fault would experience an outage when the fault occurs. With an ASR scheme in place, these same upstream customers are automatically switched over to be fed from another source and do not experience an outage when the fault occurs. Thus, for these customers, the benefit of an ASR scheme can be measured in terms of CI and CMI avoided.

Figure 9: District of Columbia 2013-2018 Activated ASR Scheme – Customer Interruptions Saved



8.2. Feeder Improvement Program Benefits

The measurement of benefits associated with the Worst Performing Feeder Program (also called "2% Feeders" or "Least Performing Feeders") feeder reliability projects can be determined by the performance of the feeders before and after the improvement projects are carried out. As shown in Table 11 and Table 12 below, the feeders that have been worked on as a part of the Worst Performing Feeder and Comprehensive Feeder Programs have demonstrated marked improvements in reliability as measured by the feeder-level SAIFI and SAIDI.

Table 11: Pepco DC Reliability Improvement Feeder SAIFI Performance (MSO)

	Beginning SAIFI	2018 SAIFI	% SAIFI Improvement
2012 Class Year Improvement Feeders	2.31	1.03	-55.61%
2013 Class Year Improvement Feeders	1.90	1.02	-46.23%
2014 Class Year Improvement Feeders	1.28	1.00	-21.91%
2015 Class Year Improvement Feeders	1.08	0.74	-31.51%
2016 Class Year Improvement Feeders	3.56	0.85	-76.02%
2017 Class Year Improvement Feeders	3.25	0.93	-71.38%

Table 12: Pepco DC Reliability Improvement Feeder SAIDI Performance in Minutes (MSO)

	Beginning SAIDI	2018 SAIDI	% SAIDI Improvement
2012 Class Year Improvement Feeders	301.4	74.5	-75.29%
2013 Class Year Improvement Feeders	203.7	86.4	-57.60%
2014 Class Year Improvement Feeders	166.2	71.2	-57.13%
2015 Class Year Improvement Feeders	132.6	63.2	-52.37%
2016 Class Year Improvement Feeders	382.2	75.0	-80.37%
2017 Class Year Improvement Feeders	330.7	55.5	-83.23%

*Beginning SAIFI and SAIDI are as measured one calendar year prior to the feeder mitigation year. For example, the Beginning SAIFI and SAIDI for 2012 Worst Performing Feeders are as measured between January 1, 2011 and December 31, 2011.

The feeder reliability improvement projects are designed to work in conjunction with each of the reliability components, and therefore the benefit-cost per component would be different and difficult to isolate on an individual feeder basis. Pepco reviews each feeder to be worked on and determines the extent of equipment replacement and feeder upgrade that is needed based on physical inspection of the line and past reliability performance. Each feeder is reviewed to identify other initiatives that involve these feeders such as load related upgrades, distribution automation or customer related upgrades. After a detailed review has been completed a coordinated plan is developed so that the combined benefits from each of these initiatives can be realized. Therefore, evaluating a feeder in its entirety, and not by individual initiative, is the only accurate comparison.

8.3. Feeder Level Outage Data

The following tables show the annual feeder-level outage data for feeders improved in a given year, summarized by the number of total Customer Interruptions (CI) as well as total Customer Minutes of Interruptions (CMI) seen during the year. For example, Table shows the CI and CMI for each year from 2013 to 2017 for each feeder that was improved in 2013 as part of the Worst Performing Feeder Program, Comprehensive Feeder Program or ASR Scheme roll-out. The subsequent tables show CI and CMI over time for feeders improved in 2013 (see Table 13), 2014

(see

Table 14), 2015 (see Table 15), 2016 (see Table 16), and 2017 (see Table 17). CI and CMI indicate the totals from the outage events, rather than the averages represented by the SAIFI and SAIDI metrics. Not every feeder will experience outages in a given year, so only those feeders that have been worked on under Pepco's Worst Performing Feeders, Comprehensive Feeders, and ASR Schemes, are included in these tables (MSO exclusive outages only).

Table 13: Pepco DC 2013 Feeder Year – Aggregated Feeder Level Outage Data

2013 Feeder Year - Aggregated Feeder Level Outage Data																
Feeder	Substation	2013 Worst Performing Feeder	2013 Comprehensive Feeder	2013 ASR Scheme	2013 CI	2013 CMI	2014 CI	2014 CMI	2015 CI	2015 CMI	2016 CI	2016 CMI	2017 CI	2017 CMI	2018 CI	2018 CMI
15707	Benning A23013 7	Yes	No	No	10,162	831,973	5,456	619,746	5,041	1,224,171	301	51,250	656	44,437	878	37,346
14006	12th Irving 133	Yes	No	No	2,155	129,890	2,222	103,061	2,324	75,000	924	22,933	13	2,727	1	84
15705	Benning A23013 7	Yes	No	No	2,518	173,956	4,680	916,621	191	27,009	11,487	1,910,102	2947	238,597	476	67,570
14014	12th Irving 133	Yes	No	No	7,152	931,392	5,732	603,403	2,266	126,799	7,268	617,421	8147	586930.1	2691	124716.2
15943	Van Ness 129	No	No	Yes	83	20,160	2,133	32,213	5,059	667,309	1,810	87,495	124	31,080	217	38,830
15710	Benning A23013 7	Yes	No	No	8,251	1,004,007	268	90,926	127	15,536	4,756	369,623	546	22,239	2,443	203,554
14009	12th Irving 133	Yes	No	No	2,490	409,806	712	206,254	313	45,671	4,224	859,418	75	6,690	864	65,202
15166	Alabama Ave 136	Yes	No	No	12,081	802,462	68	16,205	2,073	53,689	1,489	174,974	93	4,819	495	106,706
14896	Harrison13 38	No	No	Yes	0	0	0	0	0	0	0	0	0	0	0	0
14788	New Jersey 161	Yes	No	No	5	809	1,134	406,973	104	10,327	345	90,836	2	106	32	2,490
14900	Harrison13 38	Yes	No	Yes	3,017	148,596	155	48,749	3,022	114,371	1,700	90,604	1226	146,175	5,855	248,480
15174	Alabama Ave 136	Yes	No	No	11,443	609,843	2,436	230,781	451	66,915	2,542	123,323	5060	503,595	1407	29,888
14001	12th Irving 133	Yes	No	No	62	20,016	314	62,876	706	112,187	164	52,750	72	4,570	56	15,372
15801	Little Falls 77	Yes	No	Yes	2,374	313,204	216	43,180	1,516	28,949	2,506	309,510	11	1,729	708	85,835
15206	Tenth St 52	No	Yes	No	4,285	1,230,636	564	135,764	60	11,534	114	12,136	187	39,045	1818	342755
15945	Van Ness 129	Yes	No	No	1,904	262,127	1,324	92,421	70	13,200	1,281	87,706	1434	164887	1148	72,498
14767	Little Falls 77	No	No	Yes	155	40,081	1,866	215,986	881	238,537	2,802	275,204	1350	119137.1	3106	389,869
14787	New Jersey 161	Yes	No	No	452	64,216	384	122,740	116	33,209	2,165	727,933	1973	220658.9	1040	266,715
14135	Van Ness 129	No	No	Yes	651	78,211	263	71,473	905	31,586	62	9,915	1786	343515.2	2166	184,474
15015	Ft Slocum 190	No	Yes	No	814	132,585	259	33,982	4,507	409,820	1,204	45,944	205	44229.57	3396	219,471
15014	Ft Slocum 190	No	No	Yes	201	10,765	3,628	264,355	1,161	23,366	7,631	387,928	66	7545.067	1459	78,772
14890	Harrison13 38	No	Yes	Yes	922	43,209	35	3,502	1,313	143,789	29	3,695	4	307.1333	351	24,380
15009	Ft Slocum 190	No	No	Yes	2,465	115,355	3,043	211,952	114	18,188	3,833	264,080	179	18017.25	119	13,401
14703	Anacostia13 8	No	Yes	No	2,058	448,903	72	6,473	0	0	0	0	0	0	0	0
15703	Benning A23013 7	No	Yes	No	497	146,992	79	28,799	112	23,487	864	231,593	2619	199748.9	1050	153,497
14007	12th Irving 133	No	Yes	Yes	1,929	132,623	89	11,514	30	4,566	727	72,937	36	3169.7	700	48,992
14786	New Jersey 161	Yes	No	No	3,068	449,914	1,388	131,384	3,872	391,141	1,698	575,761	1359	163685.8	1711	329,506
147	Harvard4 13	No	Yes	No	1,803	406,959	127	29,841	0	0	0	0	0	0	0	0
14765	Little Falls 77	No	No	Yes	330	67,458	1,143	134,460	1,014	42,168	1,021	82,740	145	12626.92	404	75,877
308	Harrison4 38	No	Yes	No	0	0	596	7,502	1	236	5	547	1	204.5167	574	46,664
14768	Little Falls 77	No	No	Yes	0	0	0	0	0	0	0	0	0	0	0	0
15021	Ft Slocum 190	No	Yes	No	5,271	667,406	2,329	221,797	2,289	296,156	509	70,752	7644	647393.3	9240	478,203
14200	12th Irving 133	Yes	No	No	2,997	52,141	2,522	71,195	4,090	929,852	4,357	322,131	190	20193.73	1709	139,084
14015	12th Irving 133	No	Yes	Yes	520	118,317	280	41,818	30	5,762	1,524	132,776	96	19978.58	1323	120,739
14145	Van Ness 129	No	Yes	No	102	13,139	106	74,403	2	419	108	25,807	785	99613.35	348	28,596
325	Ft Carroll 130	No	Yes	No	442	40,710	30	3,690	0	0	0	0	0	0	0	0

Table 14: Pepco DC 2014 Feeder Year – Aggregated Feeder Level Outage Data

2014 Feeder Year - Aggregated Feeder Level Outage Data														
Feeder	Substation	2014 Worst Performing Feeder	2014 Comprehensive Feeder	2014 ASR Scheme	2014 CI	2014 CMI	2015 CI	2015 CMI	2016 CI	2016 CMI	2017 CI	2017 CMI	2018 CI	2018 CMI
14717	Benning A23013 7	Yes	No	No	7,248	819,150	3,115	832,258	12,003	1,321,987	12160	810,683	5,508	151,225
14136	Van Ness 129	Yes	No	No	2,818	762,335	376	69,035	3,188	121,220	420	25,637	1,622	168,938
14758	NRL 168	Yes	No	No	4,386	404,110	2,619	96,663	9,089	414,618	2,154	121,226	2707	200,696
333	Chesapeake 181	No	Yes	No	1,654	251,363	2	568	0	0	73	3917.667	1	75.86667
15206	Tenth St 52	No	Yes	No	564	135,764	60	11,534	114	12,136	187	39,045	1818	342,755
14004	12th Irving 133	No	Yes	No	844	208,423	219	31,754	290	31,234	486	66,132	2,126	65,652
14769	Little Falls 77	No	Yes	No	0	0	0	0	0	0	0	0	0	0
14753	NRL 168	Yes	No	No	72	4,116	7	1,795	1714	199,203	163	10,218	48	9,189
14890	Harrison13 38	No	Yes	No	35	3,502	1,313	143,789	29	3,695	4	307	351	24,380
15009	Ft Slocum 190	Yes	No	No	3,043	211,952	114	18,188	3,833	264,080	179	18,017	119	13,401
14703	Anacostia13 8	No	Yes	No	72	6,473	0	0	0	0	0	0	0	0
97	Ft Chaplin 70	No	Yes	No	212	19,104	8	1,568	1532	117,036	24	5,360	10	1,342
15703	Benning A23013 7	No	Yes	No	79	28,799	112	23,487	864	231,593	2,619	199,749	1,050	153,497
53	Harvard4 13	Yes	No	No	362	122,175	684	128,758	231	63,034	497	196,191	1	245
15199	Takoma13 27	Yes	No	No	4,920	809,577	3,679	487,856	2,582	354,465	2045	275066.6	1666	81,223
147	Harvard4 13	No	Yes	No	127	29,841	0	0	0	0	0	0	0	0
308	Harrison4 38	No	Yes	No	596	7,502	1	236	5	547	1	205	574	46664.27
14768	Little Falls 77	No	Yes	No	0	0	0	0	0	0	0	0	0	0
15021	Ft Slocum 190	Yes	No	No	2,329	221,797	2,289	296,156	509	70,752	7644	647,393	9240	478203.3
212	G Street 28	Yes	No	No	196	14,896	745	92,430	0	0	5	30	619	193221.5
14015	12th Irving 133	No	Yes	No	280	41,818	30	5,762	1524	132,776	96	19,979	1323	120738.6
177	Anacostia4 8	No	Yes	No	30	4,684	54	9,885	3	506	4	944	359	8408
211	G Street 28	No	Yes	No	1,279	148,070	2	289	4	1,002	1	225	309	20779.98
66	Harvard4 13	No	Yes	No	24	2,979	0	0	437	102,644	1	160	1	22.11667
14005	12th Irving 133	No	Yes	No	538	53,579	709	62,050	79	10,703	3	350	2	481.3833
128	VeazeyEast 90E	No	Yes	No	75	7,066	38	2,824	227	25,178	3	346	234	33239.07
15204R	Tenth St 52	No	Yes	No	1,763	752,613	1,746	373,238	17	3,193	218	66,079	205	36887.43
15200	Takoma13 27	No	Yes	No	0	0	0	0	0	0	0	0	0	0
15171	Alabama Ave 136	Yes	No	No	2,890	32,268	105	29,665	207	40,618	305	30,746	27	3586
14700	Anacostia13 8	No	Yes	No	1,063	24,944	6	1,209	297	50,675	0	0	0	0
15711	Benning A23013 7	No	Yes	No	14	11,137	23	7,131	2	453	9	909	1	222.1833
15207R	Tenth St 52	Yes	No	No	639	257,745	726	253,602	19	2,928	7	979	1169	239206.2
178	Congress Hts 64	No	Yes	No	144	15,552	329	52,815	0	0	166	13,944	0	0
15867	Van Ness 129	Yes	No	No	168	33,821	71	9,735	1338	102,876	851	36,838	104	15573.37
15173	Alabama Ave 136	Yes	No	No	2	182	588	11,048	614	17580.12	5553	712,758	2163	64813.23
14031	Suitland 134	Yes	No	No	2,015	106,418	71	13,225	69	48,476	2648	152,073	62	6148.633
15085	St Barnabas 59	Yes	No	No	2,275	265,262	1,852	187,444	5,703	393,227	1971	131,287	1731	61013.65
15130	Walker Mill 15	Yes	No	No	4,534	325,420	8,178	622,332	43	3,501	2291	407,991	2117	114463.7

Table 15: Pepco DC 2015 Feeder Year – Aggregated Feeder Level Outage Data

2015 Feeder Year - Aggregated Feeder Level Outage Data												
Feeder	Substation	2015 Worst Performing Feeder	2015 Comprehensive Feeder	2015 ASR Scheme	2015 CI	2015 CMI	2016 CI	2016 CMI	2017 CI	2017 CMI	2018 CI	2018 CMI
14006	12th Irving 133	Yes	No	No	2,324	75,000	924	22,933	13	2,727	1	84
14722	Harvard13 13	Yes	No	No	1,031	280,251	1,097	236,203	1,336	153,930	57	5,692
15174	Alabama Ave 136	Yes	No	No	451	66,915	2,542	123,323	5060	503,595	1,407	29,888
333	Chesapeake 181	No	Yes	No	2	568	0	0	73	3917.667	1	75.86667
15945	Van Ness 129	Yes	No	No	70	13,200	1,281	87,706	1434	164,887	1,148	72,498
15701	Benning A23013 7	Yes	No	No	5,375	585,290	3,578	328,532	4,251	208,847	3,810	346,878
14767	Little Falls 77	Yes	No	No	881	238,537	2,802	275,204	1350	119,137	3,106	389,869
15014	Ft Slocum 190	Yes	No	No	1,161	23,366	7,631	387,928	66	7,545	1,459	78,772
14702	Anacostia13 8	Yes	No	No	6,089	416,625	2,181	498,034	500	138,490	3	267
15170	Alabama Ave 136	Yes	No	No	2,362	948,185	1,636	69,055	3,626	275,068	1,684	162,601
490	No Capitol 40	Yes	No	No	16	4,359	1,183	78,956	277	44,848	3	427
133	Nebraska 92	Yes	No	No	18	2,119	492	143,538	13	8,372	50	13,897
14200	12th Irving 133	Yes	No	No	4,090	929,852	4,357	322,131	190	20,194	1,709	139,084
82	VeazeyEast 90E	Yes	No	No	8	1,939	37	2,608	1	46	23	3,014
177	Anacostia4 8	No	Yes	No	54	9,885	3	506	4	944	359	8408
211	G Street 28	Yes	No	No	2	289	4	1,002	1	224.8	309	20,780
76	Harvard4 13	Yes	No	No	173	43,849	5	1,114	297	36526.97	0	0
128	VeazeyEast 90E	No	Yes	No	38	2,824	227	25,178	3	346.0167	234	33,239
15200	Takoma13 27	No	Yes	No	0	0	0	0	0	0	0	0
14017	12th Irving 133	Yes	No	No	19	2,919	110	19,724	1554	139411.4	76	12,946

Table 16: Pepco DC 2016 Feeder Year – Aggregated Feeder Level Outage Data

2016 Feeder Year - Aggregated Feeder Level Outage Data										
Feeder	Substation	2016 Worst Performing Feeder	2016 Comprehensive Feeder	2016 ASR Scheme	2016 CI	2016 CMI	2017 CI	2017 CMI	2018 CI	2018 CMI
15707	Benning 7	Yes	No	Yes	301	51,250	656	44,437	878	37,346
14713	Benning 7	Yes	No	No	1,545	411,832	180	20,705	318	43,211
15130	Walker Mill RD. 15	Yes	No	Yes	43	3,501	2,291	407,991	2117	114,464
15702	Benning A23013 7	Yes	No	No	707	160868.1	89	19764.78	1283	178866.9
15943	Van Ness 129	Yes	No	Yes	1810	87,495	124	31,080	217	38,830
14786	New Jersey Ave. 161	Yes	No	No	1,698	575,761	1,359	163,686	1,711	329,506
15756	Buzzard Point B	Yes	No	No	963	80,250	703	209,555	0	0
227	"G" Street, SE 28	Yes	No	No	1,081	192,716	2	673	205	60,581
15706	Benning 7	Yes	No	Yes	169	20,348	71	9,781	118	10,939
15011	Fort Slocum 190	Yes	No	No	2,998	158,984	160	79,061	252	46,542
14900	Harrison 38	Yes	No	Yes	1700	90,604	1,226	146,175	5855	248,480
14035	Suitland 134	Yes	No	No	1904	141,818	283	97,441	1447	100,951
14016	12th & Irving 133	Yes	No	No	1,389	178,705	184	38,707	411	63,560
14765	Little Falls 77	Yes	No	Yes	1021	82,740	145	12,627	404	75,877
212	"G" Street, SE 28	Yes	No	No	0	0	5	30	619	193,221
233	Twelfth St., SW 126	Yes	No	No	243	81437.98	49	16,985	49	12356.37
75	Wesley 61	No	Yes	No	227	31478.85	316	72,113	4	524.9
117	Nebraska 92	No	Yes	No	597	67299.27	286	37,369	291	8419.75
120	Chesapeake 181	No	Yes	No	24	3000.483	548	53,131	1	80.4
292	Wesley 61	No	Yes	No	83	44861.28	123	41,506	1	134.7167
327	Ft dupont 58	No	Yes	No	21	4739.8	2	146	126	13104
329	Chesapeake 181	No	Yes	No	556	66296.67	277	32,514	3	212.6833
347	Twiningcity 150	No	Yes	No	594	129773	589	67,888	93	7960.667
386	53rd street 48	No	Yes	No	3	159.5667	470	185,507	78	10222.27
14261	Beech road 159	No	Yes	No	3016	377489.9	201	22,251	3246	82957.2
14717	Benning a23013 7	No	Yes	Yes	12003	1321987	12160	810,683	5508	151225.4
14733	Champlain 25	No	Yes	No	846	350381.7	1417	236,500	904	234902.6
14736	Champlain 25	No	Yes	No	1126	728392	544	158,662	7	1371.483
14755	Nrl 168	No	Yes	No	3261	393629.3	422	34,035	390	44478.55
14758	Nrl 168	No	Yes	No	9089	414618.3	2154	121,226	2707	200695.6
15015	Ft slocum 190	No	Yes	No	1204	45944.35	205	44,230	3396	219471.3
15175	Alabama ave 136	No	Yes	No	836	40715.02	675	27,536	359	40834.35
15875	Southwest 18	No	Yes	No	5	1389.633	5	654	393	106290.7
15986	Harvard13 13	No	Yes	No	182	32600.17	222	45,493	323	284354.8

Table 17: Pepco DC 2017 Feeder Year – Aggregated Feeder Level Outage Data

2017 Feeder Year - Aggregated Feeder Level Outage Data								
Feeder	Substation	2017 Worst Performing Feeder	2017 Comprehensive Feeder	2017 ASR Scheme	2017 CI	2017 CMI	2018 CI	2018 CMI
14717	Benning A23013 7	Yes	No	Yes	12,160	810,683	5508	810,683
14758	NRL 168	Yes	No	No	2,154	121,226	2,707	121,226
15705	Benning A23013 7	Yes	No	Yes	2947	238,597	476	238,597
15085	St Barnabas 59	Yes	No	No	1971	131287.5	1731	131287.5
14755	NRL 168	Yes	No	No	422	34,035	390	34,035
14009	12th Irving 133	Yes	No	No	75	6,690	864	6,690
15710	Benning A23013 7	Yes	No	No	546	22,239	2,443	22,239
15755	Buzzard B13	Yes	No	No	1,778	113,416	0	113,416
14014	12th Irving 133	Yes	No	No	8,147	586,930	2,691	586,930
14701	Anacostia13 8	Yes	No	No	140	5,810	10	5,810
15013	Ft Slocum 190	Yes	No	No	7685	332,771	2,004	332,771
14261	Beech Road 159	Yes	No	No	201	22,251	3246	22,251
15014	Ft Slocum 190	Yes	No	Yes	66	7,545	1,459	7,545
14702	Anacostia13 8	Yes	No	No	500	138,490	3	138,490
14753	NRL 168	Yes	No	No	163	10,218	48	10217.97
228	G Street 28	Yes	No	No	1	150.9167	52	151
117	Nebraska 92	No	Yes	No	286	37368.85	291	37,369
14136	Van ness 129	No	Yes	No	420	25636.57	1622	25,637
15709	Benning a23013 7	No	Yes	Yes	3418	112439.6	384	112,440
15801	Little falls 77	No	Yes	Yes	11	1729.35	708	1,729

B.L. Clark
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (I) – 2

DC CONSTRUCTION REPORT: PEPCO (I)-2

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DC Construction Report

No:	1
ITN Name:	73127: Pepco: Purchase Two 1.5MW Portable Generators (UOTPOGND)
ITN:	UOTPOGND
FERC / State:	Distribution - DC
Category:	Other
Sub-Category:	Other
2018 Actual (000s):	$1,428.39
2019 Budget (000s):	$0.00
2020 Budget (000s):	$0.00
2021 Budget (000s):	$0.00
2022 Budget (000s):	$0.00
2023 Budget (000s):	$0.00
Start:	9/20/2017
Est. ISD:	11/30/2018
Finish:	3/29/2019
Scope of Work:	Purchase of 2 portable Diesel Standby Generator Set rated 1500kW in Pepco region for system outage support
Justification:	Standby Generators are to be utilized during Pepco system emergency restorations to pick up part of the grid and/or individual customers in order to limit actual outages experienced by customers. Utilization of these portable generators in Pepco will have positive impact to CAIDI.Provide additional restoration options to Operations during outages.Decision to utilize or deploy generators during an outage event will become much more flexible and faster.
Alternative:	Continue to rent generators from vendors which complicates the deployment decision during system emergencies and units may not be available.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	2
ITN Name:	73045: Pepco DC Reg: Salvage Scrap Wire/Cable (UDLPOSV5D)
ITN:	UDLPOSV5D
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	Other
2018_Actual_(000s):	($0.10)
2019_Budget_(000s):	($1,000.00)
2020_Budget_(000s):	($1,000.00)
2021_Budget_(000s):	($1,000.00)
2022_Budget_(000s):	($1,000.00)
2023_Budget_(000s):	($1,000.00)
Start:	12/31/2012
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	Salvage scrap wires and cables for DC
Justification:	WBS to capture salvage scrap wires and cable credit.
Alternative:	No alternative available.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	3
ITN Name:	71426: Pepco DC CM Distribution Substation Capital
ITN:	UDSPRD71D
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	Corrective Maintenance
2018_Actual_(000s):	$627.74
2019_Budget_(000s):	$624.50
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	8/1/2011
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	The scope of this project is an emergency blanket allocated to provide funding for replacement of failed substation equipment due to unforeseen fault events in the DC distribution system. The substation equipment includes both major and minor power equipment including transformers, power breakers, disconnect switches, surge arresters, instrumentation transformers, switchgear, bus work, insulators, relays, cables, and other equipment installed in substations.
Justification:	The project is providing a placeholder to fund projects to replace equipment which have failed and have reduced the reliability or caused an outage on the distribution system in DC. Without this project, there will be no funding available to replace any failed equipment during emergency, and the distribution system would not be able to be restored back to normal condition.
Alternative:	An alternative would be no action; however, the system would have sustained outages due to failed equipment or reduced capacity on the system due to less power circuit due to damaged equipment.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	4
ITN Name:	74590: DDOT Frederick Douglass bridge project (UDLPLM7001)
ITN:	UDLPLM7001
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$3,500.00
2019_Budget_(000s):	$4,500.00
2020_Budget_(000s):	$18,700.00
2021_Budget_(000s):	$12,400.00
2022_Budget_(000s):	$5,000.00
2023_Budget_(000s):	$0.00
Start:	1/1/2019
Est. ISD	6/30/2022
Finish:	9/30/2022
Scope of Work:	Construct two 8-way sub 69Kv duct bank and cable utilizing the new South Capitol Street Bridge (DDOT) project to cross over Anacostia River to replace ageing cable. This work will be done based on agreed Memorandum of Understanding between Pepco and DDOT.
Justification:	Replacing aging cable
Alternative:	Horizonal Directional Drilling
Reimbursable:	No
Related Circuit:	69015 & 69014
Related Substation:	Station C, NRL, 9th Street and I street

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DC Construction Report

No:	5
ITN Name:	70024: 092 Nebraska Ave T1 B-0659 Transformer/LTC Replace (ECA) (UDSPRD8AD7)
ITN:	UDSPRD8AD7
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$57.53
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/2/2018
Est. ISD	TBD
Finish:	TBD
Scope of Work:	The scope of this project is to replace the (T1) transformer 13/4kV B-0659 at Nebraska Ave. Substation.
Justification:	The T1 Transformer at Nebraska Ave is sponsored for replacement due to oil conditions in the LTC showing high acid and may be forming sludge. Sludge in the LTC compartment can originate from wear of contact surfaces due to arcing, as well as by-products from the oil, causing pollution in the form of particles. Smaller particles will be suspended in the oil while larger particles will form sludge that can affect the operation of the LTC. This Transformer was identified on the Transformer Health Index as having a score of 6 (relatively healthy with the exception of recent sludge problems). Factors that are considered in a health index score is age, recent trouble history, DGA, Doble test, condition (such as rust or leaking) and manufacturer. The biggest detractor to the transformer is the age and oil sludge history. As the transformer increases in age the potential for failure increases. Also with its recent history of acid/sludge problems in the LTC, it is possible for the transformer to decrease in health rapidly.
Alternative:	The only alternative to replacing the transformer is continued maintenance. However with the transformer being aged equipment and recent problems with oil condition, the operation of the LTC can be affected. Oil can be replaced/reclaimed to temporarily correct the sludge problem however the root cause (such as possible wear of

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	the contact surface in the LTC) of the sludge/acid will still be present and will present future problems. The transformer will continue to be maintained and is schedule for replacement in 2019 when it will be approximately 60 years old. The engineering for this project will start in 2018. Construction is expected to start in spring 2019.
Reimbursable:	No
Related Circuit:	-
Related Substation:	NEBRASKA (92)

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DC Construction Report

No:	6
ITN Name:	70053: 12th & Irv. Area Plan-Sub Work (UDSPRM4WA7)
ITN:	UDSPRM4WA7
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$91.66
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	2/1/2018
Est. ISD	5/31/2019
Finish:	9/28/2019
Scope of Work:	This project is in support of the Substation portion of the 12th & Irving Area Plan. The plan calls for extending Feeder 14003 out of 12th & Irving Sub. The dollar spend will be on fixing the substation door and doing required testing.
Justification:	This project is in support of the 12th & Irving Area Plan. 12th & Irving substation produces the highest CI and CMI of any DC substation. The project will take a holistic approach to remediating the circuits out of 12th & Irving substation focused on DA, ASR schemes, reclosers, TripSavers, circuit reconfiguration, new feeders, and minimizing the number of customers on each feeder.
Alternative:	Circuits from 12th & Irving substation will continue to show up on the poorest performing list based on reliability metrics if this area is not addressed.
Reimbursable:	No
Related Circuit:	14003
Related Substation:	12th & IRVING, NE (133)

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DC Construction Report

No:	7
ITN Name:	70058: 12th Street Sub: Retire Sub (UDSPRD8RK)
ITN:	UDSPRD8RK
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$167.03
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/2/2018
Est. ISD	12/31/2019
Finish:	4/29/2022
Scope of Work:	The scope of this project is to retire 12th Street Sub. 124, terminate all electrical connections, retire all electrical equipment including transformers, and demolish the building and clear up all underground cables.
Justification:	The 12th Street Sub. 126 contains oil circuit breakers that will be removed based on review of condition and reliability. Both the 13 kV/4 kV transformers are identified as suspect and in need of eventual replacement. These oil circuit breakers are no longer manufactured and the manufacturer no longer provides spare parts. The existing conduit and cables are very old and upgrades of this system are being proposed to eliminate potential reliability concerns proactively.
Alternative:	An alternative to converting all 12th St. Sub 4 kV load to 13 kV is to maintain the 4 kV system by replacing all conduit, cable, substation transformers and substation switchgear.
Reimbursable:	No
Related Circuit:	-
Related Substation:	12th STREET, SW (126)

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DC Construction Report

No:	8
ITN Name:	70060: 13.8kV Swgr Replacement - Pepco DC (UDSPRD8KD)
ITN:	UDSPRD8KD
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$441.70
2019_Budget_(000s):	$1,727.38
2020_Budget_(000s):	$4,250.01
2021_Budget_(000s):	$5,000.00
2022_Budget_(000s):	$6,925.00
2023_Budget_(000s):	$9,125.00
Start:	9/3/2013
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This project is for the purchase and installation of replacement 13.8kV switchgear for Van Ness Substation 129.
Justification:	The existing switchgear has reached the end of its useful life. Failure of a breaker or cubicle can result in significant collateral damage to other equipment that are housed in the same control building of the switchgear and extended power outage on the DC distribution system.
Alternative:	Replace 7 bus sections of switchgear with 6 new bus sections.
Reimbursable:	No
Related Circuit:	-
Related Substation:	VAN NESS (129)

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DC Construction Report

No:	9
ITN Name:	70187: 4kv Substation Automation - DC (UDSPRD8H)
ITN:	UDSPRD8H
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$1,079.06
2019_Budget_(000s):	$761.02
2020_Budget_(000s):	$0.03
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	9/5/2014
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This project is to improve reliability and the level of monitoring and control at 4 kV substations. This will require the installation of smart relays for the feeders and transformer secondary cubicles, one DRTU and communication equipment at each substation to allow control and monitoring from the Control Center. The engineering for the 4kV Substation Automation at wining City Sub 150, 53rd Street Sub 48 and Chesapeake St Sub 181 was completed in 2014. The prefabrication control relay panels for Sub 150 were purchased and delivered in 2014 and the installation work was completed in 2015. 53rd Street Sub. 48 is scheduled for completion in 2016.
Justification:	Improves reliability of 4 kV substations by providing Control Center with monitoring and control of substation transformer and feeder breakers improving chances of identifying operational issues early and remotely operating equipment to avoid outage or speed restoration in event of an outage. As per the 2007 Long Range Study of the 4 kV Distribution System, Pepco will be maintaining many of the 4 kV substations serving areas of low or no load growth and that provide relatively good reliability. For these substations, Pepco will be replacing or upgrading substation equipment, transformers and lines and cables as necessary. None of the substations selected for automation are planned to be converted within the next ten years.
Alternative:	Maintaining the bell alarm system that only provides information about a breaker operation or a limit being

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	exceeded. It requires dispatch of personnel to assess the problem and take action. This was not considered as it could lead to higher likelihood of equipment failure as loads and statuses are not being monitored and the longer outage time to account for dispatching of mobile operator. The automation system selected is in line with Pepco's current SCADA standard of using GE F60 smart relays and remote terminal units connected to Pepco's fiber system. This provides reliable monitoring and control from Pepco's control center and extra functionality such as distance to fault indication and down conductor alarming. For this reason, no alternative for this project was considered.
Reimbursable:	No
Related Circuit:	-
Related Substation:	CHESAPEAKE STREET, SE (181);"G" STREET, SE (28);TWINING CITY (150);53rd STREET, SE (48)

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DC Construction Report

No:	10
ITN Name:	70442: Animal Guards in Dist Subs: Pepco DC (UDSPRD8JD)
ITN:	UDSPRD8JD
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$110.43
2019_Budget_(000s):	$214.65
2020_Budget_(000s):	$180.78
2021_Budget_(000s):	$180.80
2022_Budget_(000s):	$180.80
2023_Budget_(000s):	$200.15
Start:	10/1/2013
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	As a result of documented animal related outages within substations in Pepco in DC, this project will either install animal guards on identified vulnerable insulators and equipment or install the new vanquish animal fencing around the substation to entirely keep animals out. Size and cost are key factors when determining if a fence will be used. Station completed Van Ness Sub. 129 (2013), Fort Chaplin Sub. 70 (2014), Little Falls Sub. 77 (2015)
Justification:	Without the proper guards and fences, animals can get into Pepco equipment and cause customers outage and damage equipment; Guards and fences are needed to mitigate animal caused outages and to improve customer reliability.
Alternative:	The alternative is to not install the animal guards. The consequences would be the continuation of animal causing outages which would result in sustained outages for the customer and damaged equipment. The alternative option costs zero dollars, but would have a negative impact on Pepco reliability.
Reimbursable:	No
Related Circuit:	-
Related Substation:	FORT CHAPLIN (70);LITTLE FALLS (77);VAN NESS (129)

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DC Construction Report

No:	11
ITN Name:	70602: Batt & Chgr Replacement Distri. Subs. - DC (UDSPRD8ED)
ITN:	UDSPRD8ED
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$135.39
2019_Budget_(000s):	$398.89
2020_Budget_(000s):	$411.94
2021_Budget_(000s):	$424.97
2022_Budget_(000s):	$377.74
2023_Budget_(000s):	$416.62
Start:	1/2/2012
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Battery systems across the Pepco system will be tested and visually inspected for condition and replaced accordingly to ensure reliable DC power systems in all Pepco stations. Chargers will be replaced as well as internal caps that have degraded over time. The existing batteries and chargers at the following substations have been determined to be beyond their design life, or have been determined to be in failure mode due to testing and observation results.
Justification:	Batteries have exceeded their useful life and are showing signs of degradation (cracked cells, high resistances and failure to hold charge).
Alternative:	Substations are equipped with AC and DC station service systems, used for protection, control and supervision. AC station service is available during normal system operation. DC which is stored in lead acid batteries, is a back-up due to the loss of AC station service. If both AC and DC are not available, it is possible to destroy an entire substation. The consequences of doing nothing are catastrophic and collateral damage due to lack of protection, controls and supervision for the electric system. Alternatives include standby automatic generators which are expensive, maintenance intense, and often unreliable. UPS systems are another alternative but not very practical.The cost of replacing a stored energy battery system is about $50k. The initial cost of installing an UPS for a distribution station including the battery is about $300k. The initial cost of

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	installation of a standby automatic generator is about $500k. Doing nothing can result in the loss of the entire station that would cost about $100 million.
Reimbursable:	No
Related Circuit:	-
Related Substation:	CHAMPLAIN (25);FLORIDA AVENUE (10);TENTH STREET (52)

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DC Construction Report

No:	12
ITN Name:	70834: Buzzard Point Sta. B- Replace Live Parts 138kv (UDSPRD8Z)
ITN:	UDSPRD8Z
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$214.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/31/2012
Est. ISD	12/31/2019
Finish:	4/30/2020
Scope of Work:	Project scope is to replace the 138kV disconnect switches within the ring bus at Buzzard Point
Justification:	Project scope is to replace the 138kV disconnect switches within the ring bus at Buzzard Point
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	BUZZARD POINT STATION ("B")

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DC Construction Report

No:	13
ITN Name:	71011: Champlain - New 34kV Sub (UDSPRD8AD8)
ITN:	UDSPRD8AD8
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$1,377.16
2019_Budget_(000s):	$1,866.72
2020_Budget_(000s):	$611.43
2021_Budget_(000s):	$552.09
2022_Budget_(000s):	$2,760.04
2023_Budget_(000s):	$14,033.75
Start:	4/21/2017
Est. ISD	6/1/2026
Finish:	10/1/2026
Scope of Work:	Build New Champlain 230/69/34kV sub with 3-230/69kV, 225 MVA transformers, a 69kV GIS breaker and half bus, 4bays, 14 breakers, 4-69/34kV transformers, 4-34kV outgoing feeders to resupply "L" Street, and 4-69kV outgoing feeders to resupply "F" Street and Georgetown Subs.
Justification:	Champlain Sub Rebuild is being built as part of PHI's Capital Grid Program, which addresses aging infrastructure, enhances reliability, and supports load growth in the District of Columbia. Champlain Sub is being rebuilt to allow for the resupply (4) 34
Alternative:	Capital Grid Configuration Alternatives - Resupply F Street and Georgetown from Takoma at 69kV via four (4) new 69kV XLPE cables and resupply L Street from Takoma via four (4) new 34kV XLPE cables. Resupply 22nd Street from 9th Street via "I" Street Supplies.
Reimbursable:	No
Related Circuit:	-
Related Substation:	CHAMPLAIN (25)

PEPCO(I)-2

DC Construction Report

No:	14
ITN Name:	71012: Champlain - New 69kV Sub (DSPRD8AD17)
ITN:	DSPRD8AD17
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$2,880.62
2019_Budget_(000s):	$1,503.82
2020_Budget_(000s):	$604.63
2021_Budget_(000s):	$604.63
2022_Budget_(000s):	$6,664.61
2023_Budget_(000s):	$2,937.10
Start:	1/1/2018
Est. ISD	6/1/2026
Finish:	10/1/2026
Scope of Work:	Build New Champlain 230/69/34kV sub with 3-230/69kV, 225 MVA transformers, a 69kV GIS breaker and half bus, 4bays, 14 breakers, 4-69/34kV transformers, 4-34kV outgoing feeders to resupply "L" Street, and 4-69kV outgoing feeders to resupply "F" Street and Georgetown Subs.
Justification:	Champlain Sub Rebuild is being built as part of PHI's Capital Grid Program, which addresses aging infrastructure, enhances reliability, and supports load growth in the District of Columbia. Champlain Sub is being rebuilt to allow for the resupply (4) 34kV outgoing feeders to resupply "L" Street and (4) 69kV outgoing feeders to resupply "F" Street and Georgetown Subs.
Alternative:	Capital Grid Configuration Alternatives - Resupply F Street and Georgetown from Takoma at 69kV via four (4) new 69kV XLPE cables and resupply L Street from Takoma via four (4) new 34kV XLPE cables. Resupply 22nd Street from 9th Street via "I" Street Supplies.
Reimbursable:	No
Related Circuit:	-
Related Substation:	CHAMPLAIN (25)

PEPCO(I)-2

DC Construction Report

No:	15
ITN Name:	71213: DC Distributed RTU HMI Computer Replacement (UDSPRD8CR1)
ITN:	UDSPRD8CR1
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$38.51
2019_Budget_(000s):	$40.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2018
Est. ISD	12/31/2019
Finish:	4/30/2020
Scope of Work:	Replace substation HMI computers (both hardware and software) which have failed due to harsh environmental conditions and age.
Justification:	The HMI computer is one of the primary means for control and monitoring of a substation and is a core component of the DRTU. Without a functioning station HMI operators and technicians lose a central point for monitoring and controlling substation equipment.
Alternative:	One alternative is to replace the computer hardware only without the software component. However, the existing Windows XP operating system on failed computers is no longer supported or maintained. Computers cannot be purchased with the older operating system anymore and those that are still in-service can no longer be patched for security updates. This drives the need for a computer replacement with the latest operating system and new HMI software compatible with the operating system.
Reimbursable:	Yes
Related Circuit:	-
Related Substation:	Benning (7); 12th & Irving (133); Northeast (212)

PEPCO(I)-2

DC Construction Report

No:	16
ITN Name:	71222: DC- Ground Test Device Installation Program (UDSPRD8GTD)
ITN:	UDSPRD8GTD
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$60.00
2020_Budget_(000s):	$60.00
2021_Budget_(000s):	$60.00
2022_Budget_(000s):	$60.00
2023_Budget_(000s):	$60.00
Start:	1/1/2018
Est. ISD	12/31/2023
Finish:	4/30/2024
Scope of Work:	Install 10 Ground Test Devices at various DC Substations from 2019 to 2023
Justification:	There aren't sufficient GTD in DC substations. Many of planned outages were cancelled due to the lack of GTD for grounding properly. The impact of forgoing this job will be negatively affect the Company's ability to provide safe and reliable electric service.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	O St 002, Benning (7); Southwest (18), 12th & Irving, NE (133), 22nd St (124)

PEPCO(I)-2

DC Construction Report

No:	17
ITN Name:	71405: Digital Fault Recorder/Expert Sys (UDSPRD8SG)
ITN:	UDSPRD8SG
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$563.94
2020_Budget_(000s):	$2,179.00
2021_Budget_(000s):	$2,179.00
2022_Budget_(000s):	$2,179.00
2023_Budget_(000s):	$2,179.00
Start:	8/1/2011
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	Replacement of Digital Fault Recorders/Expert Systems for several Pepco Substations
Justification:	Aging equipment
Alternative:	Install replacement DFRs to replace aging systems
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

PEPCO(I)-2

DC Construction Report

No:	18
ITN Name:	71417: Dist Sub Bushing Replacement: Pepco DC (UDSPRD8FD)
ITN:	UDSPRD8FD
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$111.19
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	8/1/2013
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	The project scope is to replace U-Type bushings that are susceptible to an industry known problem for failure. This includes the purchase and installation of the replacement bushing, and the removal of the existing U-Type bushings on the power transformer. The need for replacement would be identified during routine maintenance if the power factor of the bushing is below the acceptable value.
Justification:	U-style bushings are a known industry problem. As power factor degrades, these bushings need to be replaced or they will fail and damage the transformer.
Alternative:	An alternative would be to not replace the bushings which would lead to the bushing failing and damaging the transformer. The alternative is more expensive since the cost of a power transformer is significantly more than a transformer bushing.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

PEPCO(I)-2

DC Construction Report

No:	19
ITN Name:	71418: Dist Sub Bushing Replacement: Pepco DC (UDSPRD8FV)
ITN:	UDSPRD8FV
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$75.56
2020_Budget_(000s):	$75.56
2021_Budget_(000s):	$75.56
2022_Budget_(000s):	$75.56
2023_Budget_(000s):	$75.55
Start:	6/1/2016
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	The project scope is to replace U-Type bushings that are susceptible to an industry known problem for failure. This includes the purchase and installation of the replacement bushing, and the removal of the existing U-Type bushings on the power transformer. The need for replacement would be identified during routine maintenance if the power factor of the bushing is below the acceptable value.
Justification:	U-style bushings are a known industry problem. As power factor degrades, these bushings need to be replaced or they will fail and damage the transformer.
Alternative:	An alternative would be to not replace the bushings which would lead to the bushing failing and damaging the transformer. The alternative is more expensive since the cost of a power transformer is significantly more than a transformer bushing. The alternate option costs zero dollars.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	20
ITN Name:	71505: E-Key Program Zone 23 Distribution - DC (UDSPRD8E23)
ITN:	UDSPRD8E23
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$131.71
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	4/26/2018
Est. ISD	12/31/2019
Finish:	12/31/2019
Scope of Work:	The E-Key program will replace every control house door lock and padlock at PEPCO Distribution DC substations with a Cyberlock system. This system will get PEPCO in line with other Exelon Utilities standard for NERC compliance access control systems. The Cyberlock system will serve as secondary access to substations with card access and will mirror their access governance. The substations included under this zone are:“F” Street(DC) “G” St. SE(DC) “I” Street ”L” Street 10th Street 12th & Irving 12th Street SW(DC) 22nd Street 53rd Street SE(DC) 9th Street Anacostia(DC) Benning 69kV Champlain Chesapeake St. SE(DC) Congress Heights(DC) Florida Ave. Ft. Chaplin(DC) Ft. Davis(DC) Ft. Slocum Fulton Street(DC) Georgetown Harrison Harvard Little Falls Longwood(MD) Metzerott Rd. West(MD) N. Capitol(DC) Navy Yard(DC) Nebraska(DC) New Jersey Ave. Northeast NRL(DC) Oliver Street(DC) Palisades(DC) Quesada(DC) Randle Highlands(DC) Southwest Texas Avenue(DC) Twining City(DC) Van Ness Veazey East(DC) Veazey West(DC) Wesley(DC)
Justification:	The E-Key program will replace every control house door lock and padlock at each substation in a PEPCO territory with a Cyberlock system. This system will get PEPCO in line with other Exelon Utilities standard for NERC compliance access control systems. The Cyberlock system

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DC Construction Report

	will serve as secondary access to substations with card access and will mirror their access governance.
Alternative:	None
Reimbursable:	No
Related Circuit:	
Related Substation:	“F” Street(DC) “G” St. SE(DC) “I” Street ”L” Street 10th Street 12th & Irving 12th Street SW(DC) 22nd Street 53rd Street SE(DC) 9th Street Anacostia(DC) Benning 69kV Champlain

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DC Construction Report

No:	21
ITN Name:	71631: F St Sub Rebuild (UDSPLM717A)
ITN:	UDSPLM717A
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$325.36
2019_Budget_(000s):	$602.30
2020_Budget_(000s):	$3,355.72
2021_Budget_(000s):	$536.52
2022_Budget_(000s):	$536.52
2023_Budget_(000s):	$859.45
Start:	1/1/2017
Est. ISD	6/1/2026
Finish:	9/29/2026
Scope of Work:	Increase the firm capacity increased from 82 MVA to 210 MVA by rebuilding substation using Anniversary park in front of property; Net 128 MVAResupply with 69 kV from New Champlain Substation.This work is needed to Retire "I" St Sub
Justification:	Downtown Resupply - The replacement of the 69kV underground supply feeders from Potomac River to Georgetown & "F" Street and Takoma to 22nd St. These are part of Transmission Engineering's plan to replace self-contained cables. The proposed work resupplies all three subs from a single set of higher capacity solid dielectric cables in two new 8-ways from Takoma and avoids any new river crossings. This will allow retirement of 11 self-contained cables identified as high priority for replacement. Seven of these cables cross the Potomac River and if they fail, they cannot be repaired and will result in an extended outage in excess of 12 months to install new Horizontal Directional Drilled (HDD) cables across the river. F St Rebuild will also allow for the retirement of I St Substation.
Alternative:	Maintain “I” St, renew the lease agreement and the following:Resupply 22nd Street, F St and Georgetown via Champlain 69kV new 230/69/34kV subRefurb/Upgrade existing equipment at ‘I’ Street Sub. 197 in the future (2026) Switchgear & TransformersRefurb/Upgrade existing equipment at ‘F’ Street Sub. 74 in the future (2026) SwitchgearRefurb/Upgrade existing equipment at ‘L’ Street Sub. 21 in the future (2027) Switchgear & Transformers –

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DC Construction Report

	common to both plansThis option was not pursued because it would require the continued lease of the "I" St property and the property owner is requesting $2.55M-$3.5M / year with escalation.
Reimbursable:	No
Related Circuit:	-
Related Substation:	"F" STREET (74)

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DC Construction Report

No:	22
ITN Name:	71641: FEP Physical Security - Pepco (DC): I Street Sub 197 (UDSPRD8I
ITN:	UDSPRD8ISS
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$53.36
2019_Budget_(000s):	$100.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/18/2018
Est. ISD	4/29/2020
Finish:	8/26/2020
Scope of Work:	One of several indoor Tier 1 FEP sites in the Pepco region to install intrusion detection, camera system and access controls around the perimeter and within the substation. This project also includes the installation of data collection equipment in the relay room.
Justification:	This project is required to meet Exelon FEP security standards.This project is a part of a long-term strategy to upgrade the physical security installations, based on Tiering criteria, at critical substations and facilities.
Alternative:	Do Nothing - Violates Exelon FEP security requirements and leaves substation at risk to various levels of potential threats in dense metropolitan area.
Reimbursable:	No
Related Circuit:	-
Related Substation:	"I" STREET (197)

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DC Construction Report

No:	23
ITN Name:	71642: FEP Physical Security - Pepco (DC): L Street Sub 21 (UDSPRD8LS
ITN:	UDSPRD8LSS
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$56.88
2019_Budget_(000s):	$100.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/18/2018
Est. ISD	4/29/2020
Finish:	8/26/2020
Scope of Work:	One of several indoor Tier 1 FEP sites in the Pepco region to install intrusion detection, camera system and access controls around the perimeter and within the substation. This project also includes the installation of data collection equipment in the relay room.
Justification:	This project is required to meet Exelon FEP security standards.This project is a part of a long-term strategy to upgrade the physical security installations, based on Tiering criteria, at critical substations and facilities.
Alternative:	Do Nothing - Violates Exelon FEP security requirements and leaves substation at risk to various levels of potential threats in dense metropolitan area.
Reimbursable:	No
Related Circuit:	-
Related Substation:	"L" STREET (21)

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DC Construction Report

No:	24
ITN Name:	71643: FEP Physical Security - Pepco (DC): 10th Street Sub 52 (UDSPRD8
ITN:	UDSPRD81S1
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$52.38
2019_Budget_(000s):	$900.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/18/2018
Est. ISD	4/29/2020
Finish:	8/26/2020
Scope of Work:	One of several indoor Tier 1 FEP sites in the Pepco region to install intrusion detection, camera system and access controls around the perimeter and within the substation. This project also includes the installation of data collection equipment in the relay room.
Justification:	This project is required to meet Exelon FEP security standards.This project is a part of a long-term strategy to upgrade the physical security installations, based on Tiering criteria, at critical substations and facilities.
Alternative:	Do Nothing - Violates Exelon FEP security requirements and leaves substation at risk to various levels of potential threats in dense metropolitan area.
Reimbursable:	No
Related Circuit:	-
Related Substation:	TENTH STREET (52)

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DC Construction Report

No:	25
ITN Name:	71644: FEP Physical Security - Pepco (DC): O Street Sub 2 (UDSPRD8PS1)
ITN:	UDSPRD8PS1
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$43.78
2019_Budget_(000s):	$900.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	6/11/2018
Est. ISD	4/29/2020
Finish:	8/27/2020
Scope of Work:	One of several indoor Tier 1 FEP sites in the Pepco region to install intrusion detection, camera system and access controls around the perimeter and within the substation. This project also includes the installation of data collection equipment in the relay room.
Justification:	This project is required to meet Exelon FEP security standards.This project is a part of a long-term strategy to upgrade the physical security installations, based on Tiering criteria, at critical substations and facilities.
Alternative:	Do Nothing - Violates Exelon FEP security requirements and leaves substation at risk to various levels of potential threats in dense metropolitan area.
Reimbursable:	No
Related Circuit:	-
Related Substation:	"O" STREET (2)

PEPCO(I)-2

DC Construction Report

No:	26
ITN Name:	71855: Harrison Sub: Construct New Sub (UDSPLNW2)
ITN:	UDSPLNW2
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$6,825.16
2019_Budget_(000s):	$2,999.92
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	4/2/2014
Est. ISD	12/31/2020
Finish:	4/30/2021
Scope of Work:	Install three (3) 56.0 MVA, 132 kV to 13.8 kV transformers and six (6) bus sections of 13.8 kV, 1000 MVA, 3000 Amp metalclad switchgear with a minimum of thirty eight (38) outgoing feeder positions, four (4) bus capacitor positions and two (2) station service feeder positions. Install a 138 kV high-side bus. Install two (2) 9.0 MVar, 13.8kV bus capacitors.
Justification:	The main building was constructed in 1940 with various additions. The existing 4 kV substation at Harrison Sub. 38 is in deteriorating condition. The transformers are aging. Transformer 1 was evaluated to be impaired as part of the Equipment Condition Assessment (ECA) process. The switchgear is a non-standard double bus configuration and in need of replacement.
Alternative:	Rebuilding Harrison Sub. 38 is recommended to replace aging infrastructure in Harrison Sub. 38.
Reimbursable:	No
Related Circuit:	13815;13816;13825;13826
Related Substation:	HARRISON (38)

PEPCO(I)-2

DC Construction Report

No:	27
ITN Name:	71864: Harvard - New Sub - Distr Upgr to 230/13kV, 210 MVA (UDSPRD8AD2)
ITN:	UDSPRD8AD2
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$2,116.88
2019_Budget_(000s):	$1,633.20
2020_Budget_(000s):	$4,544.45
2021_Budget_(000s):	$6,584.43
2022_Budget_(000s):	$27,423.81
2023_Budget_(000s):	$5,431.82
Start:	5/27/2015
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	The scope of this project includes building a new 230/13kV, 210MVA class substation on existing Harvard Sub. 13 site. All 13kV load would be temporarily transferred to a temporary substation consisting of mobile transformers and switchgear then cutover to the new Harvard sub when complete. Substation to consist of 6 bus sections, 48 feeder positions, 6 bus cap positions, 4 230/13kV 56MVA transformer bays. Initial build will install three 230/13kV transformers, four 230kV supplies and four 9.0MVAR bus capacitor banks.
Justification:	Existing Harvard Sub. 13 was originally constructed in the 1920's and has some very old concrete encased switchgear that cannot be upgraded without demolishing the existing infrastructure. The new sub will be used also to extend feeders to retire Champlain Sub. 25 that was originally built for 13 kV in the 1930's and has similar concrete encased switchgear that can’t be upgraded.
Alternative:	An alternative to rebuilding Harvard would be to purchase a new property in order to build a new substation. Since Pepco already owns most of the needed property at Harvard Sub. 13, there would be less cost and less risk of not obtaining approval by using the existing property and not obtaining a new one.
Reimbursable:	No
Related Circuit:	-

PEPCO(I)-2

DC Construction Report

Related Substation:	CHAMPLAIN (25);HARVARD (13)

PEPCO(I)-2

DC Construction Report

No:	28
ITN Name:	71987: Improve/Add Substation Enclosures (UDSPRD8D2)
ITN:	UDSPRD8D2
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$160.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	12/31/2012
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	This is a blanket WBS that covers all substations within DC. The scope for this project is to provide new, improve, or to restore substation enclosures. This includes, but is not limited to, transformer bays, fire walls, building restorations, and any other structural component needed to protect substation equipment.
Justification:	Several substations need new or repaired transformer enclosures to increase air circulation in each bay. A well ventilated transformer reduces the risk of damaging the transformer, therefore decreasing the risk of failure.
Alternative:	Alternatives would be:To let the unenclosed equipment go unprotected from fire and other adverse conditionTo allow existing damaged or underperforming enclosures to continue to degrade and pose risk to the liability of the protected equipment
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

PEPCO(I)-2

DC Construction Report

No:	29
ITN Name:	72685: NERC Physical Security Pepco Dist Sub.- DC (UDSPRD8VD)
ITN:	UDSPRD8VD
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$3.04
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$3,420.00
2021_Budget_(000s):	$3,320.17
2022_Budget_(000s):	$908.82
2023_Budget_(000s):	$119.00
Start:	1/31/2011
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	The project scope is to install security cameras, card readers, and recording devices for the cameras at the substation control building. The budget includes the procurement of the security system, the design & engineering, and installation of the system at the site. 2015 (Completed)Sub. 77 Little Falls 2016 (Completed)Sub. 7 Benning 13kVSub. 133 12th & IrvingSub. 212 Northeast 2016 (Planned)Sub. 41 Benning 69kVStation B Buzzard Point 13kVSub. 185 Central Ave.
Justification:	To improve security at DC distribution substations for EU compliance as some of the substations have very minimal security or outdated system.
Alternative:	Upgrade substation to meet EU security standards.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

PEPCO(I)-2

DC Construction Report

No:	30
ITN Name:	72808: Ninth Street - Sub 117 - 3T (UDSPRD89S1)
ITN:	UDSPRD89S1
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$500.00
2022_Budget_(000s):	$1,500.00
2023_Budget_(000s):	$0.00
Start:	1/1/2018
Est. ISD	1/1/2023
Finish:	1/1/2023
Scope of Work:	Replace aging transformer due to non-repairable LTC mechanical components.
Justification:	Non-repairable mechanical components in LTC due to years of continued service
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	NINTH STREET (117)

PEPCO(I)-2

DC Construction Report

No:	31
ITN Name:	72811: North Capitol Sub: Retire Sub (UDSPRD8RJ)
ITN:	UDSPRD8RJ
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$596.39
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2018
Est. ISD	12/31/2020
Finish:	4/30/2020
Scope of Work:	Retire North Capitol Sub 40 upon conversion of all 4kV load to Fort Slocum Sub. 190.
Justification:	The North Capitol Sub. 40 - 4kV system is an aging, isolated area on the Pepco distribution system that is not connected to any other 4kV substations or systems. Recent substation inspections have revealed deteriorating circuit breakers that are subject to failures that include a high number of arc chute and internal problems. The current Preventive Maintenance Program for these breakers requires them to be overhauled every 72 months. The advanced age of the switchgear necessitates the salvage of spare parts from like equipment. In the event of a catastrophic failure at North Capitol Sub. 40, no external 4kV support is available. 4kV feeders are of mostly older construction and backed up by other North Capitol Sub. 40 feeders or through bus ties. The transformers are 57 to 59 years old. Transformers 1, 3 & 4 have been DGA tested, assessed as impaired and require eventual replacement. Capacity from nearby Fort Slocum Sub. 190 is readily available for the 4kV to 13kV conversions.
Alternative:	An alternative to converting all North Capitol Sub. 40 - 4kV load to 13kV is to maintain the 4kV system by replacing the substation transformers, substation switchgear, and rebuilding many of the Overhead 4kV feeders.
Reimbursable:	No
Related Circuit:	-

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DC Construction Report

Related Substation:	NORTH CAPITOL (40)

PEPCO(I)-2

DC Construction Report

No:	32
ITN Name:	72850: O Street (Sub 2) 4T (DSPRD8AD10)
ITN:	DSPRD8AD10
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$1,050.00
2022_Budget_(000s):	$2,450.00
2023_Budget_(000s):	$0.00
Start:	3/1/2019
Est. ISD	10/28/2022
Finish:	3/1/2023
Scope of Work:	Replace #4 - 138/13kV Transformer at O Street (Sub 2) need replacement due to LTC reversing contacts coking. This Moloney transformer was installed in 1968 and has been repaired several times.
Justification:	The transformer has experienced mechanical problems with the LLTC reversing contacts. The contacts has shown continuous coking after repairs.
Alternative:	None. If leave it the way it is, the transformer could fail which will affect thousands of customers.
Reimbursable:	No
Related Circuit:	-
Related Substation:	"O" STREET (2)

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DC Construction Report

No:	33
ITN Name:	72851: O Street (sub 2) 2T (UDSPRD8OS2)
ITN:	UDSPRD8OS2
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$1,050.00
2022_Budget_(000s):	$2,450.00
2023_Budget_(000s):	$0.00
Start:	1/1/2018
Est. ISD	12/31/2022
Finish:	4/30/2023
Scope of Work:	Replace 2T -138/13 kV transformer at O Street (sub 2).This transformer needs replacement due to the LTC reversing contacts coking. This Moloney transformer was installed in 1968 and has been repaired several times.
Justification:	The transformer has experienced mechanical problems with the reversing contacts. The contacts have shown continuous coking after repairs.
Alternative:	None, if we leave it this way; the transformer could fail affecting thousands of customers.
Reimbursable:	No
Related Circuit:	-
Related Substation:	"O" STREET (2)

PEPCO(I)-2

DC Construction Report

No:	34
ITN Name:	73050: Pepco DC: Roof Replacements (UDSPRD8TD)
ITN:	UDSPRD8TD
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$41.88
2019_Budget_(000s):	$104.03
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	12/31/2011
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	The scope of this project is to replace and repair various substation roofs in order to avoid equipment and further structural damage. Multiple points of failure have been identified in the form of severe leaks which are no longer economically feasible to repair. Affected stations require partial or total replacement in both flat and sloped roofing structures. Such significant failures put the station equipment at serious risk due to water and elemental exposure, in turn putting Pepco at serious financial risk.
Justification:	To replace and repair various substation roofs in order to avoid equipment and further structural damage. Multiple points of failure have been identified in the form of severe leaks which are no longer economically feasible to repair.
Alternative:	The alternative is to continue to allow roofs to leak, which would put equipment as well as customer reliability at risk.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	35
ITN Name:	73052: Pepco DC: Substation Ventilation (UDSPRD8LD)
ITN:	UDSPRD8LD
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$34.06
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	12/31/2012
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	This project is for the engineering, design, construction, and procurement of new HVAC systems for DC substations to protect operational personnel and equipment from overheating during hot periods.
Justification:	As the system continues to age, HVAC systems in substations must be replaced to maintain proper temperature controlled environments for equipment and company personnel.
Alternative:	None, proper HVAC transformers and control house equipment are required, as they impact the useful lives of this equipment. If no action is taken, equipment such as relays and battery systems could catastrophically fail and leave major equipment (such as
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	36
ITN Name:	73054: Pepco DC: Add Sub Condition Monitoring Points (UDSPRD9D5)
ITN:	UDSPRD9D5
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$112.00
2020_Budget_(000s):	$121.22
2021_Budget_(000s):	$121.22
2022_Budget_(000s):	$121.22
2023_Budget_(000s):	$141.12
Start:	1/1/2013
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	This project allows us to add condition monitoring points to equipment as it may become impaired throughout the year to enable proactive repair/replace decisions. These monitoring points can include transformer Dissolved Gas Analysis (DGA) monitors, bushing monitors, Load Tap Changer monitors and breaker or battery monitors.
Justification:	Analytics in the form of gas monitors etc. provide the Failure Analysis group with more real time data in which to better gauge the need to repair or replace a suspect piece of equipment. This project gives additional data to all
Alternative:	If equipment becomes impaired, the alternative would be to do nothing and run to failure with no considerations for diagnostics or analytics.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

PEPCO(I)-2

DC Construction Report

No:	37
ITN Name:	73116: Pepco-DC: Fort Slocum Sub 190-Switchgear Repl (UDSPRD8AD1)
ITN:	UDSPRD8AD1
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$3,052.00
2020_Budget_(000s):	$4,282.01
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	6/1/2015
Est. ISD	9/14/2024
Finish:	9/14/2024
Scope of Work:	This project is for the purchase and installation of replacement 13.8kV switchgear in Fort Slocum, Sub. 190. Existing deteriorated switchgear will be replaced based on priority list determine through 2013 revised Kinectrics study. Proposed plan is to replace all bus sections. Failure of a breaker or cubicle can result in significant collateral damage.
Justification:	Failure of a breaker or cubicle can result in significant collateral damage.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	FORT SLOCUM (190)

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DC Construction Report

No:	38
ITN Name:	73371: Repl Eng Generators Dist Sub: Pepco DC (UDSPRD8UD)
ITN:	UDSPRD8UD
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$367.27
2019_Budget_(000s):	$402.67
2020_Budget_(000s):	$99.27
2021_Budget_(000s):	$99.27
2022_Budget_(000s):	$99.27
2023_Budget_(000s):	$99.27
Start:	2/28/2013
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	The scope of this project is to replace engine generators that are beyond their useful design life. The scope for an engine generator replacement includes engineering design, procurement of material and construction for installation. A total of twenty two replacements have been identified. Work to be performed in each year funded would be two replacements.
Justification:	Generators needed to provide backup power to miscellaneous substation lighting, communication equipment and provide backup AC power to oil console for power supply cables.
Alternative:	With a loss of normal AC station service power supply, the generator provides backup power which is essential to maintaining underground transmission facilities (power cables), substation lighting and essential communication equipment.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	39
ITN Name:	73380: Replace 9th Street (Sub 117) Drive Way Repair (UDSPRD89DW)
ITN:	UDSPRD89DW
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$224.56
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	4/1/2018
Est. ISD	6/30/2019
Finish:	10/28/2019
Scope of Work:	The scope of work for the 9th st substation driveway replacement and façade remediation which includes repair and/or replacement.
Justification:	Work not routine work. Material degradation on substation building and driveway/sidewalk is a safety hazard.
Alternative:	Repair the driveway
Reimbursable:	No
Related Circuit:	-
Related Substation:	NINTH STREET (117)

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DC Construction Report

No:	40
ITN Name:	73399: Replace Deteriorated Dist Transformers DC (UDSPRD9GD)
ITN:	UDSPRD9GD
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	($73.86)
2019_Budget_(000s):	$10,141.82
2020_Budget_(000s):	$21,931.18
2021_Budget_(000s):	$2,049.16
2022_Budget_(000s):	$1,540.00
2023_Budget_(000s):	$7,940.00
Start:	5/1/2013
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	The project is to engineer, procure and install replacement transformers in DC based on age and condition as required either through failure or recommendation through the ECA (Equipment condition assessment) process. The number of units replaced each year is determined by system need. A detailed ranking is used to determine the overall health of a transformer on the Pepco system. Based on this ranking the transformers in the "poorest" condition are chosen to be replaced first. This ranking incorporates age, maintenance reports, physical condition, and manufacturer history. Units replaced since 2013:F Street T1 (2015)New Jersey Ave T1 (2015)Champlain T7 (2014)Fort Davis T1 (2014)Benning System spare (2015)O Street T1 (2015) Pending units:2 Buzzard Point system spare unitsF Street T3
Justification:	This is a WBS blanket to fund the replacement of aged and deteriorated transformers. A detailed ranking is used to determine the overall health of a transformer on the Pepco system. Based on this ranking the transformers in the "poorest" condition are chosen to be replaced first. This ranking incorporates age, maintenance reports, physical condition, and manufacturer history. This project was created in 2013 as a result of the following conditions:T2 at L Street Sub 21 is 73 years old and needs to be re-gasketed and re-conditioned to extend its useful life. Replacement parts are unavailable due to age. The transformer in its existing condition is a reliability concern. T4 at New Jersey

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	Ave Sub 161 has wet oil and paper that must be removed in order to prolong the life of this unit. Trying to dry the paper on a transformer this age may do more harm than good, which would lead to a future failure. Replace T4 with a new unit to ensure continued reliability.
Alternative:	An alternative is to wait until transformer fails before replacing it. This alternative was not accepted because it would put the system at risk of extended outages and hinder our ability to supply the substation's load at peak time if a unit were to fail in this critical area.
Reimbursable:	No
Related Circuit:	-
Related Substation:	CHAMPLAIN (25)

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DC Construction Report

No:	41
ITN Name:	73413: Replace Distribution Sub Structures (UDSPRD8YD)
ITN:	UDSPRD8YD
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$172.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	12/31/2012
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	This scope of work is dependent on each replacement. The replacement of aging distribution substation structures is required each year to maintain a reliable electrical system. Additional information is based on the history of customer compliants received.
Justification:	This blanket ITN for project is for the replacement of aging distribution substation structures is required each year to maintain a reliable electrical system. Additional information is based on the history of customer complaints received.
Alternative:	For substations that have deteriorated structures, the substation infrastructure assessment is in place to evaluate and plan structure replacement periodically to keep the reliability of the system. This solution will eliminate the impact of a sudden failure and provide an upgrade to the infrastructure so the system continues to be reliable.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	42
ITN Name:	73454: Retire Congress Height Sub. 64 (UDSPRD8RD1)
ITN:	UDSPRD8RD1
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$8.86
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	4/16/2015
Est. ISD	6/30/2019
Finish:	4/29/2020
Scope of Work:	Retire Congress Heights Sub. 64 after Feeders 178 and 294 are converted to 13kV construction, that involves the following: 1. Extend and/or rearrange Alabama Avenue Sub. 136 – 13kV Feeder 15171 and Congress Heights Sub. 64 Feeders 178 and 294 in order to accomplish the following: a.) Convert all load (approximately 0.6 MVA summer 2017 load) from Congress Heights Sub. 64 Feeder 178 to Feeder 15171. Retire Feeder 178. This involves changing poles, transformers, wires, and insulators. b.) Convert all load (approximately 0.4 MVA summer 2017 load) from Congress Heights Sub.64 Feeder 294 to Feeder 15171. Retire Feeder 294. c.) Retire Congress Heights Sub. 64 after Feeders 178 and 294 are converted to 13kV construction. 2. Install normally open switch on Wheeler Road SE in the vicinity of pole #802364-580400 and establish a new tie Chesapeake St. Sub. 181 4kV Feeders 329 and 120. 3. Establish an open tie between Chesapeake St. Sub. 181 4kV Feeders 165 and 324 at pole # 800364-860730. 4. Install one normally closed SF6 switch and one normally open SF6 tie-switch in Alabama Avenue Sub. 136 Feeder 15171 (at the intersection of Savannah St. and 15th St. SE)

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	and between Feeders 15166 and 15171 (at the intersection of Mississippi Ave. and 13th St. SE), respectively. These switches should be added to the ASR scheme proposed for Feeder 15171. Include this work with the Congress Heights Sub. 64 conversion project.
Justification:	From 2007 Long Range Study for the Pepco 4kV system concluded that it is more economical to retire the substation rather than replacing and maintaining the existing switchgear.
Alternative:	Retire sub after 4kV conversion.
Reimbursable:	No
Related Circuit:	-
Related Substation:	CONGRESS HEIGHTS (64)

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No:	43
ITN Name:	73456: Retire Fort Carroll Sub. 130 (UDSPRD8SD3)
ITN:	UDSPRD8SD3
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$300.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2019
Est. ISD	12/31/2019
Finish:	4/30/2020
Scope of Work:	Retire Fort Carroll after Feeders 122, 234 and 325 are converted to 13kV construction.
Justification:	The proposed conversions of load from Fort Carroll Sub. 130– 4kV Feeders 122, 234 and 325 to NRL Sub. 168 Feeders 14752 and 14755. is recommended to facilitate the retirement of Fort Carroll Sub. 130. The 2007 long range study for the Pepco 4kV system concluded that because Fort Carroll is a single transformer substation not networked with other substations, this substation should be retired. In addition, the switchgear assessment study performed by Kinetrics in 2013 concluded that switchgear Fort Carroll Sub. 130 needed to be replaced and so the retirement was advanced to avoid replacement.
Alternative:	Maintain operations at Sub. 130 replacing transformer, switchgear and 4 kV feeder infrastructure. This would not achieve the goal of eliminating all non-networked 4 kV single transformer substations.
Reimbursable:	No
Related Circuit:	-
Related Substation:	Ft. Caroll (130)

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DC Construction Report

No:	44
ITN Name:	73554: SPCC - Distribution Oil Brkr Replacements : Pepco DC (UDSPRD8Q1
ITN:	UDSPRD8Q1D
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$1,189.62
2019_Budget_(000s):	$18.40
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/2/2015
Est. ISD	12/31/2018
Finish:	4/30/2019
Scope of Work:	The scope of this project involves replacing 69kV Oil Circuit Breakers with SF6 Gas Circuit Breakers for the following Substations: 1) Ft Slocum - replaced five 69kV Oil Circuit Breakers (OCBs), and 2) 12th & Irving - replaced five 69kV OCBs. The new breakers for Sub 133 and Sub 190 were purchased in 2015. Engineering is completed for both Subs. Sub 190 construction is in progress and scheduled to be completed by end of 2016. The breakers replacement work at Sub 133 is scheduled for 2018. Additional funding needs to be allocated to complete the work.
Justification:	The oil circuit breakers selected for replacement based on their age and health condition. Consequences of circuit breaker failure include interruptions over significantly long duration. Catastrophic failure of circuit breakers may also result in collateral damage to other transformers, damage to other station equipment and if staff are present, injury to personnel. Furthermore, considering they are filled with mineral oil, there is a risk of oil spills containing ground and water systems if the tank fails.
Alternative:	Alternatives considered addressing the issues posed by oil breakers of running them to failure or proactive replacement. The approach of allowing oil circuit breakers to run to failure would have significant impacts on reliability and safety. In addition to rising maintenance costs and increased difficulty in obtaining parts for oil

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	circuit breakers, the replacement would lower the estimated avoided risk cost associated with these assets when compared to deferring replacement, thus the most cost-effective option is replacement of obsolete equipment before failure. If no action is taken, there is high risk to have oil spills containing ground and water systems. Two alternative technologies considered for replacing the existing oil breakers are: Vacuum circuit breakers to SF6 circuit breakers. Both technologies exhibit high degrees of reliability under normal and abnormal conditions. Due to vacuum circuit breaker technology does not cover 69kV and above, SF6 circuit breakers were proposed for the replacement program.
Reimbursable:	No
Related Circuit:	-
Related Substation:	FORT SLOCUM (190);12th & IRVING, NE (133)

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DC Construction Report

No:	45
ITN Name:	73734: Sub 150 Twining City T2 - B-0551 (ECA) (UDSPRD8TC1)
ITN:	UDSPRD8TC1
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$47.28
2019_Budget_(000s):	$1,300.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	7/19/2018
Est. ISD	12/31/2019
Finish:	4/30/2020
Scope of Work:	Replace T2 Transformer B-0551 Twining City substation 150, 13.5 kV to 4.3 kV, 5 MVA, Pennsylvania Transformer 1956
Justification:	The power factor of the main insulation has been increasing in an accelerated pattern. This includes the low voltage winding, low voltage to high voltage and high voltage insulation. While the level is similar for all areas, the power factor is highest in the low to high insulation with 1.35%. The excitation current in neutral and tap position did almost triple indicating an issue in the LTC or windings. The unit might undergo a major failure in the near to intermediate future.
Alternative:	Hot oil circulation would dry out the insulation and most likely lower the power factor if it was driven by moisture and the insulation is not overly deteriorated. To enable this operation new gaskets would have to be applied as a likely scenario. An intrusive inspection of the LTC and the element might give insight why the excitation current increased. There is a high probability that the coils have to be removed from the core to have a possible finding. To inspect the element and pull the coils the unit has to be untanked, given the small size of 5 MVA entering the tank is not possible. Comparing the financial and operational effort and including the uncertainty of a repair option

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	replacement appears to be preferred. The replacement project is expected to be concluded Fall 2018/ Spring 2019.
Reimbursable:	No
Related Circuit:	-
Related Substation:	TWINING CITY (150)

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DC Construction Report

No:	46
ITN Name:	73747: Sub. 052 Replace T2 Transformer at Tenth Street Substation (ECA) (DSPRD8A
ITN:	DSPRD8AD16
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$790.69
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	5/3/2017
Est. ISD	6/15/2019
Finish:	10/13/2019
Scope of Work:	Replace T2 transformer at Tenth Street Sub (Sub 52)
Justification:	The T2 transformer at Tenth street is being sponsored for replacement due to mechanical problems with the LTC (reversing contact coking).
Alternative:	The only alternative to replacing the transformer is continued maintenance. However with the recent problems with oil condition, the operation of the LTC can be affected. Reliability of the transformer has become a concern.
Reimbursable:	No
Related Circuit:	-
Related Substation:	TENTH STREET (52)

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DC Construction Report

No:	47
ITN Name:	73754: Sub. 50 Marine D & R All 4kV Electrical (UDSPRD8RM)
ITN:	UDSPRD8RM
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$400.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	10/1/2013
Est. ISD	5/29/2020
Finish:	9/29/2020
Scope of Work:	This is not a blanket project and this is not part of a blanket. The site is completely de-energized and no longer in service. The abandoned equipment will be removed and the building will be demolished. The contractor will excavate to ensure that no underground utilities are left on site. The site will be graded and a new fence will be installed on the empty lot once the demolition is completed. Pepco currently has the scope of work and environmental assessments and is also currently working on developing a demolition permit request package for the sites and the demolition is expected to take place on 2020. No funds will be needed until 2019 for the permit efforts.
Justification:	Demolition efforts are on hold until 2019. This station has been decommissioned for many years and currently is not supplying any load.
Alternative:	There are no alternatives, all of the load was transferred to other stations as this was one of the old 4kv systems. The site is no longer in use and will no longer be needed for the future.
Reimbursable:	No
Related Circuit:	-
Related Substation:	Marine

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DC Construction Report

No:	48
ITN Name:	73757: Sub.12 Georgetown Replace T1 Transformer (69/13kV) (DSPRD8AD13)
ITN:	DSPRD8AD13
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$1,299.99
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2018
Est. ISD	12/31/2019
Finish:	4/30/2020
Scope of Work:	Replace the T1 transformer at Georgetown Substation. Voltage -69/13kVSize-30MVA
Justification:	The transfomer is aging and the health index of the transformer is poor. The transformer has had a history of high acidity and humid oil in the main tank and LTC.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	49
ITN Name:	73762: Sub.168 Naval Research-Replace T1 Transformer (DSPRD8AD11)
ITN:	DSPRD8AD11
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$9.57
2019_Budget_(000s):	$1,451.81
2020_Budget_(000s):	$1,008.82
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/2/2018
Est. ISD	12/1/2019
Finish:	4/1/2020
Scope of Work:	Replace the T1 transformer at Naval Research Substation. Voltage -69/13kVSize-30MVA
Justification:	The transformer is aging and the health index of the transformer is poor. Doble notes overall deteriorated conditions.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	NAVAL RESEARCH LAB (168)

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DC Construction Report

No:	50
ITN Name:	73781: Substation Improvements and Additions - DC (UDSPRD8AD)
ITN:	UDSPRD8AD
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$399.99
2020_Budget_(000s):	$400.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	12/31/2012
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This blanket was created to support various projects related to enhancing and replacing deteriorated /failed equipment, foundations, and structures related to maintaining the reliability of D.C. substations. Projects can range from Fire Protection equipment replacement/upgrade, sinkhole repairs, foundation repairs, steel structure replacements, driveway repairs, storm-water management installation, etc. The details of each project varies depending on the scope; all of the projects require all three phases of engineering, procurement and construction. For 2016, Pepco is working on three fire protection jobs one fire pump replacement at Benning Sub 7 and two jobs at Buzzard Sub 42. Also, Pepco has worked on storm water management modification at Little Falls Sub 77 and landscaping/sidewalk improvement at Tenth St. Sub 52.
Justification:	The substation infrastructure and equipment has deteriorated over time and it is critical that the upgrades are made to ensure reliability and safety of the substation equipment. Fire protection is very critical for maintaining safety in the unforeseen case that an electrical piece of equipment causes a fire. Foundation and steel structure upgrades are necessary to ensure equipment is properly supported and does not pose a reliability/safety hazard. Without upgrading the substation infrastructure and equipment more structures and elements within the substation would be susceptible to failure. Fires would be

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	able to spread around the substation and damage surrounding equipment, which will cause for more money for additional replacements. It will help the company save money if the upgrades were made at a reasonable time before things become critical which could lead to something catastrophic.
Alternative:	There are no alternatives because it is necessary to perform the necessary upgrades for fire protection, structures, and foundations. It would be in the benefit of the company from a reliability and budget stand point to make these upgrades because without these upgrades other pieces of equipment can be impacted, therefore escalating the cost.
Reimbursable:	No
Related Circuit:	-
Related Substation:	ALABAMA AVENUE (136);BENNING (7);BUZZARD POINT (42);TENTH STREET (52)

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DC Construction Report

No:	51
ITN Name:	73796: Surge Arrester Replacement - DC (UDSPRD8WD)
ITN:	UDSPRD8WD
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$68.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	12/31/2012
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	This project is created to replace exising surge arresters that are in poor condition
Justification:	Aging substations have surge arresters that are prone to bursting if they are not in a good condition. This program is to identify and replace those arresters
Alternative:	Replace aeging surge arresters
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	52
ITN Name:	73906: Transformer Replacement T9 at Benning Road (Sub 41) (UDSPRD8AD9
ITN:	UDSPRD8AD9
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$1,499.99
2021_Budget_(000s):	$3,500.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	3/1/2019
Est. ISD	11/18/2020
Finish:	3/18/2021
Scope of Work:	The original scope of this project is to replace the T9 transformer at Benning (Sub 41). However, there is a plan to repair LTC starting in Fall of 2019 under corrective maintenance ITN#85529 as per ECA list and AME.
Justification:	The transformer was identified on the ECA list due to high age and high maintenance cost.
Alternative:	None. If keep operating or maintaining the way it is, it could lead to a failure. LTC repair has been scheuled starting in Fall of 2019.
Reimbursable:	No
Related Circuit:	-
Related Substation:	BENNING (7)

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DC Construction Report

No:	53
ITN Name:	74351: PEPCO DC Fire Pre-Plan development -Distribution Substations (U
ITN:	UDSPRD8DFP
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$605.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2018
Est. ISD	3/26/2021
Finish:	3/26/2021
Scope of Work:	The contractor will visit every substation as part of preparing pre-fire plans for each site. Pre-fire plans contain information such as substation layout and a list of hazards that will be used by emergency response personnel to respond to emergencies safely and effectively. The project also includes the installation of the fire pre-plans in an on-site, weather-proof enclosure for every substation. A gap analysis will be performed at each site to identify where site conditions do not meet the current fire protection standards for every substation. The gap analysis will be used to scope future capital jobs to mitigate exposure to fire. These fire pre-plans will be part of integrating PHI into Exelon Utilities Process AM-EU-P115.
Justification:	
Alternative:	
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	54
ITN Name:	74352: FEP Physical Security - Pepco (DC): 22nd Street Sub 124 (UDSPRD
ITN:	UDSPRD8PS3
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$896.35
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2018
Est. ISD	12/31/2019
Finish:	4/28/2020
Scope of Work:	One of several indoor Tier 1 FEP sites in the Pepco region to install intrusion detection, camera system and access controls around the perimeter and within the substation. This project also includes the installation of data collection equipment in the relay room.
Justification:	This project is required to meet Exelon FEP security standards.This project is a part of a long-term strategy to upgrade the physical security installations, based on Tiering criteria, at critical substations and facilities.
Alternative:	Do Nothing - Violates Exelon FEP security requirements and leaves substation at risk to various levels of potential threats in dense metropolitan area.
Reimbursable:	No
Related Circuit:	22nd St (124)
Related Substation:	-

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DC Construction Report

No:	55
ITN Name:	74353: FEP Physical Security - Pepco (DC): 9th Street Sub 117 (UDSPRD8
ITN:	UDSPRD8PS9
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$896.35
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2018
Est. ISD	12/1/2020
Finish:	3/31/2021
Scope of Work:	One of several indoor Tier 1 FEP sites in the Pepco region to install intrusion detection, camera system and access controls around the perimeter and within the substation. This project also includes the installation of data collection equipment in the relay room.
Justification:	This project is required to meet Exelon FEP security standards.This project is a part of a long-term strategy to upgrade the physical security installations, based on Tiering criteria, at critical substations and facilities.
Alternative:	Do Nothing - Violates Exelon FEP security requirements and leaves substation at risk to various levels of potential threats in dense metropolitan area.
Reimbursable:	No
Related Circuit:	9th St (117)
Related Substation:	-

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DC Construction Report

No:	56
ITN Name:	74383: FEP Physical Security - Pepco (DC): 12th & Irving Sub 133 (
ITN:	UDSPRD8PS2
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$896.35
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2018
Est. ISD	6/30/2020
Finish:	10/30/2020
Scope of Work:	One of several indoor Tier 1 FEP sites in the Pepco region to install intrusion detection, camera system and access controls around the perimeter and within the substation. This project also includes the installation of data collection equipment in the relay room.
Justification:	This project is required to meet Exelon FEP security standards.This project is a part of a long-term strategy to upgrade the physical security installations, based on Tiering criteria, at critical substations and facilities.
Alternative:	Do Nothing - Violates Exelon FEP security requirements and leaves substation at risk to various levels of potential threats in dense metropolitan area.
Reimbursable:	No
Related Circuit:	12th & Irving (133)
Related Substation:	-

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DC Construction Report

No:	57
ITN Name:	70056: 12th & Irving Sub. 133 Feeder 14200 - Transfer 1.0 MVA to Feeder 14022
ITN:	UDLPLM7W5
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$2.21
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	4/9/2014
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Extend and/or rearrange 12th & Irving Sub. 133 Feeders 14200 and 14022 in order to transfer approximately 1.0 MVA of summer 2015 13 kV load from 12th & Irving Sub. 133 Feeder 14200 to 12th & Irving Sub. 133 Feeder 14022.
Justification:	12th & Irving Sub. 133 Feeder 14022 is recommended to relieve a predicted summer 2015 normal capacity overload of approximately 5% on Feeder 14200.
Alternative:	Extend Feeder 14022 across the railroad tracks to pick up 1 MVA of load
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	58
ITN Name:	70096: 13kV Distribution Cutovers "F" St to "L" St (UDLPLM7W27)
ITN:	UDLPLM7W27
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$165.50
2019_Budget_(000s):	$7,000.19
2020_Budget_(000s):	$7,000.00
2021_Budget_(000s):	$8,500.00
2022_Budget_(000s):	$7,500.00
2023_Budget_(000s):	$5,000.00
Start:	1/1/2018
Est. ISD	12/31/2027
Finish:	4/29/2028
Scope of Work:	Conduit & Cable for cutovers L Street SUB#21 Cutovers from F Street SUB#74
Justification:	Downtown 69kV resupply - The existing lease agreement for “I” St Sub 197, located on Pennsylvania Ave, is scheduled to end at 2023. Forces a decision point for the company: The “I” St Sub 197 existing lease agreement has effects on future capital work including the 69kV Downtown Re-supply as well as the 230kV Capital Grid
Alternative:	Maintain “I” St, renew the lease agreement and the following:Resupply 22nd Street, F St and Georgetown via Champlain 69kV new 230/69/34kV subRefurb/Upgrade existing equipment at ‘I’ Street Sub. 197 in the future (2026) Switchgear & TransformersRefurb/Upgr
Reimbursable:	No
Related Circuit:	-
Related Substation:	"F" STREET (74);"I" STREET (197);"L" STREET (21)

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DC Construction Report

No:	59
ITN Name:	70097: 13kV Distribution Cutovers from "I" St to "F" St & "L" St (UDLPLM7W28)
ITN:	UDLPLM7W28
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$1,500.00
2023_Budget_(000s):	$1,434.95
Start:	7/1/2018
Est. ISD	12/31/2027
Finish:	4/29/2028
Scope of Work:	Conduit & Cable for cutovers F Street SUB#74 Cutovers from I Street SUB197 L Street SUB#21 Cutovers from I Street SUB197
Justification:	Downtown 69kV resupply - The existing lease agreement for “I” St Sub 197, located on Pennsylvania Ave, is scheduled to end at 2023. Forces a decision point for the company: The “I” St Sub 197 existing lease agreement has effects on future capital work including the 69kV Downtown Re-supply as well as the 230kV Capital Grid
Alternative:	Maintain “I” St, renew the lease agreement and the following:Resupply 22nd Street, F St and Georgetown via Champlain 69kV new 230/69/34kV subRefurb/Upgrade existing equipment at ‘I’ Street Sub. 197 in the future (2026) Switchgear & TransformersRefurb/Upgr
Reimbursable:	No
Related Circuit:	-
Related Substation:	"F" STREET (74);"I" STREET (197);"L" STREET (21)

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DC Construction Report

No:	60
ITN Name:	70432: Alabama Ave Sub 136 - Transfer 1.3 MVA 15177 to 15176 (UDLPLM7W3)
ITN:	UDLPLM7W3
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$3.58
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/23/2016
Est. ISD	6/30/2019
Finish:	10/28/2019
Scope of Work:	Alabama Ave Sub. 136 - Install a Normally Open Gang Switch in Alabama Avenue Sub. 136 Feeder 15177 in order to transfer 1.3 MVA summer 2016 load from Feeder 15177 to 15176.
Justification:	The transfer of approximately 1.3 MVA of summer 2016 load from Feeder 15177 to Feeder 15176 is recommended to adequately supply the Poplar Point Pumping Station load without overloading Feeder 15177, and to relieve a predicted summer 2016 overload of approximately 4%.
Alternative:	Installing the NO switch and performing the load transfer to mitigate over loading on the Feeder 15177.
Reimbursable:	No
Related Circuit:	15176;15177
Related Substation:	ALABAMA AVENUE (136)

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DC Construction Report

No:	61
ITN Name:	70433: Alabama Ave Sub 136: Extend 7 Fdrs to Retire Anacostia (UDLPLWF1)
ITN:	UDLPLWF1
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$74.95
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	3/13/2019
Est. ISD	12/31/2019
Finish:	4/30/2020
Scope of Work:	This project consists of extending two overhead distribution feeders from Alabama Ave. Sub 136, which along with existing feeders will be used to transfer all distribution load from Anacostia Sub. 8. Three new 13kV sub-transmission feeders would be extended to transfer the supplies of Twining City Sub. 150 from Sub. 8 to Sub 136. Two new spot network feeders would be extended to transfer the spot network load from Sub. 8 to Sub. 136. The three sub-transmission feeders and the two spot networks would be extended underground in a new 8-way conduit from Sub. 136 to Sub. 8 to cutover the five Anacostia feeders, a distance of approximately 9500 feet. This project supports the retirement of Anacostia Sub. 8 after the project in WBS number UDLPLWF3 is completed.
Justification:	The project is needed to retire Anacostia Sub. 8 - 13 kV substation which has concrete encased switchgear in need of improved operations. The substation is also supplied from 34 kV feeders consisting of 70+ year old submarine cables that would be difficult to replace in an emergency. This project also supports Pepco's long term plan to convert 4kV system.
Alternative:	Extend 7 new feeders from Alabama Sub 136 to transfer load from Anacostia and retire Anacostia Sub. 8
Reimbursable:	No
Related Circuit:	-

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Related Substation:	-

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DC Construction Report

No:	62
ITN Name:	70439: Anacostia Sub : Convert 4 to 13kv & Retire Sub (UDLPLWF3)
ITN:	UDLPLWF3
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$1,514.53
2019_Budget_(000s):	$3,600.00
2020_Budget_(000s):	$5,858.63
2021_Budget_(000s):	$4,316.38
2022_Budget_(000s):	$7,979.66
2023_Budget_(000s):	$9,815.26
Start:	12/31/2009
Est. ISD	12/25/2025
Finish:	4/24/2026
Scope of Work:	This project is to retire an aging Anacostia 4kV substation and its supply feeders from Buzzard point as part of Pepco's long term plan to convert 4kV to 13kV, and retire aging infrastructure. Project scope includes the removal of underground (UG) cables from Substation to Getaway pole in order to retire the substation. All overhead conversion will be done via DC PLUG project. The schedule for this project is associated with the DC PLUG schedule. Install one open switch for Feeder 499 and 348 as recommended for backup.
Justification:	This work is proposed to retire an aging substation supplied from 34kV submarine cables from Buzzard Point Sta. B that are approaching the end of their useful life.
Alternative:	Convert remaining 4kV load to 13kV load and retire the Sub.
Reimbursable:	No
Related Circuit:	348;34915;34917;499
Related Substation:	ALABAMA AVENUE (136);ANACOSTIA (8);CONGRESS HEIGHTS (64);Ft. Caroll (130);TWINING CITY (150)

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DC Construction Report

No:	63
ITN Name:	70767: Benning Sub. 7 - Transfer portions of Feeder 15703 to Feeders 14152 and 14708
ITN:	UDLPLM7W25
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$7,336.97
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/3/2017
Est. ISD	5/29/2019
Finish:	9/26/2019
Scope of Work:	Extend and/or rearrange Benning Sub. 7 – 13kV Feeders 14152, 14708, 15703, 15704, and 15708 to transfer approximately 0.2 MVA Summer 2017 load from Feeder 15703 to Feeder 15708, 0.6 MVA Summer 2017 load from Feeder 15703 to Feeder 14152, and 0.6 MVA Summer 2017 load from Feeder 15703 to Feeder 14708.
Justification:	Benning Sub. 7 – 13kV Feeder 15703 is predicted to have a Summer 2017 voltage drop of 4.5% under normal conditions. In addition, this recommended work will bring the half loop on Feeder 15703 up to the standards outlined in Pepco's four-wire guidelines as well as supply the beginning of the Hill East Neighborhood re-development in the vicinity of 19th Street and Massachusetts Avenue, SE.
Alternative:	An alternative to extending Feeders 14152 and 14708 to facilitate the recommended load transfers from Feeder 15703 would be to perform load transfers to neighboring feeders. This alternative was not selected because these nearby feeders lack the capacity to carry this transferred load plus meet future load growth in the area, specifically the Hill East Neighborhood re-development. With no capacity available on area feeders, two new feeders would need to be extended from Waterfront Sub. 223. This would require a much longer extension with greater expense and would not be completed in time to serve new customers in the Hill East neighborhood.
Reimbursable:	No

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Related Circuit:	14152;14708;15703;15704;15708
Related Substation:	BENNING (7)

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DC Construction Report

No:	64
ITN Name:	71138: Convert Alabama Ave. Sub 136 Feeder 15178 and 15165 from a 3-wire to a 4-wire
ITN:	UDLPLM7401
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$400.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	6/1/2018
Est. ISD	6/1/2019
Finish:	9/29/2019
Scope of Work:	Convert Alabama Ave. Sub. 136 Feeder 15178 (originally Anacostia Sub. 8 Feeder 14709) and Feeder 15165 from a 3-wire to a 4-wire feeders by extending a neutral and transfer approximately 2.2 MVA summer 2019 load from Feeder 15166 to Feeder 15165 and transfer approximately 2.4 MVA summer 2019 load from Feeder 15177 to Feeder 15178 (see Dwg. # 05-19-02.0 for details). This feeder overload will be mitigated by Battery Storage in 2020, if the battery doesnot work we will continue with traditional solution.
Justification:	The conversion and/or rearrangement of Alabama Ave Sub. 136 Feeders 15165, 15166, 15178 and 15177 to transfer approximately 2.2 MVA and 2.4 MVA summer 2019 load from Alabama Ave. Sub. 136 Feeder 15166 to Feeder 15165 and Feeder 15177 to Feeder 15178, respectively are recommended to relieve a 4% and a 5% normal capacity over loads on Feeder 15166 and 15177, respectively.
Alternative:	Convert feeders 15178 and 15165 from a 3-Wire to a 4-wire distribution feeders.
Reimbursable:	No
Related Circuit:	15165;15178
Related Substation:	ALABAMA AVENUE (136)

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DC Construction Report

No:	65
ITN Name:	71411: Dist Feeder Load Relief - DC (UDLPLM7W)
ITN:	UDLPLM7W
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$414.87
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	5/31/2011
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This blanket budget captures miscellaneous system projects recommended for small load transfers and installing capacitors and regulators to radial systems. Minor carryover charges and charge transfers for same type of legacy blanket RDLPLM07 is included. Below are examples of the type of work performed under this project budget. 2013-2014: Distribution Planning System Work Log 2013 DC Region Miscellaneous Distribution Projects 2013 Project Ranking - 1.01 Ward - 7&8 Description - Balance phase loadings on 53rd Street Sub. 48 - 4kV Feeder 372.2013 Project Ranking - 1.02 Ward - 7&8 Description - Balance phase loadings on Seat Pleasant Sub. 30 - 4kV Feeder 205 2013 Project Ranking - 2.01 Ward - 7&8 Description - Balance phase loadings on 53rd Street Sub. 48 - 4kV Feeder 388 2015: Install one (1) 300 kVar capacitor bank on 4 kV Feeder 65 (Veazey West Sub. 90-W & Oliver Street Sub. 146 2016: Inst one 300 kVar cap bank each on Feeders 292 and 133 2017-2020: Placeholder for all Miscellaneous Line Work.
Justification:	These projects will prevent normal capacity overloads ranging from 1% to 15%, and Voltage Drops exceeding 3.7%
Alternative:	These are all small projects without alternatives except to do nothing and tolerate exceeding the operating condition. Doing nothing was not considered because customers would see reduced reliability due to outages from overloads

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DC Construction Report

	and reduced power quality due to voltages falling below acceptable levels.
Reimbursable:	No
Related Circuit:	133;292
Related Substation:	NEBRASKA (92);WESLEY (61)

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DC Construction Report

No:	66
ITN Name:	71441: Distribution Feeder Load Relief DC (UDSPLM7W)
ITN:	UDSPLM7W
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$720.46
2019_Budget_(000s):	$188.11
2020_Budget_(000s):	$200.00
2021_Budget_(000s):	$200.00
2022_Budget_(000s):	$200.00
2023_Budget_(000s):	$200.00
Start:	12/31/2008
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This project is for the work needed in substations to support the extension of new distribution feeder(s) in DC to relieve system overload. The work entails the procurement, design, installation, testing, and commissioning of F60 relays and 15kV circuit breakers in the substation for the new feeder extension. Work completed for 2013 - 2015 includes:· Alabama Sub. 136 - Extend new Feeder 15178 & 15179 by June 2016 to cutover Anacostia Sub. 8 Feeders 14709 & 14702.· Alabama Sub. 136 - Extend new Feeder 15180, 15181, & 15182 by June 2016 to cutover Anacostia Sub. 8 Feeders 14718, 14719, & 14707.· Georgetown Sub. 12 - Extend new Feeder 15995 by December 2016 to convert all 4 kV feeders at Georgetown Sub. 12.· 12 & Irving Sub. 133 – Extend new Feeder 14002 Work planned for 2016 includes: · Fort Slocum Sub. 190 - Extend new Feeder 15003 by June 2016 to relieve load from Fort Slocum Sub. 190 Feeder 15012 & 15197.· Champlain Sub. 25 - Extend new Feeder 15991 & 15992 by June 2016 to transfer load from Harvard Sub. 13.· Northeast Sub. 212 - Extend new network group (Feeder 15475-15480) by June 2016 to relieve load from Tenth St. Sub. 52 and Northeast Sub. 212.· Northeast Sub. 212 - Extend new South Spot network group by June 2016 to relieve load from Northeast Sub. 212 Southeast Sport Network Group. Work planned for 2017 includes: · Van Ness Sub. 129 - Extend new Feeder 15946 by June 2017 to relieve load from Little Falls Sub. 77 Feeder

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	14766.· Fort Slocum Sub. 190 - Extend new Feeder 15018 by June 2017 to relieve load from Fort Slocum Sub. 190 Feeder 15016.Southwest Sub. 18 - Extend new Feeder 15876 & 15877 by June 2017 to convert 4kV feeders from G Street Sub. 28.
Justification:	Substation work to relieve system overloads on various feeders and network groups in the DC system.
Alternative:	Extend new feeders to relieve different overloads in different areas of the system.
Reimbursable:	No
Related Circuit:	-
Related Substation:	ALABAMA AVENUE (136);FORT SLOCUM (190);GEORGETOWN (12);NORTHEAST (212);SOUTHWEST (18)

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No:	67
ITN Name:	71867: Harvard Rebuild - 13 kV Feeders to Cutover Existing Sub 13 (UDLPRM4WA6)
ITN:	UDLPRM4WA6
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$10,547.20
2019_Budget_(000s):	$7,227.62
2020_Budget_(000s):	$3,938.32
2021_Budget_(000s):	$9,945.58
2022_Budget_(000s):	$8,938.44
2023_Budget_(000s):	$3,000.00
Start:	3/22/2017
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Extend 12 new 13 kV feeders (4 LVAC, 6 radial distribution, 2 Metro Traction feeders) from new Harvard substation to cutover existing feeders supplied from existing Harvard Sub. 13. Cutovers would occur a short distance from the substation.
Justification:	Existing Harvard Sub. 13 was originally constructed in the 1920's and has some very old concrete encased switchgear that cannot be upgraded without demolishing the existing infrastructure. Champlain Sub. 25 was originally built for 13 kV in the 1930's and has similar concrete encased switchgear as Harvard Sub. 13.
Alternative:	An alternative to rebuilding Harvard would be to purchase a new property in order to build a new substation. Since Pepco already owns most of the needed property at Harvard Sub. 13, there would be less cost and less risk of not obtaining approval by using the existing property and not obtaining a new one.
Reimbursable:	No
Related Circuit:	-
Related Substation:	CHAMPLAIN (25);FLORIDA AVENUE (10);FORT SLOCUM (190);HARVARD (13)

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DC Construction Report

No:	68
ITN Name:	71876: Heavy Up Station B East Network Group Feeders - Waterfront Sub. 223 (UDLPLM7D3)
ITN:	UDLPLM7D3
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$4,765.34
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2017
Est. ISD	4/15/2019
Finish:	8/13/2019
Scope of Work:	Heavy up Station B East network group feeders 14407, 14408, 14409, 14410, 14411 & 14412 from 350 MCM to 600 EPR 1/C from vicinity of new Waterfront Sub. 223 at the corner of First Street and 'Q' Street Southwest to corners of First Street and 'N' Street Southwest, and South Capitol and 'N' Street Southwest (approximately 2900' of conduit and 10,000' of cable total).
Justification:	Existing Buzzard Point Station B East LVAC Network Group cable configuration in the duct bank running north on First Street Southwest between 'V' Street and 'N' Street Southwest limits the firm capacity of the network group to 39.0 MVA. After the network group is transferred to new Waterfront Sub. 223 East Network group, the section between 'Q' Street Southwest and 'N' Street Southwest will remain to be the limiting factor. As a result heavying up that section will be necessary to increase the firm capacity to 51.0MVA to accommodate the load growth and to avoid transferring the 4% overload to the new East group out of Waterfront.
Alternative:	This is part of the Waterfront Substation project. Please refer to the Waterfront Substation (UDSPLWF1) for alternatives to the substation.
Reimbursable:	No
Related Circuit:	14407;14408;14409;14410;14411;14412

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Related Substation:	BUZZARD POINT STATION ("B");WATERFRONT (223)

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DC Construction Report

No:	69
ITN Name:	71902: I Street Sub 197 Central to Sub 197 North LVAC Cutover (UDLPLIST2)
ITN:	UDLPLIST2
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$231.65
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2016
Est. ISD	1/31/2018
Finish:	5/31/2018
Scope of Work:	Extend and/or rearrange the I St. Sub. 197 North LVAC group and Central LVAC group to transfer approximately 10.8 MVA summer 2017 load from the I St. Sub. 197 Central LVAC group to the North LVAC group. Requires approximately 900' of conduit and 5400' of cable.
Justification:	Predicted 2017 2% Expected Feeder Overload Under Single Contingency on the Sub. 197 Central LVAC Group
Alternative:	If we do not use the existing Sub 197 North LVAC network group to relieve this overload, and also because there are no feeder positions at nearby area substations (i.e. there is no more space at the substation to add additional circuits), the only alternative is to build a new substation and extend a new LVAC group to relieve the overload (this would be the new substation close to the area. It would be in the $200M range and only if there is real estate available in the area). This alternative would be much more expensive than the proposed solution.
Reimbursable:	No
Related Circuit:	15382;15383;15384;15385;15386;15387;15426;15427;15428;15429;15430;15431
Related Substation:	"I" STREET (197)

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DC Construction Report

No:	70
ITN Name:	72004: Install 4th 230/69kV 224MVA transformer #12 at Benning (UDSPLM720A)
ITN:	UDSPLM720A
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$2,430.00
2021_Budget_(000s):	$2,510.00
2022_Budget_(000s):	$350.00
2023_Budget_(000s):	$0.00
Start:	1/1/2020
Est. ISD	6/1/2022
Finish:	10/1/2022
Scope of Work:	Install 4th 230/69kV 224MVA transformer #12 at Benning
Justification:	The future 4th 220/69kV, 224 MVA transformer at Benning Sub. 41 is projected to be required in approximately 2022 or beyond.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	BENNING 69KV (41)

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DC Construction Report

No:	71
ITN Name:	72137: L St Sub Capacity Expansion Work (UDSPLM722A)
ITN:	UDSPLM722A
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$500.00
2020_Budget_(000s):	$500.05
2021_Budget_(000s):	$1,000.00
2022_Budget_(000s):	$1,500.00
2023_Budget_(000s):	$511.56
Start:	3/1/2018
Est. ISD	6/1/2022
Finish:	9/29/2022
Scope of Work:	Increase capacity at "L" St. Sub by resupplying from Champlain by extending four (4) 34kV solid dielectric supplies from Champlain; Add13 feeder positions to accommodate two (2) LVAC Networks and one (1) backup feeder. Install 2-18 MVAR cap bank to support the additional load at L Street. This work is needed to Retire "I" St Sub
Justification:	Downtown 69kV resupply - The existing lease agreement for “I” St Sub 197, located on Pennsylvania Ave, is scheduled to end at 2023. Forces a decision point for the company: The “I” St Sub 197 existing lease agreement has effects on future capital work including the 69kV Downtown Re-supply as well as the 230kV Capital Grid
Alternative:	Maintain “I” St, renew the lease agreement and the following:Resupply 22nd Street, F St and Georgetown via Champlain 69kV new 230/69/34kV subRefurb/Upgrade existing equipment at ‘I’ Street Sub. 197 in the future (2026) Switchgear & TransformersRefurb/Upgrade existing equipment at ‘F’ Street Sub. 74 in the future (2026) SwitchgearRefurb/Upgrade existing equipment at ‘L’ Street Sub. 21 in the future (2027) Switchgear & Transformers – common to both plansThis option was not pursued because it would require the continued lease of the "I" St property and the property owner is requesting $2.55M-$3.5M / year with escalation.
Reimbursable:	No

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Related Circuit:	-
Related Substation:	"L" STREET (21)

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DC Construction Report

No:	72
ITN Name:	72525: Mt Vernon Sq Sub: Construct 230/13kv Sub (UDSPLMV3)
ITN:	UDSPLMV3
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$2,265.82
2019_Budget_(000s):	$291.32
2020_Budget_(000s):	$7,577.98
2021_Budget_(000s):	$11,984.36
2022_Budget_(000s):	$17,813.25
2023_Budget_(000s):	$4,684.58
Start:	7/3/2015
Est. ISD	6/1/2023
Finish:	9/29/2023
Scope of Work:	This substation is being built to relieve the S212 Southwest LVAC group by 2023. The substation will be 230/13kV 210 MVA. Four 56 MVA transformer bays are needed with 3 transformers going in service in 2023 and 1 for future growth. Six (6) bus sections are needed. Four 9 MVARs Capacitor Bank units for a total of 36 MVAR are needed with two units going in service in 2023 and two for future growth.
Justification:	This project is part of the New Mt. Vernon Square Substation work to establish a new 230 kV/13 kV Substation initially built with a 140 MVA of firm capacity, with an ultimate capacity of 210 MVA. This is needed to provide relief to existing Northeast Sub. 212. It will also provide reliability benefits to 10th Street Sub. 52. This substation will bring distribution capacity to the fast growing NE District of Columbia area, including the downtown DC area.
Alternative:	Alternative to delaying construction: First, load from the FloridaAvenue Substation would have to be transferred to the rebuilt Harvard Substation inorder to accommodate the extension of a new LVAC group out of Florida AvenueSubstation. After the creation of a new LVAC group out of the Florida AvenueSubstation a cascading transfer would then be required from the Tenth StreetSubstation to Florida Avenue Substation and then from the Northeast Substation tothe Tenth Street Substation and then from the

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	New Jersey Substation to the NortheastSubstation. This alternative is not practical due to load proximity. The LVACfeeders required to be extended from the Florida Avenue Substation would be lessreliable due to their length and would reduce area operating flexibility as FloridaAvenue Substation and other area substations will be loaded near full capacity.Establishing new spot networks on the same group will not relieve a group overload.
Reimbursable:	No
Related Circuit:	15451;15452;15453;15454;15455;15456
Related Substation:	-

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No:	73
ITN Name:	72527: Mt Vernon Sq Sub: Extend 3 Distribution Fdrs - Relieve S052 (UDLPLM7D1)
ITN:	UDLPLM7D1
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$3,900.00
2022_Budget_(000s):	$3,400.00
2023_Budget_(000s):	$500.00
Start:	6/1/2020
Est. ISD	6/1/2023
Finish:	9/29/2023
Scope of Work:	Extend three (3) 13kV underground distribution feeders from Mount Vernon S230 . Construct approximately 6,100 feet of new 8wy duct bank. Install three (3) 3-600kcmil-3/c EPR (quad) cable in existing conduit approximately 6,100 feet along New Jersey Ave, N St, and 10th Street. Install three (3) 3-way subsurface switches.
Justification:	Improve reliability of Sub. 52 distribution feeders by reducing the length of the feeders and the amount of customers on them.
Alternative:	Transfer load from S052 to Northeast S212. This option is more expensive and was not chosen.
Reimbursable:	No
Related Circuit:	15204R;15206;15207R
Related Substation:	TENTH STREET (52)

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DC Construction Report

No:	74
ITN Name:	72529: Mt Vernon Sq Sub: Extend LVAC (UDLPLMV1)
ITN:	UDLPLMV1
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$2,000.00
2021_Budget_(000s):	$1,500.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2017
Est. ISD	6/1/2023
Finish:	9/29/2023
Scope of Work:	The scope of this project is to extend a new 6 Feeder LVAC Group from Mt. Vernon Square Sub. 230 to transfer approximately 40.0 MVA from Northeast Sub. 212 Southwest LVAC Group in 2023. Total distance of extension is approximately 2,000 feet.
Justification:	Sub. 212 Southwest is expected to have a 5% firm capacity overload in Summer 2023.
Alternative:	Alternative to delaying construction: First, load from the FloridaAvenue Substation would have to be transferred to the rebuilt Harvard Substation inorder to accommodate the extension of a new LVAC group out of Florida AvenueSubstation. After the creation of a new LVAC group out of the Florida AvenueSubstation a cascading transfer would then be required from the Tenth StreetSubstation to Florida Avenue Substation and then from the Northeast Substation tothe Tenth Street Substation and then from the New Jersey Substation to the NortheastSubstation. This alternative is not practical due to load proximity. The LVACfeeders required to be extended from the Florida Avenue Substation would be lessreliable due to their length and would reduce area operating flexibility as FloridaAvenue Substation and other area substations will be loaded near full capacity.Establishing new spot networks on the same group will not relieve a group overload.
Reimbursable:	No
Related Circuit:	15451;15452;15453;15454;15455;15456

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Related Substation:	NORTHEAST (212)

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DC Construction Report

No:	75
ITN Name:	72838: Northeast Sub New HV Grp, Transfer HV Load fm Sub. 161 to Sub. 212
ITN:	UDLPLNE4
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$15.00
2023_Budget_(000s):	$2,000.00
Start:	12/30/2012
Est. ISD	6/1/2024
Finish:	10/1/2024
Scope of Work:	Extend the Northeast Sub. 212 Southeast Spot Network Group south along North Capitol St from H St to Mass Ave using approximately 1100’ of new conduit and 6600’ of new cable to transfer load from the Sub. 161 South Group.
Justification:	The extention and/or rearrangement of the 10th St. Sub. 52 North LVAC group and Northeast Sub. 212 West LVAC groups are recommended to relieve a predicted summer 2016 firm capacity overload on 10th St. Sub. 52 of approximately 2%.
Alternative:	There are no practical alternatives for this project due to limited available capacity in the area.
Reimbursable:	No
Related Circuit:	-
Related Substation:	BENNING 69KV (41);NEW JERSEY AVENUE (161);NORTHEAST (212)

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DC Construction Report

No:	76
ITN Name:	72840: Northeast Sub. 212 East Network Group (NEW) (UDLPLM7W14)
ITN:	UDLPLM7W14
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$9,299.03
2019_Budget_(000s):	$8,000.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2016
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Extend the New LVAC Network Group (East Network Group, Feeders 15481-15486) from Northeast Sub. 212 to the Union Market Development as shown indrawing No. 03-18-03.1. Recommendations 3-4 must still remain in place but recommendation 2 needs to be altered at K St. & 2nd St. and Penn St. & 4th St. NE. as shown in Sketch "A" Drawing No. 03-18-03.1). Then re-stencil the feeders accordingly. Also transfer approximately 6.0 MVA summer 2018 load from the 12th & Irving Sub. 133 East Network group to the Northeast Sub. 212 East Network group as shown in drawing Nos. 03-18-01.1 (Sketch "C"), and 03-18-03.1.
Justification:	Only 2 network Feeders available from 12th & Irving Sub. 133 which do not have enough capacity to supply the Union Market Development project
Alternative:	Extend 6-feeder network Group to the Union Market Area to be able to supply the future load demand
Reimbursable:	No
Related Circuit:	14010;14020
Related Substation:	NORTHEAST (212);12th & IRVING, NE (133)

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DC Construction Report

No:	77
ITN Name:	73684: Southwest Sub 18: Rearrange Central LVAC to South LVAC (UDLPLWF5)
ITN:	UDLPLWF5
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$2,244.72
Start:	1/30/2013
Est. ISD	6/1/2023
Finish:	10/30/2023
Scope of Work:	SW Sub. 18 Central LVAC group will be extended from D St., SW along 6th St., to C St., SW to transfer 5.0 MVA of summer 2017 load from SW Central to SW South LVAC group. This will require approximately 3500 feet of 8way conduit bank and 21000 feet of new 500 3/c cable.
Justification:	Needed to address emergency overloads predicted to occur on Sub. 18 Central LVAC group feeders under contingency conditions.
Alternative:	Extend a new LVAC group from Waterfront Sub. 223 and transfer load from Sub. 18 Central LVAC. This alternative is far more costly than the proposed project.
Reimbursable:	No
Related Circuit:	-
Related Substation:	BUZZARD POINT STATION ("B");SOUTHWEST (18)

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No:	78
ITN Name:	73730: Sub 12 Georgetown Underground Feeder Swapping (UDLPLM7W23)
ITN:	UDLPLM7W23
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$68.38
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	10/7/2017
Est. ISD	1/31/2019
Finish:	5/31/2019
Scope of Work:	Rearrange Feeders 15408 and 15409 by cutting and tapping each feeder in Manhole 781389-131756, moving Feeder 15408 from Bus #3 to Bus #2 and Feeder 15409 from Bus #2 to Bus #3.
Justification:	Georgetown University CVC546 is currently supplied by a non standard configuration as two of the supplies (Feeders 15409 and 15999) originate from the same bus and both supply the CVC 546 north vault. In the current configuration, should Bus 3 at Sub. 12, the remaining feeders (15410 and 15411) to the North vault would be loaded above their emergency capacities.
Alternative:	Swapping Feeders 15409 and 15408 will make the supplies to CVC 546 in accordance with current standards. This is required to ensure that the four feeders supplying the Georgetown University CVC 546 north and south vaults are supplied from feeders originating from different bus sections, thereby assuring no feeders are loaded above emergency capacity in the event of a bus outage.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	79
ITN Name:	73749: Sub. 12 to Sub. 124 to Sub. 21 Network Cutover (UDLPLGW1)
ITN:	UDLPLGW1
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$10.00
2023_Budget_(000s):	$2,500.00
Start:	6/30/2014
Est. ISD	6/1/2024
Finish:	10/1/2024
Scope of Work:	Extend 22nd St. Sub. 124 Sout1h LVAC Group south along 24th St. NW from K St. to New Hampshire Ave. using approximately 1200’ of new conduit and 7200’ of new cable to transfer load from the Sub. 12 South LVAC Group to the 22nd St. Sub. 124 South LVAC Group. Transfer load of Sub. 124 South LVAC Group running north along 18th St. from the intersection of 18th St. and L St. to Sub. 21 North Group at the intersection of 17th St. & L St. using approximately 900' of new conduit and approximately 5400' of new cable.
Justification:	This work will correct predicted 1% and 2% Georgetown Sub. 12 firm capacity overloads in 2025 and 2026 respectively.
Alternative:	Resupply L Street from Champlain Sub. 25 and extend new feeder group from Sub. 21 to relieve Sub. 12. This would require much more conduit and cable.
Reimbursable:	No
Related Circuit:	-
Related Substation:	GEORGETOWN (12);"L" STREET (21);22nd STREET (124)

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DC Construction Report

No:	80
ITN Name:	73839: Takoma to Sligo 69kV Line: Install Three 69kV Feeders (UDLPLM72
ITN:	UDLPLM72
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$9,976.57
2019_Budget_(000s):	$16,176.79
2020_Budget_(000s):	$15,626.60
2021_Budget_(000s):	$2,096.36
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2017
Est. ISD	6/30/2021
Finish:	10/30/2021
Scope of Work:	DC Portion: Install three new 69kV solid dielectric undergrould lines in two 8-way duct banks from Takoma to Sligo with provisions to install circuits in and out of Sligo to provide 3rd 69kV supply (Scheduled for 2020) and 4th 69kV supply (in future).
Justification:	This project is required to address the age and condition of existing Sligo Sub. 9 supply feeders and to meet the 2018 load requirements for Sligo Sub. 9. The scope of work includes installing three underground 69kV feeders from Takoma Sub. 27 to Sligo Sub. 9 in two 8-way duct banks (approximately 3.5 miles) and resupplying Sligo Transformers 1, 3 and 4 from these new feeders. These new supplies will increase the firm capacity at Sligo Sub.9 by making use of the additional capacity of two replacement Sligo transformers scheduled to be installed in 2016 and 2017. Sligo is currently supplied by two 34kV and two 69kV feeders from Takoma Substation. Conversion of the 3rd and 4th supplies to 69kV and reconnection of one existing 69kV supply will replace existing self-contained cables that are 35 years old and approaching the end of their useful life and increase the supply capacity to Sligo to meet load growth. These new 69kV feeders provide for the long term supply of Sligo Sub. 9.
Alternative:	Use of existing duct bank to replace existing self-contained supplies was investigated. It was found that the poor condition of the existing duct banks required building 2 new

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	8-ways from Takoma. · A plan to extend the 69kV bus at Takoma to connect the three new feeders was investigated but was determined to not be feasible due to space constraints.
Reimbursable:	No
Related Circuit:	34957;34958;69097
Related Substation:	SLIGO (9);TAKOMA (27)

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DC Construction Report

No:	81
ITN Name:	73861: Tenth St Sub 52 - Transfer 0.5 MVA from Network Fdr. 15327 to Fdr. 15330
ITN:	UDLPLM7W19
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$53.59
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2017
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Extend and/or rearrange Tenth St Sub. 52 East LVAC Network group – 13kV Feeders 15327 and 15330 to transfer approximately 0.5 MVA summer 2018 load from Feeder 15327 to Feeder 15330.
Justification:	Tenth St Sub. 52 East LVAC Network group – 13kV Feeder 15327 is predicted to exceed its summer 2018 normal capacity by approximately 1%.
Alternative:	An alternative to transferring this load to Tenth St Sub. 52 East LVAC Network group – 13kV Feeder 15330 would be to heavy-up the feeder in the vicinity of the substation. The estimated cost of the alternative is approximately $175,000.
Reimbursable:	No
Related Circuit:	15327;15330
Related Substation:	TENTH STREET (52)

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No:	82
ITN Name:	73862: Tenth St Sub 52 - Transfer 0.5 MVA from Network Fdr. 15329 to Fdr. 15332
ITN:	UDLPLM7W20
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$34.16
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2017
Est. ISD	6/1/2018
Finish:	10/1/2018
Scope of Work:	Extend and/or rearrange Tenth St Sub. 52 East LVAC Network group – 13kV Feeders 15329 and 15332 to transfer approximately 0.5 MVA summer 2018 load from Feeder 15329 to Feeder 15332.
Justification:	Tenth St Sub. 52 East LVAC Network group – 13kV Feeder 15329 is predicted to exceed its summer 2018 normal capacity by approximately 1%.
Alternative:	An alternative to transferring this load to Tenth St Sub. 52 East LVAC Network group – 13kV Feeder 15332 would be to heavy-up the feeder in the vicinity of the substation. The estimated cost of the alternative is approximately $175,000.
Reimbursable:	No
Related Circuit:	15329;15332
Related Substation:	TENTH STREET (52)

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DC Construction Report

No:	83
ITN Name:	73902: Transformer Load Management (TLM) Pep - DC (UDLPLM7W21)
ITN:	UDLPLM7W21
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$4.95
2019_Budget_(000s):	$500.00
2020_Budget_(000s):	$2,500.00
2021_Budget_(000s):	$1,500.00
2022_Budget_(000s):	$700.00
2023_Budget_(000s):	$700.00
Start:	6/17/2016
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	Blanket project will replace selected distribution transformers found to be in an overloaded state through PHI's transformer load management program.
Justification:	Overloaded transformers are subject to higher rates of failure subjecting customers to significant outage time.
Alternative:	Alternative is to do nothing and replace transformers when they fail. This alternative was rejected because this would not help Pepco meet reliability goals for the District
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	84
ITN Name:	74083: Waterfront Sub - Establish Waterfront North LVAC Network Group
ITN:	DLPLM7W223
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$9,203.52
2019_Budget_(000s):	$10,681.86
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	6/14/2017
Est. ISD	4/25/2020
Finish:	4/30/2020
Scope of Work:	Establish and extend six (6) outgoing 13kV Network Group feeders from Waterfront Sub. 223 (Waterfront Sub. 223 North LVAC Network Group Feeders 16338, 16639, 16340, 16641,16642, &16343) to transfer portions of Waterfront Sub. 223 West, East, and Southeast LVAC Network groups:a. Extend and/or rearrange new Waterfront Sub. 223 North LVAC group and West LVAC group, as shown on the subject drawing 01-19-02.0, to transfer approximately 7.5MVA summer 2019 load from the Waterfront Sub. 223 West LVAC group to the North LVAC groupb. Extend and/or rearrange new Waterfront Sub. 223 North LVAC group and East LVAC group, as shown on the subject drawing 01-19-02.0, to transfer approximately 7.7 MVA summer 2019 load from the Waterfront Sub. 223 East LVAC group to the North LVAC group.c. Extend and/or rearrange new Waterfront Sub. 223 North LVAC group and Southeast LVAC group, as shown on the subject drawing 01-19-02.0, to transfer approximately 4.0 MVA summer 2019 load from the Waterfront Sub. 223 Southeast LVAC group to the North LVAC group.
Justification:	All the areas that are supplied from the Buzzard Point Sta. “B” and future Waterfront Sub. 223 Network groups are currently experiencing considerable load growth and will continue to experience load growth in the next several years. The area supplied from the West group is expected to receive additional load from the large multi-phased Wharf

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	development project. The first phase of construction is nearing its completion and the second phase will begin in 2018. The Capitol River Front development area, The Yards, and the area around National's Park supplied from the East and Southeast group will continue to grow considerably. There are several commercial and residential projects that are under various stages of planning and implementation. The Pennsylvania Avenue SE corridor is experiencing increased redevelopment activities in pockets north and south of Pennsylvania Avenue SE. Since "G" Street – 4kV Sub. 28 is supplied by feeders from the East and Southeast LVAC network groups, in the event that the project to convert to 13kV is delayed, this cutover will free up needed capacity to accommodate future load growth in the area supplied by the other groups.
Alternative:	None
Reimbursable:	No
Related Circuit:	14401;14402;14403;14404;14405;14406
Related Substation:	BUZZARD POINT STATION ("B");WATERFRONT (223)

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No:	85
ITN Name:	74084: Waterfront Sub - Install 4th Transformer (UDSPLM7WF4)
ITN:	UDSPLM7WF4
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$1,034.82
2019_Budget_(000s):	$1,890.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	3/1/2018
Est. ISD	12/30/2019
Finish:	9/1/2022
Scope of Work:	Install 4th Transformer at Waterfront Sub. 223 and 18 MVAr of bus capacitors.
Justification:	Current firm capacity is 144MVA, whereas projected load by Summer 2019 is 147MVA. Unanticipated load on Waterfront sub. 223 is projected to cause 2% firm capacity overload. These loads include the radial 13.8kV feeders from Buzzard Point Sta. B used to energize Waterfront and the load that would remain on Waterfront Sub. 223 due to delay in project to convert “G” St. 4kV feeders to Southwest Sub. 18 13kV.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	WATERFRONT (223)

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No:	86
ITN Name:	74085: Waterfront Sub - Install 5th Transformer (UDSPLM7WF3)
ITN:	UDSPLM7WF3
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$420.37
2021_Budget_(000s):	$5,585.99
2022_Budget_(000s):	$3,825.00
2023_Budget_(000s):	$0.00
Start:	6/1/2020
Est. ISD	6/1/2022
Finish:	10/1/2022
Scope of Work:	Install the 5th Transformer at Waterfront Sub. 223 along with 18 MVAr bus capacitor and 5 transformer secondary series reactors for each one of the transformers..
Justification:	All loads from Buzzard Point Sta. B are planned to be transfered to Waterfront Sub. 223 by 2022 surpassing the firm Capacity of the 4 transformers. The 5 transformer secondary series reactors are needed to avoid bus duty issues that arise after the installation of the 5th transformer.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	WATERFRONT (223)

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No:	87
ITN Name:	74087: Waterfront Sub-Extend Fdrs: Transfer HV, Metro, Distrib frm Sta
ITN:	UDLPLM7D2
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$210.00
2020_Budget_(000s):	$1,255.98
2021_Budget_(000s):	$1,336.01
2022_Budget_(000s):	$928.18
2023_Budget_(000s):	$0.00
Start:	6/1/2019
Est. ISD	12/31/2022
Finish:	4/30/2023
Scope of Work:	Extend Twelve -13kV feeders from the new Waterfront Sub. 223 to accomplish the following:1. Six - 13kV underground high voltage feeder group to cutover Buzzard Point Sta. B - Central High Voltage Group. (Build approximately 0.2 miles of a new 8 way conduit bank and install approximately 0.9 miles of 600 MCM 3/c cable.) 2. Six - 13kV 2 dedicated Metro feeders per vault to cutover Buzzard Point Sta. B supplies to Potomac TPS (CVG 330), Federal Center TPS (CVG 328) & Main Ave. TPS (CVG 372).(Build approximately 0.2 miles of a new 8 way conduit bank and install approximately 1.1 miles of 600 MCM 3/c cable.)
Justification:	To transfer the remaining load from Buzzard Pt. Sta. B, furthering the goal of retiring Buzzard Point Station B 13kV load.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	BUZZARD POINT STATION ("B");WATERFRONT (223)

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No:	88
ITN Name:	74088: Waterfront Sub: New 138/13.8 kV Distribution Sub (UDSPLWF1)
ITN:	UDSPLWF1
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$339.82
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	2/20/2012
Est. ISD	6/23/2018
Finish:	10/21/2018
Scope of Work:	The scope of this project is to build a new substation, Waterfront Substation, with three 230/138/13 kV transformers, six bus sections, and sixty-six feeder positions.
Justification:	The Buzzard Point Sta. “B” East LVAC Network Group is predicted to exceed its firm capacity in Summer 2017 by 4%. There are no nearby substations with available feeder positions for extending a new LVAC network feeder group to relieve the Buzzard Point Sta. “B” East LVAC Network Group. The Buzzard Point Sta. “B” Southeast LVAC Network group is experiencing widespread network protector operational issues due to feeder voltage imbalances partly resulting from having bus-tie reactors at Sta. “B”. Furthermore, the area supplied by this group is continuing to experience significant load growth. Buzzard Point Sta. “B” was originally constructed in the 1930’s as a generating station and a series of transmission and distribution substations. The station has been renovated over the years, most recently with a life-extension project performed in the early 1990’s, which replaced circuit breakers and relays, but did little to improve the physical substation building.

	The substation bus configuration is considered non-standard, with a double-bus configuration that reduces feeder group redundancy. High fault current availability required installation of in-line reactors between Buzzard Point's 13kV busses, creating operational issues on the Southeast LVAC Network Group, the only group supplied by all six of Buzzard Point Sta. B's busses. Three of Buzzard Point Sta. B's 138/13kV transformers were installed in 1964 while the other three were installed in 1979, 1980, and 2008, respectively. The area served by Buzzard Point Station "B" will continue to experience significant load growth, especially the area around Southwest Waterfront. The Waterfront Substation will enable new feeder groups to be extended to relieve overloads and accommodate expected future load growth. Navy Yard Tempo. Sub. 33 needs to be retired. Navy Yard Tempo. Sub. 33 was put in service in 1957 as a temporary substation to supply the Navy Yard. It has been maintained as a permanent substation, but the equipment is aging. The load on the substation is approaching its firm capacity of 21 MVA due to load growth in the Navy Yard campus. New 13kV supplies to the Navy Yard and O St. Pumping Station will be extended from Waterfront Sub. 223, current in-service date Dec 2019, enabling the retirement of Navy Yard Tempo. Sub. 33
Alternative:	Install new Waterfront Sub. 223 as a standard 350 MVA substation, initially with three (3) 56 MVA, dual primary voltage 230/138kV to 13kV transformers and six (6) bus sections of 13.8kV, 1200 MVA, 3000 Amp stacked-metalclad switchgear with a minimum of seventy two (72) outgoing feeder positions, six (6) bus capacitor positions, two (2) station service feeder positions and enough space to allow the installation of up to eighteen (18) 13kV feeder series reactors, six (6) 56 MVA transformers, and six (6) transformer secondary series reactors. There are three alternatives associated with this effort:

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	1. Rebuild Buzzard Pt and Construct new 350MVA 230kV/138kV/13kV indoor GIS substation with new underground transmission and distribution feeders. Reasons alternative not pursued include: One Large substation (No redundancy), facilities must remain in service during construction, additional land would be needed for a temporary sub to facilitate construction,time to construct would surpass need date, increased cost 2. Construct new 210 MVA Area Substation near Navy Yard Sub and a new 80 MVA Area Substation at Buzzard Pt Sub Parcel and Rebuild 13kV facilities at Buzzard Pt. Reasons alternative was not pursued include: Facilities must remain in service during construction, additional land would be needed at both locations, time to construct would surpass need date, combined capacity of 290 MVA, increased cost 3. Do nothing. Reasons alternative was not pursued include: Load Shed
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	89
ITN Name:	74092: Waterfront Sub: Construct New LVAC Groups (UDLPLWF4)
ITN:	UDLPLWF4
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$623.37
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	12/30/2014
Est. ISD	3/17/2018
Finish:	7/15/2018
Scope of Work:	The purpose of this project is to cut over 2 of the network feeder groups coming out of Station B substation on to the new Waterfront Sub by June 2017. This includes both conduit and cable work.
Justification:	The Buzzard Point Sta. “B” East LVAC Network Group is predicted to exceed its firm capacity in Summer 2017 by 4%. There are no nearby substations with available feeder positions for extending a new LVAC network feeder group to relieve the Buzzard Point Sta. “B” East LVAC Network Group. The Buzzard Point Sta. “B” Southeast LVAC Network group is experiencing widespread network protector operational issues due to feeder voltage imbalances partly resulting from having bus-tie reactors at Sta. “B”. Furthermore, the area supplied by this group is continuing to experience significant load growth.
Alternative:	This is part of the Waterfront Substation project. Please refer to the Waterfront Substation (UDSPLWF1) for alternatives to the substation.
Reimbursable:	No
Related Circuit:	14119;14120;14407;14408;14409;14410;14411;14412;15596;15597;15598;15599
Related Substation:	WATERFRONT (223)

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No:	90
ITN Name:	74093: Waterfront Sub: Construct Third LVAC Group (UDLPLWF6)
ITN:	UDLPLWF6
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$4,130.13
2019_Budget_(000s):	$3,143.91
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2016
Est. ISD	9/30/2019
Finish:	3/29/2020
Scope of Work:	Heavy up Station “B” West Network group feeder 14401, 14402, 14403, 14404, 14405, & 14406 to 600 EPR 1/C or equivalent from vicinity of new Waterfront Sub. 223 to 4th ST SW and “P” Street SW (approximately 2100’ of cable each). Then transfer the entire Buzzard Point Sta. “B” West LVAC Network Group (Feeders 14401, 14402, 14403, 14404, 14405, & 14406), approximately 34.9 MVA Summer 2018 load to Waterfront Sub. 223 West LVAC Network Group Feeders 16332, 16333, 16334, 16335, 16336, & 16337, respectively and balance the Waterfront Sub. 223 West LVAC Network Group.
Justification:	Existing Buzzard Point Station “B” West LVAC Network Group cable configuration in the duct bank running north to “P” ST SW and east to the corner of 4th and “P” Street SW, limits the firm capacity of the network group to 38.0 MVA. After the network group is transferred to new Waterfront Sub. 223 West Network group, the same section will remain to be the limiting factor. Heavying up that section will increase the firm capacity to 57.5 MVA. The Waterfront Sub. 223 West LVAC Network Group is predicted to be loaded to 92% of its firm capacity in Summer 2019. The area supplied from this network group is experiencing intensive load growth due to large scale development projects that are underway.
Alternative:	An alternative to extending a new LVAC group from Waterfront Substation would be to build a new substation

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	near the Southwest waterfront and extend a new feeder group from there. This alternative was rejected because of its high expense.
Reimbursable:	No
Related Circuit:	14401;14402;14403;14404;14405;14406
Related Substation:	WATERFRONT (223)

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No:	91
ITN Name:	74349: Benning 4kV Area-Phase Balancing to Fix Voltage Drop Issues UDLPLM7D4A
ITN:	UDLPLM7D4A
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$399.99
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	4/27/2018
Est. ISD	5/1/2019
Finish:	12/30/2040
Scope of Work:	Install 1 300k VAr capacitor bank, extend 1907 ft of cable and change 16 transfer phase taps.
Justification:	This plan will require balancing phase loadings in Wards 7 and 8 (on Feeders 97, 118, 205, 244, 328, 368, and 372) to fix voltage drops under normal conditions.
Alternative:	Phase changes on transformers, cable extensions, and a capacitor installation.
Reimbursable:	-
Related Circuit:	-
Related Substation:	-

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No:	92
ITN Name:	72733: Navy Yard: Transfer to Waterfront Sub. 223 (UDLPLWF7)
ITN:	UDLPLWF7
FERC:	Distribution - DC
Category:	Load Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$5,056.77
2019_Budget_(000s):	$5,000.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	6/1/2016
Est. ISD	4/30/2020
Finish:	8/28/2020
Scope of Work:	Establish and extend six (6) outgoing 13kV High Voltage feeders from Waterfront Sub. 223 (Feeders 16600, 16601, 16602, 16603, 16604, & 16605) to the vicinity of Navy Yard Sub. 33, near the intersection of 5TH and “M” Street SE, as shown on the subject drawing: a. Extend and/or rearrange new 13kV High Voltage feeders 16600, 16601, 16602 & 16603 to transfer Navy Yard Sub. 33 – 13kV feeders 14644, 14648, 14657 & 14658 supplying Navy Yard CVG 098, respectively. b. Extend and/or rearrange new 13kV High Voltage feeders 16604 & 16605 to transfer Navy Yard Sub. 33 – 13kV feeders 14659 & 14660 supplying D.C Sewage Pumping Sta. CVG 061, respectively.In order to retire Navy Yard Sub. 33. and requires 5,700 ft. new duct bank and 22,800 feet 600 1/C EPR cable.
Justification:	This is an aging infrastructure project. The temporary Navy Yard Sub. 33 was put into service in 1957. Substation equipment and 34 kV supplies are aging and need to be replaced or retired.
Alternative:	Rebuild Navy Yard substation on site of current substation and this alternative was rejected because of cost as Waterfront substation has capacity to supply entire load of Navy Yard Sub. 33.
Reimbursable:	No
Related Circuit:	-

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Related Substation:	NAVY YARD (33);WATERFRONT (223)

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No:	93
ITN Name:	73348: Reg Cntrl Install/Replace - Pepco DC (UORPODRC01)
ITN:	UORPODRC01
FERC:	Distribution – DC
Category:	Other
Sub-Category:	Application Technology
2018_Actual_(000s):	$7.94
2019_Budget_(000s):	$50.00
2020_Budget_(000s):	$20.00
2021_Budget_(000s):	$20.00
2022_Budget_(000s):	$20.00
2023_Budget_(000s):	$20.00
Start:	12/1/2017
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	ITN to support installation or replacement of distribution regulators controls across PEPCO DC service territory.
Justification:	ITN to support installation or replacement of distribution regulators controls across PEPCO DC service territory.
Alternative:	No alternatives are available.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	94
ITN Name:	71438: Distribution Automation - Pepco DC (UDLPRDA1D)
ITN:	UDLPRDA1D
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	Application Technology
2018_Actual_(000s):	($0.14)
2019_Budget_(000s):	$1,999.98
2020_Budget_(000s):	$2,000.00
2021_Budget_(000s):	$100.00
2022_Budget_(000s):	$100.00
2023_Budget_(000s):	$100.00
Start:	12/31/2014
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Design & Install automated switches and automatic circuit reclosers on various feeders per System Planning recommendations under Distribution Automation (DA) Program. Pepco mainly uses G&W 12kA Viper ST ACR as both recloser for fault interruption and as switch. In some cases SF6 switches are used in location which exceed the 12KA fault rating of the Viper ST. ASR Selection MethodologyThe ASR selection process involves determining areas where distribution feeders experienced three or more substation breaker lockouts over the most recent two year period. Recloser lockout data was also taken into consideration. The priority feeder list was also taken into account and analyzed for possible improvement through ASR. Reliability indices that are used in determining priority feeder status include outages that cannot be mitigated by the implementation of ASR (such as fuse blows) and, as such, are not a good indicator for the selection of ASR. Therefore, all priority feeders have not been targeted for an ASR scheme.
Justification:	Automatic Sectionalizing and Restoration (ASR) scheme helps to improve customer reliability by reducing the number of customers that experience a sustained outage in an event of a fault on the distribution system. ASR scheme also helps with quick restoration of customers that experience a sustained outage. The feeders that are selected

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	for ASR capability are located in areas where many feeders experienced three or more lockouts over a two year period. Area grouping produces synergies by using the same substation equipment to control multiple feeders. ASR prior experience indicates that feeder reliability performance (SAIDI, SAIFI) can be improved by as much as 50%.
Alternative:	The alternative would be to not install Distribution Automation and maintain existing levels of reliability that can be achieved with traditional methods such as tree trimming, animal guards etc. These methods, however, do not prevent all outages such as those resulting from pole accidents, downed large trees and other unavoidable causes. Distribution Automation is needed to obtain the next level of reliability improvement.
Reimbursable:	No
Related Circuit:	14006;14102;14107;14108;14110;14132;14200;15010;15199;15200;15710;15867;15945
Related Substation:	BENNING (7);FORT SLOCUM (190);TAKOMA (27);TUXEDO (148);VAN NESS (129);12th & IRVING, NE (133)

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No:	95
ITN Name:	72064: Install Smart Relays & Replace RTU's -DC (UDSPRD8SD)
ITN:	UDSPRD8SD
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	Application Technology
2018_Actual_(000s):	$2,204.89
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$900.09
2021_Budget_(000s):	$900.00
2022_Budget_(000s):	$900.00
2023_Budget_(000s):	$900.00
Start:	1/31/2013
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This WBS element is for the installation of Smart Relays GE F60's and the replacement of existing legacy analog Remote Terminal Units (RTUs) with digital RTU (DRTUs) at Pepco Substations in DC. The smart relays and DRTU are installed to improve visibility and SCADA control at the Substations.
Justification:	The Smart Relays and digital Remote Terminal Units (RTU's) are necessary for improved visibility and control at the substations and to replace aging RTU's that are no longer supported by the manufacture. This equipment will support the operation of Automatic Sectionalizing and Restoration (ASR) schemes. These schemes help to improve customer reliability by reducing the number of customers that experience a sustained outage in an event of a fault on the distribution system. ASR scheme also helps with quick restoration of customers that experience a sustained outage. The feeders that are selected for ASR capability are located in areas where many feeders experienced three or more lockouts over a two year period. Area grouping produces synergies by using the same substation equipment to control multiple feeders. ASR prior experience indicates that feeder reliability performance (SAIDI, SAIFI) can be improved by as much as 50%.
Alternative:	The alternative is to not install RMS equipment on Pepco network transformers and maintain existing levels of local monitoring and control of the system which includes having

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	to send personnel to operate network protector locally in emergency events and relying on physical inspections to gain knowledge of equipment like open protector, loss of pressure in protector housing, blown protector fuse and environmental conditions like water ingress into the protector housing. This alternative was not selected because of the desired reliability improvements.(i.e. prevention of transformer overload and catastrophic protector failure).
Reimbursable:	No
Related Circuit:	-
Related Substation:	ALABAMA AVENUE (136);BENNING (7);"I" STREET (197);NAVAL RESEARCH LAB (168);NORTH CAPITOL (40)

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No:	96
ITN Name:	72746: Network RMS - Line - Pepco DC (UDLPRM4DR)
ITN:	UDLPRM4DR
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	Application Technology
2018_Actual_(000s):	$330.34
2019_Budget_(000s):	$4,000.02
2020_Budget_(000s):	$3,250.02
2021_Budget_(000s):	$4,000.00
2022_Budget_(000s):	$3,250.00
2023_Budget_(000s):	$4,000.00
Start:	2/1/2015
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This is Pepco's project to install remote monitoring systems (RMS) on approximately 4200 network transformers over a period of 15-years on UDLPRM4DR. A remote monitoring system consists of a communication platform with a variety of different sensors used to collect data affecting network transformers. The RMS line equipment will continue to be installed on UDLPRM4DR with a yearly goal of 2-3 Telecom RMS Networks. The remote monitoring system provides real time remote control/monitoring capability as well as load information from network transformers through the implementation of two way communication for an enhanced reliability of the network system. The Network RMS-Pepco DC (UDLPRM4DR) project is related to the Network Transformer Protector RMS-Telecom (UORPORNPD).
Justification:	Install RMS equipment on Pepco network transformers, most of which are located in the District of Columbia. This equipment will give Pepco system operators and engineers real-time load and environmental information, as well as transformer condition information and remote control capabilities. Control and Monitoring capabilities gained from Network RMS will allow System Operators to attend swiftly to emergencies when any transformer needs to be isolated from the network. The system will also provide operators real-time information on the status of a protector breaker (if open or closed), which can be useful in detecting transformers going on and off the network. The system will

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	also allow the analysis of trends in the underground network and can be useful in asset and maintenance strategy. RMS can be useful in avoiding transformer overload and catastrophic protector failure.
Alternative:	The alternative is to not install RMS equipment on Pepco network transformers and maintain existing levels of local monitoring and control of the system which includes having to send personnel to operate network protector locally in emergency events.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	97
ITN Name:	70251: 69kV Lines NRL Sub 168 to Blue Plains Sub 83 (UDLPRM8BB)
ITN:	UDLPRM8BB
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$852.06
2019_Budget_(000s):	$1,100.01
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	7/1/2012
Est. ISD	12/21/2019
Finish:	4/19/2020
Scope of Work:	Extend two 69 kV feeders from Blue Plains Sub. 83 to NRL Sub. 168 in order to serve as backup supply feeders to NRL Sub. 168.
Justification:	Project provides flexibility in supplying NRL Sub. 168 and increases operating flexibility of the 69 kV subtransmission system out of Potomac River Sta. C. These extensions would be used to backup supply to NRL Sub from the Blue Plains supply
Alternative:	Installation of spare pipes and conduits across the Potomac River were considered but were not selected due to high cost (estimated at $4 million) and feasibility concerns, as this would require Horizontal Directional Drilling (HDD) under the Potomac River
Reimbursable:	No
Related Circuit:	69008;69009W;69038;69067;69207;69208
Related Substation:	BLUE PLAINS (83);NAVAL RESEARCH LAB (168)

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No:	98
ITN Name:	71630: F St Sub Rebuild (69kV) (UDSPLM718A)
ITN:	UDSPLM718A
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$123.98
2019_Budget_(000s):	$662.14
2020_Budget_(000s):	$5,839.90
2021_Budget_(000s):	$788.88
2022_Budget_(000s):	$788.88
2023_Budget_(000s):	$1,289.18
Start:	6/3/2017
Est. ISD	6/1/2026
Finish:	9/29/2026
Scope of Work:	Increase the firm capacity increased from 82 MVA to 210 MVA by rebuilding substation using Anniversary park in front of property; Net 128 MVAResupply with 69 kV from New Champlain Substation.This work is needed to Retire "I" St Sub.
Justification:	Downtown 69kV resupply - The existing lease agreement for “I” St Sub 197, located on Pennsylvania Ave, is scheduled to end at 2023. Forces a decision point for the company: The “I” St Sub 197 existing lease agreement has effects on future capital work including the 69kV Downtown Re-supply as well as the 230kV Capital Grid.
Alternative:	Maintain “I” St, renew the lease agreement and the following:Resupply 22nd Street, F St and Georgetown via Champlain 69kV new 230/69/34kV subRefurb/Upgrade existing equipment at ‘I’ Street Sub. 197 in the future (2026) Switchgear & TransformersRefurb/Upgrade existing equipment at ‘F’ Street Sub. 74 in the future (2026) SwitchgearRefurb/Upgrade existing equipment at ‘L’ Street Sub. 21 in the future (2027) Switchgear & Transformers – common to both plansThis option was not pursued because it would require the continued lease of the "I" St property and the property owner is requesting $2.55M-$3.5M / year with escalation.
Reimbursable:	No
Related Circuit:	-
Related Substation:	"F" STREET (74)

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No:	99
ITN Name:	73452: Retire Anacostia 4kV and 13kV Substations (UDSPRD8RW1)
ITN:	UDSPRD8RW1
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$555.00
2021_Budget_(000s):	$555.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2020
Est. ISD	5/30/2021
Finish:	9/30/2021
Scope of Work:	This project is to retire Anacostia 4kV and 13kV substations
Justification:	This work is proposed to retire an aging substation (built in 1936) supplied from 34kV submarine cables from Buzzard Point Sta. B that are approaching the end of their useful life; 80 year old cable would take months to replace if there was an outage.
Alternative:	Retire the Aging Substation once all load is transferred to Alabama Sub. 136
Reimbursable:	No
Related Circuit:	-
Related Substation:	ALABAMA AVENUE (136);ANACOSTIA (8);ANACOSTIA (8);TWINING CITY (150)

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No:	100
ITN Name:	73787: Substation Retirements-DC. (UDSPRD8RN)
ITN:	UDSPRD8RN
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$0.13
2019_Budget_(000s):	$1,163.14
2020_Budget_(000s):	$400.08
2021_Budget_(000s):	$200.00
2022_Budget_(000s):	$200.00
2023_Budget_(000s):	$200.00
Start:	3/1/2013
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Two sites are under this WBS. The sites are completely de-energized and no longer in service. The abandoned equipment will be removed and the building will be demolished. The contractor will excavate to ensure that no underground utilities are left on site. The sites will be graded and a new fence will be installed on the empty lot once the demolition is completed. We currently have the scope of work and environmental assessments. We are also currently working on developing a demolition permit request package for the sites and the demolition is expected to take place on 2020. No funds will be needed until 2019 for the permit efforts.
Justification:	Demolition efforts are on hold until 2019. This station has been decommissioned for many years and currently is not supplying any load.
Alternative:	There are no alternatives, all of the load was transferred to other stations as this was one of the old 4kv systems. The site is no longer in use and will no longer be needed for the future.
Reimbursable:	No
Related Circuit:	-
Related Substation:	Hillcrest

No:	101
ITN Name:	73918: Trinidad Sub 106 - Retire (UDSPRD8RO)

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ITN:	UDSPRD8RO
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	Capacity Expansion
2018_Actual_(000s):	$0.13
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$400.03
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	10/1/2013
Est. ISD	4/30/2020
Finish:	8/30/2020
Scope of Work:	Raze and demolish retired station. This site is completely de-energized and no longer in service. The abandoned equipment will be removed and the deteriorated building will be demolished. The contractor will excavate to ensure that no underground utilities are left on site. The site will be graded and a new fence will be installed on the empty lot once the demolition is completed. We currently have the scope of work and environmental assessments. We are also currently working on developing a demolition permit request package for this site and the demolition is expected to take place on 2020. Planning, survey, engineering, and permitting activities have been performed to prepare for the demolition in 2019.
Justification:	This station has been decommissioned for many years and currently is not supplying any load.
Alternative:	All of the load was transferred to other stations as this was one of the old 4kv systems. The site is no longer in use and will no longer be needed for the future. The options are to either demolish the site and place a fence around or leave the abandoned and deteriorated building in place.
Reimbursable:	No
Related Circuit:	-
Related Substation:	Trinidad

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No:	102
ITN Name:	71605: Emergency Restoration OH PEP DC (DLPRM32DXX)
ITN:	DLPRM32DXX
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	Corrective Maintenance
2018_Actual_(000s):	$6,952.51
2019_Budget_(000s):	$6,501.30
2020_Budget_(000s):	$6,696.28
2021_Budget_(000s):	$6,897.17
2022_Budget_(000s):	$7,104.08
2023_Budget_(000s):	$7,317.21
Start:	12/31/2009
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This project scope includes reactive replacement of damaged and / or failed overhead primary and secondary cable and other equipment. The failed portion of the cable is typically replaced. These projects are initiated by outages due to typical emergency response, weather, and normal operating conditions.
Justification:	Reactive/Emergency work tied to the overhead system.
Alternative:	Emergency repairs to the overhead system to maintain reliability.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	103
ITN Name:	71615: Emergency Restoration: Network Transfs & Protectors (UDLPRM3K1)
ITN:	UDLPRM3K1
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	Corrective Maintenance
2018_Actual_(000s):	$1,581.04
2019_Budget_(000s):	$2,060.41
2020_Budget_(000s):	$2,122.25
2021_Budget_(000s):	$2,185.92
2022_Budget_(000s):	$2,251.50
2023_Budget_(000s):	$2,319.04
Start:	12/31/2009
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	The project scope includes emergency/ unplanned replacement of failed network transformers and protectors as well as Priority 1 replacements that were identified during the Network Transformer Inspection program and Remote Monitoring System (RMS) Network Transformer Replacements. These projects are initiated based on equipment failures or inspection program results. Work requests are created by District Service Coordinators in Construction. These are created as ACCAP WRs (accelerated jobs) and no design/ engineering is involved. The budget amounts are determined based on the historical trend in expenditures.
Justification:	If the failed equipment is not replaced, customers will not be put back to normal service. Abnormal system configuration could lead to further unexpected and extended outages for the customers.
Alternative:	The alternative is to not to replace the equipment. If a failed network equipment is not replaced, abnormal system configuration could lead to further unexpected and extended outages for the customers. Priority 1 transformers and RMS network transforme
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	104
ITN Name:	73032: Pep-DC Damage Equipment Replacements (UDLPOEMGD)
ITN:	UDLPOEMGD
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	Corrective Maintenance
2018_Actual_(000s):	$813.42
2019_Budget_(000s):	$309.00
2020_Budget_(000s):	$318.27
2021_Budget_(000s):	$327.82
2022_Budget_(000s):	$337.65
2023_Budget_(000s):	$347.78
Start:	12/31/2011
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This is a blanket project to capture any unrecoverable equipment and asset replacement caused by others such as theft and accidents. Any recoverable charges from responsible parties and/or insurance companies are credited to this budget as a reimbursed cost. The amount of charges to this budget will fluctuate based on frequency and the scale of damage/theft caused by others, and the successful recovery of charges from responsible parties.
Justification:	Unrecovered expenses due to third party damage will not be covered. If the damaged equipment is not replaced, customers will not be restored or returned to normal service. An abnormal system configuration could lead to further unexpected and extended ou
Alternative:	The unrecovered cost would reside in the emergency restore WBS (UDLPRM3B1), and Pepco will either want to collect the claim, or transfer it out of emergency restore WBS. Either way, the work needs to be done to restore the system.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	105
ITN Name:	73039: Pepco DC - Deteriorated Cap Bank Replacement (UDLPRM4S1)
ITN:	UDLPRM4S1
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	Corrective Maintenance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$100.00
2022_Budget_(000s):	$100.00
2023_Budget_(000s):	$100.00
Start:	10/30/2014
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	This project covers the replacement of capacitor banks in the District. Capacitor banks are identified for replacement through the Beckwith Capacitor Controller Replacement program, UORPORCPD.1. Capacitor Banks are replaced on an as needed basis based on field condition when assessing the bank for the installation of the replacement capacitor controller.
Justification:	Under the current process, all capacitor bank replacements are processed through the emergency blankets. This WBS is needed in order to capture all expenses related to replacement of capacitor banks identified as non-operational or deteriorated.
Alternative:	The only alternative is to reevaluate the need for a capacitor in that location, per system planning. The likely consequence of not taking action to replace the defective capacitor banks will be power quality issues during the summer months, leading to fl
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	106
ITN Name:	74237: Dist Electric Storm Cap DC
ITN:	PEPMSTRM2
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	Corrective Maintenance
2018_Actual_(000s):	$323.84
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2015
Est. ISD	7/26/2018
Finish:	3/28/2018
Scope of Work:	Capital costs related to emergency preparation and restoration efforts for Winter Storm Toby.
Justification:	Capital costs related to emergency preparation and restoration efforts for Winter Storm Toby.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	107
ITN Name:	74238: Dist Electric Storm Cap DC
ITN:	PEPMSTRM1
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	Corrective Maintenance
2018_Actual_(000s):	$5,611.82
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	5/1/2017
Est. ISD	7/7/2018
Finish:	3/9/2018
Scope of Work:	Capital costs related to emergency preparation and restoration efforts for Winter Storm Riley.
Justification:	Capital costs related to emergency preparation and restoration efforts for Winter Storm Riley.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	108
ITN Name:	71448 and 75293: Distribution Pole Replacements PEP DC (UDLPRM4BE)
ITN:	UDLPRM4BE
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	Corrective Maintenance
2018_Actual_(000s):	($99.51)
2019_Budget_(000s):	$717.26
2020_Budget_(000s):	$735.18
2021_Budget_(000s):	$753.57
2022_Budget_(000s):	$772.40
2023_Budget_(000s):	$791.71
Start:	3/21/2011
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	This project covers the replacements or reinforcement of Pepco owned distribution utility poles in the District of Columbia. Poles are identified for replacement by routine inspections performed by a third party contractor. Additional poles are identified by overhead construction inspectors through routine work. Pole replacements are addressed in the following manner: 1) Poles are identified for replacement by inspection2) Poles replacements are submitted to regional engineering for design work3) After design work and necessary permits are obtained, the work is released to overhead construction. Approximately 50 identified poles will be replaced in the District in 2016. Up to two adjacent poles may require replacement for each identified pole, to ensure additional stress is not placed on the conductors due to the height difference of the new pole compared to the existing poles. Approximately 10 poles are expected to be replaced in each subsequent calendar year, with up to two adjacent poles required to support the replacement.
Justification:	If the poles are not replaced within the specified time frame they are at a risk of failure causing damages to wires, transformers and other equipment, thereby causing outages to customers.
Alternative:	The only alternative to replacing reject poles is reinforcement of the base with a C truss. The poles identified for replacement are inspected for the possibility

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	of c-truss reinforcement. Poles identified as reject poles do not qualify for reinforcement
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	109
ITN Name:	71612 and 75309: Emergency Restoration UG PEP DC (UDLPRM32DX)
ITN:	UDLPRM32DX
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	Corrective Maintenance
2018_Actual_(000s):	$18,192.98
2019_Budget_(000s):	$6,501.29
2020_Budget_(000s):	$6,696.28
2021_Budget_(000s):	$6,897.17
2022_Budget_(000s):	$7,104.08
2023_Budget_(000s):	$7,317.21
Start:	1/1/2004
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This project scope includes reactive replacement of damaged and / or failed underground (in duct) primary and secondary cable. The failed portion of the cable is typically replaced and in some occasions additional stretches are replaced based on their condition. These projects are initiated by outages due to cable failures; most failures are the result of aged cable, the entrance of water into splices and / or workmanship errors. Another reason for cable failures occur is due to a breakdown in the conduit that pierces the cable causing a fault. These are generally fault located and replaced. Larger jobs account for faults that are in between manholes requiring an entire stretch of cable to be replaced.
Justification:	Reactive/Emergency work tied to the underground system.
Alternative:	Emergency repairs to the underground system to maintain reliability.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	110
ITN Name:	72997 and 75314: Padmount Transformer Replacements PEP DC (UDLPRM4BO)
ITN:	UDLPRM4BO
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	Corrective Maintenance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$980.42
2020_Budget_(000s):	$1,009.89
2021_Budget_(000s):	$1,040.17
2022_Budget_(000s):	$1,071.38
2023_Budget_(000s):	$290.57
Start:	12/31/2013
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	The scope of this project is to replace padmount transformers identified via the Padmount Transformer Inspection program. Transformers are identified for replacement if they are found to be deteriorated or damaged as a result of age, external forces, leaking, etc.
Justification:	If the transformers are not replaced, they have a high potential of failing within a short period of time.
Alternative:	If this program work is not completed, the customer may experience additional outages causing additional disruptions. An alternative would be to tie customers off to other transformers, but this could lead to a higher risk of outages due to overloaded tra
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	111
ITN Name:	71015: Champlain to L Street 34kV (UDLPRM4WA8)
ITN:	UDLPRM4WA8
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$124.59
2019_Budget_(000s):	$7,367.97
2020_Budget_(000s):	$6,497.99
2021_Budget_(000s):	$15,298.71
2022_Budget_(000s):	$18,842.09
2023_Budget_(000s):	$16,200.93
Start:	7/1/2017
Est. ISD	12/31/2027
Finish:	4/29/2028
Scope of Work:	The scope of this project includes the installation of four underground 34 kV solid dielectric cables in two new 8-way ductbanks to resupply “L” Street Substation. This project also includes double legging “L” Street substation to temporarily transfer load off of “F” Street Substation.
Justification:	This project is needed to replace the 34kV underground supply feeders currently supplying L Street to increase capacity and address aging infrastructure. The proposed work resupplies “L” Street from higher capacity solid dielectric cables in two new 8-ways from Champlain and allow for the retirement of the 34 kV feeders from Buzzard Point. This plan also allows for “L” Street to be temporarily double-legged to transfer load off of “F” Street Substation for rebuild.
Alternative:	Replace supplies from “L” Street using existing routes, however, current infrastructure would not be able to support capacity needs to transfer load to rebuild “F” Street.
Reimbursable:	No
Related Circuit:	-
Related Substation:	CHAMPLAIN (25);"L" STREET (21)

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No:	112
ITN Name:	74372: Pepco DC: Benning Area Plan - Feeder Improvement Work (UDLPRM4F
ITN:	UDLPRM4F02
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$1,749.96
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2018
Est. ISD	12/31/2019
Finish:	4/29/2020
Scope of Work:	Reconductoring, armless to crossarm construction, recloser and fuse installation, etc.
Justification:	Improve the reliability in the subject area range from rearranging the feeders to minimize overhead exposure, adding feeder ties and automated devices to aid in the restoration of customers, upgrading aging infrastructure, and reducing the number of customers on the feeders by transferring portions to neighboring feeders.
Alternative:	Miscellaneous feeder improvements to 14717, 15705, 15706, 15707, 15709, 15710 including reconductoring, armless to crossarm construction, recloser and fuse installation, etc.
Reimbursable:	No
Related Circuit:	14717;15705;15706;15707;15709;15710
Related Substation:	BENNING (7)

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No:	113
ITN Name:	70897 and 75317: Cable PEP DC (UDLPRM4BCX)
ITN:	UDLPRM4BCX
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$583.67
2019_Budget_(000s):	$3,999.96
2020_Budget_(000s):	$4,000.05
2021_Budget_(000s):	$4,000.00
2022_Budget_(000s):	$4,000.00
2023_Budget_(000s):	$4,000.00
Start:	12/31/2008
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	The scope of this project covers the installation of cable and wire on an as needed basis. Work to address non-emergency deficiencies on wires, cables, and transformers. The work could involve improving feeder performance by replacing and upgrading deteriorating sections of wires and cable, replacing overloaded transformers, etc.
Justification:	If the work is not performed, it will lead to customer outages due to conductor and transformer overloads, and possible damage.
Alternative:	The alternative would be to leave the equipment temporarily repaired and address it under a comprehensive feeder program, if it meets the selection criteria.
Reimbursable:	No
Related Circuit:	14158;15707
Related Substation:	BENNING (7);GRANT AVENUE (183)

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No:	114
ITN Name:	72251 and 75312: MDO & CEMI REMEDIATION- PEP DC (UDLPRM4BQX)
ITN:	UDLPRM4BQX
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$63.23
2019_Budget_(000s):	$1,506.15
2020_Budget_(000s):	$1,721.90
2021_Budget_(000s):	$1,700.00
2022_Budget_(000s):	$1,700.00
2023_Budget_(000s):	$1,700.00
Start:	12/31/2012
Est. ISD	12/31/2029
Finish:	12/30/1940
Scope of Work:	Remediation for outages where devices (transformer, fuse, recloser, breaker) have opened 3 or more times in the previous 12 months.
Justification:	Issues on the system related to MDO (device operated 3 or more times in previous 12 months) and CEMI (Customers Experiencing Multiple Interruptions) customers.
Alternative:	Planned work for MDO (device operated 3 or more times in previous 12 months) and CEMI (Customers Experiencing Multiple Interruptions) customers.
Reimbursable:	No
Related Circuit:	14755;15986
Related Substation:	HARVARD (13);NAVAL RESEARCH LAB (168)

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No:	115
ITN Name:	71119: Comprehensive Feeder Improvements- PEPCO:DC (UDLPRM63D)
ITN:	UDLPRM63D
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$974.61
2019_Budget_(000s):	$1,999.97
2020_Budget_(000s):	$2,000.02
2021_Budget_(000s):	$2,000.00
2022_Budget_(000s):	$2,000.00
2023_Budget_(000s):	$2,000.00
Start:	11/30/2010
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	The comprehensive feeder improvement blanket is designed to address poor areas of reliability that arise during each year. These projects include, but are not limited to:- Individual feeder remediation based on current and past year performance- CEMI -5: which addresses locations where customers have experienced over five outages during the past twelve months- Customer complaints that address poor areas of reliability for individual customers or a specific area- Neighborhood selection based on the DC annual consolidated report to address the poorest performing feeder in each neighborhood that was not identified as a poorest performing feeder
Justification:	The project justification is to improve overall system reliability and mitigate future outages. These infrastructure improvements are needed to improve system reliability.
Alternative:	Comprehensive feeder remediation work is required to augment the poorest performing feeder remediation program. Failure to do so will decrease the overall system reliability and not enable Pepco to meet the reliability standard set forth by the DC PSC.
Reimbursable:	No
Related Circuit:	14006;14007;14722;14729;15012;15701;308;325
Related Substation:	-

PEPCO(I)-2

DC Construction Report

No:	116
ITN Name:	71125: Congress Heights Sub. 64 - Convert all 4kV load from Feeder 178 and 294
ITN:	UDLPRM4WA
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$283.24
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2016
Est. ISD	12/31/2017
Finish:	1/24/2019
Scope of Work:	This is part of Pepco's long term plan to convert 4kV system to 13kV / extend and/or rearrange Alabama Avenue Sub. 136 – 13kV Feeder 15171 and Congress Heights Sub. 64 Feeders 178 and 294 in order to accomplish the following: a.) Convert all load (approximately 0.6 MVA summer 2017 load) from Congress Heights Sub. 64 Feeder 178 to Feeder 15171. Retire Feeder 178. b.) Convert all load (approximately 0.4 MVA summer 2017 load) from Congress Heights Sub. 64 Feeder 294 to Feeder 15171. Retire Feeder 294. c.) Retire Congress Heights Sub. 64 after Feeders 178 and 294 are converted to 13kV construction. 2. Install normally open switch on Wheeler Road SE in the vicinity of pole #802364-580400 and establish a new tie between Chesapeake St. Sub. 181 4kV Feeders 329 and 120. 3. Establish an open tie between Chesapeake St. Sub. 181 4kV Feeders 165 and 324 at pole # 800364-860730.
Justification:	Historical Long Range Study for the Pepco 4kV system concluded that all single supply/single transformer 4kV substations are to be converted and retired to improve reliability and operational flexibility.
Alternative:	Convert all 4kV load to 13kV and retire the Sub.
Reimbursable:	No

PEPCO(I)-2

DC Construction Report

Related Circuit:	120;15171;165;324;329
Related Substation:	ALABAMA AVENUE (136);CHESAPEAKE STREET, SE (181);CONGRESS HEIGHTS (64)

PEPCO(I)-2

DC Construction Report

PEPCO(I)-2

DC Construction Report

No:	117
ITN Name:	74371: 69019 Potomac River Crossing Emergency Rebuild (UDLPRM4ER1)
ITN:	UDLPRM4ER1
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$641.85
2019_Budget_(000s):	$14,000.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	10/1/2018
Est. ISD	9/30/2019
Finish:	1/28/2020
Scope of Work:	Install 4200 ft of new XLPE submarine cable across the river, install new 40x10x8 manholes on both sides, install transition joints from XLPE to SCFF cables, install new 75ft of duct banks on both sides to extend the new stretch of SCFF cable to tie in with existing feeder. In addition to the river crossing, the project also includes supplying 69019 feeder from F St. Substation 74 temporarily to firm up Georgetown Substation 12. This will bring Georgetown Substation back to its normal contingency (N-1 during Summer Peak, N-2 other times)
Justification:	River section of 69kV Feeder 69019 supplying Georgetown Substation from Station C failed on Oct 3rd 2018 dropping Georgetown to N (from N-1) contingency for Winter load and putting considerable summer peak load at risk.
Alternative:	Replace the failed self contained fluid filled (SCFF) cable by armored sub-marine XLPE cable in the Potomac river and tie it with existing feeder through a new small sections of SCFF cable.
Reimbursable:	No
Related Circuit:	69019
Related Substation:	GEORGETOWN (12)

PEPCO(I)-2

DC Construction Report

No:	118
ITN Name:	71204: Fault Detection System - Pepco DC
ITN:	UDLPRM4SD1
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$20.56
2019_Budget_(000s):	$125.00
2020_Budget_(000s):	$125.00
2021_Budget_(000s):	$125.00
2022_Budget_(000s):	$125.00
2023_Budget_(000s):	$125.00
Start:	12/1/2015
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	Install remote fault indicators on 69kv oh lines in dc per system planning recommendations. fault indicators will be added every 4 miles so we do not have to patrol the whole line when a fault arises. the installation of these indicators will result in trouble being found quicker, restoring the line quicker and in turn speeding up the entire restoration process.
Justification:	This project is needed to improve efficiency of the distribution system by improving outage management. with the fault indicators installed the entire restoration process will be sped up as faults will be located quicker.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

PEPCO(I)-2

DC Construction Report

No:	119
ITN Name:	71440: Distribution DC - HPFF System Cathodic Protection Program (UDLP
ITN:	UDLPRM4FC2
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$515.00
2020_Budget_(000s):	$530.49
2021_Budget_(000s):	$546.36
2022_Budget_(000s):	$562.75
2023_Budget_(000s):	$0.00
Start:	6/8/2018
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	At Four Corners Substation #26 the oil supply lines for the underground transmission pipe-type feeders were corroding due to the outdated cathodic protection scheme for the piping and associated oil tank. Since this discovery of this issue, other distribution substations have been identified as having similar insufficient protection schemes for the oil supply copper piping. This program will address the issues with the piping to update the outdated cathodic protection scheme to a conventional anodes configuration to help avert corrosion.
Justification:	This project is needed to address the corrosion of the oil supply lines for the underground pipe type feeders and associated oil tanks. If the cathodic protection schemes for the piping are not updated, then oil spills at various substations could occur over time as the pipes continually corrode.
Alternative:	Replace the feeders with XLPE system; the replacement cost for each feeder will be more than twenty times the cost provided herein per feeder.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

PEPCO(I)-2

DC Construction Report

No:	120
ITN Name:	71710: Fort Slocum Sub Switchgear Replacement: Dist Line (UDLPRM4WA3)
ITN:	UDLPRM4WA3
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$750.00
2021_Budget_(000s):	$750.00
2022_Budget_(000s):	$10.00
2023_Budget_(000s):	$0.00
Start:	1/1/2020
Est. ISD	12/31/2022
Finish:	4/30/2023
Scope of Work:	This project is for the distribution line work in support of the purchase and installation of replacement 13.8kV switchgear in DC substations. Existing deteriorated switchgear will be replaced based on priority list determined through Kinectrics study. All bus sections of the substation will be replaced and the cubicle repaired.
Justification:	The project is needed to enable Pepco to meet reliability objectives set forth by the DC Public Service Commission and Exelon. A failure of a breaker or cubicle can result in significant collateral damage as well as poor reliability for all feeders associated with this substation.
Alternative:	Use the existing switchgear until failure which will result in an extended period of poor reliability and vulnerability to outages.
Reimbursable:	No
Related Circuit:	-
Related Substation:	FORT SLOCUM (190)

PEPCO(I)-2

DC Construction Report

No:	121
ITN Name:	71721: Ft Lincoln Reliability Initiative (DC) (UDLPRM4LRD)
ITN:	UDLPRM4LRD
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$1,000.00
2020_Budget_(000s):	$999.99
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	7/1/2018
Est. ISD	9/15/2020
Finish:	12/31/2020
Scope of Work:	Ft Lincoln area reliability plan focused on distribution feeders out of substation.
Justification:	Ft Lincoln has shown diminishing reliability performance over the last few years and this will provide targeted solutions for this area.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	BLADENSBURG (175);12th & IRVING, NE (133)

PEPCO(I)-2

DC Construction Report

No:	122
ITN Name:	71731: G STREET SUB 28 - CONVERT 4KV LOAD AND RETIRE - Line Work (UDLP
ITN:	UDLPRGST1
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$568.71
2019_Budget_(000s):	$8,000.00
2020_Budget_(000s):	$8,000.00
2021_Budget_(000s):	$8,000.00
2022_Budget_(000s):	$9,000.00
2023_Budget_(000s):	$8,000.00
Start:	8/27/2016
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This project is recommended to begin the infrastructure upgrades to the existing 4kV system supplied from G St. Sub. 28 in parts of Capitol Hill, Barney's Circle and Navy Yard areas. Two 13kV feeders, to be extended from Southwest Sub. 18, will provide capacity for the conversion and allow load to be transferred to Sub. 18 from Sub. 28.
Justification:	This area is underground and some of the 4kV Feeders have had voltage problems. The existing conduit and cables are very old and upgrades of this system are being proposed to eliminate potential reliability concerns proactively.
Alternative:	An alternative to converting all the 4 kV load to 13 kV is to maintain the 4 kV system by replacing all conduit, cable, substation transformers and substation switchgear.
Reimbursable:	No
Related Circuit:	15876;15877;208;209;210;211;212;223;227;228;229
Related Substation:	"G" STREET, SE (28)

PEPCO(I)-2

DC Construction Report

No:	123
ITN Name:	71782: Georgetown : 4 to 13 kv Conver Phs 3-8 (UDLPRM8BT)
ITN:	UDLPRM8BT
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$4,238.33
2019_Budget_(000s):	$5,000.00
2020_Budget_(000s):	$4,999.97
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	12/31/2009
Est. ISD	12/31/2022
Finish:	12/31/2022
Scope of Work:	This is the continuation of M34 for the Georgetown infrastructure projects and will convert the remaining 4kV load supplied from this substation. The project will identified all required underground system modifications necessary to maintain and improve distribution facilities by converting to 13kV. Area 2B is the next location identified for conversion and encompasses between P and S St. east of Wisconsin Avenue, NW. 50,000 ft. conduit, 115,000 ft. cable, 8 3-way switchgears., 3 13/4kV step down transformers., replace secondary where needed. Area 3B will begin at the end of 2013 and running into 2014, location is west of Wisconsin Ave and Reservoir St NW. It encompasses 25,000 ft. of conduit, 10,000 ft. of primary cable, 5-13 KV step down transformers, and replace secondary as needed.
Justification:	The existing equipment at the Georgetown 4kV Substation, as well as the existing conduit and cables all date from the 1950s and they are at various stages of deterioration. A modernization of this area infrastructure started in 2001 to ultimately retire the 4kV radial distribution systems in order to proactively eliminate potential reliability concerns.
Alternative:	TTo convert all equipment and load from 4kV to 13kV. An option is installing a Battery to feed a majority of the load around the National Mall (streetlights, traffic signals, lighting for monuments, etc.)
Reimbursable:	No

PEPCO(I)-2

DC Construction Report

Related Circuit:	-
Related Substation:	GEORGETOWN (12)

PEPCO(I)-2

DC Construction Report

No:	124
ITN Name:	71859: Harrison Sub: Extend New Dist Fdrs to 38 (UDLPLNW3)
ITN:	UDLPLNW3
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$279.07
2019_Budget_(000s):	$2,227.38
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	6/1/2013
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Extend 17 -13.8kV underground feeder supplies from the Temp Sub. located in the adjacent lot, and rearrange with each of the existing Harrison Sub. 38 Distribution feeders. Build 4 -8W duct banks from the Temp. Sub. Model with new Harrison Sub. 38 138/13kV Sub. projects UTLPLNW1, UDSPLNW2.
Justification:	The main building was constructed in 1940 with various additions. Transformer 1 was evaluated to be impaired as part of the Equipment Condition Assessment (ECA) process. The 34 kV supply ducts are very small core duct so trying to upgrade the four 20 MVA transformers to 30 MVA would require the duct bank to be rebuilt. The switchgear is a double bus configuration and in need of replacement.
Alternative:	Upgrade of Harrison Sub. 38 as a new 140MVA, 13kV distribution substation
Reimbursable:	No
Related Circuit:	-
Related Substation:	BETHESDA (6);HARRISON (38);VAN NESS (129)

PEPCO(I)-2

DC Construction Report

No:	125
ITN Name:	71870: Harvard Sub - Convert 4-13 kV- CAP GRID (UDLPRM8BY)
ITN:	UDLPRM8BY
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$3,703.97
2019_Budget_(000s):	$999.99
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	12/31/2009
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This project is being recommended to continue infrastructure upgrades to the existing 4kV system in the Upper Shaw and Harvard/Columbia Heights areas. Two 13kV Feeders extended from Florida Avenue Sub. 10 in 2011 provide capacity for portion of the conversion and allow load to be transferred to Sub. 10 from Sub. 13. Existing 13kV Feeders from Sub. 13 and new 13kV Feeders from Sub. 25 will be used to convert the remaining 4kV load starting in 2014. Total amount to be converted is approximately 60,200 feet.
Justification:	The load at Harvard Sub. 13 (4kV) is predicted to exceed its transformer firm capacity by 4% in 2013 and 2014. This area is underground and some of the 4kV Feeders are very long and have had voltage problems. The existing conduit and cables are very old and upgrades of this system are being proposed to eliminate potential reliability concerns proactively. The transformers, supply feeders and switchgear are all vintage 1960 and need to be replaced.
Alternative:	An alternative to converting all the 4 kV load to 13 kV is to maintain the 4 kV system by replacing all conduit, cable, substation transformers and substation switchgear.
Reimbursable:	No
Related Circuit:	-
Related Substation:	CHAMPLAIN (25);FLORIDA AVENUE (10);HARVARD (13)

PEPCO(I)-2

DC Construction Report

No:	126
ITN Name:	72268: MISC. RELIABILITY IMPROVEMENTS- PEP DC (UDLPRM4BA)
ITN:	UDLPRM4BA
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$3,222.14
2019_Budget_(000s):	$400.00
2020_Budget_(000s):	$400.00
2021_Budget_(000s):	$400.00
2022_Budget_(000s):	$400.00
2023_Budget_(000s):	$400.00
Start:	12/31/2009
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	The scope of this project covers the replacement of overhead (OH) and underground (UG) equipment as needed based on equipment conditions. Work to address non-emergency deficiencies on equipment such as poles, wires, cable, fuse cutouts and boxes, transformers, etc. The work could involve improving feeder performance by installing or replacing fuse cutouts and fuse boxes, replacing and upgrading deteriorating sections of wires and cable, replacing poles in bad condition, replacing failing transformers and overloaded transformers, adding ties for circuit backup, etc. OH and UG equipment will be replaced on an as needed basis.
Justification:	If unaddressed, these imminent items could result in unexpected outages to customers that could have been prevented with performing this work.
Alternative:	The alternative would be to leave the equipment temporarily repaired and address it under a comprehensive feeder program, if it meets the criteria. The equipment may have multiple outages affecting customers and meeting performance standards and commitments.
Reimbursable:	No
Related Circuit:	117;14158;14987;15707
Related Substation:	BENNING (7);GRANT AVENUE (183);NEBRASKA (92)

PEPCO(I)-2

DC Construction Report

No:	127
ITN Name:	72750: Network Xfmr&Prot Repl Planned: Benni (UDLPRM4BN)
ITN:	UDLPRM4BN
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$21,735.32
2019_Budget_(000s):	$13,000.00
2020_Budget_(000s):	$15,300.00
2021_Budget_(000s):	$17,400.00
2022_Budget_(000s):	$16,000.00
2023_Budget_(000s):	$16,000.00
Start:	12/31/2011
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This is a blanket WBS which is used to replace network transformers and protectors on an as-needed basis based on network transformer inspection. Based on replacement priority each year, 100-120 network transformers are planned to be replaced.
Justification:	Replace identified network transformers and protectors that may fail due to deterioration causing extended outages.
Alternative:	The alternative is to put transformer out of service and transfer customers to different transformers. This could create overloaded transformer conditions; as a result, customer may experience extended outages.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

PEPCO(I)-2

DC Construction Report

No:	128
ITN Name:	72810: North Capitol Sub 4-13kV conversion (UDLPRM8BC)
ITN:	UDLPRM8BC
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$80.63
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	12/31/2012
Est. ISD	12/31/2019
Finish:	4/18/2020
Scope of Work:	Initiate infrastructure upgrades to the existing 4kV system in the North Capitol Street., Kennedy Street, and New Hampshire Avenue, NW area. The proposed 4 to 13kV conversions will be accomplished by extending and/or rearranging existing or new 13kV distribution feeders from Fort Slocum Sub. 190.
Justification:	The North Capitol Sub. 40 4kV system is an aging, isolated area on the Pepco distribution system that is not connected to any other 4kV substations or systems. Recent substation inspections have revealed deteriorating circuit breakers. The obsolete Allis Chalmers switchgear necessitates the salvage of spare parts from like equipment. In the event of a catastrophic failure at Sub. 40, no external 4kV support is available. 4kV Feeders are backed up by other Sub. 40 feeders or through bus ties. Capacity from nearby Fort Slocum Sub. 190 is readily available for the 4kV to 13kV conversions. The upgrades of this system are being proposed to eliminate potential reliability concerns proactively.
Alternative:	An alternative to converting all North Capitol Sub. 40 - 4kV load to 13kV is to maintain the 4kV system by replacing the substation transformers, substation switchgear, and rebuilding many of the Overhead 4kV feeders.
Reimbursable:	No
Related Circuit:	-

PEPCO(I)-2

DC Construction Report

Related Substation:	NORTH CAPITOL (40)

PEPCO(I)-2

DC Construction Report

No:	129
ITN Name:	74033: Van Ness Switchgear Replacement: Distribution Line (UDLPRM4WA1)
ITN:	UDLPRM4WA1
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$75.12
2019_Budget_(000s):	$660.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2017
Est. ISD	12/31/2019
Finish:	4/29/2020
Scope of Work:	This project is for the distribution line work in support of the purchase and installation of replacement 13.8kV switchgear in DC substations. Existing deteriorated switchgear will be replaced based on priority list determined through 2011-2012 Kinectrics study. All bus sections of the substation will be replaced and the cubicle repaired.
Justification:	The project is needed to enable Pepco to meet reliability objectives set forth by the DC Public Service Commission and Exelon. A failure of a breaker or cubicle can result in significant collateral damage as well as poor reliability for all feeders associated with this substation
Alternative:	Use the existing switchgear until failure which will result in an extended period of poor reliability and vulnerability to outages.
Reimbursable:	No
Related Circuit:	-
Related Substation:	VAN NESS (129)

PEPCO(I)-2

DC Construction Report

No:	130
ITN Name:	72978: PILC REPLACEMENT PLANNED (UDLPRPLIC)
ITN:	UDLPRPLIC
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$5,570.07
2019_Budget_(000s):	$5,000.00
2020_Budget_(000s):	$9,999.99
2021_Budget_(000s):	$5,000.00
2022_Budget_(000s):	$10,000.00
2023_Budget_(000s):	$5,000.00
Start:	1/1/2014
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	The scope of this project is to replace approximately 4-5 miles per year of paper lead insulated cable with EPR. Replacement targets determined by paper-insulated lead-covered (PILC) replacement strategy. Detailed scopes for planned improvements will be developed and subsequent scope descriptions added to program description.
Justification:	Pepco has committed to analyze and investigate Radial feeders with PILC type cable in the District of Columbia which have experienced 3+ outages in 5 years and 5+ outages in 10 year. Proactive rather than reactive strategy.
Alternative:	The PILC replacement program is required by Pepco as part of the reliability improvement programs that are filed with and approved by the DC PSC. The alternative is to continue to repair failing joints and portions of the PILC that would result in increased outages and longer duration of outages. This would also impact overall system reliability
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

PEPCO(I)-2

DC Construction Report

No:	131
ITN Name:	73042: Pepco DC Distrib - Upgrade Pumping Plants (UDLPRM9PD)
ITN:	UDLPRM9PD
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$3,121.26
2019_Budget_(000s):	$54.00
2020_Budget_(000s):	$55.00
2021_Budget_(000s):	$800.00
2022_Budget_(000s):	$800.00
2023_Budget_(000s):	$2,400.00
Start:	7/1/2011
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	UDLPRM9PD Scope: Replace 15 High Pressure Pipe Type Pumping Stations.•The 15 New Pumping Stations include remote communication between Substations and OCC.
Justification:	The current pumping plants are out dated and replacement parts are no longer available to maintain adequate operation. The new pumping plant will enhance the reliability of the underground pipe-type system, as well as create a more efficient working environment with the ability for remote monitoring of the alarms. Pepco maintains a total of 61 pumping stations. Target is to complete ALL installations by December 2024
Alternative:	There are no feasible alternatives, if they fail, Pepco runs the risk of losing a fluid filled feeder. The current outdated plants were built by manufacturers that are no longer in business or no longer manufacture pumping plants making replacement parts very difficult to come by.
Reimbursable:	No
Related Circuit:	69008;69014;69015;69017;69042R;69042W;69043;69044;69045;69045;69048;69048W;69049W;69054;69067;69125;69126;69155;69156;69157;69162;69167;69168;69183
Related Substation:	CHAMPLAIN (25);FLORIDA AVENUE (10);FORT SLOCUM (190);NEW JERSEY AVENUE (161);NINTH STREET (117);POTOMAC RIVER ("C")

PEPCO(I)-2

DC Construction Report

No:	132
ITN Name:	73053: Pepco DC: 12th & Irving Area Plan (UDLPRM4WA7)
ITN:	UDLPRM4WA7
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$2,149.34
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	5/4/2017
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Reconductor and redistribute load on 12th & Irving Substation overhead feeders. The project will include reclosers, ASR schemes, reconductoring, reconfiguring of circuits, new feeders, and optimizing all circuits out of 12th & Irving Substation.
Justification:	12th & Irving substation produces the highest CI and CMI of any DC substation. The project will take a holistic approach to remediating the circuits out of 12th & Irving substation focused on DA, ASR schemes, reclosers, TripSavers, circuit reconfiguration, new feeders, and minimizing the number of customers on each feeder.
Alternative:	Circuits from 12th & Irving substation will continue to show up on the poorest performing list based on reliability metrics.
Reimbursable:	No
Related Circuit:	14014;14016
Related Substation:	12th & IRVING, NE (133)

PEPCO(I)-2

DC Construction Report

No:	133
ITN Name:	73055: Pepco DC: Benning Area Plan (UDLPRM4WA2)
ITN:	UDLPRM4WA2
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$4,946.06
2019_Budget_(000s):	$8,750.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2017
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Reconductor and redistribute load on Benning Substation overhead feeders. The project will include reclosers, ASR schemes, reconductoring, reconfiguring of circuits, new feeders, and optimizing all circuits out of Benning Substation.
Justification:	Benning substation produces the highest CI and CMI of any DC substation. The project will take a holistic approach to remediating the circuits out of Benning substation focused on DA, ASR schemes, reclosers, TripSavers, circuit reconfiguration, new feeders, and minimizing the number of customers on each feeder.
Alternative:	Circuits from Benning substation will continue to show up on the poorest performing feeder list.
Reimbursable:	No
Related Circuit:	-
Related Substation:	BENNING (7)

PEPCO(I)-2

DC Construction Report

No:	134
ITN Name:	73149: Placeholder - Future 69kV Pepco DC: OH Misc Planned Distributio
ITN:	UDLPRM41D
FERC:	Distribution - DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$1.00
2020_Budget_(000s):	$1.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	6/1/2016
Est. ISD	12/31/2018
Finish:	4/30/2019
Scope of Work:	Pepco DC: OH Misc Planned Distribution Blanket
Justification:	Misc Planned Distribution Blanket
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

PEPCO(I)-2

DC Construction Report

No:	135
ITN Name:	73150: Placeholder - Future 69kV Pepco DC: UG Misc Planned Distributio
ITN:	UDLPRM42D
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$579.64
Start:	6/4/2013
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	Pepco DC: UG Misc Planned Distribution Blanket
Justification:	This blanket is set up to complete non-reimbursable projects in DC. This is typical for DDOT projects which impact Pepco facilities and need to be funded quickly.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

PEPCO(I)-2

DC Construction Report

No:	136
ITN Name:	73179: Planned Rubber/Lead Secondary Replacement (UDLPRM4WA9)
ITN:	UDLPRM4WA9
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$2,865.06
2019_Budget_(000s):	$1,750.00
2020_Budget_(000s):	$3,500.00
2021_Budget_(000s):	$3,500.00
2022_Budget_(000s):	$3,500.00
2023_Budget_(000s):	$3,500.00
Start:	5/10/2017
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	This is a 10 year project aimed at replacing all rubber lead and other aged secondary on the DC Underground system. Most of this cable is in outdated duct system so will require conduit work as well.
Justification:	Most of Pepco's reportable manhole events in the District of Columbia can be attributed to smoking or gas build-up caused by deterioration of rubber insulation on the underground secondary cables. Some of these events can lead to entire network groups being shut down. In order to increase the reliability and safety of our underground system for the general public, it is necessary to replace these aged cables.
Alternative:	Alternative will be to tackle these manhole events as they surface and replace only the aged cables that reveal themselves in such cases.
Reimbursable:	No
Related Circuit:	-
Related Substation:	BENNING (7);TENTH STREET (52);12th STREET, SW (126);22nd STREET (124)

PEPCO(I)-2

DC Construction Report

No:	137
ITN Name:	73250: Priority Feeder Improvements- PEP DC (UDLPRM4BF)
ITN:	UDLPRM4BF
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$2,263.15
2019_Budget_(000s):	$3,950.00
2020_Budget_(000s):	$3,960.00
2021_Budget_(000s):	$3,210.00
2022_Budget_(000s):	$3,200.00
2023_Budget_(000s):	$3,200.00
Start:	12/31/2011
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	The scope of this project is to meet the DC Public Service Commission requirement to remediate the worst performing 2% of the DC feeders. The feeders are selected each year using the filed System Performance Contribution (SPC) method. The remediation work performed and work planned is filed in the DC Annual Consolidated Report by Pepco each year. The scope of work for each feeder includes, but is not limited to installing or replacing: reclosers, switches, animal guards, lightning arresters, transformers, poles, primary and secondary wires, and distribution automation schemes. This project includes selecting the priority feeders, engineering identification and design of the remediation work, and construction of the planned work. This is a blanket WBS that will continue to support the required feeder remediation as directed by the DC Public Service Commission.
Justification:	The work is designed to reduce outages and the duration of outages for each feeder selected. The intent is to bring the circuit performance to the system average or better. If this remediation is not performed customers may continue to experience outages
Alternative:	Failure to remediate the selected feeders would be a violation of the DC Public Service Commission requirement to work on the 2% of the worst performing feeders each year.
Reimbursable:	No

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DC Construction Report

Related Circuit:	-
Related Substation:	-

PEPCO(I)-2

DC Construction Report

No:	138
ITN Name:	73332: Recloser Installations (ACR)- PEPCO:DC (UDLPRM4DJ)
ITN:	UDLPRM4DJ
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$4,953.14
2019_Budget_(000s):	$250.00
2020_Budget_(000s):	$250.00
2021_Budget_(000s):	$250.00
2022_Budget_(000s):	$250.00
2023_Budget_(000s):	$250.00
Start:	12/31/2012
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Install additional automatic circuit reclosers (ACRs) to improve feeder reliability as identified by the various programs in the Reliability Enhancement Plan, as part of the enhanced feeder sectionalization initiative. The work was completed under this WBS: 2015 – 7 reclosers installed under this WBS2016 - funding for 19 reclosers. Actual installed will depend on feeder analysis/needs.2017 - funding for 10 reclosers. Actual installed will depend on feeder analysis/needs.2018-2020 - funding for 19 reclosers/year. Actual installed will depend on feeder analysis/needs. Additional reclosers may be deployed as a part of the Worst Performing Feeder Project (UDLPRM4F)
Justification:	Additional reclosers are needed to improve Pepco's system reliability and meet regulatory SAIDI and SAIFI performance requirements. ACRs provide a way to sectionalize the feeder in smaller sections and minimize impacts of outages to customers upstream of the ACR. If there is a fault downstream of the ACR it is able to automatically sectionalize the downstream section, limiting the customer impacts of the outage. ACRs can also open and close (reclose) multiple times to allow momentary faults to clear, thus also limiting momentary outages downstream from the recloser, and potentially avoiding a permanent outage if the section was protected by a fuse instead of a recloser

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DC Construction Report

Alternative:	One alternative is to continue to install auto switches and clear faults utilizing the substation feeder breaker. This option was rejected as it required the feeder breaker to clear the fault exposing all customers on the feeder to the fault. In addition switches must be remotely operated by the dispatcher and do not prevent customers from outages and delay restoration times.
Reimbursable:	No
Related Circuit:	14023;14701;14755;15016;15264
Related Substation:	ANACOSTIA (8);FORT SLOCUM (190);NAVAL RESEARCH LAB (168);TAKOMA (27);12th & IRVING, NE (133)

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DC Construction Report

No:	139
ITN Name:	73368: Repl 69kV SCFF UG Supl-Georgetown, F St, 22nd St (UDLPRM5SG)
ITN:	UDLPRM5SG
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$837.20
2019_Budget_(000s):	$4,957.91
2020_Budget_(000s):	$6,794.86
2021_Budget_(000s):	$28,577.72
2022_Budget_(000s):	$39,091.80
2023_Budget_(000s):	$29,458.54
Start:	5/18/2013
Est. ISD	12/31/2028
Finish:	4/30/2029
Scope of Work:	The scope of this project includes the installation of four underground 69 kV solid dielectric cables in two new 8-way conduit to resupply several downtown substations from Champlain Substation.
Justification:	The replacement of the 69kV underground supply feeders from Potomac River to Georgetown & "F" Street and Takoma to 22nd St. These are part of Transmission Engineering's plan to replace self-contained cables. The proposed work resupplies all three subs from a single set of higher capacity solid dielectric cables in two new 8-ways from Takoma and avoids any new river crossings. This will allow retirement of 11 self-contained cables identified as high priority for replacement. Seven of these cables cross the Potomac River and if they fail, they cannot be repaired and will result in an extended outage in excess of 12 months to install new Horizontal Directional Drilled (HDD) cables across the river.
Alternative:	Replace supplies from Potomac River to Georgetown and "F" Street and from Takoma to 22nd Street using existing routes. Use of new solid dielectric cables in two new 8-ways was considered as well as replacing the self-contained cables in existing ducts and new HDD installations across the Potomac River was considered. These options were eliminated due to the high cost and complexity. It was determined that supplying all three subs from a single set of higher capacity solid dielectric cables in two new 8-ways

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	from Takoma and avoiding any new river crossings was the least cost solution.
Reimbursable:	No
Related Circuit:	69011;69012R;69012W;69013W;69016;69017;69019;69035;69036;69041;69042W;69051W;69052W
Related Substation:	CHAMPLAIN (25);"F" STREET (74);GEORGETOWN (12);"L" STREET (21);POTOMAC RIVER ("C");22nd STREET (124)

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DC Construction Report

No:	140
ITN Name:	73463: Retire for Downtown Resupply 34kV and 69kV for DC (UDLPRM4RDR)
ITN:	UDLPRM4RDR
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$2,934.37
Start:	8/1/2018
Est. ISD	12/31/2028
Finish:	4/30/2029
Scope of Work:	The scope of this project includes the retirement of existing 34kV and 69kV assets following the Downtown Resupply project.
Justification:	Following the Downtown Resupply project some of the existing 34kV and 69 kV circuits will need to be retired.
Alternative:	None
Reimbursable:	No
Related Circuit:	34906;34907;34912;34913;34914;34918;34919;69012R;69013W;69016;69017;69019;69035;69036;69041;69042W;69049R;69051R;69051W;69052R;69052W
Related Substation:	CHAMPLAIN (25);"F" STREET (74);GEORGETOWN (12);HARVARD (13);"L" STREET (21);22nd STREET (124)

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DC Construction Report

No:	141
ITN Name:	73651: Single Phase Reclosing Devices- PEPCO:DC (UDLPRM4WJ)
ITN:	UDLPRM4WJ
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$108.85
2019_Budget_(000s):	$250.00
2020_Budget_(000s):	$250.00
2021_Budget_(000s):	$250.00
2022_Budget_(000s):	$250.00
2023_Budget_(000s):	$250.00
Start:	8/18/2016
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Install single phase reclosing devices (TripSavers) on fused taps and other locations.
Justification:	The Company will install the recloser fuse devices where there is the highest probability to address either 1) chronic issues (e.g. more than 1 outage on average over the past 3 years) or 2) large issues (e.g. where outages have caused more than 50 CI on average). The primary location for the devices will be on lateral fused taps. A large number of faults that occur below fuses are transient in nature, and will be avoided by the reclosing fuse devices.
Alternative:	The single phase reclosing fuse devices are required to prevent transient faults and enable the Company to reach first quartile in reliability. Without the devices transient faults will turn into blown fuses, causing additional outages and cost to the Company to replace the fuses in the field.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	142
ITN Name:	73932: Twelfth St Conversions (UDLPRM8BU)
ITN:	UDLPRM8BU
FERC:	Distribution – DC
Category:	Reliability Driven
Sub-Category:	System Performance
2018_Actual_(000s):	$1,707.95
2019_Budget_(000s):	$1,300.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	12/31/2009
Est. ISD	12/31/2019
Finish:	4/29/2020
Scope of Work:	The conversion of load served from 4kV to 13kV and the retirement of the 12th Street Sub. 126 has three phases. Phase 1: Construct one mile of 8-way conduit bank from 2nd and C street SW to the vicinity of 7th and Maryland Avenue SW. Phase 2: Extend Feeders 15294, 15295 and install switch-holes and three 3-way switches to convert most of the load on Feeders 230, 233, and 370. This includes conversion of approximately 47,000 feet of 4kV line to 13kV requiring 47,000 ft of conduit, 100,000 ft. of cable, and some secondary replacements. Phase 3: Install two 13/4kV, 2000 MVA step-down transformers to supply the remaining 2.0 MVA of 4kV load on Feeders 230, 233, and 370. This includes installation of four 3-way switches.
Justification:	The 12th Street Sub. 126 contain oil circuit breakers that will be removed based on review of condition done through the Equipment Condition Assessment process and reliability. The process takes age and condition of equipment into consideration and also entails conducting ongoing tests to monitor conditions. Both the 13 kV/4 kV transformers are identified as suspect and in need of eventual replacement. These oil circuit breakers are no longer manufactured and the manufacturer no longer provides spare parts. The existing conduit and cables are very old and upgrades of this system are being proposed to eliminate potential reliability concerns proactively.

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Alternative:	An alternative to converting all 12th St. Sub 4 kV load to 13 kV is to maintain the 4 kV system by replacing all conduit, cable, substation transformers and substation switchgear.
Reimbursable:	No
Related Circuit:	-
Related Substation:	12th STREET, SW (126)

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DC Construction Report

No:	143
ITN Name:	72355: Meter Equipment DC (DLPCMR2DXX)
ITN:	DLPCMR2DXX
FERC:	Distribution – DC
Category:	Customer Driven
Sub-Category:	Customer Operations
2018_Actual_(000s):	$2,547.29
2019_Budget_(000s):	$778.76
2020_Budget_(000s):	$856.63
2021_Budget_(000s):	$942.29
2022_Budget_(000s):	$1,036.52
2023_Budget_(000s):	$1,036.52
Start:	12/7/2013
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	Used for the purchase of Electric Meters, Current Transformers and Potential Transformers in DC. Residential and Commercial.
Justification:	No Justification Provided
Alternative:	No Alternative Provided
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	144
ITN Name:	72359: Meter Install DC (UDLPCMR2DX)
ITN:	UDLPCMR2DX
FERC:	Distribution – DC
Category:	Customer Driven
Sub-Category:	Customer Operations
2018_Actual_(000s):	$1,604.40
2019_Budget_(000s):	$2,539.44
2020_Budget_(000s):	$2,584.00
2021_Budget_(000s):	$2,700.00
2022_Budget_(000s):	$2,864.70
2023_Budget_(000s):	$3,021.40
Start:	1/1/2017
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	Used to record labor costs for New Meter installations, Meter exchanges and Meter removal and primarily includes labor costs for the following types of property units: Electric Meters, Current Transformers and Potential Transformers in DC. Residential and Commercial.
Justification:	Used to record labor costs for New Meter installations, Meter exchanges and Meter removal and primarily includes labor costs for the following types of property units: Electric Meters, Current Transformers and Potential Transformers in DC. Residential and Commercial.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	145
ITN Name:	75093: NB Commercial Pepco DC
ITN:	UDLPCS6WX
FERC:	Distribution – DC
Category:	Customer Driven
Sub-Category:	New Business Connections
2018_Actual_(000s):	$50,987.06
2019_Budget_(000s):	$46,648.27
2020_Budget_(000s):	$37,033.21
2021_Budget_(000s):	$37,364.52
2022_Budget_(000s):	$37,327.85
2023_Budget_(000s):	$37,716.98
Start:	11/3/08
Est. ISD	
Finish:	12/31/29
Scope of Work:	The scope of this blanket project is to capture Commercial system extension and upgrade work in District of Columbia. Work includes both primary and secondary assets and typical charges include primary extension, transformers, and secondary mainline for commercial projects. Amount of work and spending per year varies with economic conditions.
Justification:	Customer driven work to build infrastructure for new commercial developments.
Alternative:	This is customer driven work and alternatives are not available. Pepco pursues lowest cost alternative for service work and the customer contributes should they choose a higher cost alternative.
Reimbursable:	Partially and based on tariff
Related Circuit:	
Related Substation:	

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DC Construction Report

No:	146
ITN Name:	75095: PEPCO DC NB Network Commercial[1]
ITN:	UDLPCS6WX
FERC:	Distribution – DC
Category:	Customer Driven
Sub-Category:	New Business Connections
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	12/31/08
Est. ISD	
Finish:	12/30/29
Scope of Work:	The scope of this blanket project will be to capture Network Commercial system extension and upgrade work in District of Columbia. Work will include both primary and secondary and typical charges include primary extension, network transformers, and primary mainline for Network Commercial projects. This project has not yet been established in the New Business portfolio, but is expected to be established in 2019 with spend in 2019-2022. Amount of work and spending per year will vary with economic conditions and is currently forecasted in the overall New Business blanket project.
Justification:	Customer driven work to build infrastructure for new networked commercial developments.
Alternative:	This is customer driven work and alternatives are not available. Pepco pursues lowest cost alternative for service work and the customer contributes should they choose a higher cost alternative.
Reimbursable:	Partially and based on tariff
Related Circuit:	
Related Substation:	

[1] Dollars for this project are currently combined with "75093: NB Commercial Pepco DC UDLPCS6WX". Funds for network projects will be identified and tracked separately beginning in the latter half of 2019.

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DC Construction Report

No:	147
ITN Name:	75092: NB Residential Pepco DC
ITN:	UDLPCS1W
FERC:	Distribution – DC
Category:	Customer Driven
Sub-Category:	New Business Connections
2018_Actual_(000s):	$31,600.82
2019_Budget_(000s):	$29,841.14
2020_Budget_(000s):	$29,231.18
2021_Budget_(000s):	$30,246.72
2022_Budget_(000s):	$29,908.10
2023_Budget_(000s):	$28,840.46
Start:	8/30/12
Est. ISD	
Finish:	12/31/29
Scope of Work:	The scope of this blanket project is to capture residential system extension and upgrade work in District of Columbia. Work includes both primary and secondary assets and typical charges include primary extension, transformers, and secondary mainline for residential projects. Individual service drops to residential services are included. Amount of work and spending per year varies with customer's request for new residential loads and has been averaging $376,000 each year since 2010. Budget for out years are based on 6 year average and recent trends.
Justification:	Customer driven work to build infrastructure for new residential developments.
Alternative:	This is customer driven work and alternatives are not available. Pepco pursues lowest cost alternative for service work and the customer contributes should they choose a higher cost alternative.
Reimbursable:	No
Related Circuit:	
Related Substation:	

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DC Construction Report

No:	148
ITN Name:	71223 - DC: Facility Relocations (Non-Highway) (UDLPCS3W)
ITN:	UDLPCS3W
FERC:	Distribution – DC
Category:	Customer Driven
Sub-Category:	New Business Connection
2018_Actual_(000s):	$3,072.69
2019_Budget_(000s):	$2,890.81
2020_Budget_(000s):	$2,846.24
2021_Budget_(000s):	$2,889.70
2022_Budget_(000s):	$2,866.56
2023_Budget_(000s):	$2,913.25
Start:	3/3/03
Est. ISD	
Finish:	8/13/19
Scope of Work:	The scope of this project includes miscellaneous relocation of Pepco facilities requested by customers that are not related to road improvement projects by a government agency. Amount of work and spending varies year to year based on customer's requested schedule and scope. It is expected that the majority of the work is fully reimbursed based on design estimate unless system betterment are performed at the same time. Actual spending for the past 6 years has been fluctuating as low as credit of $1.7 million in 2014 and as much as $3.5 million in 2010. Fluctuation and unpredictability of actual spending is driven mainly by the timing of customer payment and work being performed in different years.
Justification:	Customer request service to relocate Pepco facilities.
Alternative:	This is customer driven work and alternatives are not available. Pepco pursues lowest cost alternative for service work and the customer contributes should they choose a higher cost alternative.
Reimbursable:	Yes
Related Circuit:	
Related Substation:	

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DC Construction Report

No:	149
ITN Name:	71231: DDOT DC South Capitol Street Relocation 34kV UG (UDLPCSCAP2)
ITN:	UDLPCSCAP2
FERC:	Distribution – DC
Category:	Customer Driven
Sub-Category:	New Business Connections
2018_Actual_(000s):	$2,037.93
2019_Budget_(000s):	$2,655.47
2020_Budget_(000s):	$3,026.88
2021_Budget_(000s):	$1.49
2022_Budget_(000s):	$0
2023_Budget_(000s):	$0
Start:	12/31/08
Est. ISD	
Finish:	12/30/29
Scope of Work:	The purpose of this project is to relocate feeders to assist with the construction of the South Capitol Street bridge. The plan for the bridge has not been finalized so the specific facilities that must be relocated have not been identified. The area on the north side of the bridge contains underground 13kV and 34kV distribution feeders, while that on the south side contains both underground and overhead 13kV and 4kV distribution feeders.
Justification:	DDOT/Customer driven work to build infrastructure for DDOT.
Alternative:	This is customer driven work and alternatives are not available. Pepco pursues lowest cost alternative for service work and the customer contributes should they choose a higher cost alternative.
Reimbursable:	Partially and based on tariff
Related Circuit:	
Related Substation:	

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DC Construction Report

No:	150
ITN Name:	71214: DC Highway Relocations (UDLPCH0W)
ITN:	UDLPCH0W
FERC:	Distribution – DC
Category:	Customer Driven
Sub-Category:	New Business Connections
2018_Actual_(000s):	$2,224.39
2019_Budget_(000s):	$2,742.83
2020_Budget_(000s):	$2,829.25
2021_Budget_(000s):	$2,914.29
2022_Budget_(000s):	$3,003.90
2023_Budget_(000s):	$3,099.55
Start:	12/31/2008
Est. ISD	
Finish:	12/30/2029
Scope of Work:	The scope of this project includes miscellaneous relocation of Pepco facilities due to highway improvement projects driven by DDOT. The amount of work and spending varies year to year based on DDOT's road improvement project schedule and scope. Actual spending for the past 6 years has been as low as $444,000 in 2014 and as much as $16.7 million in 2010. Average spending for 6 years, excluding 2010 and 2014, was $2.3 million per year and future budgets are set based on this average. Any large scale DDOT road improvement projects such as South Capitol bridge relocation will be handled by a separate WBS element as a special project (UDLPCSCAP2).
Justification:	DDOT request service to relocate Pepco facilities due to improvement projects.
Alternative:	This is customer driven work and alternatives are not available. Pepco pursues lowest cost alternative for service work and the customer contributes should they choose a higher cost alternative.
Reimbursable:	No
Related Circuit:	
Related Substation:	

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DC Construction Report

No:	151
ITN Name:	74565: SF6 detection camera (UOTPOSF6)
ITN:	UOTPOSF6
FERC:	Electricity – DC
Category:	Other
Sub-Category:	Back Office Allocation
2018_Actual_(000s):	$202.12
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	3/3/2003
Est. ISD	3/29/2019
Finish:	12/30/2029
Scope of Work:	Purchase SF6 detecting camera over $100k
Justification:	To have as SF6 detecting camera for monitoring and detecting SF6 substation equipment for possible leaks to be addressed in a timely manner before alarms and more serious leaks occur.
Alternative:	
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	152
ITN Name:	73880: Tools DC (UOTPOMR1DX)
ITN:	UOTPOMR1DX
FERC:	Electricity – DC
Category:	Other
Sub-Category:	Other
2018_Actual_(000s):	$1,312.17
2019_Budget_(000s):	$374.79
2020_Budget_(000s):	$196.17
2021_Budget_(000s):	$198.35
2022_Budget_(000s):	$200.58
2023_Budget_(000s):	$202.85
Start:	12/31/2012
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	To purchase Meter Tools for use in DC
Justification:	
Alternative:	No Alternative Provided
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	153
ITN Name:	70768: Benning Substation Storage Facility (CMP335)
ITN:	CMP335
FERC:	Electricity – DC
Category:	Other
Sub-Category:	Real Estate and Facilities
2018_Actual_(000s):	$0.06
2019_Budget_(000s):	$2,199.99
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/31/2017
Est. ISD	12/31/2021
Finish:	4/30/2022
Scope of Work:	An equipment storage area will be designed and constructed to increase the storage capacity of Benning Service Center. Equipment to be stored includes twelve (12) 230/69kV transformers, ten (10) CT/PT combo revenue metering units, ten (10) 230kV SF6 gas breakers, ten (10) 230kV disconnect switches, six (6) 13kV bus sections switch gear, which will be housed inside of a prefab building. The foundations to be designed includes: six (6) dual concrete foundations with oil containment for twelve (12) transformers, one (1) 44ft x 66ft transformer salvage area, one concrete slab foundation for a 16ft x 36ft prefab building. The design of the new storage area shall include improvements to the storm water management system, per District of Columbia codes and regulation. This should include the construction of (3) three paved drive way sections that will withstand AASHTO HS 20 loading.
Justification:	A staging yard is needed to receive system spares to be used across the system. The Benning site has available space and is easily assessable by flatbed tractor trailers and is a central location in the Pepco service territory.
Alternative:	Other sites were considered - Buzzard Pt was considered but it has less space available than Benning and does not have rail access like Benning. Also, Benning has Stores personnel available on site for goods receipt.
Reimbursable:	No
Related Circuit:	-

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Related Substation:	-

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DC Construction Report

No:	154
ITN Name:	71227: DC: Security Systems & Equipment (CMP85D)
ITN:	CMP85D
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Real Estate and Facilities
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$21.00
2020_Budget_(000s):	$21.00
2021_Budget_(000s):	$21.00
2022_Budget_(000s):	$21.00
2023_Budget_(000s):	$21.00
Start:	12/31/2010
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	This is a Blanket Project for Capital Improvements related to Security Equipment and Systems in the PEPCO - DC Region. The associated projects consist of 2014 Benning road Security System, 2015 Benning Stores – New CCTV System, 2015 MLK Office in DC – Security System, 2016 Access control system at Benning Bldg 56. 2014 Benning road Security System involved installing card readers and cameras on the exterior doors at Building 44. 2015 Benning Stores – New CCTV System involved replacing the CCTV system with new video recorder and IP cameras at the Benning Stores location. 2015 MLK Office in DC – Security System involved installing card access control and CCTV on exterior doors to the old DC MLK office. 2016 Access control system at Benning Bldg 56 will involve installing card readers and cameras on the exterior doors at Building 56. Pepco will identify the work based on aging systems requiring upgrade and the need for new security controls to improve life safety measures. The typical work that falls under this WBS are Physical Security improvements to PHI facilities.
Justification:	2014 Benning road Security System – Install a complete Physical Security system at the Benning Bldg 44 business office located in Washington DC. This location is currently being used by PHI employees who did not have any security controls in place. 2015 Benning Stores – New CCTV System – Pepco installed an NVR and 8 cameras at this location. The new camera coverage provided a better

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	view of the loading docks as well as the storage yard. The increase in security measures will help deter theft and assist with incident investigations 2015 MLK Office in DC – Security System – Install a complete Physical Security system at the Martin Luther King Jr. business office located in Washington DC. This location will be used by PHI employees who did not have any security controls in place. 2016 Access control system at Benning Bldg 56 – Install a complete Physical Security system at the Benning Bldg 56 business office located in Washington DC. This location is currently being used by PHI employees who currently do not have any security controls in place.
Alternative:	Bldg 56 – WBS not created - Allow the guard to continue manually locking the doors each night.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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DC Construction Report

No:	155
ITN Name:	71664: Facilities Improvements DC (CMP130Z)
ITN:	CMP130Z
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Real Estate and Facilities
2018_Actual_(000s):	$501.70
2019_Budget_(000s):	$959.99
2020_Budget_(000s):	$960.00
2021_Budget_(000s):	$960.00
2022_Budget_(000s):	$960.00
2023_Budget_(000s):	$0.00
Start:	1/1/2012
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	The scope of this project includes funds for facility upgrades (CMP130) for the Benning location.
Justification:	Benning is a work center location in the district of Columbia that has mix use Facilities with office, warehouses, and Fleet Services buildings. The fund is used for several projects including a replacement of HVAC / Fire Pumps system that is needed to be complete during the year at Benning Service Center
Alternative:	If the fire pumps are not replaced, they will fail to operate and will not have fire protection for the facility. If the HVAC system fails to operate, employees cannot occupy the building and need to be sent home.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	156
ITN Name:	73058: Pepco DC: Electric Vehicles (CMP1143D)
ITN:	CMP1143D
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Real Estate and Facilities
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$200.00
2020_Budget_(000s):	$200.00
2021_Budget_(000s):	$200.00
2022_Budget_(000s):	$200.00
2023_Budget_(000s):	$200.00
Start:	1/1/2011
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	This is a blanket project to install Electic Vehicle Charging Stations at Pepco facilities.
Justification:	This is a blanket project to install Electic Vehicle Charging Stations at Pepco facilities.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	157
ITN Name:	73059: Pepco DC: Green Initiatives (CMP114D)
ITN:	CMP114D
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Real Estate and Facilities
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$30.00
2020_Budget_(000s):	$30.00
2021_Budget_(000s):	$30.00
2022_Budget_(000s):	$30.00
2023_Budget_(000s):	$30.00
Start:	12/31/2010
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	The scope of work of this blanket project is to install LED lights and streetlights at Pepco facilities.
Justification:	The scope of work of this blanket project is to install LED lights and streetlights at Pepco facilities.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	158
ITN Name:	73062: Pepco DC: Office Furniture (CMP120D)
ITN:	CMP120D
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Real Estate and Facilities
2018_Actual_(000s):	($575.81)
2019_Budget_(000s):	$85.00
2020_Budget_(000s):	$85.00
2021_Budget_(000s):	$85.00
2022_Budget_(000s):	$85.00
2023_Budget_(000s):	$85.00
Start:	12/31/2010
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Scope of Work to include Procurement of Office Furniture Systems and Equipment in PEPCO DC Region.
Justification:	The funds are used to purchase office furniture such as cubicles, chairs, tables for Pepco facilities. The furniture is purchased to replace old furniture, to buy new furniture for new employees and to configure existing office space for employees.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	159
ITN Name:	74440: Benning Bldg 59 Parking lot light and GFCI replacement (CMP367)
ITN:	CMP367
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Real Estate and Facilities
2018_Actual_(000s):	$314.92
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	3/3/2003
Est. ISD	5/17/2019
Finish:	12/30/2029
Scope of Work:	Install a new 400 Amp 3-Phase 277/480 Volt Service from an existing power pole with a step down transformer to 120/208 Volts. Replace all parking lot GFCIs with new underground raceways, wires and LED pole light fixtures. The majority of the underground installation will be bored.
Justification:	Old lights not operating GFCI outlets for work trucks to plug into during winter
Alternative:	None
Reimbursable:	-
Related Circuit:	-
Related Substation:	-

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No:	160
ITN Name:	74441: Benning Building 54 UG Area (CMP366)
ITN:	CMP366
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Real Estate and Facilities
2018_Actual_(000s):	$472.82
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	3/3/2003
Est. ISD	12/31/2018
Finish:	12/30/2029
Scope of Work:	Refresh a training area for Underground group at Benning
Justification:	Driven by UG Groups training needs
Alternative:	None
Reimbursable:	-
Related Circuit:	-
Related Substation:	-

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No:	161
ITN Name:	74553: Rockville Light Replacement (CMP369)
ITN:	CMP369
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Real Estate and Facilities
2018_Actual_(000s):	$114.97
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	3/3/2003
Est. ISD	12/31/2018
Finish:	12/30/2029
Scope of Work:	Remove all existing interior lights at Stores buildingReplace with LED lighting to meet criteria of June internal auditRemove all existing interior lights, excluding garage area, at VRM. Replace with LED lighting to meet criteria of June internal audit.
Justification:	Lighting at Stores interior warehouse does not satisfy requirements of internal June audit.
Alternative:	We explored placing guards on existing lights but was found to not be feasible and would not satisfy requirement.
Reimbursable:	No
Related Circuit:	
Related Substation:	

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No:	162
ITN Name:	72924: PEPCO DC SMSG LRP (2019 - 2023) Capital Project (UDLPCSCPDC)
ITN:	UDLPCSCPDC
FERC:	Electricity - DC
Category:	Customer Driven
Sub-Category:	Smart Meter / Smart Grid
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$640.00
2020_Budget_(000s):	$640.00
2021_Budget_(000s):	$640.00
2022_Budget_(000s):	$640.00
2023_Budget_(000s):	$640.00
Start:	7/18/2018
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	To use as SMSG Capital coverage over LRP 2019 - 2023ITN: UDLPCSCPDC
Justification:	To prepare for Regulatory Projects that have not been identified.
Alternative:	None
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	163
ITN Name:	71212: DC Comm Work: Install Radios (UORPODA1D)
ITN:	UORPODA1D
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Application Technology
2018_Actual_(000s):	$351.22
2019_Budget_(000s):	$900.04
2020_Budget_(000s):	$350.04
2021_Budget_(000s):	$200.00
2022_Budget_(000s):	$200.00
2023_Budget_(000s):	$200.00
Start:	6/7/2011
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Complete engineering and installation of Distribution Automation (DA) field device controls, radios and antennas. Pepco uses reclosers and SF6 switches as the main in-line devices to isolate faults and perform switching operations. This WBS covers the cost of the controls and for equipping the controls with radios and antennas that enable remote operability and ASR capabilities of the devices as they are integrated into the radio network. This work is coupled with the installation of the line DA devices in UDLPRDA1D. For the reporting period, this WBS also covers similar costs for non-ASR line devices in various feeder reliability programs (e.g. UDLPRM4DJ UDLPRM63D UDLPRM5BP), which facilitates remote visibility and control of the non-ASR devices.
Justification:	For ASR devices, installation of controls, radios and antennas for Automatic Sectionalizing and Restoration (ASR) schemes that help improve customer reliability by reducing the number of customers that experience a sustained outage in an event of a fault on the distribution system. ASR scheme also helps with quick restoration of customers that experience a sustained outage. The feeders that are selected for ASR capability are located in areas where many feeders experienced three or more lockouts over a two year period. Area grouping produces synergies by using the same substation equipment to control multiple feeders. ASR prior experience indicates that feeder reliability performance (SAIDI, SAIFI) can be improved by

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	as much as 50%. For non-ASR devices, the electronic controls, radios, antennas allow visibility and control of the devices, speeding up the restoration and operations processes, reducing length of crew travel time and speeding up the work process and restoration time by one to two hours per event.
Alternative:	For ASR and Non-ASR devices, an alternative would be to reduce the upfront costs by not installing radios and antennas and operate the devices locally/manually. Controls would still be needed to operate the devices locally. This would not allow Pepco to install and operate ASR schemes, or add remote visibility and control to non-ASR devices, therefore missing out on the reliability and operational process improvements that the ASR schemes brings.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	164
ITN Name:	72012: Install ASR Computer - Pepco DC (UOIPRASRD)
ITN:	UOIPRASRD
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Application Technology
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$150.01
2020_Budget_(000s):	$150.00
2021_Budget_(000s):	$150.00
2022_Budget_(000s):	$150.00
2023_Budget_(000s):	$150.00
Start:	1/1/2014
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	This WBS element is for: The installation and configuration of ASR computers.The testing of the software to support DA Schemes in Pepco DC. The Pepco DC: Install ASR Computer (UOIPRASRD) is related to the Distribution Automation Project – Line Equipment – Pepco DC (UDLPRDA1D). Pepco preferred PC to operate the ASR with Copper YFA software is the SEL – 3355. This provides high performance at a lower cost than Advantech servers.
Justification:	The Automatic Sectionalizing and Restoration (ASR) scheme helps to improve customer reliability by reducing the number of customers that experience a sustained outage in an event of a fault on the distribution system. ASR scheme also helps with quick restoration of customers that experience a sustained outage. The feeders that are selected for ASR capability are located in areas where many feeders experienced three or more lockouts over a two year period. Area grouping produces synergies by using the same substation equipment to control multiple feeders. ASR prior experience indicates that feeder reliability performance (SAIDI, SAIFI) can be improved by as much as 50%. In the past, Pepco used DC system's RT SCADA platform to configure the ASR Schemes. Ultimately this was too costly and Pepco decided to go with Copper YFA as Pepco is able to cut cost and time by doing the ASR configuration in house.

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Alternative:	The alternative would be not to install Distribution Automation and maintain existing levels of reliability that can be achieved with traditional methods such as tree trimming, animal guards etc. These methods however do not prevent all outages such as those resulting from pole accidents, downed large trees and other unavoidable causes. Distribution Automation is needed to obtain the next level of reliability improvement. ASR offers faster restoration time and increase in reliability by providing real time response to outages and minimizing the number of customers affected. The estimate to perform tree trimming and install animal guards at all the ASR stations would be in the millions.
Reimbursable:	No
Related Circuit:	14006;14132;14200;15199;15200;15867;15945
Related Substation:	BENNING (7);TAKOMA (27);VAN NESS (129);12th & IRVING, NE (133)

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No:	165
ITN Name:	72032: Cap Cntrl Install/Replace - Pepco DC (UORPORCPD)
ITN:	UORPORCPD
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Application Technology
2018_Actual_(000s):	$37.45
2019_Budget_(000s):	$250.00
2020_Budget_(000s):	$29.91
2021_Budget_(000s):	$30.00
2022_Budget_(000s):	$30.00
2023_Budget_(000s):	$30.00
Start:	10/2/2014
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	The scope of the project is to install Beckwith controllers and remote eBridge radios for line capacitors in the District of Columbia (Pepco DC). Capacitor control provides remote capacitor automation, monitoring, and protection. It also facilitates two-way communication and remote control of the Pepco DC capacitors to/from the control room. The budget for this project includes the engineering, procurement, installation, and integration into the energy management system (EMS). The plan is to have at least 25 installations completed in DC each year. The WBS element under which this work is performed is UORPORCPD.
Justification:	The installation of Beckwith controllers and remote eBridge radios is needed to reduce system losses and improve the capacitor maintenance process. This engineering solution is the best for this application because control of reactive power comes from monitoring the reactive power at the substation relays, instead of measuring at the capacitor controller. Remote control of distribution capacitors is done to maintain a unity power factor. It also prepares system for conservation voltage reduction (CVR) and variable voltage regulation (VVR) functionalities which improve control of feeder reactive power and results in reduced overall power needs for transmission, distribution, and substation. The Silver Spring Network (SSN) radio network was chosen to leverage the infrastructure that was already in place and a

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	mesh-type network was chosen for densely populated coverage.
Alternative:	The alternative to not installing the controllers and remote radios will be to maintain local capacitor by intelligent controller with time, voltage or reactive control, and to maintain one-way communication in Pepco. However, Pepco is not considering this option because it is Pepco's desire to facilitate two-way communication and remote control with the capacitors to maintain unity power factor. The SSN radio network was also chosen to leverage the infrastructure that was already in place and a mesh-type network was chosen for densely populated coverage.
Reimbursable:	No
Related Circuit:	-
Related Substation:	BENNING (7);GRANT AVENUE (183);HARRISON (38);LINDEN (156);TAKOMA (27);VAN NESS (129)

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No:	166
ITN Name:	72748: Network RMS - Telecom - Pepco DC (UORPORNPD)
ITN:	UORPORNPD
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Application Technology
2018_Actual_(000s):	$261.21
2019_Budget_(000s):	$700.01
2020_Budget_(000s):	$550.00
2021_Budget_(000s):	$700.00
2022_Budget_(000s):	$550.00
2023_Budget_(000s):	$700.00
Start:	6/30/2012
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This WBS element is for the radio portion of the Network RMS (Remote Monitoring Systems) project in DC. There will be 4200 network transformers equipped with monitoring equipment over 15 years. The Telecom scheme consists of a radio network with eBridges, antennas, and repeaters. The Network Transformer Protector RMS-Telecom is related to the Network RMS-Pepco DC project.
Justification:	Install radio networks for RMS communications. A wireless radio network will alleviate much of the project cost over a fiber network. RMS will give Pepco system operators and engineers real-time load and environmental information, as well as transformer condition information and remote control capabilities. Control and Monitoring capabilities gained from Network RMS will allow System Operators to attend swiftly to emergencies when any transformer needs to be isolated from the network. The system will also provide operators real-time information on the status of a protector breaker (if open or closed), which can be useful in detecting transformers going on and off the network. The system will also allow the analysis of trends in the underground network and can be useful in asset and maintenance strategy.
Alternative:	The alternative is to not install Network RMS and maintain existing levels of local monitoring and control of the system which includes having to send personnel to operate network protector locally in emergency events and relying on

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	physical inspections to gain knowledge of equipment like open protector, loss of pressure in protector housing, blown protector fuse and environmental conditions like water ingress into the protector housing. This alternative was not selected because of the desired reliability improvements.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	167
ITN Name:	73383: DA Battery Replacement - Pepco DC
ITN:	UORPORBAD
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Application Technology
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$30.00
2020_Budget_(000s):	$30.01
2021_Budget_(000s):	$30.00
2022_Budget_(000s):	$50.00
2023_Budget_(000s):	$50.00
Start:	6/5/2013
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	To replace batteries in control cabinets for reclosers, capacitors and voltage regulators on a 4-5 year replacement cycle in the District of Columbia.
Justification:	When a feeder goes out of service, the power source to the controller is lost. These batteries are needed to operate the various DA devices under such conditions. The expected life span of each battery is approximately 5 years by manufacturer specs, but the batteries may be replaced with the 4 year planned inspection of the device. If an inspection cycle is missed, there will be one more year of window of opportunity, assuming average battery life.
Alternative:	Alternatives: 1. Run the batteries to failure; this option was rejected because of potential loss of DA activation opportunities. 2. Wait five years; this option was rejected because Pepco would miss out on the work cost/time synergies that come by coupling the work with the planned inspections.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	168
ITN Name:	73223: Post-Deployment AMI Comm Meter to Pole Pepco DC (UORPODCAMI)
ITN:	UORPODCAMI
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Smart Meter / Smart Grid
2018_Actual_(000s):	$342.27
2019_Budget_(000s):	$606.60
2020_Budget_(000s):	$340.27
2021_Budget_(000s):	$340.27
2022_Budget_(000s):	$242.70
2023_Budget_(000s):	$242.70
Start:	9/1/2016
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	The scope of the project is to install additional AMI communication equipment (access points, relays, battery backups) as required to read (1) AMI meters that are going to be installed and wouldn't be covered by the existing AMI communication network in Pepco DC or (2) AMI meters that have been installed but are unable to communicate with the existing AMI communication network in Pepco DC and require additional relays.
Justification:	This post-deployment AMI communication project will be funded with dollars from the deployment AMI Comm Meter to Pole Project DORPBR1D. The 2016-2017 budget in DORPBR1D reflects the installation of additional AMI communication network devices to read certain large customer meters that have been or will be replaced with AMI meters. This work is necessary to allow over-the-air reads of these large customer AMI meters in DC.
Alternative:	For the AMI Communication Equipment for Large Customer Meters: 1. Continue to manually read these large customer meters through the Itron P4 system. Like any manual reads, success is dependent on access to the meters. In today's environment access to critical work areas can be difficult and cause estimation issues if access is not granted. The process is costly because Pepco must maintain meter readers to support the process. 2. Continue to remotely interrogate those large customer meters with the technology installed. Even though these large customer locations do

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	not have a meter installed with SSN technology, they are read remotely using different technologies and do not require physical field visits. The additional cost for this alternative is maintaining these other technologies for remotely interrogating the meters - in addition to the already existing AMI communication network for DC.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	169
ITN Name:	74101: PHI Web Release 1 - Cap
ITN:	UOIPO030
FERC:	Electricity - DC
Category:	Other
Sub-Category:	IT BU Projects
2018_Actual_(000s):	$351.95
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	9/26/2017
Est. ISD	10/21/2018
Finish:	2/18/2019
Scope of Work:	Converge the look & feel for the PHI website to align with the other OpCo websites, Pepco.com, Atlanticcityelectric.com and Delmarva.com, to create consistent user experience & improve user satisfaction, implement a common governance & support processes.For Pepco.com, Atlanticcityelectric.com and Delmarva.com, create new sites utilizing the exact infrastructure (SharePoint 2013 and Azure Cloud solution) as the Exelon sites. This includes:Layouts, Content, Unauthenticated Web Applications and Microsites that are vendor hosted but still anonymous.
Justification:	The project will achieve convergence in five areas:1. Governance and Oversight - unifies the Opcos under a common set of principles2. Technology - Enables an integrated set of customer-facing business services and scalability for acquisitions3. Look & Feel - Offers a common interface and customer experience4. Functionality - Enables common account authentication, self-service options and programs - enabled but implemented during phase 25. Analytics & Reporting - Understanding the customers' digital behavior
Alternative:	No alternatives considered; This project must be undertaken to achieve convergence of PHI websites.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	170
ITN Name:	74171: WMS Integration & Implementation (PEPCO) - Cap
ITN:	UOIPO024
FERC:	Electricity - DC
Category:	Other
Sub-Category:	IT BU Projects
2018_Actual_(000s):	$9,789.17
2019_Budget_(000s):	$2,309.01
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	4/3/2017
Est. ISD	2/9/2019
Finish:	6/9/2019
Scope of Work:	- PHI will adopt the Exelon business processes and IT systems for Work and Asset Management (Asset Suite) and Scheduling (Primavera P6). - Asset Suite and P6 functionality implemented for PHI will be consistent with what has been implemented for the other Exelon Utilities. - The project will support the attainment of merger synergy savings and is aligned to the North Star strategy for the affected systems.
Justification:	Advantages- Enables merger synergy savings- Supports common EU tools and processes- Implements platform for future synergy opportunities- Enables retirement of aging WMIS applications- Supports common mobile enablement for work management
Alternative:	Disadvantages- Does not support merger synergies or business process standardization- Would require alternative project work to extend or replace WMIS
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	171
ITN Name:	70569: BENNING INSTALL BB WIRELESS BASE STATION (UORPORBSB)
ITN:	UORPORBSB
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Telecomm
2018_Actual_(000s):	$115.59
2019_Budget_(000s):	$82.86
2020_Budget_(000s):	$99.99
2021_Budget_(000s):	$100.00
2022_Budget_(000s):	$100.00
2023_Budget_(000s):	$100.00
Start:	12/31/2013
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Plan, engineer, design, and construct broadband radio base stations to support transport of Smart Grid (e.g., Distribution Automation (DA) & AMI) data communications traffic over private, licensed & managed wireless infrastructure, to interface and ultimately be backhauled by the PHI Power Delivery Data Network (PDDN). This project comprises the engineering & implementation of base station radio assets with antennas, feedline, power supplies, other ancillary equipment and related materials. Base station radios were CalAmp Viper-SC 900+ 100kHz channel Base Stations.
Justification:	Pepco Holdings is building an infrastructure to transition from public, commercial wireless services to private company-owned broadband radio infrastructure with quality of service (QOS), reliability, security and low latency to serve core Smart Grid & off-network substation communications requirements. Smart Grid encompasses Supervisory Control & Data Acquisition (SCADA), Distribution Automation (DA) which Pepco Holdings does not want operation or command/control data traversing public carrier or internet infrastructure. Pepco Holdings' past experiences with commercial services during storms, hurricanes, derechos, earth quakes and inaugurations has shown that in times when most needed, commercial services have not been available and have had significant

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	time to repair and restore services, thus negatively impacting Pepco's operations of critical systems that depend on the communications systems. This project has been underway since 2013.
Alternative:	Continue using public wireless carrier. Commercial wireless services lack sufficient reliability, QOS, survivability, and latency can vary to the extent that renders DA switching schemes ineffective in restoring service to Customers.
Reimbursable:	No
Related Circuit:	-
Related Substation:	BENNING (7);CHESAPEAKE STREET, SE (181);FULTON STREET (157);NORTH CAPITOL (40);QUESADA (89);53rd STREET, SE (48)

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No:	172
ITN Name:	70762: ACR/SF6 Cntrl Install/Replace - Pepco DC (UORPOR
ITN:	UORPORBTB
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Telecomm
2018_Actual_(000s):	$1,959.42
2019_Budget_(000s):	$1,000.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	4/4/2015
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	To plan, engineer, design, configure, install, test, and (performance) optimize recloser and SF6 switch controllers along with remote eBridge radios, antenna and ancillary materials.
Justification:	Silver Spring Networks' (SSN) eBridge remote radio units are installed with grid automation devices located along feeder lines out of electrical substations to facilitate communications to these remote devices. Substations include Anacostia Sub-008, 12th & Irving sub Sub-133, NRL Sub-168, Suitland Sub-134, and Fort Slocum Sub-190. The grid automation, or distribution automation (DA), devices serve to enhance the reliability and quality of service of the distribution feeder lines serving our electric service customers. The worst performing feeders (i.e., those suffering the worst reliability) have been targeted for improvement to achieve more reliable power delivery to customers. The technique being employed to achieve such (reliability) improvement is to install advanced control re-sectionalizing (ACR) schemes with radios serving communications between the remote DA devices and the SCADA/ECS master station.
Alternative:	Alternative means of communications (to SSN mesh radio) include use of Commercial wireless services (e.g., Verizon and/or AT&T) – lacks quality of service (QOS) prioritization, suffers from variable latency, and is unpredictable. Point-to-multipoint radio – not as ubiquitous

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	coverage, limited by topology, limited by available frequency spectrum availability fiber optics – ruled out due to extraordinary high cost to implement along with excessive lead time to install.
Reimbursable:	No
Related Circuit:	-
Related Substation:	ANACOSTIA (8);FORT SLOCUM (190);NAVAL RESEARCH LAB (168);SUITLAND (134);12th & IRVING, NE (133)

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No:	173
ITN Name:	71110: Communication Work: Data Network DC (UOFPOF25D)
ITN:	UOFPOF25D
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Telecomm
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$150.00
2020_Budget_(000s):	$200.00
2021_Budget_(000s):	$200.00
2022_Budget_(000s):	$200.00
2023_Budget_(000s):	$200.00
Start:	1/1/2011
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	This project includes design, installation, and turn-up of Communication Data Network: Multiple Protocol Label Switching (MPLS), Fire Wall (FW), IMUX 2000 (T1 Multiplexing transport) for the District of Columbia.
Justification:	This transporting system will be used to support Smart Substation Supervisory Control and Data Acquisition (SCADA), Distribution Automation Projects (DA) and Advanced Metering Infrastructure projects (AMI).
Alternative:	There is no alternate communication method to support these communication requirements. MPLS is the only technology capable of meeting the various communication requirements from Ethernet IP to TDM (Time Division Multiplexing)
Reimbursable:	No
Related Circuit:	-
Related Substation:	CHAMPLAIN (25);OLIVER STREET (146)

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No:	174
ITN Name:	71210: DC - Leased Line Elimination (UORPOLL02)
ITN:	UORPOLL02
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Telecomm
2018_Actual_(000s):	$69.78
2019_Budget_(000s):	$20.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	3/30/2018
Est. ISD	11/30/2019
Finish:	3/28/2020
Scope of Work:	Eliminate existing leased lines for RTU and phones circuits in PEPCO substations and provide alternate transport path.
Justification:	Project is needed as Verizon is beginning to decommission existing copper lines, which has our RTU and Black & Red phone circuits
Alternative:	Deploy fiber in these substations, however the costs would high compared to radio solutions.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	175
ITN Name:	71682: Fiber Optic Builds - DC (UOFPODC01)
ITN:	UOFPODC01
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Telecomm
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$50.00
2020_Budget_(000s):	$50.00
2021_Budget_(000s):	$28.50
2022_Budget_(000s):	$200.00
2023_Budget_(000s):	$900.00
Start:	3/22/2018
Est. ISD	12/31/2024
Finish:	4/29/2025
Scope of Work:	This project is for unscheduled fiber repairs in the District of Columbia Area.
Justification:	This project is needed for emergency unscheduled fiber optic installation and repairs (for example, in the event of unscheduled repairs due to rodent damage or inclement weather). Existing slack may not be sufficient to complete the necessary repairs.
Alternative:	This project/emergency will use slack if available. About 100 ft. of extra fiber is looped for every 1000 ft. or so to be used as slack for future cable repair. If fiber damage is near a slack, the cable can be pulled and using the slack cable to bridge the gap. Otherwise new cable will have to be installed to replace the damaged section. Fiber cable repair cost can be far lower with slack provisions.
Reimbursable:	-
Related Circuit:	-
Related Substation:	-

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No:	176
ITN Name:	71866: Harvard - New Sub - Extend Fiber (UOFPOHS)
ITN:	UOFPOHS
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Telecomm
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$50.00
2021_Budget_(000s):	$100.00
2022_Budget_(000s):	$5.00
2023_Budget_(000s):	$0.00
Start:	1/1/2019
Est. ISD	6/1/2023
Finish:	10/1/2022
Scope of Work:	The scope of this project is to extend fiber to the newly rebuilt Harvard Substation.
Justification:	Existing Harvard Sub. 13 was originally constructed in the 1920's and has some very old concrete encased switchgear that cannot be upgraded without demolishing the existing infrastructure. The new sub will be used also to extend feeders to retire Champlain Sub. 25 that was originally built for 13 kV in the 1930's and has similar concrete encased switchgear that can’t be upgraded.
Alternative:	An alternative to rebuilding Harvard would be to purchase a new property in order to build a new substation. Since Pepco already owns most of the needed property at Harvard Sub. 13, there would be less cost and less risk of not obtaining approval by using the existing property and not obtaining a new one.
Reimbursable:	No
Related Circuit:	-
Related Substation:	CHAMPLAIN (25);HARVARD (13);TAKOMA (27);Vernon

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No:	177
ITN Name:	71912: IDS design build and install, PEPCO DC (UOFPOF33D)
ITN:	UOFPOF33D
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Telecomm
2018_Actual_(000s):	$13.59
2019_Budget_(000s):	$370.50
2020_Budget_(000s):	$370.38
2021_Budget_(000s):	$381.61
2022_Budget_(000s):	$1,592.70
2023_Budget_(000s):	$750.00
Start:	1/1/2016
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This project will support the design, engineering, purchase, and installation of Substation Firewalls in the Pepco DC region. The existing firewalls will be replaced with new units that will provide higher availability, enabling required work to take place without impacting communications or cyber security of equipment protected by these devices. The work needs to be scheduled with system operations as communications to all substation can't be lost at one time.
Justification:	This project is required to replace the legacy firewalls that currently support cyber security at Pepco DC substations. As new equipment that needs to communicate through these devices is deployed in Pepco DC substations, the amount of bandwidth/capacity at these locations continues to grow, the existing devices have reached the capacity and cannot handle additional equipment. The need to provide a solution with redundancy is required due to when patching/firmware updates are required to support compliance, there is an impact to the communications to and from a substation, which impacts Pepco's visibility to a substation. The new devices will provide the needed bandwidth and redundancy to provide updates without impacting service.
Alternative:	The alternative would be to install a second device at each location that would replicate the functionality of the existing units. Putting in two (2) devices at each substation only addresses the redundancy component of the project,

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	but would not address the issue with the bandwidth capacity of each individual unit. The alternative, while feasible, would not provide the benefits of replacing with one (1) unit to provide both bandwidth and redundancy. There would also be additional costs associate with maintaining two (2) individual devices vs. one (1) device.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	178
ITN Name:	72528: Mt Vernon Sq Sub: Extend FO (UOFPOMV1)
ITN:	UOFPOMV1
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Telecomm
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$590.00
2022_Budget_(000s):	$75.00
2023_Budget_(000s):	$0.00
Start:	1/1/2017
Est. ISD	6/1/2022
Finish:	9/29/2022
Scope of Work:	The scope of this project is to install fiber optic cable at Mt. Vernon Square Substation and terminal equipment to support new substation. The fiber terminal equipment is needed to communicate with the adjacent sites for system protection.
Justification:	Mt. Vernon Square substation is required to relieve a predicted summer 2023 firm capacity overload of 5% on the Northeast Sub. 212 Southwest LVAC Network Group. This project is part of the New Mt. Vernon Square Substation work to establish a new 230 kV/13 kV Substation initially built with a 140 MVA of firm capacity, with an ultimate capacity of 210 MVA. This is needed to provide relief to existing Northeast Sub. 212 as well as 10th Street Sub. 52. This substation will bring distribution capacity to the fast growing Northeast District of Columbia, including the downtown District of Columbia area.
Alternative:	An alternative substation location was investigated along New York Avenue in Northeast DC. It was determined that the primary amount of development and load center of the new substation was in the Mt. Vernon Triangle area. Several sites were investigated in the Mt. Vernon triangle area with many being discarded as too expensive or not having the needed access to the street.
Reimbursable:	No
Related Circuit:	-
Related Substation:	CHAMPLAIN (25);Vernon;WATERFRONT (223)

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No:	179
ITN Name:	72927: PEPCO Fiber Optic Blanket: DC (UOFPOF3D)
ITN:	UOFPOF3D
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Telecomm
2018_Actual_(000s):	$45.24
2019_Budget_(000s):	$0.00
2020_Budget_(000s):	$0.00
2021_Budget_(000s):	$0.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	1/1/2011
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This project is for unscheduled fiber repairs in the District of Columbia Area.
Justification:	This project is needed for emergency unscheduled fiber optic installation and repairs (for example, in the event of unscheduled repairs due to rodent damage or inclement weather). A certain amount of slack is already incorporated into the original fiber installation. However, th existing slack may not be sufficient to complete the necessary repairs.
Alternative:	This project/emergency will use slack if available. About 100 ft. of extra fiber is looped for every 1000 ft. or so to be used as slack for future cable repair. If fiber damage is near a slack, the cable can be pulled and using the slack cable to bridge the gap. Otherwise new cable will have to be installed to replace the damaged section. Fiber cable repair cost can be far lower with slack provisions.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	180
ITN Name:	73043: Pepco DC Install Radios in Vehicle (UORPORVRD)
ITN:	UORPORVRD
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Telecomm
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$50.00
2020_Budget_(000s):	$50.00
2021_Budget_(000s):	$50.00
2022_Budget_(000s):	$50.00
2023_Budget_(000s):	$50.00
Start:	12/31/2011
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	This project is to replace the remaining fleet of older mobile radios (truck mounted dispatch radios) with newer models to be able to convert the LMR system to DMR for advanced data and voice capability.
Justification:	Vehicle mobile radio system upgrade with replacing older mobile radios (Truck mounted) for advance data and voice communications. Vehicular radio units are essential, core assets enabling restoration activities and other critical field work when commercial services may or may not be available. For effective, efficient, safe field work to occur, communications between the control center dispatchers and the field teams is imperative.
Alternative:	Commercial wireless services were considered but not deemed suitable for survivable, mission-critical communications due to· Lack of quality of service (QOS) prioritization over any other casual customers' usage·
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	181
ITN Name:	73048: Pepco DC Unscheduled Radio (UORPOR30D)
ITN:	UORPOR30D
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Telecomm
2018_Actual_(000s):	$0.00
2019_Budget_(000s):	$53.00
2020_Budget_(000s):	$53.00
2021_Budget_(000s):	$53.00
2022_Budget_(000s):	$53.00
2023_Budget_(000s):	$53.00
Start:	12/31/2011
Est. ISD	12/31/2029
Finish:	12/30/2040
Scope of Work:	This project is to support unplanned/emergency capital radio projects.
Justification:	This provides for unplanned, or emergency, repairs and/or replacements of radio equipment that fail. Such damage may occur from storms, lightning, or premature end of life. Nothing has been charged to this year to date. We plan to reserve until at least the end of the third quarter before we consider cancellation.
Alternative:	Alternatives do not apply for unplanned emergency jobs.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	182
ITN Name:	73431: Replace SSN Access Point and Repeater Batteries, DC (UORPOAPRDC
ITN:	UORPOAPRDC
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Telecomm
2018_Actual_(000s):	$0.49
2019_Budget_(000s):	$20.00
2020_Budget_(000s):	$20.00
2021_Budget_(000s):	$20.00
2022_Budget_(000s):	$0.00
2023_Budget_(000s):	$0.00
Start:	8/16/2016
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Blanket project for the capital replacement of SSN Access Point and Repeater batteries in the District of Columbia.
Justification:	This project is required to maintain the availability and reliability of communication through the SSN Network as it supports several services. When a feeder goes out of service, the power source to the repeater is lost. These repeater batteries are needed to operate the various DA devices under such conditions. Also, if an AP loses power to its AC connection, remote management capability to connected radios will be lost via gridscape or UIQ. The AP batteries are required to maintain power to the APs under these conditions.
Alternative:	Alternative: Run the batteries to failure; this option was rejected because of potential loss of DA activation opportunities.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

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No:	183
ITN Name:	73506: Smart Grid Infrastructure (PHI) - Cap
ITN:	UOFPOF32D
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Telecomm
2018_Actual_(000s):	$510.92
2019_Budget_(000s):	$472.27
2020_Budget_(000s):	$285.78
2021_Budget_(000s):	$219.37
2022_Budget_(000s):	$241.30
2023_Budget_(000s):	$0.00
Start:	1/1/2012
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	Upgrade router binaries annually, all four regions, PEPCO. A router is classified as 3970 telecomm equipment, a transmitting and receiving device. A router binary is the code used to run the router, new versions of this code are provided by the manufacturer each year. This new code gets security enhancements each year, making the router less susceptible to cyber attacks. These binaries as they get enhanced become larger and the hardware is no longer capable of running the code. This project covers the costs of upgrading the hardware so these larger binaries can still operate the router.
Justification:	This project is required to maintain reliability and security. Provides communications services to Energy Management Operators, so they can monitor and control the electrical system. Providing our customers with rapid restoration of service, better electrical load management, and better electrical system diagnostics. This reduces truck rolls and significantly reduces response times to correct electrical system problems. Physical Security for the substations is provided by this network allowing for premises video, key card access and intruder detection. Failure to accommodate these enhanced binaries would yield a network that could not be secured, and this would cause loss of control of the electrical system, and possible intrusion into our substations. The only alternative would be to provide personnel to monitor and control each substation 24 hours a

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	day 7 days a week. This would be more costly and provide less timely outage response for our customers.
Alternative:	These routers provide connections to the substation Physical Security Systems protecting the substations from intruders, and control of the substation equipment by Energy Management System Operators. EMS operations increase reliability, and reduce outage time. The only alternative would be to man all the substations with both maintenance and security personnel 24 hours a day. Failure to do these binary upgrades would leave our substations exposed to cyber security attacks, intrusion by unauthorized personnel, theft of equipment or materials, and isolation from remote monitoring and control. These upgrades are done annually because the manufactures release a major upgrade once a year. There are no other viable engineered solutions.
Reimbursable:	No
Related Circuit:	-
Related Substation:	BENNING (7)

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No:	184
ITN Name:	73957: UF: Collector to Data Network PEPCO DC (UORPOBR1D)
ITN:	UORPOBR1D
FERC:	Electricity - DC
Category:	Other
Sub-Category:	Telecomm
2018_Actual_(000s):	$110.82
2019_Budget_(000s):	$115.59
2020_Budget_(000s):	$100.00
2021_Budget_(000s):	$100.00
2022_Budget_(000s):	$100.00
2023_Budget_(000s):	$100.00
Start:	12/30/2012
Est. ISD	12/31/2029
Finish:	12/31/2029
Scope of Work:	This project is to design and install telecom repeaters, master radios, and access points for 30-40 ASR and 20-30 non-Automatic Sectionalizing and Restoration (ASR) devices in Pepco's DC service territory. These are common elements of a Silver Spring Networks (SSN) radio mesh supporting take out points or back haul. As the radios are using unlicensed frequencies (902 – 928 MHz), they are limited to a transmit power of only 1 Watt. This limits the effective hop length between these radios such that battery-backed repeaters are required between eBridge radios. Access Points (APs) and eBridge Master (eBM) radios are used to take out mesh scheme traffic for network management (i.e., SmartGrid NMS) and SCADA or Distribution Automation (DA) traffic, respectively. This project has been underway since 2012.
Justification:	Mesh radio infrastructure is needed for ASR schemes that help improve customer reliability by reducing the number of customers that experience a sustained outage in an event of a fault on the distribution system. ASR scheme also helps with quick restoration of customers that experience a sustained outage. The feeders that are selected for ASR capability are selected using the standard ASR candidate feeder selection criteria. Area grouping produces synergies by using the same substation equipment to control multiple feeders. ASR prior experience indicates that feeder

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DC Construction Report

	reliability performance (SAIDI, SAIFI) can be improved by as much as 50%. Using Access Points and eBridge Masters in Pepco electrical substations with fiber optics connectivity to the Power Delivery Data Network (PDDN) provides a secure communication path for both management and operational traffic.
Alternative:	The alternative would be to not install DA and maintain existing levels of reliability that can be achieved with traditional methods such as tree trimming, animal guards etc. These methods, however, do not prevent all outages such as those resulting from pole accidents, downed large trees and other unavoidable causes. Distribution Automation is needed to obtain the next level of reliability improvement. Alternatives to support backhaul from collector point(s) to the Power Delivery Control & Data Network (PDDN) could use commercial or leased services. Where possible Pepco prefers to use private infrastructure, not commercial services for this work.
Reimbursable:	No
Related Circuit:	-
Related Substation:	-

Pepco I(2)
Allocated Projects

Sheet #	ITN	ITN_Name	FERC/State	Sub-Category	2018 Actual 000s	2019 Budget 000s	2020 Budget 000s	2021 Budget 000s	2022 Budget 000s	2023 Budget 000s
1	CMP136	70772: Benning: Upgrade Fuel Island (CMP136)	Common	Real Estate and Facilities	119.72	-	-	-	-	-
2	UOTPOMR1MX	73883: Tools Pepco MD (UOTPOMR1MX)	Electric - MD	Tools	336.89	411.98	288.97	288.97	292.25	292.25
3	UOFPONHS	72726: National Harbor Substation - Construct FO (UOFPONHS)	Electric - MD	IT BU Projects	-	-	-	500.00	1,000.00	1,000.00
4	UORPOAPRF, UORPOAPR	73428: Replace SSN Access Point and Repeater Batteries - Forestville,	Electric - MD	IT BU Projects	-	20.00	20.00	30.00	-	-
5	UORPOBR1Z	71100: Collector to Data Network pMD (UORPOBR1Z)	Electric - MD	IT BU Projects	379.68	223.64	200.00	200.00	200.00	(0.00)
6	UORPOCTCT	71021: Cherry Tree Crossing 2 MW PV - Telemetry (UORPOCTCT)	Electric - MD	IT BU Projects	(15.10)	20.00	-	-	-	-
7	UORPOLL01	72221: Fiber Optic - Leased Line Elimination - MD (PEPCO) - Cap	Electric - MD	IT BU Projects	513.36	99.99	-	-	-	-
8	UORPORVRM	73074: Pepco MD Install Radios in Vehicle (UORPORVRM)	Electric - MD	IT BU Projects	-	50.00	50.00	50.00	50.00	50.00
9	UORPOTR301	73923: Tucker Road Project Three (3) - Telemetry Wireless 1 MW PV ICC	Electric - MD	IT BU Projects	(14.29)	20.00	-	-	-	-
10	UORPOTRM01	73921: Tucker Road Project One (1) - Telemetry Wireless 1.5 MW PV ICC	Electric - MD	IT BU Projects	(13.99)	20.00	-	-	-	-
11	UOFPOF25M	71111: Communication Work: Data Network MD (UOFPOF25M)	Electric - MD	Telecomm	(4.10)	199.97	300.00	300.00	300.00	300.00
12	UORPOPDAMI	73224: Post-Deployment AMI Comm Meter to Pole Pepco MD (UORPOPDAMI)	Electric - MD	Telecomm	345.54	545.85	445.63	303.90	303.90	303.90
13	UOFPOMD01	71683: Fiber Optic Builds - MD (UOFPOMD01)	Electric - MD	Telecomm	-	50.00	110.00	71.50	200.00	900.00
14	UOFPOF5	71382: Darnestown: Construct New FO (UOFPOF5)	Electric - MD	IT BU Projects	42.78					
15	UOFPORTMD1	71861: Fiber Optic - Harrison Sub: Remote - MD (PEPCO) - Cap	Electric - MD	IT BU Projects	418.10					
16	UOFPOF3M	72928: PEPCO Fiber Optic Blanket: MD (UOFPOF3M)	Electric - MD	IT BU Projects	298.49					
17	CMP1143M	73087: Pepco MD: Electric Vehicles (CMP1143M)	Electric - MD	Real Estate and Facilities	85.61	200.00	200.00	200.00	200.00	200.00
18	CMP114M	73088: Pepco MD: Green Initiatives (CMP114M)	Electric - MD	Real Estate and Facilities	-	45.00	45.00	45.00	45.00	45.00
19	CMP120M	73096: Pepco MD: Office Furniture (CMP120M)	Electric - MD	Real Estate and Facilities	(60.79)	125.00	125.00	125.00	125.00	125.00
20	CMP132Z	71665: Facilities Improvements Pep MD (CMP132Z)	Electric - MD	Real Estate and Facilities	-	510.00	510.00	510.00	510.00	-
21	CMP331	71706: Forestville Service Center Expansion (CMP331)	Electric - MD	Real Estate and Facilities	-	4,500.00	-	-	-	-
22	CMP341	73068: Pepco Equipment Refresh (CMP341)	Electric - MD	Real Estate and Facilities	-	620.00	300.00	-	300.00	200.00
23	CMP85M	73098: Pepco MD: Security Systems & Equipment (CMP85M)	Electric - MD	Real Estate and Facilities	-	21.00	21.00	21.00	21.00	21.00
24	CMP336	73488: Rockville Fuel Site Upgrade (CMP336)	Electric - MD	Real Estate and Facilities	200.43	1,480.00	-	-	-	-
25	CMP368	74494: Forestville Main Building In-line Chilled Water Pumps (CMP368)	Electric - MD	Real Estate and Facilities	22.25					
26	CMP363	74532: Pepco - Upgrading all Fire Panel monitor alarm systems (CMP363)	Electric - MD	Real Estate and Facilities	4.20					
27	CMP156	73489: Rockville Ops: Construct Pole Barn (CMP156)	Electric - MD	Real Estate and Facilities	792.60					
28	UOIPRASRM	72013: Install ASR Computer - Pepco MD (UOIPRASRM)	Electric - MD	System Performance	(44.22)	99.99	100.00	100.00	100.00	100.00
29	UDLPCSEV1	71579: Electric Vehicle Distribution LRP (2019 - 2023) PEPCO - MD (UDL	Electric - MD	System Performance	-	3,726.00	4,412.00	2,463.00	2,214.00	-
30	UOIPO2018	71132: Control Center Equipment for Field Device Data - Pepco (UOIPO20	Electric - MD	System Performance	0.61	50.00	50.00	50.00	50.00	50.00
31	UORPODA1Z	72059: MD - Install Radios Line Eqp Pep (UORPODA1Z)	Electric - MD	System Performance	1,402.14	2,000.00	400.00	400.00	400.00	(0.00)
32	UORPOMR	72316: Network RMS - Telecom - Pepco MD (UORPOMR)	Electric - MD	System Performance	15.18	99.97	250.02	100.00	250.00	100.00
33	UORPORBAZ	73369: DA Battery Replacement - Pepco MD (UORPORBAZ)	Electric - MD	System Performance	-	89.99	99.99	70.00	140.00	(0.00)
34	UORPORBTZ	72040: ACR/SF6 Cntrl Install/Replace - Pepco MD (UORPORBTZ)	Electric - MD	System Performance	6,333.30	6,500.05	200.47	0.00	0.00	(0.00)
35	UORPORCPM	72033: Cap Cntrl Install/Replace - Pepco MD (UORPORCPM)	Electric - MD	System Performance	403.97	1,979.07	1,406.00	1,056.00	1,206.00	1,206.00
36	UOIPO032	71553: BIDA SES 2 (PEPCO) - Cap	Electricity - General	IT BU Projects	20,336.50	1,864.98	-	-	-	-
37	UOIPO036	71541: EMS Consolidation Implementation (PEPCO) - Cap	Electricity - General	IT BU Projects	4,026.79	3,015.37	2,515.82	148.20	-	-
38	UOIPO038	71548: BIDA Grid T&D (PEPCO)- Cap	Electricity - General	IT BU Projects	3,374.46	2,167.77	1,364.95	-	-	-
39	UOIPO044	74175: PHI IT WPT Implementation (PEPCO) - Cap	Electricity - General	IT BU Projects	2,186.10	303.92	-	-	-	-
40	UOIPO046	74014: Util Proj Port Mgmt Tool (PEPCO) - Cap	Electricity - General	IT BU Projects	370.83	340.05	118.17	-	-	-
41	UOIPO025	71558: Mobile Dispatch/Mapping (PEPCO) - Cap	Electricity - General	IT BU Projects	2,330.04	2,412.26	4,185.61	2,857.44	-	-
42	UOIPO029	74240: PHI Customer Pref Center - Cap	Electricity - General	IT BU Projects	386.52					
43	BPPCAPP000	74307: PEPCO Blng & Pymnt Prcsing Project Portfolio - Cap	Electricity - General	IT BU Projects	-	1,336.58	146.93	-	0.00	-
44	BSC34P1001	74331: BSC IT Corp Proj - Cap	Electricity - General	IT BU Projects	6.53	1,247.88	1,202.75	1,011.36	923.47	822.37

Pepco I(2)
Allocated Projects

Sheet #	ITN	ITN_Name	FERC/State	Sub-Category	2018 Actual 000s	2019 Budget 000s	2020 Budget 000s	2021 Budget 000s	2022 Budget 000s	2023 Budget 000s
45	BSC37P1001	74333: BSC Security Projects Capital	Electricity - General	IT BU Projects	-	85.50	91.27	89.19	94.69	94.74
46	BSC61P1001	74252: Security Controls - Cap	Electricity - General	IT BU Projects	200.26	22.88	4.47	-	-	-
47	CTA23P1001	74247: CTA PHI EWS Consol CAP	Electricity - General	IT BU Projects	137.64	0.59	0.90	0.92	0.92	1.15
48	CUSCAPP000	74309: PEPCO Customer Solutions Project Portfolio - Cap	Electricity - General	IT BU Projects	-	698.20	780.49	-	-	-
49	ERTCAPP000	74310: PEPCO Electric Real Time Project Portfolio - Cap	Electricity - General	IT BU Projects	-	1,167.67	3,147.31	2,694.49	2,788.83	2,512.10
50	MGCCAPP000	74312: PEPCO Mgmt & Compliance Project Portfolio - Cap	Electricity - General	IT BU Projects	-	(3,315.95)	10,786.32	19,578.45	18,126.33	18,130.80
51	OMGCAPP000	74314: PEPCO Outage Mgmt & Geo Project Portfolio - Cap	Electricity - General	IT BU Projects	-	387.61	606.22	33.10	3,391.16	2,595.62
52	SMO23P1001	74316: PEPCO Smart Meter Ops Project Portfolio - Cap	Electricity - General	IT BU Projects	-	164.09	(0.00)	0.00	(0.00)	(0.00)
53	UOIPO031	72976: Web Release 2 - My Acc (PEPCO) - Cap	Electricity - General	IT BU Projects	2,672.32					
54	UOIPO047	74432: AV / VC Enhancement Benning (UOIPO047)	Electricity - General	IT BU Projects	135.19	-	-	-	-	-
55	WMTCAPP000	74319: PEPCO Workforce Mobile Tech Project Portfolio - Cap	Electricity - General	IT BU Projects	-	241.74	99.01	(0.00)	(0.00)	(0.00)
56	UOFPORTDC1	71860: Fiber Optic Builds (PEPCO) - Cap	Electricity - General	Telecomm	249.23	-	-	-	-	-
57	UOFPOF32M	73507: Smart Grid Infrastructure (PEPCO) - Cap	Electricity - General	Telecomm	536.40	472.27	285.80	219.37	241.37	890.00
58	UOFPOF33M	71913: Firewall Refresh (PEPCO) - Cap	Electricity - General	Telecomm	322.00	1,251.53	1,251.50	1,811.55	743.18	750.00
59	UOFPOGV1	74122: Fiber Optic Builds (PEPCO) - Cap	Electricity - General	Telecomm	19.88	100.00	1,747.00	-	-	-
60	UOFPOPSN	72681: Smart Grid - NERC Physical Security Network (PEPCO) - Cap	Electricity - General	Telecomm	743.06	-	-	-	-	-
61	UORPOR30M	73080: PEPCO SSN Mesh Network - Cap	Electricity - General	Telecomm	(11.47)	50.00	50.00	50.00	50.00	50.00
62	UORPOR33M	73078: Communication Tower Infrastructure (PEPCO) - Cap	Electricity - General	Telecomm	250.66					
63	UORPORBSR	73302: SSN Mesh Network (PEPCO) - Cap	Electricity - General	Telecomm	272.66	60.02	200.00	180.00	125.00	125.00
64	CMP334	72794: New Training Facility Improvement (PHI) (CMP334)	Electricity - General	Real Estate and Facilities	-	10,000.00	19,999.78	10,000.00	-	-
65	CMP339	73037: Pepco Building Refresh (CMP339)	Electricity - General	Real Estate and Facilities	-	1,375.00	1,824.50	2,346.00	1,301.21	1,445.00
66	CMP352	74443: Benning Service Center Bldgs 54 & 56 New Perimeter Security System (	Electricity - General	Real Estate and Facilities	367.36	-	-	-	-	-
67	CMP353	74439: Benning - Replace Storm Sewer Sections from Manhole to Manhole (CMP353)	Electricity - General	Real Estate and Facilities	299.00					
68	UOFPOFFI01	71705: Forestville Fuel Island (UOFPOFFI01)	Electricity - General	Real Estate and Facilities	-	-	-	-	-	20.00
69	UOIPO028	72662: NERC CIP Projects: PHI Integration - Part 2 (PEPCO) - Cap	Transmission	IT BU Projects	1,967.42					
70	UOIPO043	73910: PHI IT Cascade Implementation (PEPCO) - Cap	Transmission - DC	IT BU Projects	1,066.34	574.00				
71	UOIPO039	72659: NERC CIP PHI Phy - Cap	Transmission - MD	System Performance	908.67					

B.L. Clark
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (I) – 3

Category	Line	PROJECT	WBS	Sum of Total 2019	Sum of Total 2020	Sum of Total 2021	Sum of Total 2022
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DAB01	UDLPOSV5D	(1,075)	(1,000)	(1,167)	(1,000)
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DCB01	DLPCMR2DXX	835	850	935	1,029
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DDB01	UDLPRDA1D	1,536	1,988	632	115
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DDB02	UDLPRM4DR	4,022	3,449	3,937	3,463
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DE101	UDLPLM72	-	-	44,971	175
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DE102	UDLPLM7W14	14,687	622	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DE106	UDLPLNJ1	-	-	-	6
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DE108	UDLPLWF6	5,650	241	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DEB02	UDLPLM7D2	-	-	-	3,653
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DEB08	UDLPLWF3	3,432	4,384	5,729	7,674
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DEB10	UDLPLM7W21	460	2,321	1,594	767
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DEB11	DLPLM7W223	14,094	674	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DEB13	UDLPRM4WA6	-	-	-	40,084
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DMB01	UDLPOEMGD	(445)	317	324	337
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DMB02	DLPRM32DXX	5,855	6,127	7,378	7,087
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DMB04	UDLPRM3K1	1,951	2,113	2,167	2,246
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DMB05	UDLPRM4BE	698	732	751	771
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DMB06	UDLPRM4BO	1,049	1,006	1,034	1,069
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DMB07	UDLPRM4S1	0	-	92	100
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DN101	UDLPCSCAP2	2,553	2,975	236	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DNB01	UDLPCM72D	359	11	1	1
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DNB03	UDLPCM71D	1	1	1	1
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DNB04	DLPCS1W007	25,414	29,157	29,266	29,400
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DNB05	UDLPCS3W	3,058	3,099	3,077	3,100
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DNB06	DLPCS1W022	41,474	36,868	36,507	36,600
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DS101	UDLPRM4WA1	644	110	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DS102	UDLPRM4WA2	10,075	2,516	70	2
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB01	UDLPLNW3	3,555	3	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB02	UDLPLWF7	4,753	388	(0)	0
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB03	UDLPRGST1	-	-	26,356	8,917
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB05	UDLPRM4WA3	-	690	748	72
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB06	UDLPRM4WA4	-	14	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB07	UDLPRM4WA5	-	-	5	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB09	UDLPRM8BT	-	12,933	71	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB10	UDLPRM8BU	3,415	105	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB11	UDLPRM8BY	6,640	68	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB13	UDLPRM41D	1	1	0	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB14	UDLPRM42D	109	-	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB15	UDLPRM4BA	409	404	399	400
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB16	UDLPRM4BCX	3,826	3,997	3,980	4,000
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB17	UDLPRM4BF	3,798	3,955	3,257	3,201
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB19	UDLPRM4BN	12,059	14,635	16,759	16,384
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB20	UDLPRM4BQX	1,215	1,708	1,698	1,700
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB21	UDLPRM4DJ	1,807	250	250	250
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB24	UDLPRM63D	1,917	1,998	1,995	2,000

Category	Line	PROJECT	WBS	Sum of Total 2019	Sum of Total 2020	Sum of Total 2021	Sum of Total 2022
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB25	UDLPRM9PD	690	71	587	794
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DSB26	UDLPRPLIC	4,958	9,594	5,382	9,583
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DZB01	UDLPCH0W	2,568	2,756	2,828	2,926
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QDB01	UDSPRD8SD	273	656	887	900
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QEB02	UDSPLM7WF3	-	-	-	9,513
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QEB03	UDSPLM7WF4	2,118	417	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QEB05	UDSPRD8AD2	-	-	-	40,860
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QEB07	UDSPLM722A	-	-	-	3,377
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QEB08	UDSPLM7W	268	199	199	200
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QEB09	UDSPRD8RN	865	445	397	205
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QMB01	UDSPRD71D	511	151	4	0
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QS101	DSPRD8AD14	2	-	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QS102	UDSPRD8RD1	-	10	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB01	UDSPLNW2	29,620	23	(0)	0
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB03	UDSPRD8AD1	-	7,391	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB07	DSPRD8AD13	1,099	208	(0)	0
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB12	UDSPRD8H	715	271	8	0
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB13	UDSPRD8JD	185	192	180	181
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB14	UDSPRD8KD	2,099	3,857	4,559	6,361
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB15	UDSPRD8RJ	569	44	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB16	UDSPRD8RK	181	11	(0)	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB18	UDSPRD8SD1	-	7	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB20	UDSPRD8VD	1	2,461	3,300	1,600
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB21	UDSPRD8Z	496	14	0	0
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB22	UDSPRD9GD	906	22,927	9,478	1,892
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB23	UDSPRD8AD	315	342	144	4
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB24	UDSPRD8BD	6	0	0	0
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB25	UDSPRD8D2	64	97	3	0
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB26	UDSPRD8ED	305	400	435	392
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB27	UDSPRD8FD	96	26	1	0
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB28	UDSPRD8FV	60	72	79	76
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB29	UDSPRD8LD	31	9	0	0
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB30	UDSPRD8SG	466	1,722	2,156	2,178
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB31	UDSPRD8TD	75	30	1	0
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB32	UDSPRD8UD	396	185	108	100
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB33	UDSPRD8WD	53	19	1	0
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB34	UDSPRD8YD	124	49	1	0
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DCB02	UDLPCMR2DX	2,625	2,495	2,760	2,851
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17DMB03	UDLPRM32DX	6,518	6,680	6,849	7,087
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QE102	UDSPRD8RO	-	368	32	(0)
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QEB01	UDSPLM720A	-	-	-	5,261
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB04	DSPRD8AD10	-	-	-	3,293
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB05	DSPRD8AD11	1,472	1,009	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB06	DSPRD8AD12	1	-	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC17QSB11	UDSPRD8AD9	-	1,379	3,329	292

Category	Line	PROJECT	WBS	Sum of Total 2019	Sum of Total 2020	Sum of Total 2021	Sum of Total 2022
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC17QSB17	UDSPRD8RM	-	362	38	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC17QSB19	UDSPRD8SD3	454	23	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC17QSB35	UDSPRD9D4	94	3	0	0
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC17QSB36	UDSPRD9D5	212	121	121	121
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC17DSB27	UDLPRM4SD1	143	125	124	125
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC17DSB28	UDLPRM4WJ	258	250	249	250
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC17DSB30	UDLPRM4WA9	1,263	2,989	3,476	3,499
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC17QEB10	UDSPRD8RW1	-	-	1,064	46
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC17QSB37	UDSPRD8Q1D	21	1	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC17DEB16	UDLPRM8BB	810	88	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC17QNB02	UDSPCCPP	2	-	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DN041	DLPCS6W016	(1,034)	-	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC17DS414	UDLPRM4BCX	6	-	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC17DM170	UDLPRM32DX	125	3	0	0
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC17DMB08	UDLPRM4BCX	325	9	0	0
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC17DSB33	UORPODRC01	56	22	20	20
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DN077	DLPCS6W044	956	57	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DN085	DLPCS6W034	505	24	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DN092	DLPCS6W040	524	44	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DN127	DLPCS1W041	1,323	32	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DN139	DLPCS6W038	1,170	40	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DS245	UDSPRD8ISS	-	644	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DS246	UDSPRD8LSS	-	695	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DS247	UDSPRD81S1	-	1,374	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DS248	UDSPRD8PS1	-	1,426	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DE090	UDLPLM7401	368	32	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DN152	DLPCS1W029	506	44	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DN154	DLPCS6W036	92	8	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DRB01	UDLPCSCPDC	564	661	641	640
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DSB06	UDLPRM4FC2	369	522	540	558
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18QS012	UDSPRD8TC1	1,225	104	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18QSB01	UDSPRD8CR1	67	3	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18QSB03	UDSPRD89S1	-	-	-	1,875
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18QSB04	UDSPRD8OS2	-	-	-	3,296
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC19DS001	UDLPRM4LRD	920	999	80	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DEB19	UDLPLM7D4A	367	33	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DNB06	DLPCS1W043	(9)	-	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DNB07	DLPCS1W052	450	-	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DNB08	DLPCS6W023	790	-	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DNB09	DLPCS1W051	120	10	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DSB07	UDLPRM4F02	1,604	146	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DSB08	UDLPRM4ER1	12,866	1,134	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18DSW01	UDSPSPDACR	4,217	1,291	83	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18SSB04	UDSPRD8DFP	557	48	-	-
Pepco Distribution - DC	OU:[Total Book Cash Closed (To Use)]	PC18SSB05	UDSPRD8PS9	825	72	-	-

Category	Line	PROJECT	WBS	Sum of Total 2019	Sum of Total 2020	Sum of Total 2021	Sum of Total 2022
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC18SSB06	UDSPRD8PS2	825	72	-	-
Pepco Distribution - DC	**OU:[Total Book Cash Closed (To Use)]**	PC18SSB07	UDSPRD8PS3	825	72	-	-
Pepco Distribution - DC Total				275,325	219,880	243,198	283,956
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	609IT04CT	CTA23P1001	-	4	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	CAPOHPEP	FAP1001	76	(0)	(0)	(0)
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	CXCP652TT	CTA23P1001	1	1	1	1
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17GIB01	UOIPO009	37	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17IDB01	UOIPRASRD	154	144	148	150
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RAB01	UOTPOMR1DX	435	211	198	200
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RDB01	UORPODA1D	762	480	245	201
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RDB02	UORPORBAD	30	30	30	48
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RDB03	UORPORCPD	260	77	30	30
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RDB04	UORPORNPD	675	598	653	592
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RF101	CMP334	-	-	40,196	833
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RF102	CMP335	-	-	2,969	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RFB01	CMP1143D	316	200	183	200
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RFB02	CMP114D	30	30	27	30
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RFB03	CMP120D	85	85	78	85
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RFB04	CMP130Z	862	956	1,015	962
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RFB05	CMP85D	21	21	19	21
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RTB02	UOFPOHS	-	-	-	155
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RTB03	UOFPOMV1	-	-	-	659
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RTB04	UOFPOF25D	79	184	200	200
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RTB05	UOFPOF32D	484	340	240	236
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RTB06	UOFPOF33D	344	370	381	1,492
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RTB07	UOFPOF3D	5	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RTB08	UORPOBR1D	85	104	100	100
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RTB09	UORPOR30D	49	53	53	53
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RTB10	UORPORBSB	62	94	100	100
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RTB11	UORPORBTB	982	286	8	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RTB12	UORPORVRD	46	50	50	50
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17GIB01	UOIPO002A	311	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17GIB02	UOIPO002A	311	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17GIB03	UOIPO009	528	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17IDB01	UOIPO2018	51	50	51	50
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17IDB02	UOIPRASRM	146	99	99	100
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17RAB02	UOTPOMR1MX	429	299	289	292
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17RDB01	UORPODA1Z	1,544	844	409	400
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17RDB02	UORPOMR	93	207	142	208
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17RDB03	UORPORBAZ	88	99	73	134
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17RDB04	UORPORCPM	2,016	1,569	1,160	1,166
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17RF101	CMP331	-	-	8,312	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17RFB01	CMP1143M	305	200	183	200
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17RFB02	CMP114M	45	45	41	45

Category	Line	PROJECT	WBS	Sum of Total 2019	Sum of Total 2020	Sum of Total 2021	Sum of Total 2022
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RFB03	CMP120M	125	125	115	125
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RFB04	CMP132Z	765	510	468	510
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RFB05	CMP85M	21	21	19	21
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RT101	UOFPOGV1	-	1,725	146	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RTB04	UOFPOPSN	345	10	0	0
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RTB05	UOFPOF25M	112	269	299	300
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RTB06	UOFPOF32M	648	344	240	236
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RTB07	UOFPOF33M	1,277	1,251	1,765	832
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RTB08	UOFPOF3M	11	0	0	0
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RTB10	UORPOBR1Z	202	206	200	200
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RTB11	UORPOR30M	45	50	50	50
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RTB12	UORPORBSR	64	160	185	141
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RTB13	UORPORBTZ	5,816	1,987	103	3
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RTB14	UORPORVRM	46	50	50	50
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RT102	UOFPOMT	1	-	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	PX16XFW01	CMP3ACR	(1,500)	-	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	PC17RTB13	UORPOAPRDC	21	20	20	2
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RAB01	CMP336	4,803	-	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RF102	CMP156	1,049	-	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RTB15	UORPOAPR	22	20	29	3
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RTB16	UORPOAPRF	22	20	29	3
Pepco General	OU:[Total Book Cash Closed (To Use)]	PX16XIW01	UOICOACCR	(30)	(4,507)	(4,762)	(6,829)
Pepco General	OU:[Total Book Cash Closed (To Use)]	CXEED234T	UOIPO036	-	2,345	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	ITHPWM06	PWMCAPP000	1,561	523	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	CXCP653TT	CTA23P1001	0	0	0	0
Pepco General	OU:[Total Book Cash Closed (To Use)]	PC17RGB01	UORPODCAMI	533	415	342	271
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17RGB01	UORPOPDAMI	514	473	345	305
Pepco General	OU:[Total Book Cash Closed (To Use)]	EED291P	UOIPO032	18,205	-	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	EWA340P	BSC35P1001	2	-	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	EWA342P	ITA35P1001	1	0	0	0
Pepco General	OU:[Total Book Cash Closed (To Use)]	EWA345P	LEG35P1001	60	-	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	ITSEC098E	BSC36P1001	2	0	0	0
Pepco General	OU:[Total Book Cash Closed (To Use)]	NERC935P	UOIPO028	1	-	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	PC17RFB06	CMP136	(51)	-	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	PHIPEC	BSC34P1001	1,089	1,216	1,041	931
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17IIB01	UOIPO024	0	-	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM17IIB02	UOIPO025	0	-	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM18RT020	UORPOTRM01	18	2	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM18RT021	UORPOTR301	18	2	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	PX107GEN	FINAP1001	66	2	0	0
Pepco General	OU:[Total Book Cash Closed (To Use)]	PX16RTW00	UORPOACR2	(115)	-	-	-
Pepco General	OU:[Total Book Cash Closed (To Use)]	RC929HP	UOIPO028	177	5	0	0
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM18RT012	UOFPOF32M	0	0	0	0
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM18RT007	UOFPOF32M	0	0	0	0
Pepco General	OU:[Total Book Cash Closed (To Use)]	PM18RT002	UOFPOF32M	1	0	0	0

Category	Line	PROJECT	WBS	Sum of Total 2019	Sum of Total 2020	Sum of Total 2021	Sum of Total 2022
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17IIB01	UOIPO023	5	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RF001	CMP332	11	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	CXEED235T	UOIPO036	64	2	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	EED352P	UOIPO031	0	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	SEC083P	BSC36P1001	2	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC18RT002	UOFPORTDC1	64	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RT010	UOFPOF32M	1	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RT015	UOFPOF32M	0	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RT006	UOFPOF32M	0	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RT008	UOFPOF32M	0	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RT009	UOFPOF32M	1	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RT001	UOFPOF32M	1	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RT003	UOFPOF32M	0	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	ITEWA351E	FIN35P1001	96	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	ITEWA353E	ITEWA353E	250	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	ITSEC113E	ITSEC113E	85	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	NERC941P	NERC941P	16	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RG103	UORPODCAMI	6	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17RD393	UORPODA1Z	82	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17RT395	UORPORBTZ	8	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM17RT399	UORPOBR1Z	0	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RTB01	UOFPORTMD1	2	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RT011	UOFPOF32M	1	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RT026	UORPONT01	(2)	(0)	(0)	(0)
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	EED360P	CUS24P1001	12	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	ITPEP053	ERT26P1001	0	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	ITPEP071	U01COBIDAC	10	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	ITPEP072	ITPEP073	16	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RT027	UORPOSOT01	(4)	(0)	(0)	(0)
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RT018	UOFPORTMD1	29	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC18RT009	UORPOAFB01	12	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RTB02	UOFPOGV1	1	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	ITPEP060	ITPEP061	11	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RGB01	UDLPCSEV1	3,375	4,523	2,716	2,235
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RG114	UORPODCAMI	3	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RG122	UORPODCAMI	4	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RG109	UORPODCAMI	2	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC18RTB01	UORPOLL02	20	1	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	ITPEP073	ITPEP074	14	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	ITPEP076	ITPEP077	6	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	ITPEP081	ITPEP082	11	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RTB03	UORPOLL01	98	3	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RG111	UORPODCAMI	0	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17RG113	UORPODCAMI	0	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RTB04	UOFPOMD01	36	92	82	163

Category	Line	PROJECT	WBS	Sum of Total 2019	Sum of Total 2020	Sum of Total 2021	Sum of Total 2022
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM19RFB01	CMP339	1,044	1,707	2,109	1,594
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM19RFB02	CMP341	471	373	74	216
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	ITEWA355E	ITEWA355E	17	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	ITSEC114E	ITSEC114E	9	0	0	0
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC17II102	UOIPO025	-	-	3,174	(0)
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	ITENT495E	ITENT495E	5	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PM18RT050	UORPOCTCT	18	2	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PC18RI001	UOIPO047	150	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PCIBHRDWR	BSC25P1001	1,809	2,003	2,031	2,003
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PCIBMDT	UOIPO009	90	100	102	100
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	PCIBPC	BSC25P1001	181	200	203	200
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	CTOUCOMHE	CTOUCOMHE	22	-	-	-
Pepco General	**OU:[Total Book Cash Closed (To Use)]**	CTOUCOMSE	CTOUCOMSE	-	69	-	-
Pepco General Total				55,865	24,054	68,861	12,657
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITHBPP06	BPPCAPP000	419	1,061	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITHCS06	CUSCAPP000	171	1,305	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITHOMG06	OMGCAPP000	-	516	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITHUC06	UCMCAPP000	420	10,915	193	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITHWMT06	WMTCAPP000	21	319	4,205	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITHMC06	MGCCAPP000	(780)	(295)	8,352	11,813
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITHNERC06	NRCCAPP000	-	510	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	CXEED232T	UOIPO036	-	-	5,668	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	EED368P	UOIPO046	-	457	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	EED285P	UOIPO044	303	-	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	EED290P	UOIPO032	-	-	1,863	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	EED295P	UOIPO038	-	3,529	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	EED301P	UOIPO025	-	-	-	9,429
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	EED318P	UOIPO043	573	-	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITPEP063	ITPEP064	583	-	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITHSS06	SUS59P1001	-	311	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITPEP047	CUS24P1001	363	-	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITPEP070	U01COBIDAC	875	-	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITPEP086	ITPEP087	-	-	130	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITPEP077	ITPEP078	-	-	-	2,965
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITPEP079	ITPEP080	62	-	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITHSMO06	SMO23P1001	164	-	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	PC17II104	UOIPO024	2,304	-	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	PC17II101	UOIPO023	177	-	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	ITHEP06	ENP24P1001	69	-	-	-
Pepco IT Projects	**OU:[Total Book Cash Closed (To Use)]**	PC18RIB01	BIDCAPP00W	-	-	-	232
Pepco IT Projects Total				5,724	18,629	20,412	24,439

IN THE MATTER OF THE APPLICATION OF POTOMAC ELECTRIC POWER COMPANY FOR AUTHORITY TO IMPLEMENT A MULTIYEAR RATE PLAN FOR ELECTRIC DISTRIBUTION SERVICE IN THE DISTRICT OF COLUMBIA	**)**	**Formal Case No. 1156**

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

VOLUME VI

DIRECT TESTIMONIES AND EXHIBITS OF

Mr. William Zarakas
Ms. Tammy D. Sanford
Mr. Phillip S. Barnett
Mr. William J. (Bill) Sullivan
Mr. Miguel A. Ortega

W.P. Zarakas
Direct Testimony
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (J)

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POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF WILLIAM P. ZARAKAS
FORMAL CASE NO. 1156

I. INTRODUCTION

Q1. Please state your name, title and professional qualifications.

A1. My name is William P. Zarakas. I am a Principal with The Brattle Group, an economics consulting firm. I lead much of Brattle's project work in the areas of performance based regulation, utility business models, benefit-cost analyses with respect to infrastructure deployments (notably for grid modernization, reliability, and resilience), and cost and pricing analyses.

I also work on economic and regulatory matters in the telecommunications industry, including the economics and financial feasibility of building out broadband infrastructure and regulatory matters concerning network access and pricing. I have recently testified on matters concerning the valuations of wireless spectrum, methodologies for the distribution of royalties and retransmission fees in the cable and satellite television industries and the economic impacts associated with mergers in the telecommunications and media industries.

I have provided testimony and expert reports before various state regulatory commissions, the Federal Energy Regulatory Commission, the Federal Communications Commission, the Securities and Exchange Commission, the Copyright Royalty Judges (Library of Congress), the U.S. Congress, arbitration panels, and courts of law. I have also authored reports concerning special investigations on

behalf of corporate boards of directors and audits of management practices and operational and financial performance on behalf of regulatory commissions.

I hold an M.A. in economics from New York University and a B.A., also in economics, from the State University of New York. I have authored articles in industry periodicals and journals on economic and regulatory matters. I have also taken and instructed courses on economic and regulatory matters. My curriculum vitae is provided in PEPCO (J)-1.

Q2. What is the purpose of your Direct Testimony?

A2. Potomac Electric Power Company (Pepco or the Company) requested that I summarize for the Commission the extent to which multiyear rate plans (MRPs) and performance incentive mechanisms (PIMs) have been adopted by regulatory commissions across the country. I will explain how Pepco's regulatory proposal fits in with other plans and regulatory mechanisms that are in place in jurisdictions across the country. I will also discuss the mechanics of MRPs and PIMs as well as incentives embedded in these mechanisms.

Q3. How is your testimony organized?

A3. My testimony is organized in five sections, including this introductory section. I provide my understanding of Pepco's operating environment and the policy goals that are in place in the District of Columbia. in Section II. I also provide a summary of Pepco's proposed regulatory plan in that section. I provide context for the use of multiyear rate plans in Section III. I discuss the use of performance incentive mechanisms in Section IV. I provide concluding comments in Section V.

Q4. Please provide some perspective on performance based regulation and alternative regulatory mechanisms.

A4. "Alternative regulatory mechanisms" are primarily adjuncts to traditional rate of return regulation that were developed primarily to address gaps in the traditional regulatory and rate case framework brought about by changing industry conditions. In its broadest sense, the scope of alternative regulatory mechanisms includes a wide range of mechanisms, including revenue decoupling and forecasted test years. Two frequently referenced alternative regulatory mechanisms – multiyear rate plans and performance incentive mechanisms – are generally considered to be incentive based or performance based regulatory mechanisms. The Brattle Group and other industry analysts have studied, categorized, detailed, and surveyed various alternative regulatory mechanisms in place in the U.S. and elsewhere in the world.

I use performance based ratemaking (PBR) as an umbrella term that covers MRPs and PIMs because these mechanisms explicitly reward or penalize a utility based on its performance, either broadly or narrowly.[1] Multiyear rate plans provide utilities with a broad-based incentive framework by extending the period between rate cases. Specifically, the multiyear framework provides an incentive for the utility to achieve cost efficiencies because it will be able to retain a portion of any enhanced earnings until the time of the next rate case. Performance incentive mechanisms are narrower in the scope than are MRPs but are performance based as they attach a reward and/or penalty to pre-specified metrics of utility performance.

[1] I am aware that "PBR" is sometimes used in a less comprehensive sense. For example, I am aware that some have used PBR and PIMs interchangeably and synonymously.

Pepco's proposed Performance Based Ratemaking plan includes the broad-based incentive mechanism embedded in an MRP and the narrowly focused performance incentives included in PIMs.

II. OVERVIEW OF PEPCO'S ENVIRONMENT AND PROPOSED REGULATORY PLAN

Q5. Please briefly describe the changing demands you see confronting Pepco now and in the near future in the District of Columbia.

A5. First, Pepco, as well as regulators and policymakers, expect that utility customers will increasingly be adopting distributed energy resources (DERs), which require that the grid is capable of effective DER integration.

Second, Pepco, along with many other utilities across the country, is being asked to make its grid more reliable and resilient.[2] The Commission is also asking Pepco to make its grid more sustainable, and has expressed that goal in the Commission's Modernizing the Energy Delivery System for Increased Sustainability (MEDSIS) proceeding. Improvements in reliability and resilience, as well as initiatives to make the grid more sustainable, require investments in various levels of grid modernization.

Third, Pepco will play a significant role in being able to achieve the goals of the Clean Energy DC Omnibus Act of 2018 ("Clean Energy Act"). The objectives of the Clean Energy Act include enhancements to energy efficiency and demand response programs as well as development and administration of electric vehicle promotional

[2] I refer to "reliability" as the voltage, stability, and continuity of service on a day-to-day level. I refer to "resilience" as hardening assets and making the grid smarter so that it can come back from outages due to extreme and unavoidable events (such as major storms) quickly and efficiently.

programs. The Clean Energy Act also calls for public transportation and privately-owned fleet vehicles to reach zero-emission levels by 2045. Pepco will have a vital role in meeting these goals.

The investments Pepco needs to make and the steps it needs to take are addressed further in the testimony of Company witnesses.

Q6. How do these demands affect Pepco's regulated revenue needs?

A6. In the immediate term, Pepco will need to make investments in its grid and incur other costs in order to meet the objectives of MEDSIS, the Clean Energy Act, and other goals concerning grid reliability and resilience. In addition, Pepco's customers are starting to acquire and use electricity through a portfolio of supply and demand options, not just from the utility. This means that some customers are shifting from full requirements (i.e., all electricity consumed coming through the grid) to partial requirements, in which a portion of electricity is self-generated, which has consequences for Pepco's business model going forward.

The combination of new capital and operating expenditures, combined with changing sales patterns, will mean that revenue requirements going forward will be different than historical levels. In other words, rates based on an historic test year will most likely lag behind actually incurred revenue requirements. From a practical standpoint, absent a change in its regulatory plan, Pepco would probably need to continue to file rate cases frequently in order to avoid being behind in its revenue recovery.

Q7. Please describe Pepco's regulatory plan proposal.

A7. Pepco's (PBR) proposal includes two primary components: an MRP and an accompanying PIM plan.

Pepco proposes that the MRP component of its plan will span three years, 2020, 2021, and 2022. Under this plan, rates will be initially set as part of a general rate case and then adjusted annually, based on projected test year revenue requirements made at the time of the initial rate case.

Pepco's proposed MRP also includes an annual reconciliation mechanism. The annual reconciliation is structured such that adjustments that share overearnings with customers are "automatic," while rate adjustments due to falling below the target ROE require a request from Pepco and explicit review and approval from the Commission. Pepco has proposed to use a deadband of +/- 25 basis points around the target ROE for each MRP term year. If Pepco's earned ROE for the prior year exceeds the upper bound of the deadband, then 75% of the overearnings are returned to customers. On the other hand, if Pepco's earned ROE is below the lower bound of the deadband, the proposed plan allows Pepco the opportunity to provide the Commission with the reasons for this deviation and to request rate adjustments to bring the Company's ROE to 75% of the difference between the lower end of the deadband and its earned ROE.

The PIM component of Pepco's proposed regulatory plan includes five PIMs: two reliability PIMs (SAIDI and SAIFI), two customer service PIMs (customer service level and call abandonment), and one PIM related to distributed energy resource (DER)

interconnection review. Pepco's proposed PIM plan includes reward and penalty components as incentives for each PIM.[3]

Q8. Is Pepco's proposed PBR plan consistent with the Commission's Order No. 18846?

A8. Yes, I believe that it is. In its order, the Commission indicated that it would consider regulatory plans that applied fully forecasted test year and/or MRP methodologies. The Commission also noted that MRPs are frequently accompanied by PIMs and that it would allow Pepco to propose a PIM plan if Pepco found it should be considered in an environment of growing DERs. Pepco's proposed PBR plan is composed of an MRP (using fully forecasted test years) and PIMs (including a PIM covering interconnection of DERs).

I understand that Pepco opted to propose an MRP rather than propose using a single fully forecasted test year because a single-test-year approach limits the duration of the solution. In other words, a fully forecasted test year may more closely match revenue requirements with actually incurred costs for the upcoming year, but mismatches may occur in subsequent years. In contrast, an MRP resolves the need for Pepco to file rate cases over the duration of its proposed PBR plan.

III. MULTIYEAR RATE PLANS

Q9. Are multiyear rate plans and forecasted test years widely applied in the U.S.?

A9. Yes, and, in addition, these mechanisms are frequently used in combination with one another. For example, it is not unusual for a regulatory plan to include an MRP using two or more forecasted test years and performance incentive mechanisms (PIMs). A

[3] Pepco is proposing an additional tracking metric, customers experiencing four or more interruptions (CEMI-4). I understand that Pepco may propose to include CEMI-4 as a PIM in the future.

recent report indicates that MRPs for utilities are in place in 17 states (14 of which apply to electric utilities) and forecasted test years are used in 24 states.[4] In addition, PIMs, another component in Pepco's proposed plan, are in place in 16 states.[5]

Q10. How prevalent are multiyear rate plans in the U.S.?

A10. Overall, it is fair to say that MRPs are part of the regulatory mainstream. As I indicated earlier, a recent survey shows that MRPs are in place for electric utilities in 14 states.[6] I note here that counting the incidence of MRPs is more challenging than it may first meet the eye for several reasons. For one, states are frequently served by multiple utilities, each of which may be regulated with a different mix of mechanisms. Most surveys note the criteria for classifying a state as having MRPs or not, but these are not necessarily consistent across surveys. Another reason for discrepancies among counts is that MRPs are not always continuously applied. For example, Consolidated Edison is generally regulated under an MRP approach, but its electric business was under a single year rate case plan for a short time in early 2015 and was excluded from the count of electric utilities with MRPs for that year.

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[4] Edison Electric Institute, Alternative Regulation for Emerging Utility Challenges: 2015 Update, prepared by Pacific Economics Group, November 11, 2015 (EEI 2015 Update). The count of future test years, as of 2015, includes states identified by the report as having fully forecasted test years either "commonly" or "occasionally" used across gas and electric utilities. The count of states with multiyear rate plans, as of 2015, includes both gas and electric utilities.

[5] O'Neil Management Consulting LLC, "Recommendations for Strengthening the Massachusetts Department of Public Utilities Service Quality Standards," December 13, 2012.

[6] This count includes all states that have a multiyear rate plan in place for an electric utility. The remaining three states, of the 17 cited previously, only have multiyear rate plans for gas utilities. See EEI 2015 Update.

Q11. How are rates adjusted during the term of a multiyear rate plan?

A11. MRPs typically allow for annual adjustments of rates or revenues via some type of pre-determined mechanism.[7] One form of annual rate adjustment is the "stair-step" approach, under which rates for the term of MRP are based on forecasts of revenue requirements, typically based on a series of forecasted test years. Under this approach, a three-year MRP may be based on three future test years; rates are then prescribed for each of the years within the scope of the MRP.[8]

A second form of adjustment is the "I-X" approach, where "I" is the rate of inflation and "X" is a productivity factor. MRPs under this approach typically start with revenue requirements and rates based on a single test year. Rates, or revenues, are then escalated in the following years by way of the I-X formula.[9] This approach to annual rate adjustments is more prevalent in the U.K., Australia, and Canada than it is in the U.S.

In practice, rate adjustments under the I-X framework may not be that much different than adjustments under a stair-step approach.[10] This is because the I-X formula is frequently supplemented with additional adjustment factors, such as the "Z" factor (covering exogenous and other events) and the "K" factor (covering changes in

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[7] These adjustments are sometimes referred to as Attrition Relief Mechanisms (ARMs). See, e.g., EEI 2015 Update.

[8] Additional modification may be made to smooth out erratic stairsteps. For example, Consolidated Edison's recent multiyear rate plan used a "levelized" stair-step ARM to avoid rate shock in the first year. See State of New York Public Service Commission, Order Approving Electric and Gas Rate Plans, Docket No. 16-E-0060, January 25, 2017, pp.4-5, 19.

[9] Annual adjustments using an I-X approach tend to be relatively smooth on a year-to-year basis, although they may not be completely linear as the inflation or productivity terms may be projected to change on a year-to-year basis.

[10] I have not conducted a study comparing adjustments under stair-step versus I-X approaches, nor I am aware of such studies conducted by others.

capital spending levels) as well as other adjustment factors. Thus, it is possible that prices yielded under an I-X framework may be more aligned with utility costs than may first appear.

A 2015 survey of U.S. electric utilities regulated under an MRP approach indicates that eight states use stair-step annual adjustments, one uses the I-X approach (for one major electric utility under its jurisdiction but uses a stair-step approach for the others), and one uses a hybrid approach.[11] The remaining five states that apply multiyear rate frameworks to electric utilities use trackers and other alternative regulatory mechanisms to adjust rates annually.

Q12. What are the reasons states cite for adopting multiyear rate plans?

A12. There are a number of reasons, but two main motivations are reducing the frequency of full rate cases and improving cost control incentives. However, it is important to keep in mind that each state regulatory commission has its own unique motivations for adopting its regulatory framework, which may include additional factors.

Q13. Why have multiyear rate plans been adopted as a means of reducing the frequency of rate case filings?

A13. When utilities are operating in an environment characterized by increasing costs and declining sales growth, there is a strong possibility of negative regulatory lag,

[11] The survey cites California, Florida, Georgia, Iowa, North Dakota, New Hampshire, New York, and Washington with stair-step ARMs for at least one electric utility. California uses an I-X approach to regulate some but not all of its electric utilities. Hawaii uses a revenue cap hybrid approach, which is currently under review. The remaining five states (in the 14 state count referenced earlier in my testimony with regard to states with electric companies under a multiyear rate plan) that have been designated as states with multiyear rate plans in the EEI survey have combinations of rate freezes, trackers, and/or other alternative regulatory mechanisms in place for a designated multiyear term. See EEI 2015 Update.

which can result in utilities filing frequent rate cases to "catch up." Many MRPs have been adopted mainly as a way to manage and reduce the frequency of rate cases. For example, regulators in California and New York have adopted the MRP approach for all of the utilities under their jurisdictions and have established general rate case cycles.

Similar reasoning also appears to have been the case in Washington state and New Hampshire. The Washington Utilities and Transportation Commission cited the need to relieve Commission staff and stakeholders "from the burdens of almost continuous general rate case proceedings" when it approved a multiyear rate plan for Puget Sound Energy that was in place from 2013 to 2016.[12] Likewise, in approving the 2010 to 2015 MRP for the Public Service Company of New Hampshire, the Public Utilities Commission noted that the plan "provides for a series of rate increases intended, among other things, to ensure that the erosion of earnings attributable to attrition will not compel the Company to seek another rate increase in a short time."[13]

Q14. Please describe the circumstances in which multiyear rate plans have been adopted as a means of enhancing cost control incentives.

A14. A second frequently cited motivation for the adoption of MRPs concerns incentives for utilities to control costs or otherwise strive to achieve cost efficiencies. The rate regulation of utilities is largely based on costs, but it is not a purely cost-plus methodology. Rates (and expected revenues and earnings) are initially set in a rate case based on costs but are not updated on an ongoing basis to reflect actually incurred costs until the next rate case. If a utility improves its operating efficiencies (in the period

[12] Washington Utilities and Transportation Commission, Order 07, Docket Nos. UE-121697 and UG-121705 (consolidated) and Docket Nos. UE-130137 and UG-130138 (consolidated), June 25, 2013, p.8.

[13] State of New Hampshire Public Utilities Commission, Order No. 25,123, Docket No. DE 09-035, June 28, 2010, p.41.

following a rate case), it can retain the increase in its earnings until the next rate case as a result of regulatory lag. By extending the time between rate cases, multiyear rate plans provide a greater incentive for the utility to reduce costs due to its ability to retain the increased earnings over a longer time period. At the time of the next rate case, the resulting cost efficiencies are passed onto customers in the form of a lower revenue requirement. Also, however, the converse is true as well: if it incurs costs that are higher than those used in setting rates, it will earn less than the authorized level of return due to regulatory lag.

Q15. Do multiyear rate plans typically include other notable provisions?

A15. Yes. MRPs frequently include a "re-opener" provision. Utilities, regulators, consumer advocates, and other interested parties are typically hesitant to agree to an open-ended commitment to an MRP because unforeseen circumstances may cause utility earnings to be significantly higher or lower than authorized levels. The most common specified trigger for review or termination concerns returns falling below specified levels. Re-opener provisions, sometimes also referred to as "off-ramps" or "exit-ramps," can also be more general and unspecified, in recognition that unforeseen factors (e.g., changes in tax laws or interest rates) may necessitate review, plan changes, and/or termination of a plan.

Q16. Are annual reconciliations frequently used in multiyear rate plans?

A16. Yes, they are in place in 10 of the 14 states that apply MRPs to electric utilities – although there is no single approach that it universally applied.[14]

[14] Annual reconciliation mechanisms are also referred to as earning sharing provisions. This count includes all of the states that have earning sharing mechanisms within electric sector MRPs. See EEI 2015 Update.

The MRPs in four states (Arizona, applied to Arizona Public Service; California, applied to Pacific Gas & Electric, PacifiCorp, San Diego Gas & Electric, Bear Valley Electric Service, and California Pacific Electric; Florida, applied to Florida Power & Light, Gulf Power, Duke Energy Florida, and Tampa Electric; and, Virginia, applied to Virginia Electric Power and Appalachian Power) do not include any annual adjustment mechanisms, irrespective of utility over or under earnings. That is, the subject utilities retain over earnings and under earnings.

Annual reconciliations that are made in the case of utility over earnings (but not under earnings) are in place in 10 states.[15] While subject to Commission review, earnings above specified levels are "automatically" passed back to customers in whole or in part.[16] One of these states, Hawaii, is currently engaged in a proceeding investigating performance based regulation. Commission Staff there has proposed to include a symmetric earnings sharing (for both over and under earnings) mechanism for the next round of MRPs in Hawaii.[17]

One state, Georgia, in applying an MRP to Georgia Power, has an annual reconciliation in the case of utility over earning and includes a provision under which the utility can request a tariff change to bring the utility back to the lower end of the allowable ROE range if its earnings falls below the plan's allowable band.[18]

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[15] These states include Colorado, Georgia, Hawaii, Iowa, Louisiana, North Dakota, New Hampshire, New York, Ohio, and Washington. See EEI 2015 Update.

[16] These plans include several different types of earnings sharing arrangements, including some that have tiers of earnings with a different sharing percentage assigned to each tier.

[17] Hawaii Public Utilities Commission, "Staff Proposal for Updated Performance-Based Regulations: Proceeding to Investigate Performance-Based Regulation (2018-0088), February 7, 2019, pp.28-29.

[18] Georgia Public Service Commission, Order Adopting Settlement Agreement, Document No. 151108, Docket No. 36989, December 23, 2013, p.5.

The annual reconciliation mechanism included in Pepco's proposed MRP includes an automatic sharing with customers when the utility earns more than the authorized ROE plus the deadband amount of 25 basis points. This is similar to the reconciliation approaches in the 10 states referenced above. Pepco's proposed plan also includes the possibility of a rate adjustment when its ROE falls below the target level less 25 basis points but, in this case, any rate adjustment is subject to request and review by the Commission, as described in detail by Company Witness Wolverton. This is similar to Georgia, which includes a request and petition approach in its MRP.

Including this option also provides an alternative to invoking a re-opener provision and undoing the goal of reducing the frequency of rate cases. Using fully forecasted test years in the MRP should mitigate much of the concern about revenue recovery not keeping up with incurred cost. However, unforeseen circumstances – costs, sales, and/or other events – can have a material impact on earnings. Including an under earning annual reconciliation option provides a reasonable way to mitigate this outcome and preserve the goal of reducing ongoing rate case filings.

Q17. Does the proposed annual reconciliation mechanism duplicate the adjustments made through Pepco's Bill Stabilization Adjustment?

A17. No, Pepco's BSA is a decoupling mechanism that removes the link between sales volumes (kWh) and utility revenues. Such a mechanism removes the incentive for Pepco to pursue increased sales; i.e., it removes the throughput incentive. The BSA sets a dollar per customer revenue target to recover the distribution portion of the revenue requirement and refunds and surcharges customers for over and undercollection (relative to the target). However, the BSA does not adjust under or

over earnings due to the misalignment of revenue requirements and actually incurred costs. Pepco's proposed annual reconciliation mechanism addresses this matter. Under Pepco's proposed MRP, an annual reconciliation is triggered when utility earnings are above or below the target ROE plus/minus 25 basis points. As indicated earlier, the reconciliation is automatic in the case of over-earning and is implemented via a request/approval process in the case of utility under-earning.

Q18. How could a multiyear rate plan approach benefit Pepco's stakeholders?

A18. As discussed in the direct testimony of Company Witness McGowan, Pepco's proposed multiyear approach supports the Company's initiatives concerning upgrading its grid and advancing the objectives established in MEDSIS and the Clean Energy Act. Company Witness McGowan also indicated that customers have benefited from improved service levels (as measured by higher levels of system reliability, customer satisfaction and safety) and new information content.[19] Similarly, additional upgrades and enhancements to grid functionality are necessary in order to transition Pepco into a "utility of the future;" that is, one that provides enhanced levels of customer engagement and participation in energy markets (e.g., peer-to-peer energy transactions) and management of distributed energy resources that are connected to the grid.

It also leads to more gradual and deterministic rate increases for customers, which are valued by some customers, and enables them to make more informed decisions about potential investments in energy efficiency, distributed energy resources and/or other technologies or options. In addition, the proposed multiyear approach

[19] Such informational content has been enabled through Pepco's deployment of automated metering infrastructure (AMI). AMI provides customers with access to information about their energy usage (via the MyAccount portal). It also enables more efficient grid operations and maintenance (e.g., remote connect/disconnect and outage detection).

better aligns incurred costs with revenue recovery and introduces transparency with respect to Pepco's plans and cost projections.

Finally, a benefit of the multiyear rate plan approach is the reduction in the frequency of rate cases. This saves participating parties the cost associated with filings, reviews, hearings, and, perhaps more importantly, frees up time and resources to examine and advance other goals and initiatives.

Q19. What is your opinion of Pepco's proposed annual adjustment mechanism?

A19. I think that Pepco's proposal to use a stair-step approach in its MRP is reasonable and appropriate and in line with the majority of state regulatory commissions that apply MRPs to electric utilities. As explained by Company Witness Wolverton, Pepco will use its Long Range Plan (LRP) and forecasted budget as the basis for projecting the capital accounts and operations and maintenance expenses, respectively, in the forecasted test years. This approach serves to match utility costs and revenue in a transparent manner (i.e., allowing parties to the enabling rate case to review capital and operating forecasts). It also preserves the incentives for cost control that are embedded in MRPs by setting rates based on realistic utility-specific forecasts and providing for the possibility of a reward if the utility is able to outperform forecasts.

IV. PERFORMANCE INCENTIVE MECHANISMS

Q20. How, in general, do Performance Incentive Mechanisms work in the regulatory environment?

A20. Performance Incentive Mechanisms (PIMs) refer to the assignment of financial rewards and/or penalties to specific areas of utility performance and/or policy

outcomes.[20] PIMs can be applied within any regulatory framework and are frequently applied in conjunction with MRPs, either to act as a counterweight to the incentives to control costs or to provide incentives for utilities to advance policy goals.

I have classified the various PIMs that are in place in the U.S. into two main categories: "traditional" and "emerging." Traditional PIMs reflect standard measures of utility operations, notably system reliability, customer service, and safety. Many of these measures have typically been tracked by utilities and regulators for some time and are well known to nearly all parties that participate in utility regulatory proceedings. However, they are only considered to be PIMs when financial incentives (in the form of rewards, penalties or both) are attached. Many of these PIMs have been in place for decades.

The PIM concept – adding rewards and/or penalties to performance measures as a way to incentivize utilities to pursue specified goals – has received renewed attention in recent years as new and sometimes challenging goals have been introduced by regulators and policymakers. "Emerging" PIMs refer to a more recent version of PIMs that address policy goals, such as emission reductions and DER interconnections. These emerging PIMs are used to incentivize utilities to pursue activities beyond their core functions and/or pursue activities or initiatives that may be otherwise contrary to optimizing their financial performance. A well-known set of emerging PIMs have been developed in New York and are referred to as earnings adjustment mechanisms

[20] An overall plan concerning such performance incentives is generally referred to as a "PIMs plan." Individual measures (and targets) are also sometimes referred to as a PIM; e.g., a SAIDI PIM.

(EAMs).[21] These PIMs set targets and provide incentives with respect to DER utilization, peak reduction, and energy efficiency, among other measures.[22]

Q21. Please describe the structure of performance incentive mechanisms.

A21. The design for PIMs typically includes four key components. First, a PIM requires the specification of a performance measure, such as SAIDI (for system reliability). The performance measure is ideally readily quantifiable and outcome-based (e.g., minutes of service interruption).

Second, a target, defining the expected level of performance, is required for each PIM measure. Ideally, the target level should balance the relevant benefits and costs associated with achieving the desired level of performance. Targets for PIMs should be set such that a utility can realistically achieve the desired performance level, even if it requires a "stretch." If the target is too stringent (or too easily achieved), it does not provide an incentive for the utility. Typically, a utility's past performance is taken into account when setting a PIM's target.

Third, PIMs can include a deadband, or a neutral zone, in which no financial incentive is applied. The use of a deadband reflects the variability of factors associated with achieving the target performance level and avoids the need for financial rewards or penalties to be applied on an annual basis due to small variances in performance. If the deadband is overly tight, then the utility may be rewarded (or penalized) for

[21] The New York Public Service Commission believes that the EAMs are a transition to fundamentally different business models. See State of New York Public Service Commission, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework, Case 14-M-0101, May 19, 2016, p.60.

[22] See Con Edison 2018 Energy Efficiency Earnings Adjustment Mechanism Achievement Report, April 1, 2019 and Consolidated Edison, Re: Case 16-E-0060 – 2018 Distributed Generation Interconnection Earnings Adjustment Mechanism Report, April 1, 2019.

circumstances beyond its control. Deadbands are typically set based on assessments of reasonableness or based on statistical variation of a utility's past performance.

Fourth, PIMs include a financial incentive structure that specifies the level of reward/penalty and how the reward/penalty is applied. Financial incentive structures may include rewards, penalties, or both. The financial incentive structure for a PIM may also include an incentive formula, which determines the level of incentive applied. Incentive formulas may reflect a maximum incentive that is applied whenever the measure is outside the deadband or may be graduated, such that a financial incentive is applied at an increasing level beyond the target to some maximum level.

The amount of incentive included in a PIM plan varies considerably across jurisdictions. Review of several PIM plans in place in the U.S. indicates that the maximum penalty amount for PIMs range from less than 40 basis points (Commonwealth Edison in Illinois) to more than 150 basis points (Consolidated Edison in New York). While rewards for PIMs are less common than penalties, the rewards levels can be sizable and within the range of PIM penalties. For example, in New York, the maximum allowable reward for the EAMs (emerging PIMs) was set to 100 bps.

Q22. What is the appropriate scope for a PIM plan?

A22. There is no standard for the number of PIMs that should be included in a plan, or whether PIMs should be set at aggregate or disaggregate levels, but it is a reasonable recommendation that PIMs plans should start off at a simple and manageable level. This means that it is reasonable for a new PIMs plan to include a few PIMs specified at the system-wide level, rather than being made up of numerous disaggregated measures. A review of various PIMs plans indicates that the more detailed and

expansive plans (e.g., plans that include many performance measures broken down by geographic region) have evolved over time (e.g., Consolidated Edison). More detailed break downs can evolve as interested parties gain experience with PIMs and identify areas that are not sufficiently covered in aggregate measures. Experience with emerging PIMs is more limited but, here too, starting simply appears to be the informal rule.

Q23. Are rewards and penalties typically included in PIMs?

A23. Not always. In practice, penalties (and not rewards) tend to be attached to traditional PIMs, and rewards (usually without penalties) tend to be attached to emerging PIMs and other policy goal-related PIM-like measures (e.g., energy efficiency). I have not found definitive reasoning for why Commissions chose to attach a reward or penalty to specific PIMs, but a logical explanation may be found in underlying assumptions concerning the perceived marginal costs and marginal benefits associated with the PIM areas.[23] A penalty-only design for incentives can be justified if the targeted performance level for a subject PIM is at the point where regulators believe that perceived marginal cost roughly equals marginal benefits. This means that utilities should make expenditures to meet this level in order to satisfy customers but that customers do not place additional value (benefit) on higher levels of service.

[23] Unfortunately, quantification of marginal costs and marginal benefits of specific aspects of service delivery are not always readily reported or apparent. Thus, in this discussion, I refer to "perceived marginal costs and marginal benefits." Some utilities and regulators have considered the value of lost load (VOLL) as an indicator of benefit when conducting benefit-cost analyses of incremental investments in reliability. However, absent strong indicators to the contrary, some regulators and utilities view current levels of service as representative of marginal cost/marginal benefit equilibrium. This is not an unreasonable assumption considering that current levels of reliability and customer service have evolved over time and reflect interventions by the utility, regulators, and a range of affected parties.

Following from this, it is reasonable for regulators to include rewards in the incentive structure for traditional PIMs if they value enhanced levels of, for example reliability and/or customer service.[24] For example, the California Public Utilities Commission (CPUC) opted to include both rewards and penalties in the reliability PIMs for San Diego Gas & Electric. The CPUC found it ineffective to adopt a PIMs plan characterized by "unbalanced incentives" and found that "without rewards for marked improvement there is a lesser likelihood that the company will strive to exceed the target and only minimize the risk of penalty."[25] Including rewards in the incentive structure for traditional PIMs may be relevant going forward, as policy goals such as those included in MEDSIS, indicate that higher levels of reliability and resilience are increasingly important to consumers.

The incentive structure applied to emerging PIMs is primarily based on rewards. Regulators appear to have concluded that customers (and society) benefit from the achievement of certain policy goals, such as the integration of DERs into utility distribution systems. That is, the marginal benefits of achieving these goals are perceived as greater than the marginal costs that would need to be incurred in order to get there – leading to a reward-based incentive.

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[24] There are also other arguments for taking a symmetric approach to PIM incentives. Regulatory guidelines typically emphasize the importance of providing utilities with a reasonable opportunity to earn the authorized rate of return, sometimes referred to as a fair return standard. In other words, the chance that a utility will realize financially favorable outcomes (i.e., earning at the authorized level) should be roughly equal to its probability of realizing an unfavorable one (i.e., earning below the authorized level). It can be argued that a penalty-only PIM (i.e., an asymmetrical incentive) results in a higher probability that a utility will earn a rate of return that is lower than its authorized rate of return, thereby conflicting with the fair return standard.

[25] California Public Utilities Commission, Decision 08-07-046, Application 06-12-009, July 31, 2008, p. 56.

Q24. What PIMs does Pepco propose to include as part of its PBR Proposal?

A24. Pepco's proposal includes five PIMs in total. Four of these are traditional PIMs. Two of these cover measures of reliability performance: system-wide SAIDI and system-wide SAIFI.[26] Two of the proposed PIMs cover areas of customer service performance: service level (which measures the percentage of calls that are answered within 30 seconds) and call abandonment rate (which measures the percentage of calls that are dropped).[27] One of the proposed PIMs falls into the emerging PIM category and covers the time elapsed in review of applications for interconnection of distributed energy resources. This measure is referred to as Approval to Install (ATI).

Pepco is currently required to adhere to standards for the five performance areas that it is proposing to include in its PIM framework. Standards for Pepco's performance with respect to reliability and customer service measures are set under the Commission's EQSS. In addition, the 2016 agreement in which the Commission approved the merger between Pepco Holdings and Exelon set reliability standards that are stricter than those under the EQSS; these remain in effect through 2020.[28] The Commission also has set standards for the Approval to Install time under Order 19795.[29]

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[26] SAIDI stands for System Average Interruption Duration Index. SAIFI stands for System Average Interruption Frequency Index.

[27] Electricity Quality of Service Standards (EQSS) defines an abandon call as, "a call received from a customer that a customer terminates after the customer selects the menu option and is placed in the queue, but before the call is answered by the utility customer representative or any other automated response system."

[28] The Commission established performance commitments including SAIDI and SAIFI in Conditions 54, 55, and 56 of the 2016 merger agreement.

[29] Public Service Commission of the District of Columbia, Order No. 19795, RM40-2017-01 and Formal Case No. 1050, January 9, 2019.

Pepco is proposing to incorporate PIMs into its PBR plan with which the Commission and stakeholders are already familiar. All of the proposed PIMs are also "outcome-based," which means that performance levels can be directly measured and compared to performance targets.[30] This should lessen ambiguities about measurement and provide a historical benchmark for performance.

Q25. How does the portfolio of PIMs proposed by Pepco compare to other such plans in place elsewhere in the U.S.?

A25. The traditional PIMs proposed by Pepco cover reliability and customer service, areas typically included in PIM plans that have been applied elsewhere in the country. Also, PIMs covering DER interconnection time (i.e., PIMs similar to Pepco's Approval to Install PIM) are notable among emerging PIMs, mainly because of the importance that many policy makers and regulators have placed upon the integration of renewable distributed resources. PIMs that address DER interconnection are included in the Staff Proposal for Updated Performance-Based Regulations in Hawaii.[31]

Q26. What is the basis for the PIM targets that Pepco is proposing?

A26. Pepco has proposed that it set PIM targets for its proposed SAIFI and Approval to Install PIMs based on existing standards. For SAIDI, service level, and call abandonment, Pepco has been outperforming the existing Commission standards and is proposing to set targets at higher performance levels. For SAIDI, Pepco proposes to set the PIM target at the average of the three best-performing recent years' SAIDI,

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[30] SAIDI is an example of an "outcome-based" PIM because it is reported in measurable units (minutes of outage). In contrast, some PIMs are "process based" and are typically measured in terms of level of activity or effort (e.g., number of stakeholder workshops held).

[31] Staff Proposal for Updated Performance-Based Regulations, Proceeding to Investigate Performance-Based Regulation (2018-0088), Hawaii Public Utilities Commission, February 7, 2019.

which reflect a higher level of reliability (lower duration of outages) than specified under either EQSS or the 2016 merger agreement.[32] Pepco also proposes to raise the targets for service level from 70% (included in the current standards) to 90% call answering within 30 seconds, and lower the target for call abandonment from 10% to 1.5%. Company Witnesses Clark and Poncia provide further explanation behind Pepco's determination of its proposed PIMs targets.

Q27. Please provide context for Pepco's proposed Approval to Install PIM.

A27. Pepco has proposed to include a PIM that covers the average time for it to review and approve (or decline) requests for DER interconnection. DER interconnection is viewed as an important part of the integration of renewable and local energy resources into the grid and participation in wholesale power markets, in general. DER integration and interconnection are tied into the District of Columbia's solar generation-related policy goals.[33]

Utilities have been criticized by DER developers and/or installers that the review cycle for approving DERs tying into the electricity grid takes too long and, effectively, slows down deployment of DERs. Pepco's proposed Approval to Install PIM sets a target for acceptable timeline for review of DER interconnection requests equal to five days on average (across all requests). As indicated above, this target was set based on the current standard set by the Commission.[34]

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[32] These years are 2014 (96 minutes), 2017 (58 minutes), and 2018 (52 minutes). Pepco's SAIDI scores in 2015 and 2016 were higher at 112 minutes and 115 minutes.

[33] The Council of the District of Columbia's recent passage of the Clean Energy DC Omnibus Amendment Act of 2018 increases the District's Renewable Portfolio Standard to 100% by 2032 and establishes an increasing solar energy standard that must be met by solar generation within the District and that reaches 10% by 2041. Timely DER interconnections to the grid will be important in achieving both of these goals.

[34] Public Service Commission of the District of Columbia, Order No. 19795, RM40-2017-01 and Formal Case No. 1050, January 9, 2019.

Q28. Please describe the incentive that Pepco proposes to apply to its PIMs.

A28. Pepco has attached rewards and penalties to each of its proposed PIMs, with total annual penalties and rewards capped at 25 basis points. The sum of possible penalties equals 30 basis points (20 basis points for reliability, five basis points for customer service and five basis points for Approval to Install) and the sum of possible rewards equals 35 basis points (20 basis points for reliability, five basis points for customer service and 10 basis points for Approval to Install).[35] Capping PIMs penalties and/or rewards places a limit on the annual level of financial impact from a PIMs plan and has been used by the California Public Utilities Commission.[36]

Q29. What is your view of Pepco's proposed PIM incentive structure?

A29. Including rewards and penalties as incentives for Pepco's proposed Approval to Install PIM is in line with the incentive structure applied to emerging PIMs elsewhere in the U.S. and may be considered "conservative" in comparison to the incentive structure applied to emerging PIMs in New York, which uses a rewards-only approach. Pepco's proposal to include rewards and penalties as incentives with respect to the four traditional PIMs is less mainstream but has merit nonetheless. Specifically, including rewards in a PIM incentive structure is reasonable and appropriate if the Commission and customers value higher levels of service quality than has historically been the case. Pepco's Company Witness Clark has indicated that the requirement for reaching reward levels (i.e., target plus relevant half of deadband) represents service levels that are

[35] If the total penalties or rewards earned by Pepco across the individual PIMs exceeds 25 basis points, the total penalty (or reward) will be capped to a maximum of 25 basis points.

[36] SDG&E, Preliminary Statement, CPUC Sheet No. 30687-E, "Electric Distribution & Gas Performance Based Ratemaking (PBR) Mechanism," effective June 28, 2018.

achievable but involve a stretch beyond current standards and/or best historical averages.

V. CONCLUSION

Q30. Please provide your concluding comments concerning Pepco's PBR Proposal.

A30. Pepco's proposed multiyear rate plan and performance incentive mechanisms are both in the regulatory mainstream and are generally accepted by industry analysts and industry participants. The annual rate adjustments under Pepco's proposed MRP are based on a stair-step approach that uses Pepco forecasts that will be made available to the Commission and participating parties for review.

In addition, Pepco's proposed annual reconciliation mechanism provides for adjustment in the case of utility over and under earning. The inclusion of a deadband in the proposed plan mitigates the possibility that the multiyear rate mechanism mirrors a cost-plus environment and preserves some incentive for Pepco to improve cost efficiencies. Furthermore, Pepco has made the upward adjustment "automatic," while any annual rate adjustment due to utility under earning is not. Instead, the proposal calls for the opportunity to explain the reasons for any such performance and, if due to reasonable circumstances (e.g., unforeseen changes in input costs), request that the Commission adjust rates accordingly. Thus, the burden is upon Pepco to demonstrate the reasonableness of costs above those forecast at the outset of its MRP, while customers benefit automatically in the case of over earnings.

Pepco's proposed PIMs plan includes both penalties and rewards. Penalties protect customers from service degradation and are standard fare in traditional PIMs constructs. Including rewards in this construct is also beneficial when customers value

improved service levels (i.e., above historic levels) and/or when regulators recognize such service levels as important to facilitating a transition to the next generation of utility operations.

Q31. Does this conclude your Direct Testimony?

A31. Yes, it does.

W.P. Zarakas
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (J) – 1

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William Zarakas is a Principal with The Brattle Group, an economics consulting firm, and an expert on economic and regulatory matters in the electricity, telecommunications and media industries. He heads Brattle's retail energy practice, and leads much of Brattle's work concerning regulatory and business models, cost and rate analysis, infrastructure deployments and grid modernization, and smart grid and utility platform issues. Mr. Zarakas has authored reports and articles on performance based regulation (PBR), "utility of the future" visions and implementation, and inter-modal competition in the retail electricity sector.

Mr. Zarakas also has a leadership role in Brattle's practice in telecommunications and media. He has provided expert reports and testimonies in a range of regulatory proceedings concerning competition issues in the telecommunications industry, forbearance from price regulation, and price and foreclosure issues potentially associated with mergers among telecom carriers and media companies. He has also developed models concerning the economics and financial feasibility of building-out broadband infrastructure, conducted valuations of a wide range of wireless spectrum bands and holdings, and examined the distribution of royalties and retransmission fees in the cable and satellite television industries.

He has also led special investigations on behalf of corporate boards of directors and audits of management practices and operational and financial performance on behalf of regulatory commissions.

Mr. Zarakas has provided testimony and expert reports before the Federal Communications Commission, the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Copyright Royalty Judges (Library of Congress), the U.S. Congress, state regulatory agencies, arbitration panels, foreign governments and courts of law.

He holds an M.A. in economics from New York University and a B.A., also in economics, from the State University of New York.

Utility Regulatory and Business Models. Analyzed, advised and/or testified on matters concerning regulatory frameworks, performance-based regulation (PBR) and utility business models, notably with respect to emerging competitive alternatives and network integration. Recent work includes:

- Analyzed implementation of New York's Reforming the Energy Vision by modeling the economics of the utility platform model, access pricing and financial impacts of retail competition on utility.
- Analyzed, advised and/or testified on matters concerning performance incentive mechanism (PIMs); e.g., analyses of: New York's "earnings adjustment mechanisms" on behalf of New York's six investor owned utilities) and performance measures and incentive structures on behalf of the Hawaiian Electric Companies.
- Surveyed and analyzed PBR frameworks and applications, including multi-year rate plans (MRPs), PIMs and other alternative regulatory mechanisms, including the U.K.'s "RIIO" model.

- Surveyed and analyzed regulatory approaches to setting electric distribution reliability standards around the world on behalf of the Australian Energy Market Commission (AEMC).
- Modeled multi-variate "utility of future" scenarios using system dynamic approach on behalf of utilities and industry groups.
- Advised Board of Directors of a major generation and transmission (G&T) cooperative and its member electric distribution cooperatives on matters concerning: asset valuations, risk management strategy, merger and acquisition options, and outlook for retail electric markets.

Infrastructure and Investment Analysis. Analyzed and testified on matters concerning infrastructure economics and financial feasibility. Work includes:

- Led benefit-cost and economic "break-even" analysis of utility system reliability and resilience investment using a value of lost load (VOLL) methodology on behalf of Public Service Electric & Gas Company (PSE&G).
- Developed cost and revenue models to estimate costs, feasibility and customer rates associated with deploying wireless broadband to rural areas on behalf of GCI Communications.
- Conducted financial feasibility analysis concerning deployment of a broadband communications network for an Asian electric utility.
- Analyzed economics and financial feasibility of providing (wholesale) transport and (retail) broadband services for multiple U.S. electric utilities.
- Led comprehensive modeling concerning costs and rates for unbundled network elements (UNEs), undertaken in fulfillment of requirements associated with the Telecommunications Act of 1996, using the Total Element Long Run Incremental Cost (TELRIC) methodology.

Due Diligence, Valuation and Management Audits. Work includes:

- Due diligence of northwestern U.S. electric and gas utility on behalf of buyer; analysis included comprehensive sales, revenue, and operating and capital cost modeling and scenarios.
- Led numerous analyses of the values of wireless spectrum in the U.S., Canada, the Middle East and North Africa (MENA), and other geographic markets. Scope of analyses included: PCS, AWS, 2.3-2.5 GHz, SMR, PLMR, IVDS, MSS and Big Leo spectrum bands, among others, for purposes of planning, transactional analysis, regulatory proceedings, domestic and international arbitration, and commercial litigation.
- Led strategic organizational options analysis for the Board of Trustees of the Long Island Power Authority (LIPA).
- Led special investigations; e.g., economic analysis of "swap" transaction for the Special Committee of the Board of Directors of Global Crossing.
- Led management and/or regulatory audits of utilities and telecommunications carriers on behalf of state regulatory commissions Alabama, Kentucky, Maryland, New York and Pennsylvania.

Competition and Antitrust. Recent work includes:

- Analyzed prospective merger savings and divestiture losses for electric and gas utilities in merger applications before the U.S. Securities and Exchange Commission (SEC).
- Analyzed effectiveness of retail competition in U.S. electricity markets.

- Examined market structure and degree of competition in U.S. retail telecom markets, with regard to Petitions for FCC to forbear from price regulating resale services and UNEs.
- Conducted merger simulation and horizontal and vertical foreclosure analyses for telecom and media mergers; e.g., Comcast-Time Warner Cable; AT&T-Time Warner; Sinclair-Tribune; and, Disney-Fox.
- Led comprehensive analysis of competition in U.S. markets for business data services (BDS, previously referred to as special access).
- Analyzed acquisition price premium in merger of cross-state gas and electric utilities.

Other Regulatory Analyses. Recent work includes:

- Led benchmarking studies of utility costs and regulatory practices.
- Analyzed markets for and costs of providing utility pole attachments.
- Calculated total factor productivity (TFP) and X factors in price regulation proceedings involving utilities before state regulatory commissions and incumbent telecommunications carriers before the FCC.
- Analyzed costs and value of retransmitted television programming in cable and satellite video markets on behalf of Music Claimants in proceedings involving distribution of royalty funds.
- Examined impact of regulatory fees and constraints on economic output in 22 countries in the Middle East and Africa for international mobile carrier.

Expert Testimony

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T.D. Sanford
Direct Testimony
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (K)

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EXECUTIVE SUMMARY- TAMMY D. SANFORD

This testimony provides background on the Potomac Electric Power Company's (Pepco or the Company) Benning Road facility, including the prior release of polychlorinated biphenyls (PCBs) at the facility, and a description of the environmental remediation efforts at the Benning Road facility. It addresses the costs the Company has incurred in connection with these remediation efforts (i) from January 1, 2018 to March 31, 2019 and (ii) related to the removal of cooling tower basins at the Benning site. The testimony also describes the costs the Company anticipates will be incurred in connection with the remediation efforts at the Benning Road facility from April 1, 2019 through December 31, 2020. Finally, the testimony discusses the related Anacostia River Sediment Project and the work that has and will be done as a result of that project.

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF TAMMY D. SANFORD
FORMAL CASE NO. 1156

I. INTRODUCTION

Q1. Please state your name and position.

A1. My name is Tammy D. Sanford. I am the Manager of Environmental Services at Pepco Holdings LLC (PHI). I am testifying on behalf of Pepco.

Q2. What are your responsibilities in your role as Manager of Environmental Services?

A2. I am responsible for all aspects of environmental oversight and compliance for the utilities of PHI.[1] My responsibilities also include oversight of the investigative and remedial activities necessary to address environmental liabilities at the Company's properties.

Q3. Please state your educational background and professional experience.

A3. I hold a Bachelor of Science in Chemical Engineering from the Pennsylvania State University. I have over 19 years of project management and consulting experience with an emphasis on environmental capital project management, power plant and electric utility project development, environmental due diligence, environmental permitting, and environmental management system development and implementation.

[1] The "PHI" utilities include Pepco, Delmarva Power & Light Company, and Atlantic City Electric Company.

1 **Q4. What is the purpose of your Direct Testimony in this proceeding?**

2 A4. In my Direct Testimony, I provide background on the Company's Benning
3 Road facility, including the prior release of PCBs at the Benning Road facility, and a
4 description of the environmental remediation efforts at the Benning Road facility.
5 Additionally, I describe (1) the costs the Company has incurred related to the Benning
6 Road facility from January 1, 2018 to March 31, 2019; (2) the costs that the Company
7 has incurred related to the removal of cooling tower basins at the Benning site; and (3)
8 the costs that the Company projects to incur and expend from April 1, 2019 through
9 December 31, 2020 related to the Benning site. Company Witness Wolverton describes
10 the proposed rate making treatment of these costs in the MRP through Ratemaking
11 Adjustments (RMA) 10(a) and 10(b) in his Direct Testimony. Company Witness
12 Ziminsky describes the proposed rate making treatment of these costs in the traditional
13 test period compliance filing through RMAs 20(a) and 20(b) in his Direct Testimony.
14 Finally, I will discuss the related Anacostia River Sediment Project and the work that
15 has and will be done as a result of that project.

16 **Q5. Have you previously testified before the Public Service Commission of the District**
17 **of Columbia (Commission)?**

18 A5. No.

19 **Q6. What is the basis for your Direct Testimony?**

20 A6. This testimony and accompanying exhibits were prepared by me or under my
21 direct supervision and control. The sources for my testimony are Company records,
22 public documents, previous testimony filed by Company Witness McNealy in Formal
23 Case No. 1150, and my personal knowledge and expertise.

1 **II. Background on the Benning Road Facility**

2 **Q7. What is the Benning Road facility and how is it used by Pepco?**

3 A7. The Benning Road facility is Pepco's only service center (in this context,
4 referred to as the "Benning Road Service Center") located in the District of Columbia.
5 The Benning Road Service Center is a hub for employees supporting maintenance,
6 operation, and construction of Pepco's electric transmission and distribution system;
7 system engineering; vehicle fleet maintenance and refueling; and central warehousing
8 for materials, supplies, and equipment needed to operate the Pepco electrical
9 distribution system. The site currently accommodates approximately 700 Pepco
10 employees.

11 **Q8. Where is the Benning Road facility located?**

12 A8. The Company's Benning Road facility is located at 3400 Benning Road, N.E.,
13 Washington, DC, and occupies approximately 77 acres. It is located adjacent to the
14 Anacostia River, the National Park Service Kenilworth Maintenance Yard, and the
15 District Department of Public Works Solid Waste Transfer Facility.

16 **Q9. Please provide a history of the Company's operations at the Benning Road facility.**

17 A9. Pepco purchased the first parcel of land comprising the current facility, 11 acres
18 abutting the Anacostia River, in 1906, and began construction of the original Benning
19 power plant in April of the same year.[2] Pepco expanded the site to its current size of
20 77 acres by acquiring seven additional parcels between 1906 and 1956 to accommodate
21 growing infrastructure needs. As of 1956, operations at the site included not just the

[2] Detailed information regarding the history of the Benning Road facility is provided in Section 2.2 and Appendix D (historical photos) of the Benning Road Facility Technical Memorandum #1, Conceptual Site Model, September 2016 (hereinafter, Tech Memo #1). A copy of Tech Memo #1 is available at http://www.benningservicecenter.com/ as Appendix C to the RI/FS Work Plan Addendum #3.

electric generation station but also various activities and facilities associated with the construction, operation, and maintenance of Pepco's electric transmission and distribution system serving Washington, DC and portions of Montgomery and Prince George's Counties in Maryland. Now part of what is referred to as the Benning Road Service Center, these facilities included warehouses, maintenance buildings, and equipment laydown areas. The first of the three electric substations was operating at the site by 1963. Activities currently conducted at the Benning Road facility include system engineering and telecommunications; vehicle fleet maintenance and refueling; central warehousing for materials, supplies and equipment; and the operation of three electric substations. The Benning Road Service Center has also served as Pepco's central facility for the storage, repair, and processing for disposal of transformers and other electrical equipment used in Pepco's transmission and distribution system.

The original Benning power plant, which burned coal, was Pepco's first central generating station and served most of the electric load in the greater Washington D.C. area from the time it was built through World War II. Pepco added two oil-fired steam turbine units in 1968 and 1972, respectively. Pepco also constructed two cooling towers at that time to prevent thermal pollution to the Anacostia River from the operation of these two new steam turbines. The Benning power plant ceased burning coal in approximately 1976, and thereafter operated exclusively on fuel oil to supply electric power to meet peak demand within the District of Columbia and nearby Montgomery and Prince George's counties in Maryland. In December of 2000, Pepco transferred the Benning power plant facilities to Potomac Power Resources, LLC

(PPR).[3] PEPCO (K)-1 is an aerial photo showing the site as of May 2015.

Q10. Please describe the authority under which Pepco transferred the Benning power plant to PPR.

A10. Pepco transferred the Benning power plant, together with the Buzzard Point generating facilities, to PPR following Commission approval issued on November 15, 2000 in Formal Case No. 945. In Order No. 11834, paragraph 10, the Commission recognized that Section 119(b)(2)(A) of the Retail Competition and Consumer Protection Act of 1999, D.C. Law 13-107, mandated that Pepco transfer its unauctioned generation assets to an affiliate at book value. Order No. 11834 was issued in response to Pepco's Petition for an Eligible Facility Determination of Generating Facilities and Authorization to Transfer Certain Generation Assets to an Affiliate, filed September 19, 2000 (the Petition to Transfer). As explained in the Petition to Transfer at pages 7-8, Pepco and other parties entered into a Non-unanimous Agreement of Stipulation and Full Settlement (Settlement Agreement) that was approved by the Commission on December 30, 1999 by Order No. 11576. Section 1.05 of the Settlement Agreement provided Pepco with the flexibility not to offer the Benning power plant and the Buzzard Point generating facilities for sale when Pepco auctioned the balance of its generating assets. Furthermore, as also explained in the Petition to Transfer at pages 7-8, in Order No. 11576, the Commission required Pepco to obtain the Commission's prior approval of the sale, transfer, lease or other disposition of the Benning power

[3] Originally, PPR was formed as a corporation and was a wholly owned subsidiary of Pepco Energy Services, Inc. (PES), which in turn was an indirect subsidiary of Pepco. As a result of various corporate reorganizations, most recently those associated with the merger of Pepco Holdings, Inc. into Exelon Corporation, PES has been merged into Constellation NewEnergy, Inc., and PPR was converted into a limited liability company and is now a wholly owned subsidiary of Exelon Generation Company, LLC.

1 plant, which approval was granted by the Commission in Order No. 11834. Among
2 the attachments to the Petition to Transfer was the form of the Asset Transfer
3 Agreement that Pepco and PPR proposed to execute (the Asset Transfer Agreement).
4 On December 19, 2000, Pepco and PPR signed the Asset Transfer Agreement
5 substantially in the form filed with the Commission, and in accordance with its terms,
6 Pepco transferred to PPR the improvements constituting the Benning power plant and
7 granted an easement to the real property necessary to operate the facilities.

8 **Q11. What is the history of PCB contamination at the Benning Road facility?**

9 A11. There were several releases of PCBs at the site prior to the transfer of the
10 Benning power plant to PPR. In each case, Pepco conducted cleanups in accordance
11 with the applicable regulatory standards established by the U.S. Environmental
12 Protection Agency (EPA) to protect human health and the environment.[4] The extent of
13 any residual contamination was further assessed as part of the comprehensive site-wide
14 investigation that commenced in 2012 and is described later in my testimony.

15 **Q12. What is the current status of the Benning power plant?**

16 A12. PPR retired the Benning power plant in June 2012, and most of the structures
17 were demolished and removed by May 2015.

18 **III. ENVIRONMENTAL REMEDIATION AT THE BENNING ROAD FACILITY**

19 **Q13. Please describe the events that led to the Remedial Investigation/Feasibility Study**
20 **(RI/FS).**

21 A13. On October 8, 2010, the District of Columbia Department of Energy and
22 Environment (DOEE) sent a notice to the Company of its intent to file an action under

[4] The releases and Pepco's response actions are described in detail in Section 5.2 of Tech Memo #1.

1 the Resource Conservation and Recovery Act (RCRA) to compel the Company to take
2 certain environmental investigation and cleanup actions at the Benning Road facility.
3 The notice cited several documented spills of PCB-contaminated oil at the facility
4 between 1985 and 2003. Despite the Company's actions to clean up these spills in
5 accordance with applicable legal requirements, the notice alleged that PCBs released
6 as a result of these spills had migrated over time from the site into sediments in the
7 adjacent Anacostia River. The notice further alleged that this condition posed a risk to
8 human health and the environment for which Pepco was subject to suit compelling it
9 to take corrective action.[5] A copy of this notice is attached as PEPCO (K)-2.

10 To resolve this threatened lawsuit, Pepco entered into a consent decree with
11 DOEE pursuant to which Pepco agreed to conduct a Remedial Investigation (RI) to
12 assess the environmental conditions at the entire 77-acre Benning Road facility and
13 within the adjacent segment of the Anacostia River, and to conduct a Feasibility Study
14 (FS) to evaluate possible cleanup actions. The consent decree allowed Pepco to address
15 the environmental conditions at the Benning Road facility in a constructive manner
16 without the expense and risk of litigation. The consent decree did not include any
17 finding or admission by Pepco of any failure to comply with applicable law or any
18 improper action. On February 1, 2011, after the consent decree was signed by Pepco,
19 DOEE filed suit in the U.S. District Court for the District of Columbia solely for the
20 purpose of obtaining court approval of the agreement. After an opportunity for public
21 comment, the Court approved the consent decree on December 1, 2011, finding that it

[5] Notice of Intent to Sue Under Section 7002(a)(1)(B) of the Resource Conservation and Recovery Act, 42 U.S.C. § 6972(a)(1)(B), October 8, 2010.

was "adequate, reasonable, and appropriate."[6] A copy of the District Court's memorandum opinion is provided herein as PEPCO (K)-3.

Q14. Did DOEE find that Pepco was negligent or not prudent in the operation of the Benning Road facility because of the PCB contamination?

A14. No. DOEE made no finding or allegation that the PCB contamination was the result of negligence or lack of prudent operation by Pepco. DOEE was authorized to file the lawsuit threatened by the notice letter under the citizen suit provision of RCRA, which provides a legal mechanism by which Pepco could be required to address environmental conditions resulting from past operations even where such operations were conducted in accordance with the law and prudent industry practice at the time.

Q15. Did DOEE find that the PCB contamination at the Benning Road facility was the result of any violation of environmental law or requirement?

A15. No. DOEE made no finding or allegation that the PCB contamination was the result of any violation of any environmental law or requirement, and DOEE acknowledged that "Pepco conducted remedial actions in response to each of [the six PCB releases] in accordance with applicable legal requirements."[7] However, as explained in response to Question 14, Pepco could be required under RCRA to address environmental conditions resulting from past operations even where such operations were conducted in accordance with the law.

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[6] Memorandum Opinion at 12, *District of Columbia v. Potomac Electric Power Co., et al.*, No. 1:11-cv-00282, (D.D.C. December 1, 2011) (Dkt. No. 31).

[7] Consent Decree at 2 (fifth recital), available at http://www.benningservicecenter.com/.

Q16. Did DOEE engage Pepco in any litigation regarding the PCB contamination at the Benning Road facility?

A16. As explained above, DOEE filed a lawsuit for the purpose of obtaining court approval of the consent decree, but there was no active litigation regarding the PCB contamination or Pepco's liability to take corrective action.

Q17. What are the details of the consent decree?

A17. The consent decree obligates Pepco to conduct an RI/FS to assess the environmental conditions at the 77-acre Benning Road facility and an approximately 10- to 15-acre portion of the adjacent Anacostia River, and to evaluate possible cleanup actions. The consent decree specifies that the RI/FS must be conducted in accordance with EPA regulations and guidance documents and applicable District of Columbia law. Pepco's work on the RI/FS is being overseen by DOEE and the consent decree obligates Pepco to reimburse DOEE for the costs of such oversight. The court order approving the consent decree requires DOEE to solicit public comment on drafts of the RI and FS reports, as well as various work plans and other deliverables. The consent decree will terminate upon a determination by DOEE and the court that Pepco has fulfilled all of its obligations related to the RI/FS.

Q18. What is the purpose of the RI?

A18. The purpose of the RI is to: 1) evaluate the environmental conditions on the Benning Road facility and the adjacent portion of the Anacostia River; 2) determine if and to what extent historical operations at the Benning Road facility have contributed to the contamination of the Anacostia River; and, 3) assess potential risks to human

1 health and the environment as a result of these conditions.[8]

2 **Q19. What is the purpose of the FS?**

3 A19. The purpose of the FS is to evaluate appropriate cleanup options or other actions
4 to address any risks to human health and the environment identified by the RI.[9]

5 **Q20. Has the Company completed the RI?**

6 A20. Pepco completed the first phase of field sampling and data analysis for the RI
7 and released a Phase I RI report for public review and comment on March 1, 2016. At
8 the request of DOEE, Pepco completed a second phase of RI field sampling and data
9 analysis and submitted a draft Final RI Report to DOEE for review on November 5,
10 2018. It is common for an RI to involve two or more phases of field sampling as the
11 results from each phase are analyzed to identify any additional data needs. At Benning,
12 DOEE determined that additional sampling was necessary to fully delineate the extent
13 of each area where contamination was found during the first phase of sampling. No
14 further field sampling is expected to be required for the remedial investigation. Further
15 sampling may be conducted as part of the FS and/or as part of the design work for any
16 remedial action deemed necessary by DOEE based on the results of the RI/FS.

17 As stated above, Pepco submitted a draft Phase II RI Report to DOEE on
18 November 5, 2018. This submission consisted of a main report containing over 200
19 pages of text, along with 619 pages of tables and 70 pages of figures presenting the
20 results of the entire field sampling program and associated data evaluations. The
21 November 5, 2018 draft RI Report submission also included 28 separate appendices,
22 including a Baseline Human Health Risk Assessment and a Baseline Ecological Risk

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8 http://www.benningservicecenter.com/library/documents/BenningRIFSFactSheet.pdf.
9 *Id.*

1 Assessment. As described further below, Pepco is currently working to respond to
2 comments from DOEE on the draft Phase II RI report and will be revising the report
3 and supporting appendices in accordance with DOEE's comments before the report is
4 released for public review and comment.

5 **Q21. What was involved in the RI?**

6 A21. The RI—including the first and second phases—involved the collection of
7 hundreds of samples of soil and groundwater at the Benning Road facility and of
8 surface water and sediments in the adjacent segment of the Anacostia River, laboratory
9 testing of the samples, and detailed evaluation of the sampling results. Each of the two
10 phases of the RI also included a baseline human health risk assessment and a baseline
11 ecological risk assessment.

12 **Q22. What were the findings of the RI?**

13 A22. A number of constituents of potential concern (COPCs),[10] including PCBs,
14 have been detected in the RI study area. The nature and extent of these COPCs was
15 generally consistent with historical operations at the Benning Road facility and other
16 sites along the river as well as the general urban character of the surrounding area. The
17 risk assessments conducted for the Phase I RI report concluded, on a preliminary basis,
18 that contaminants detected at the Benning Road facility posed no unacceptable
19 ecological risk and no unacceptable potential risks to human health in light of existing
20 operational and institutional controls that are in place at the site. The risk assessments

[10] According to the EPA, a "constituent of potential concern" (COPC) is "any contaminant that is shown to pose possible ecological risk to a site. A Contaminant of Potential Ecological Concern (COPEC) or Contaminant of Potential Concern (COPC) is generally a contaminant which may or may not be causing risk or adverse effects to the plants and animals at a site."
See https://archive.epa.gov/reg5sfun/ecology/web/html/glossary.html.

1 for the Phase I RI further concluded, on a preliminary basis, that risks to human health
2 posed by exposure to contaminants in water and sediments in the river portion of the
3 RI study area are all within EPA's acceptable risk ranges, and ecological risks are
4 relatively low and not substantively different from risks at reference areas in other
5 segments of the Anacostia and Potomac Rivers considered in the RI. Finally, under the
6 conservative assumptions used for the Phase I RI risk assessment, fish consumption
7 was found to pose a non-cancer risk above the EPA target levels due to PCBs, a
8 contaminant which is found at similar concentrations in fish tissue collected at
9 sampling locations throughout the Anacostia and Potomac Rivers.

10 **Q23. What is the current status of the RI?**

11 A23. The Company is currently working with DOEE to finalize the draft Phase II RI
12 report. According to the most recent schedule for the RI/FS, which was approved by
13 the district court on March 12, 2019,[11] a draft of the Final RI Report is expected to be
14 released by DOEE for public comment by September 6, 2019, and the Final RI Report,
15 as approved by DOEE, is expected to be completed by February 3, 2020.

16 **Q24. What are the Company's next steps for the RI/FS?**

17 A24. Once the Final RI Report is issued, Pepco will conduct an FS to identify and
18 evaluate potential cleanup options and other actions as necessary to ensure there are no
19 long-term risks to human health or the environment attributable to past site operations
20 or current site conditions. Pepco has already begun work on certain tasks required for
21 the FS. One such task is a revised and expanded statistical analysis of the sampling
22 data from the RI combined with a detailed forensic evaluation of the extent to which

[11] PEPCO (K)-4.

1 contaminants in the river sediments are attributable to activities at the Benning Road
2 facility site. This forensic analysis and source evaluation are scheduled to be completed
3 by November 21, 2019. Pepco also is planning to conduct a treatability study to
4 evaluate the effectiveness of potential remedial options consistent with the court-
5 approved order. Pepco currently anticipates that the Treatability Study will be
6 completed by October 2020 and a draft FS report will be submitted in February 2021
7 for review and comment by DOEE and then the public.

8 **Q25. What are the objectives of the FS?**

9 A25. The FS will identify remedial action objectives for areas where remediation is
10 identified as necessary based on the findings of the RI. The remedial action objectives
11 will be developed, in consultation with DOEE, based on risk factors specific to the
12 Benning Road facility site taking into account existing institutional, administrative and
13 engineering controls. The FS report will describe the rationale for cleanup objectives
14 and evaluate the relative effectiveness of a range of potential remedial alternatives.

15 **Q26. What is the long-term outlook for environment remediation activities at the**
16 **Benning Road facility?**

17 A26. It is not uncommon for an RI/FS process to take many years to complete as each
18 site is unique and the amount of time it takes to complete the process can vary
19 significantly. Pepco will work with DOEE and other environmental regulatory
20 agencies to implement cost-effective and sustainable remedial actions as necessary to
21 ensure long term protection of human health and the environment.

IV. COSTS INCURRED AT THE BENNING ROAD FACILITY

Q27. Can you describe the costs the Company has incurred related to the Benning Road facility RI/FS?

A27. From January 1, 2011 through March 31, 2019, the Company has incurred approximately $10.7 million in costs related to the RI/FS. These costs relate primarily to RI work and the removal of the cooling tower basins at the Benning Road facility to eliminate a possible source of PCBs.

Q28. For which costs is the Company seeking recovery in this case?

A28. The Company is proposing RMA 20a and RMA 20b as part of its traditional test period compliance filing to recover current costs incurred related to the RI/FS and the projected future costs through December 2020.[12] Company Witness Ziminsky discusses in his Direct Testimony the Pepco DC distribution amounts being sought for these two RMAs.

Table 1

RMA	Description	Period Covered	Total Cost (Unallocated) (Dollars in Millions)
20a	Cost of Removal of Cooling Tower (CT) Basins	January 1, 2011 to March 31, 2019	$3.43
20a	Actual Dollars Spent for RI/FS	January 1, 2018 to March 31, 2019	$1.56
20b	Future Costs for RI/FS	April 1 through December 31, 2020	$0.84

In Formal Case No. 1150, Pepco was permitted to receive regulatory asset treatment to recover approximately $3.3 million in costs already incurred related to the

[12] The proposed rate making treatment of these costs in the MRP is addressed by Company Witness Wolverton through RMA 10(a) and 10(b) which refer to Company Witness Ziminsky's Direct Testimony.

1 RI at the Benning Facility up to January 1, 2018. The $3.3 million did not include costs
2 related to the removal of the cooling tower basins.

3 In this case, and as further described in the testimony of Company Witness
4 Ziminsky, through RMA 20a Pepco proposes to recover costs related to RI work
5 through March 31, 2019, and costs related to the removal of the cooling tower basins
6 at the Benning Road facility. The Company-incurred costs between April 1, 2019 and
7 December 31, 2020 in RMA 20b include costs related to: finalizing the draft RI report
8 and issuing the document for public review, in consultation with DOEE; preparing a
9 forensic and source evaluation report for submittal to DOEE; preparing a revised
10 Treatability Study work plan based on the outcome of the forensic and source
11 evaluation report; conducting the Treatability Study, and preparing a FS Report. These
12 costs, for the period April 1, 2019 through December 31, 2020, are estimated to total
13 approximately $840,000.[13] These costs are necessary and reasonable to continue the
14 RI/FS for the Benning Road facility.

15 **Q29. How does the removal of the cooling tower basins relate to the RI/FS?**

16 A29. The RI/FS obligated Pepco to conduct a comprehensive assessment of
17 subsurface conditions at the Benning Road facility. This site investigation was guided
18 by information already obtained as a result of prior site investigations. In 1995, Pepco
19 discovered that the caulk used to seal the joints for the cooling tower concrete basins
20 when they were constructed in 1968 and 1972 contained PCBs. All of the exposed
21 caulk was removed at that time and PCBs that had leached into the basins, without the
22 Company's prior knowledge or expectation, were cleaned up in accordance with EPA

[13] The costs identified in this Direct Testimony are the total costs. Company Witness Ziminsky provides the DC allocated portion of these costs in his Direct Testimony.

1 requirements. Any residual PCB contamination that may have leached from the caulk
2 to soil beneath the basins was effectively encapsulated so no further action was
3 necessary at that time as long as the cooling tower basins remained in place. As part
4 of the RI/FS, the Company conducted a comprehensive investigation of the area
5 beneath and adjacent to the cooling tower basins to fully delineate the extent of PCB
6 contaminated soils in this area. Based on the results of this delineation, the Company
7 determined that the most cost-effective approach was to remove additional
8 contaminated soil at the same time that it removed the concrete basins to complete the
9 demolition process, rather than defer all such response action until the remedial phase
10 of work to be defined after the full RI/FS was completed (which would have required
11 backfilling the basin excavation with clean fill only to be removed again as part of a
12 later remedial action). DOEE approved the removal project as part the RI/FS and
13 oversaw completion of this work. This project is documented in a completion report
14 submitted to DOEE dated September 11, 2017.[14] The costs related to the removal of
15 the cooling towers basins total approximately $3.43 million.

16 **Q30. Were the costs incurred to investigate the Benning Road facility reasonable and**
17 **prudently incurred?**

18 A30. Yes. All of the RI/FS work performed to date was necessary to comply with
19 the Company's legal obligations under the consent decree and directives issued by
20 DOEE in overseeing the RI/FS. As explained in response to Question Nos. 13 and 14
21 above, the requirement to conduct the RI/FS was not the result of any violation of
22 environmental requirements by Pepco. Moreover, the Company has engaged in

[14] A copy of this report is available at http://www.benningservicecenter.com/.

1 extensive technical discussions with DOEE to manage the scope of the RI/FS work and
2 avoid unnecessary effort and is overseeing the work so that it is being completed cost
3 effectively. The Company is committed to protecting the public health and the
4 environment at the most reasonable cost.

5 **Q31. What amount does the Company currently expect to incur for future remediation**
6 **costs at the Benning Road facility?**

7 A31. An FS has not yet been fully prepared for the Benning Road facility and site.
8 Accordingly, the Company cannot reasonably estimate total remediation costs.

9 **Q32. The Settlement in Formal Case No. 1150 required Pepco to report, on a bi-annual**
10 **basis beginning January 2019, efforts by the Company to diligently pursue**
11 **recovery of RI costs through insurance. Please explain what efforts have been**
12 **made to recover RI costs through insurance and what prospects there are to**
13 **obtain such recovery.**

14 A32. As directed by the Commission, the Company is pursuing insurance recovery
15 related to the costs incurred by Pepco for the remediation of the Benning Road facility
16 and will do so until such efforts have been exhausted. The first status report to the
17 Commission was filed on December 27, 2018 in Formal Case No. 1150. Status reports
18 regarding the Company's efforts will be filed bi-annually.

19 Pepco's pursuit of any available insurance proceeds in this matter is
20 complicated. The alleged contamination dates back five decades and purportedly
21 continues to the present, therefore five decades of excess insurance policies of varying
22 levels are potentially implicated, not including the overlap of triggering events from
23 year-to-year. Pepco has placed dozens of insurance carriers on notice of claims relating

1 to this matter. In addition, each policy has varying degrees of insurance limits,
2 insurance coverages, insurance exclusions (particularly pollution exclusions),
3 insurance triggers, and insurance periods. Further, each policy has different treatment
4 of the effect of coverage by other policies. Moreover, Pepco's self-insured retention
5 level varied from policy to policy. Finally, some of the insurers no longer exist, are
6 insolvent, or have transferred indemnification obligations to other carriers on a limited
7 basis. These nuances result in the insurance coverage evaluation being very complex
8 and slow-moving. Pepco has been updating its insurance carriers with the most recent
9 investigative information as reviewed in this testimony, which also has new effect on
10 coverage analysis. Although, to date, no carrier has provided or committed to insurance
11 coverage for any past or expected loss associated with this matter, Pepco will continue
12 its efforts to maximize the insurance recoveries available to the Company in connection
13 with this matter.

14 **V. ANACOSTIA RIVER SEDIMENT PROJECT**

15 **Q33. Please describe the Anacostia River Sediment Project.**

16 A33. The Anacostia River Sediment Project (ARSP) is a joint effort by the District
17 of Columbia (acting through DOEE) and the National Park Service (NPS) to assess
18 environmental conditions within the lower Anacostia River and select and implement
19 cleanup actions as deemed necessary. As part of this project, DOEE and the NPS are
20 currently conducting an RI/FS for the entire nine-mile-long tidal reach of the Anacostia
21 River extending from the Maryland border to the confluence with the Potomac river.
22 The area being investigated for the river-wide RI/FS includes the portion of the river
23 that is being studied as part of Pepco's RI/FS for the Benning site, and DOEE and the

1 NPS have incorporated sampling data from Pepco's investigation into their river-wide
2 assessment. At this time, it is uncertain how DOEE plans to integrate any remedial
3 actions for river sediments that may result from the Benning RI/FS into the overall
4 remedial effort for the river.

5 **Q34. Please describe the actions that Pepco has taken to date with respect to the**
6 **Anacostia River Sediment Project?**

7 A34. To date, Pepco has been involved in the ARSP in two significant ways. First,
8 at the request of DOEE, Pepco has participated actively as a member of the
9 Consultative Working Group (CWG) formed by DOEE and the NPS in 2016. The
10 CWG consists of several entities that are expected to have some responsibility for
11 cleanup of the Anacostia River sediments. In addition to Pepco, other participating
12 CWG members include Washington Gas Light Company, the U.S. Navy, DC Water,
13 and Prince George's County, Maryland. According to DOEE and NPS, the role of the
14 CWG is (i) to assist with the identification of other potentially responsible parties, (ii)
15 to participate in an allocation process by which the group members would reimburse
16 DOEE and the NPS for the cost of the RI/FS and assume responsibility for funding the
17 remedy, and (iii) to provide technical input to the RI/FS. To date, the CWG has been
18 focused on providing technical input to DOEE and the NPS regarding the river-wide
19 RI/FS. With the assistance of a technical consultant and working jointly with
20 Washington Gas where appropriate to share costs and capture efficiencies, Pepco has
21 participated in a series of technical meetings, beginning in September of 2016, with
22 DOEE and the NPS, and has prepared and submitted a series of technical papers and
23 other technical submissions for consideration by DOEE and the NPS, including written

1 comments on a draft RI report filed in May 2018. In addition to its efforts in connection
2 with the CWG, in June of 2017, Pepco received a formal request from DOEE for
3 information regarding current and historical operations at the Benning Road facility, as
4 well as Pepco's facility at Buzzard Point and its transformer vaults located throughout
5 the District of Columbia. The request sought "information related to the contamination
6 of sediments in the Anacostia River that may have resulted, in part, from materials that
7 were generated, treated, deposited, stored, disposed on, or transported to" the identified
8 Pepco facilities. Pepco submitted detailed responses to these requests, along with
9 numerous supporting documents, in November of 2017.

10 **Q35. What costs has Pepco incurred in connection with the ARSP?**

11 A35. From May 1, 2018 through March 31, 2019, the Company has incurred $0.827
12 million in costs related to the ARSP. These costs relate primarily to RI work and
13 associated studies conducted by the District of Columbia including Pepco's review and
14 comment on documents issued for public review. Additional costs include those for
15 Pepco's participation in the CWG formed by DOEE and the NPS.

16 **Q36. Do you anticipate incurring additional costs in the future in connection with the**
17 **ARSP?**

18 A36. Pepco will continue to participate actively in providing technical input on the
19 RI/FS and remedy selection process as the ARSP proceeds. ARSP activities anticipated
20 during the remainder of 2019 include the release of a draft FS report for public
21 comment and a proposed plan seeking public comment on any proposed river cleanup
22 actions. Thereafter, Pepco anticipates that DOEE and the NPS will look to Pepco,
23 along with other parties, to pay some portion of the costs for the river-wide RI/FS and

1 to perform or pay for some portion of the river cleanup. Pepco's liability for any such
2 costs has not yet been established but is expected to be addressed through a future law
3 suit or other legal proceeding to determine responsibility for the costs to investigate
4 and clean up the river sediments and to allocate those costs on an equitable basis.
5 Whatever its ultimate liability may be, Pepco is acting prudently by participating in the
6 ARSP process to advocate for remedial decisions based on sound science and cleanup
7 measures for which the costs will be reasonable and appropriate.

8 **Q37. Does this conclude your Direct Testimony?**

9 A37. Yes, it does.

T.D. Sanford
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (K) – 1

0 125 250 500
SCALE IN FEET

Pepco Benning Road Facility

3400 Benning Rd., NE
Washington, DC 20019

T.D. Sanford
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (K) – 2

GOVERNMENT OF THE DISTRICT OF COLUMBIA
District Department of the Environment

Office of the Attorney General

October 8, 2010

VIA U.S. REGISTERED MAIL, RETURN RECEIPT REQUESTED

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RE: Notice of Intent to Sue Under Section 7002(a)(1)(B) of the Resource Conservation and Recovery Act, 42 U.S.C. § 6972(a)(1)(B)

Pursuant to section 7002(a)(1)(B) of the Resource Conservation and Recovery Act ("RCRA"), 42 U.S.C. § 6972(a)(1)(B), the District of Columbia, on behalf of the District Department of the Environment ("DDOE"), hereby puts you on notice of the District's intent to sue Pepco Energy Services, Inc., and Potomac Electric Power Company (collectively referred to as "Pepco") for abatement of conditions that may present an imminent and substantial endangerment to health and the environment. These conditions result from the disposal and management of solid wastes at Pepco's facility, located at 3400 Benning Road, N.E., Washington, D.C. 20019 (the "Facility").

OCT 11 2010

The approximately 77-acre Facility is used by Pepco to manage all operations and maintain all equipment associated with its electrical distribution system. The Facility is where all used electrical equipment, or debris from cleanup or repairs of electrical equipment, is brought for processing. Between 1985 and 2003 there have been six (6) documented releases of PCBs into the environment at the Facility[1]. These releases have contributed to the contamination of the Anacostia River's sediment with PCBs, causing an imminent and substantial endangerment to the River's aquatic life and to human health (for example, persons who eat fish caught from the River). These conditions are further described in this letter and in the accompanying attachments, which are incorporated by reference.

1. The Facility.

The Facility is located at 3400 Benning Road NE, Washington, D.C. The geographic coordinates for the approximate center of the site are 38.898 north latitude and 76.959 west longitude. The site is located in a mixed industrial/residential/commercial area, and is bordered to the north by the Washington D.C. Benning Road Transfer Station, the Kenilworth Maintenance Yard (part of the National Park Service) to the northwest, the Anacostia River and wetlands associated with the river to the west, Benning Road with commercial development to the south, and residential areas to the east. Residential communities, including the River Terrace community, are located to the south of the facility.

The approximately 77-acre facility is used by Pepco to manage all operations and maintain all equipment associated with its electrical distribution system. Pepco refers to this facility as the Pepco Benning Road Service Center. The Benning Road site is where all used electrical equipment, or debris from cleanup or repairs of electrical equipment is brought for processing.
In addition to these activities, an active oil-fired power plant is located on the western portion of the site. The power plant has been in operation since 1906. The power plant currently utilizes two generating units that were constructed in 1968 and 1972. In December 2001, Pepco was reorganized due to deregulation of the electrical power industry. The power plant is owned by Pepco Energy Services and operated by North American Energy Services. Pepco maintained ownership of the land on which the power plant is located. Both Pepco and Pepco Energy Services are subsidiaries of Pepco Holding Incorporated.

The 77-acre site is completely surrounded by a fence with two guarded entrances (see Figure 2, Site Layout, of EPA SI). The guard shacks are manned 24 hours a day, 7 days a week. One entrance is located off of Foote Street. The second entrance is located off of Benning Road. In the eastern section of the site are two large active substations (Substation #41 and Substation #7, EPA SI). To the south of the substations is a large asphalt-covered Pepco employee parking lot. To the south of this area are railroad tracks and Buildings 56, 57 and the T & D Holding area. These areas are used for activities associated with processing the used electrical equipment and associated debris brought to the site for disposal. The center of the site is occupied by buildings associated with office space, vehicle maintenance, equipment repair shops, and storage, including hazardous waste and materials. Two large oil/water separators are located in the center of the site, south of Building 75. Areas located outside of

[1] U.S. EPA, Region 3, *Final Site Inspection Report for the Pepco Benning Road Site Washington, D.C.*, prepared by Tetra Tech EM Inc. (June 30, 2009), EPA Document Tracking # 0763 (hereinafter "EPA SI").

the buildings are used for new equipment storage and also storage of used electrical equipment after it has been processed for disposal.

Railroad tracks enter the site in the south and run to the north. These tracks were formerly used to transport coal to the power plant and are no longer active. The only area on the site not covered with asphalt, concrete or gravel is an area located in the western portion of the site, directly south of the cooling towers. This area was used at one time for the storage of coal when the power plant used coal (it currently uses No. 4 fuel oil) to generate electricity. Later, this area was used to dewater sludge cleaned out from the basins located underneath the cooling towers.

2. RCRA Section 7002.

Section 7002(a)(1)(B) of RCRA, 42 U.S.C. § 6972(a)(1)(B), allows any person to bring suit against:

> *" any person... including any past or present generator, past or present transporter, or past or present owner or operator of a treatment, storage, or disposal facility, who has contributed or who is contributing to the past or present handling, storage, treatment, transportation, or disposal of any solid or hazardous waste which may present an imminent and substantial endangerment to health or the environment;"*

Under this provision, the District, as a "person," is authorized to initiate a civil action against Pepco, as a "generator" for contributing to past handling, storage and disposal of solid waste (PCBs), which presents an imminent and substantial endangerment to health and the environment.

3. Responsible Parties.

Based on our present information, we believe Pepco is responsible for the contamination described herein. According to EPA's SI, there have been six (6) documented spills of PCB-contaminated oil and leaking equipment that occurred between 1985 and 2003[2]. Because of Pepco's proximate location to the Anacostia River, the PCBs that have been released on the Pepco site over time have migrated from the property into the sediment of the adjacent Anacostia River via the storm water system, overland flow or groundwater discharge. The discharge of these contaminants into the Anacostia has contributed to conditions which pose an imminent and substantial endangerment to aquatic life in the Anacostia River, and to human health, as further described in this letter, and in the accompanying attachments.

PCB's behave in such a way that they first cling to the soil, and then leach into water. The National Oceanic and Atmospheric Administration's (NOAA) White Paper identifies the contaminated sediment as being within an area in the Anacostia watershed which may pose risk to fish and other aquatic organisms due to elevated PCB concentrations[3]. The approximately 14,397 square foot former sludge dewatering area on the Facility continues to harbor PCBs, and although the sludge dewatering area is currently not used and has not been regraded or filled-in subsequent to use as a dewatering area, EPA's

[2] *Final Site Inspection Report for the Pepco Benning Road Site*, prepared on behalf of EPA Region 3, by Tetra Tech EM Inc, Pages 4-6, June 30, 2009, EPA Document Tracking Number 0763.
[3] National Oceanic and Atmospheric Administration, *White Paper on PCB and PAH Contaminated Sediment in the Anacostia River*, Page 9, February 23, 2009.

Site Investigation indicates that PCBs were detected in every soil sample collected from the former sludge dewatering area ranging from 83 μg/kg of Aroclor-1260 to 2,200 μg/kg for Aroclor-1254.

EPA has conducted several environmental investigations at the Pepco facility and recently completed sampling of soil and sediments at the site in September 2008 as part of its Site Investigation (SI) efforts. EPA's SI concludes that high levels of PCBs at this facility and in the Anacostia's sediment may pose unacceptable risk to aquatic organisms, as they exceed EPA's Biological Technical Assistance Groups (BTAG) sediment screening levels. The Report further states that "analytical results obtained during this sampling event indicate that PCBs have been released from the site to the Anacostia River. The concentrations of PCBs and some metals in the Anacostia River downstream of the site were greater than three times the concentrations reported in upstream samples, indicating that, although other sources of contamination likely exist in the area, the Facility is at least partially responsible for the PCB and metals contamination detected in the vicinity of the site[4]."

4. Imminent and Substantial Endangerment Caused by PCB Releases into the Anacostia.

   a. Risk to Human Health and the Environment from PCBs in the Anacostia.

PCBs belong to a broad family of man-made organic chemicals known as chlorinated hydrocarbons. PCBs were domestically manufactured from 1929 until their manufacture was banned in 1979. They have a range of toxicity and vary in consistency from thin, light-colored liquids to yellow or black waxy solids. Due to their non-flammability, chemical stability, high boiling point, and electrical insulating properties, PCBs were used in hundreds of industrial and commercial applications including electrical, heat transfer, and hydraulic equipment.

Prior to the 1979 ban, PCBs entered the environment during their manufacture and use in the United States. Today PCBs can still be released into the environment from poorly maintained hazardous waste sites that contain PCBs; illegal or improper dumping of PCB wastes; leaks or releases from electrical transformers containing PCBs; and disposal of PCB-containing consumer products into municipal or other landfills not designed to handle hazardous waste.

Once in the environment, PCBs do not readily break down and therefore may remain for long periods of time cycling between air, water, and soil. PCBs can accumulate in the leaves and above-ground parts of plants and food crops. They are also taken up into the bodies of small organisms and fish. As a result, people who ingest fish may be exposed to PCBs that have bioaccumulated in the fish they are ingesting.

PCBs have been demonstrated to cause a variety of adverse health effects. PCBs have been shown to cause cancer in animals. PCBs have also been shown to cause a number of serious non-cancer health effects in animals, including effects on the immune system, reproductive system, nervous system, and endocrine system. Studies in humans provide supportive evidence for potential carcinogenic and non-carcinogenic effects of PCBs.

[4] *Final Site Inspection Report for the Pepco Benning Road Site*, prepared on behalf of EPA Region 3, by Tetra Tech EM Inc, Page ES-3, June 30, 2009, EPA Document Tracking Number 0763.

The different health effects of PCBs may be interrelated, as alterations in one system may have significant implications for the other systems of the body.

Pepco's historic activities at the Facility have created an ongoing imminent and substantial endangerment to health and the environment. Specifically, it has been recognized for many years that water quality and sediment quality in the Anacostia River are highly degraded due to point source, non-point source pollution, and refuse. The problem has been made particularly troublesome because the lower reaches of the Anacostia River are tidally influenced and the slow moving water causes contaminants to settle out of the water column into bottom sediments and prevents flushing that might otherwise remove some of the contamination. Contaminated sediment can affect burrowing organisms that live within the sediment, fish that feed on those organisms, and people who consume those fish. The degree of contamination prompted public health agencies to establish advisories prohibiting fish consumption from the river. Although efforts have been initiated to control many of the sources, sediment acts as a repository for contaminants, most notably PCBs and PAHs. PCBs have been measured in Anacostia River sediments at concentrations between 2 μg/kg and 12,000 μg/kg, with a mean concentration of 579 μg/kg. The mean concentration exceeds a probable effects threshold for ecological resources by a factor of 2.

b. Sampling Results and Contamination.

All source samples collected at the Facility during EPA's SI were analyzed under EPA's contract laboratory program (CLP) in accordance with the EPA CLP Statement of Work for target compound list (TCL) VOCs, semi-volatile organic compounds (SVOC), PCBs, pesticides, and target analyte list (TAL) metals and cyanide. The complete analytical results for the surface soil samples collected during the SI are provided in Appendix B, Tables 1 through 6 of EPA's SI. Appendix A, Figures 4 and 5 of EPA's SI provide the source sampling locations and tables summarizing the metals and PAH/PCB concentrations detected at the source.

As shown in Appendix B, Table 4 of EPA's SI, PCBs were detected in every soil sample collected from the former dewatering area ranging from 83 μg/kg of Aroclor-1260 reported in PB-SS-08 to 2,200 μg/kg for Aroclor-1254 reported in PB-SS-02. The concentrations of compounds detected in soil samples were compared to EPA Region 3 Soil Screening Levels ("SSL") established for industrial soils. Aroclor-1254 was reported in two soil samples above the corresponding SSL of 740 μg/kg.

EPA Region 3's reported Biological Technical Assistance Groups (BTAG) levels for Aroclor-1254 and Aroclor-1260 is 59.8 μg/kg. As shown in Appendix B, Table 9 of EPA's SI, the PCBs Aroclor-1254 and Aroclor-1260 were detected in every sample collected from the Anacostia River. The lowest values of PCBs were reported in the three most upstream samples. Every downstream sediment sample contained PCBs above the EPA BTAG and NOAA screening concentrations. The lowest values of PCBs found in the Anacostia sediment were reported in the three most upstream samples from Pepco. The maximum concentration reported was 1,700 μg/kg of Aroclor-1260,

detected from a sediment sample collected in an inlet located along the Anacostia River where a storm water outfall discharges. This storm water outfall receives storm water drainage from Pepco's site and other properties located in the vicinity. The second highest concentration of PCBs (Aroclor-1254 of 1,000 µg/kg and Aroclor-1260 of 1,100 µg/kg) were detected directly downstream of this outfall.

5. Intent to Sue

We are writing both to provide notice of the District of Columbia's present intention to sue Pepco, as required under RCRA § 7002(b)(2)(A), and to provide an opportunity for discussion prior to such suit. However, as expressed by EPA Region III in a letter to Pepco, signed by Ronald Borsellino, Director of the Hazardous Site Cleanup Division, and dated September 21, 2010, Region III will list the Facility on the National Priorities List by December 2010 if contamination at the Facility is not addressed in a timely manner. Accordingly, if Pepco determines that settlement of this matter is viable, the District will need to have completed such settlement by no later than early December of 2010.

If Pepco fails to meet this deadline, the District intends to sue Pepco in the United States District Court for the District of Columbia to seek abatement of the conditions described in this letter, and its accompanying attachments. We will seek abatement of the conditions that present an imminent and substantial endangerment which have been caused or contributed to by Pepco's historical activities at the Facility, including the discharge of PCBs into the environment. We will ask the court, among other things, to order Pepco to: (1) fund a thorough, independent, scientific study or studies designed to reveal the precise scope and nature of the endangerment and identify and propose to DDOE for its approval, effective, environmentally sound means to eliminate the endangerment; (2) fund appropriate abatement and cleanup measures, based on the results of the study or studies; (3) assess and pay for damages to natural resources; and (4) reimburse DDOE for its expenses in overseeing Pepco's performance of all of the above.

If you have questions about the issues raised in this letter or wish to discuss this matter with us, please contact Gabriela Delgadillo at the address and phone number listed below.

Sincerely,

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FINAL SITE INSPECTION REPORT FOR THE PEPCO BENNING ROAD SITE WASHINGTON D.C.

Prepared for

U.S. Environmental Protection Agency Region 3
Hazardous Site Cleanup Division
1650 Arch Street
Philadelphia, PA 19103

Prepared by

Tetra Tech EM Inc.
7 Creek Parkway, Suite 700
Boothwyn, PA 19061

EPA Contract No. EP-S3-05-02
Technical Direction Document No. E33-024-08-07-009
Document Tracking No. 0763

June 30, 2009

FINAL SITE INSPECTION REPORT FOR THE PEPCO BENNING ROAD SITE WASHINGTON D.C.

Prepared for

U.S. Environmental Protection Agency Region 3
Hazardous Site Cleanup Division
1650 Arch Street
Philadelphia, PA 19103

Prepared by

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Boothwyn, PA 19061

EPA Contract No. EP-S3-05-02
Technical Direction Document No. E33-024-08-07-009
Document Tracking No. 0763

June 30, 2009

Prepared by

Donna Davies
Project Manager

Approved by

Andy Mazzeo
Philadelphia Operations Manager

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EXECUTIVE SUMMARY

Tetra Tech EM Inc. (Tetra Tech) completed a site inspection (SI) under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) as amended by the Superfund Amendments and Reauthorization Act (SARA) for the Pepco Benning Road site located at 3400 Benning Road, NE in Washington D.C. EPA's Compensation, and Liability Information System (CERCLIS) database identifies the site as the Pepco Benning Road Facility, EPA Identification No. DCD983967951. The purpose of the SI was to evaluate analytical data collected during the SI under the Hazard Ranking System (HRS) to determine the need for additional action under CERCLA.

On September 3, 2008, Tetra Tech conducted field sampling activities at the site and adjacent Anacostia River. Tetra Tech collected 13 soil samples from an area located on the site known as the former dewatering area. This area was formerly used to dewater sludge that originated from cooling tower basins associated with an on-site generating station. Tetra Tech also collected 16 sediment samples and five surface water samples from the Anacostia River, upstream and downstream of the site. All samples were submitted under EPA's Contract Laboratory Program (CLP) for target compound list volatile organic compounds (VOC), semivolatile organic compounds (SVOC), pesticides and polycyclic biphenyls (PCB) and target analyte list metals analysis.

SVOCs, predominately polynuclear aromatic hydrocarbons (PAH) compounds, were detected in soil samples collected from the former sludge dewatering area. The maximum PAH compound detected was fluoranthene at 4,400 micrograms per kilogram (µg/kg). Other SVOCs reported in surface soil samples collected from the site include butylbenzylphthalate, detected up to 24,000 µg/kg, and bis(2-ethylhexyl)phthalate detected up to 1,600 µg/kg. PCBs were detected in every soil sample collected from the former sludge dewatering area ranging from 83 µg/kg of Aroclor-1260 to 2,200 µg/kg for Aroclor-1254. Metals detected three times above the levels reported in background soil samples included lead (up to 547 milligrams per kilogram [mg/kg]), copper (up to 547 mg/kg), nickel (up to 3,470 mg/kg), vanadium (up to 17,100 mg/kg) and zinc (up to 415 mg/kg).

The concentrations of compounds detected in soil samples collected from the former sludge dewatering area were compared to EPA Region 3 Soil Screening Levels (SSL) established for industrial soils. The SVOCs, benzo(a)anthracene, benzo(b)fluoranthene, benzo(a)pyrene, indeno(1,2,3-cd)pyrene and dibenzo(a,h)anthracene were all reported at concentrations above the corresponding industrial SSL established for these compounds. Aroclor-1254 was reported in two soil samples above the corresponding industrial SSL of 740 µg/kg.

The metals detected in soil samples collected from the former sludge dewatering area were also compared to EPA's SSL established for industrial soils. Lead was detected above EPA's recommended action level for lead of 400 mg//kg (there is no SSL established for lead) in one sample and vanadium was detected in one sample above the industrial SSL. No other inorganic compounds were reported above the corresponding industrial soil SSL.

PAHs were detected in every sediment sample collected from the Anacostia River. The range of total PAH concentrations reported was 2,020 µg/kg to a maximum concentration of 14,920 µg/kg. There was no distinct spatial distribution of the PAHs detected. The presence of PAHs in the Anacostia River appear to be indicative of ubiquitous levels in this vicinity of the Anacostia River rather than releases from the site.

PCBs, Aroclor-1254 and Aroclor-1260 were detected in every sample collected from the Anacostia River. The lowest values of PCBs were reported in the three most upstream samples. The maximum concentration reported was 1,700 µg/kg of Aroclor-1260 detected from a sediment sample (PB-SD-16) collected in an inlet located along the Anacostia River where a storm water outfall discharges. This storm water outfall receives storm water drainage from the site and other properties located in the vicinity. The second highest concentration of PCBs (Aroclor-1254 of 1,000 µg/kg and Aroclor-1260 of 1,100 µg/kg) were detected directly downstream of this outfall. The maximum levels of metals detected were also from the sediment sample collected in the vicinity of the outfall. No VOCs, SVOCs, pesticides or PCBs were reported above the CLP contract-required quantitation limits in any of the five surface water samples collected during the SI.

Analytical results obtained during this sampling event indicate that PCBs, specifically, Aroclor-1254 and Aroclor-1260, have been released from the site to the Anacostia River. PCBs remain within the sludge dewatering area and residue samples collected at the site during an EPA multi-media inspection completed in 1997 documented the presence of cadmium, chromium, copper, lead, mercury, nickel, zinc and PCBs in the Pepco Benning storm water system.. The concentrations of PCBs and some metals in the Anacostia River downstream of the site were greater than three times the concentrations reported in upstream samples, indicating that, although other sources of contamination likely exist in the area, the site is at least partially attributable to the PCB and metals contamination detected in the vicinity of the site. Aqueous samples are currently collected from the facilities storm water system as required for their NPDES permit. These results indicate that the storm water discharge from the site is not currently contaminated with PCBs. The contamination detected in the Anacostia River in the vicinity of the storm water outfall is most likely the result of historical discharges.

The levels of PCBs detected in the Anacostia River sediment samples were above screening concentrations established by EPA's Biological Technical Assistance Group (BTAG) and National Oceanic and Atmospheric Association's (NOAA) for aquatic life.

1.0 INTRODUCTION

Under Eastern Area Superfund Technical Assessment and Response Team (START) Contract No. EP-S3-05-02, Technical Direction Document (TDD) No. E33-024-08-07-009, U.S. Environmental Protection Agency (EPA) Region 3 tasked Tetra Tech EM Inc. (Tetra Tech), to conduct a site inspection (SI) under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) as amended by the Superfund Amendments and Reauthorization Act (SARA) for the Pepco Benning Road site located at 3400 Benning Road, NE in Washington D.C. EPA's Compensation, and Liability Information System (CERCLIS) database identifies the site as the Pepco Benning Road Facility, EPA Identification No. DCD983967951.

This SI was conducted in accordance with EPA's "Guidance for Performing Preliminary Assessments Under CERCLA" and "Guidance for Performing Site Inspections Under CERCLA (References [Ref.] 1 and 2). The purpose of this SI was to evaluate analytical data collected for the site to determine the need for additional action under CERCLA. The scope of the SI for the Pepco Benning site included a review of file information provided by EPA Region 3, a compilation and evaluation of potential targets, a site reconnaissance, development of a sampling and analysis plan, collection and analysis of environmental samples, evaluation of analytical data, and the calculation of a preliminary Hazard Ranking System (HRS) score. The preliminary HRS evaluation for this site has been submitted to EPA Region 3 as a separate, confidential document.

This report contains Section 1.0, the introduction, which presents the purpose of the SI and provides the organization of the report. This report summarizes site background information in Section 2.0; describes the source characteristics, and groundwater and surface water migration pathways in Sections 3.0, 4.0, and 5.0, respectively; discusses soil and air migration pathways in Section 6.0, and presents summaries and conclusions in Section 7.0. All figures are provided in Appendix A. Analytical data summary tables for samples collected as part of this SI are provided as Appendix B. A photographic documentation log is provided as Appendix C.

2.0 SITE BACKGROUND

This section describes the site's location, operational history, and waste characteristics.

2.1 LOCATION

The Pepco Benning Road facility is located at 3400 Benning Road NE, Washington, D.C. (see Figure 1, Site Location). The geographic coordinates for the approximate center of the site are 38.898 north latitude and 76.959 west longitude (Ref. 3). The site is located in a mixed industrial/residential/commercial area and is bordered to the north by the Washington D.C. Benning Road Transfer Station, the Kenilworth Maintenance Yard (part of the National Park Service) to the northwest, the Anacostia River and wetlands associated with the river to the west, Benning Road with commercial development to the south and residential areas to the east (Ref. 4). Residential communities, including the River Terrace community, are located to the south of the facility.

2.2 SITE DESCRIPTION AND OPERATIONAL HISTORY

The approximately 77 acre facility is used by Pepco to manage all operations and maintain all equipment associated with their electrical distribution system. Pepco refers to this facility as the Pepco Benning Road Service Center. The Benning Road site is where all used electrical equipment, or debris from cleanup or repairs of electrical equipment is brought for processing. In addition to these activities, an active oil-fired power plant is located on the western portion of the site. The power plant has been in operation since 1906. The power plant currently utilizes two generating units that were constructed in 1968 and 1972. For the past several years, the generating units for this power plant are only used during times of highest demand for electricity. In December 2001, Pepco was reorganized due to deregulation of the electrical power industry. The power plant is owned by Pepco Energy Services and operated by North American Energy Services. Pepco maintained ownership of the land the power plant is located on. Both Pepco and Pepco Energy Services are subsidiaries of Pepco Holding Incorporated (Refs. 4, 5 and 6).

The 77-acre site is completely surrounded by a fence with two guarded entrances (see Figure 2, Site Layout). The guard shacks are manned 24 hours a day, 7 days a week. One entrance is located off of Foote Street, the second entrance is located off of Benning Road. In the eastern section of the site are two large active substations (Substation #41 and Substation #7). To the

south of the substations is a large asphalt-covered Pepco employee parking lot. To the south of this area are railroad tracks and Buildings 56, 57 and the T & D Holding area. These areas are used for activities associated with processing the used electrical equipment and associated debris brought to the site for disposal. Refer to the June 26, 2008 Site Reconnaissance Trip Report for the Pepco Benning Road Site for a full description of the waste handling procedures currently followed at the facility (Ref. 7). The center of the site is occupied by buildings associated with office space, vehicle maintenance, equipment repair shops, and storage, including hazardous waste and materials. Two large oil/water separators are located in the center of the site, south of Building 75. Areas located outside of the buildings are used for new equipment storage and also storage of used electrical equipment after it has been processed for disposal. Structures located on the western portion of the site are associated with the active power plant. These structures include the generating station, cooling towers, three aboveground storage tanks and storage buildings. The aboveground storage tanks, surrounded by secondary containment walls, hold no. 4 fuel oil used to power the generating station (Refs. 4 and 6).

There are five regulated underground storage tanks (UST) at the site. One is a 15,000 gallon steel and fiberglass (dual walled) tank installed in 1988 and used to hold new transformer oil. A 20,000 gallon fiberglass tank was installed in 1975 to contain gasoline and a second 20,000 gallon coated steel tank was installed in 1979 to hold gasoline. A 2,000 gallon steel tank used to hold used oil was installed in 1976 and a 20,000 gallon composite steel and fiberglass tank was installed in 1991 to hold diesel fuel. All tanks have leak detection devices and have been tested for tightness (Refs. 4 and 6).

Railroad tracks enter the site in the south and run to the north. These tracks were formerly used to transport coal to the power plant and are no longer active (Ref. 4).

The majority of the site is covered in impervious material such as concrete or asphalt. Active storage areas not covered in impervious material are covered in gravel. The only area on the site not covered with asphalt, concrete or gravel is an area located in the western portion of the site, directly south of the cooling towers. This area was used at one time for the storage of coal when the power plant used coal (it currently uses No. 4 fuel oil) to generate electricity. Later, this area was used to dewater sludge cleaned out from the basins located underneath the cooling towers. The area is no longer used for any purpose. The only other areas on the site that are covered in

soil are along borders of parking lots or office buildings. Low impact development (LID) rain gardens have been constructed in these areas. These LID rain gardens are built in low-lying areas and are intended to absorb and filter storm water runoff near its source (Ref. 4).

2.3 PREVIOUS INVESTIGATIONS

There have been numerous documented cleanups of contaminated soil and other materials completed at the site. In 1985, an underground pipe which was used to transfer waste oils containing PCBs from the Kenilworth Transformer Shop (in area of what is now Building 56) to two waste oil aboveground storage tanks located on a bermed concrete pad outside of the building had leaked. The leak was discovered when oil appeared on the asphalt located adjacent to the concrete pad. A test pit was excavated to determine the source of the leak. It was determined that a 2-inch underground pipe that transferred PCB-oil to the storage tanks was leaking. Remediation efforts initially focused on determining the extent of contamination. Boring samples collected under the concrete pad indicated oil at depths up to 48 inches below the ground surface (bgs). A PCB concentration of 3,000 parts per million (ppm) was detected in a soil sample collected directly under the concrete pad in the vicinity of the leaking pipe. Soil samples collected at 8 feet bgs indicated PCB concentrations of 10 ppm. Remediation for the leak included removal of the storage tanks, excavation of the concrete pad, rerouting of the pipe, and removal of all soils and other materials with PCB concentration over 5 ppm. Confirmatory sampling was performed after removal of the material to ensure all contaminated material had been removed (Ref. 11).

In 1988, soil samples were collected from an area designated to be paved for use as a parking lot. This area had been used for storing transformers and other used electrical equipment before the T & D Holding Area was constructed. A fifty foot grid was set-up in this area and one soil sample was collected from a depth of 12 inches bgs from each grid block. The samples were tested for PCBs only. All grid areas were clean (10 ppm or less) with the exception of an area around a concrete pad that was used to prepare off-line PCB capacitor banks for disposal. Samples were collected to determine the extent of PCB contamination in this area. Results indicated PCB concentrations up to 140 ppm in a 100 foot by 100 foot area and up to 12 inches bgs. Approximately, 389 tons of PCB-contaminated soil was removed from this area and disposed of off site. This area has subsequently been paved over and is used as a parking lot (Ref. 12).

In 1991, a leaking PCB capacitor was discovered in a concrete covered area between Buildings 42 and 61. Approximately, 8 pounds of PCBs had leaked onto the concrete surface and seeped through the expansion joints into the underlying soil. The concrete and soil underlying the leak were excavated and soil samples were collected to confirm all contaminated material was removed. After analytical results were received documenting the effectiveness of the cleanup, the area was backfilled and the concrete was replaced (Ref. 13).

In 1995, routine sampling of the sludge that had been placed in the area for dewatering indicated contamination with PCBs. This sludge originated from the generating station's cooling tower basins. The source of the PCB was determined to be PCB-contaminated caulk and joint filler located inside the cooling towers. The following materials were determined to be contaminated with PCBs: the cooling tower concrete basins, sludge inside the basins, water inside the basins and soil adjacent to the basin's wall expansion joints. Pre-cleanup sampling was implemented to determine the extent of contamination. As part of this sampling, soil samples were collected from around the perimeter of the cooling towers and sediment samples were collected from the cooling tower blowdown discharge. This discharge enters the 54-inch storm water pipe that discharges through outfall 013 and eventually into the Anacostia River. The pre-cleanup sampling result indicated that no PCBs were detected (detection limit of 1 ppm) from the sediment sample collected at this discharge point. The highest concentration of PCBs detected in the soil surrounding the concrete basins was 975 ppm. All soils contaminated with PCBs at greater than 1 ppm were excavated and removed (a total of 185 cubic feet). The area was restored with clean backfill. The old joint filler and caulk was removed and the expansion joints and basin were double washed and rinsed. All standing water was removed. The basin was encapsulated with concrete sealant. After cleanup and encapsulation the cooling tower basins were filled with water to operate the circulating water system. Post cleanup basin water was tested for PCBs. Analytical results indicated that no residual PCBs remained. EPA Region 3's Technical Assistance Team was involved and oversaw this cleanup effort (Ref. 14).

In 1997, EPA conducted a multi-media investigation of the Pepco Benning facility. During this investigation, an EPA inspector observed oil stains on the outside of one of the two 10,000 gallon holding tanks used to accumulate PCB oils. Reportedly, the stains originated from an incident that occurred when the operator was switching the oil inlet pipe from tank no. 1 to tank no. 2. According to Pepco's Environmental Management Services Manager, Denise Campbell,

this release was fully contained in the concrete vaults the tanks sit in and no release into the environment occurred (Ref. 4).

Finally, in 2003 Pepco tasked a subcontractor to conduct a soil investigation within an area known as the salvage yard. This area is located to the west of Building 75 and 88 and was used for storing used electrical equipment. Twenty soil samples were collected from this area from 0 to 24 inches bgs. The samples were analyzed for lead, cadmium, chromium, total petroleum hydrocarbons (TPH) and PCBs. TPH concentrations reported indicated petroleum hydrocarbon contamination existed in the soils. PCBs were detected in 18 of the 20 samples at concentrations ranging from 0.028 ppm to 2.8 ppm and up to 24 inches bgs. The extent of TPH soil contamination was defined (up to 8 feet bgs) and TPH-contaminated soil was excavated and disposed of off site. Soil lithology recorded during this investigation indicated silty-sand, sand and gravel. The saturated zone was encountered at 14 feet bgs (Ref. 15).

Table 1 summarizes the previous investigations that have been completed at the facility.

TABLE 1
PREVIOUS INVESTIGATIONS

Date	Incident	Location	PCB Concentration Detected			Remediation Activities
			Matrix	Maximum Concentration	Depth	
1985	Underground pipe that led from Kenilworth Transformer Shop to aboveground storage tank leaked waste transformer oil into underlying soil.	Building 56 currently located in vicinity where leak occurred	Soil	3,000 ppm	Directly below transfer oil pipe	Removal of aboveground storage tank, associated piping and excavation of all material contaminated with PCBs above 5 ppm
			Soil	10 ppm	8 feet bgs	

TABLE 1
PREVIOUS INVESTIGATIONS (continued)

Date	Incident	Location	PCB Concentration Detected			Remediation Activities
			Matrix	Maximum Concentration	Depth	
1988	Soil contamination detected under concrete pad used to prepare off-line PCB capacitor banks for disposal in area formerly used to store used electrical equipment.	Current location of parking lot located in northeast portion of facility.	Soil	140 ppm	Up to 12 inches bgs	Removal of concrete pad and 389 tons of PCB-contaminated soil. Area covered with asphalt for parking lot.
1991	Approximately, 8 pounds of PCBs leaked from a PCB capacitor onto a concrete surface and seeped through expansion joints into underlying soil.	Concrete covered area located between Buildings 42 and 61	Soil	PCB capacitor oil leak – assumes PCB concentration greater than 500 ppm	Directly below concrete pad	All PCB-contaminated materials removed. After analytical results confirmed effectiveness of cleanup (all soils with greater than 25 ppm PCBs removed), area backfilled and concrete replaced.
1995	PCB-contaminated caulk and joint filler located inside cooling towers	Area around cooling tower blowdown basins	Soil	975 ppm	3 feet bgs	All PCB contaminated soil above 1 ppm removed (185 cubic feet) and area restored with clean fill

TABLE 1
PREVIOUS INVESTIGATIONS (continued)

Date	Incident	Location	PCB Concentration Detected			Remediation Activities
			Matrix	Maximum Concentration	Depth	
1997	Oil staining observed on outside of one of two 10,000 gallon holding tanks used to accumulate PCB oils. Spill occurred when operator was switching oil inlet pipe from tank no. 1 to tank no. 2.	PCB oil holding tanks	Exterior of tank	No release to environment occurred	No release occurred	No release occurred.
2003	Soil investigation in area formerly used for storing used electrical equipment.	Area known as salvage yard located west of Buildings 75 and 88	Soil	2.8 ppm	Up to 24 inches bgs	All contaminated soil excavated and disposed of off site.

Notes: Bgs = below ground surface

PCBs = polychlorinated biphenyls

ppm = parts per million

As part of this SI, on June 10, 2008, Tetra Tech conducted a site reconnaissance. Tetra Tech was accompanied on the site walk-through by the following Pepco representatives: Denise Campbell, Manager, Environment Management Services, John Keiller, Enivronmental Coordinator and William Merkel, Hazardous Waste Inspector. The purpose of the site reconnaissance was to document current conditions, collect information regarding current and past site activities and waste handling procedures and identify potential sources of hazardous substances available to migrate into the environment. Sampling locations for this sampling event were determined based on this site reconnaissance and subsequent information obtained from Pepco representatives (Ref. 4).

3.0 SOURCE CHARACTERISTICS

3.1 SOURCE AREA

As detailed in the sections above, there have been numerous known spills and leaks of PCBs on the Pepco Benning Road site. Information regarding the subsequent cleanup of these spills has been summarized above. In addition, due to the historical use of this property for industrial purposes, hazardous substances have likely migrated from the property into the adjacent Anacostia River via the storm water system, overland flow or groundwater discharge. Currently, the site is properly managed and spills and leaks of hazardous substances, including PCBs are quickly addressed and if necessary properly remediated. The only potential uncontained potential source identified on the site is the approximately 14,397 square foot former sludge dewatering area. The area is currently not used and does not appear to have been regraded or filled-in subsequent to use as a dewatering area. Tetra Tech collected soil samples from this area to characterize the hazardous substances associated with the potential source. Section 3.2 describes the soil sampling locations and Section 3.3 discusses the analytical results.

3.2 SAMPLING LOCATIONS

On September 3, 2008, Tetra Tech collected 13 surface soil samples from the former sludge dewatering area. Seven of the samples (including one duplicate sample) were collected between 0 to 6 inches below the ground surface (bgs) and six of the samples were collected between 6 to 12 inches bgs (see Appendix A, Figure 3, Sampling Location Map). The subsurface samples were collected to ensure that contaminated soil is not located under uncontaminated surface soil. According to Pepco representatives, no fill material has ever been added to this area. In addition to the 13 soil samples collected from the site, two background surface soil samples (PB-SS-14 and PB-SS-15) were collected in Anacostia Park, a recreational park located adjacent to the Anacostia River outside the influence of the site. Table 2 provides identifiers, dates, and location descriptions for samples collected during the SI.

TABLE 2
SOURCE SAMPLING SUMMARY

Sample Identifiers	Matrix	Date	Depth (inches)	Sample Location and Description
PB-SS-01	Soil	9/3/08	0-6	Collected in northwest corner of the former dewatering area. Light brown/tan sandy material with cobbles and stones. Duplicate sample of PB-SS-07
PB-SS-02	Soil	9/3/08	0-6	Collected at middle sampling location along western boundary of former dewatering area, south of PB-SS-01. Light brown/tan sandy material with cobbles and stones.
PB-SS-03	Soil	9/3/08	0-6	Collected in southwest corner of the former dewatering area. Light brown/tan sandy material with cobbles and stones.
PB-SS-04	Soil	9/3/08	0-6	Collected in northeast corner of the former dewatering area. Light brown/tan sandy material with cobbles and stones.
PB-SS-05	Soil	9/3/08	0-6	Collected at middle sampling location along eastern boundary of former dewatering area, south of PB-SS-04. Light brown/tan sandy material with cobbles and stones.
PB-SS-06	Soil	9/3/08	0-6	Collected in southeastern corner of former dewatering area, south of PB-SS-05. Light brown/tan sandy material with cobbles and stones.
PB-SS-07	Soil	9/3/08	0-6	Duplicate sample of PB-SS-01.
PB-SS-08	Soil	9/3/08	6-12	Collected in northwestern corner of former dewatering area. Collocated with PB-SS-01. Light brown/tan sandy material with cobbles and stones.
PB-SS-09	Soil	9/3/08	6-12	Collected at middle sampling location along western boundary of former dewatering area, collocated with PB-SS-02. Light brown/tan sandy material with cobbles and stones.
PB-SS-10	Soil	9/3/08	6-12	Collected in southwest corner of the former dewatering area, collocated with PB-SS-03. Light brown/tan sandy material with cobbles and stones.
PB-SS-11	Soil	9/3/08	6-12	Collected in northeast corner of the former dewatering area, collocated with PB-SS-04. Light brown/tan sandy material with cobbles and stones.

TABLE 2
SOURCE SAMPLING SUMMARY (cont'd)

Sample Identifiers	Matrix	Date	Depth (inches)	Sample Location and Description
PB-SS-12	Soil	9/3/08	6-12	Collected at middle sampling location along eastern boundary of former dewatering area, collocated with PB-SS-05. Light brown/tan sandy material with cobbles and stones.
PB-SS-13	Soil	9/3/08	6-12	Collected in southeastern corner of former dewatering area, collocated with PB-SS-06. Light brown/tan sandy material with cobbles and stones.
PB-SS-14	Soil	9/3/08	0-12	Background soil sample collected in Anacostia Park outside the influence of the Pepco Benning site. Medium-grained, light brown sand with cobbles.
PB-SS-15	Soil	9/3/08	0-12	Background soil sample collected in Anacostia Park outside the influence of the Pepco Benning site. Fine to medium-grained brown sand with cobbles.

3.3 ANALYTICAL RESULTS

All source samples collected at the Pepco Benning site were analyzed under EPA's contract laboratory program (CLP) in accordance with the EPA CLP Statement of Work for target compound list (TCL) VOCs, semi-volatile organic compounds (SVOC), PCBs, pesticides, and target analyte list (TAL) metals and cyanide. The analytical results for the surface soil samples collected during the SI are provided in Appendix B, Tables 1 through 6. Appendix A, Figures 4 and 5 provide the source sampling locations and tables summarizing the metals and PAH/PCB concentrations detected at the source. Table 3 below summarizes the analytical data reported from samples collected from the source.

TABLE 3
SOURCE SAMPLING ANALYTICAL RESULTS SUMMARY

Hazardous Substance Detected	Maximum Background Concentration (µg/kg)	Range of Concentrations Detected at Source (µg/kg)	Average Concentration Detected at Source (µg/kg)	EPA Industrial SSL (µg/kg)
2-methylnapthalene	ND	200	200	4.1×10^6
Acenaphthene	ND	340	340	3.3×10^7
Anthracene	ND	ND - 850	259	1.7×10^8
Benzo(a)anthracene	380	480 – 4,300	973	2.1×10^3
Benzo(b)fluoranthene	420	500 – 1,600	930	2.1×10^3
Benzo(k)fluoranthene	270	250 – 1,100	499	2.1×10^4
Chrysene	360	430 – 1,600	821	2.1×10^5
Dibenzo(a,h)anthracene	ND	ND – 850	259	2.1×10^2
Fluorene	ND	ND – 340	267	2.2×10^7
Fluoranthene	660	690 – 4,400	1,367	2.2×10^7
Indeno(1,2,3-cd)pyrene	220	270 – 1,700	522	2.1×10^3
Pyrene	550	610 - 2,800	1,033	1.7×10^7
Total PAHs	3,930	1,960 - 17,890	8,130	NA
Aroclor-1254	ND	95 – 2,700	475	7.4×10^2
Aroclor-1260	53	ND - 310	124	7.4×10^2
Metal Detected	**Maximum Background Concentration (mg/kg)**	**Range Detected at Source (mg/kg)**	**Average Level Detected at Source (mg/kg)**	**EPA Industrial SSL (mg/kg)**
Arsenic	2.5	3.2 – 7.6	8.2	1.6
Cadmium	0.92	1.1 – 2.3	1.6	NA
Chromium	25.7	24.2 – 83.0	52	1.4×10^3
Copper	30.7	29.8 – 547	233	4.1×10^4
Iron	18,700	15,600 – 26,500	24,208	7.2×10^5
Lead	47.0	92.4 – 611	199	800
Mercury	0.30	0.16 – 0.46	0.26	24
Nickel	42.1	123 - 1,880	847	2.0×10^4
Vanadium	32.4	224 – 17,100	3,728	7,200
Zinc	64.4	70.9 - 364	227.4	3.1×10^5

Notes: µg/kg = micrograms per kilogram
mg/kg = milligrams per kilogram
ND = Not detected above the contract-required quantitation limit
PAHs = Polynuclear aromatic hydrocarbons
SSL = Soil screening level

As shown in Appendix B, Table 1, low levels of acetone and trichloroethene were detected in surface soil samples collected from the site; however these compounds were not reported significantly above the concentrations detected in laboratory blanks and therefore, cannot be attributed to the site. The only VOC that was detected significantly above the concentration reported in a laboratory blank was chloroform. Chloroform was detected in two soil samples (at 30 micrograms per kilogram [µg/kg]) collected form the former dewatering area.

As shown in Appendix B, Table 2, numerous SVOCs, specifically, polynuclear aromatic hydrocarbons (PAH) compounds were reported in all of the soil samples collected from the former dewatering area. The maximum PAH compound detected was reported for fluoranthene at 4,400 µg/kg in PB-SS-04. Numerous PAHs were also reported in the two background soil samples analyzed. Other SVOCs reported in surface soil samples collected from the site include butylbenzylphthalate, detected up to 24,000 µg/kg and bis(2-ethylhexyl)phthalate detected up to 1,600 µg/kg.

As shown in Appendix B, Table 3, numerous pesticides were reported in all of the surface soil samples collected from the site. The maximum concentration was reported for endrin aldehyde at 1,400 µg/kg. The only pesticide detected in a background sample was endosulfan sulfate, detected at 7.8 µg/kg.

As shown in Appendix B, Table 4, PCBs were detected in every soil sample collected from the former dewatering area ranging from 83 µg/kg of Aroclor-1260 reported in PB-SS-08 to 2,200 µg/kg for Aroclor-1254 reported in PB-SS-02. Aroclor-1254 was also reported in one of the background samples, PB-SS-14 at an estimated concentration of 53 µg/kg.

The concentrations of compounds detected in soil samples were compared to EPA Region 3 SSL established for industrial soils. None of the VOCs detected were reported above the corresponding SSL. The SVOCs, benzo(a)anthracene, benzo(b)fluoranthene, benzo(a)pyrene, indeno(1,2,3-cd)pyrene and dibenzo(a,h)anthracene were all reported at concentrations above the corresponding SSL established for these compounds. No pesticide compounds were detected above the corresponding SSL. Aroclor-1254 was reported in two soil samples above the corresponding SSL of 740 µg/kg.

The inorganic compounds detected in soil samples collected from the former dewatering area are shown in Appendix B, Table 5. The inorganic compounds detected were compared to EPA's SSL established for industrial soils and the background soil samples. The levels of arsenic detected in every sample were above the corresponding EPA SSL for industrial soil. The arsenic levels reported in the background soil samples were also above the EPA SSL. Arsenic is a naturally-occurring substance often detected in soils above the SSL. The levels detected in the soil samples did not significantly exceed the background level. Lead was detected above EPA's recommended action level for lead of 400 milligrams per kilogram (mg/kg) (there is no SSL established for lead) in one sample (PB-SS-06). This concentration also exceeded three times the level reported in the background sample. Vanadium was detected in one sample (PB-SS-13) above the SSL of 7,200 mg/kg and also exceeded three times the level reported in the background sample. No other inorganic compounds were reported above the corresponding industrial soil SSL. The levels of copper, nickel and zinc detected in the soil samples exceeded three times the level reported in the background samples.

3.4 SOURCE CONCLUSIONS

SVOCs, specifically PAH compounds and PCBs (Aroclor-1254 and Aroclor-1260) were reported in soil samples collected from the former dewatering area at concentrations exceeding EPA industrial soil SSLs and the concentrations reported in the background samples (Ref. 16). The concentration of arsenic reported in every sample is above EPA's SSL for industrial soil; however, the levels reported were not significantly above the level detected in the background sample. This indicates that the levels of arsenic detected are within the range expected in soil located in this area. Vanadium was also detected in one soil sample above the corresponding EPA industrial soil SSL and lead was detected in one soil sample above EPA's recommended action level.

4.0 GROUNDWATER MIGRATION PATHWAY

This section describes the site's hydrogeologic setting, the targets associated with the groundwater migration pathway, and conclusions that can be made for the groundwater migration pathway.

4.1 HYDROGEOLOGIC SETTING

The site lies in the Atlantic Coastal Plain geologic province, approximately three miles southeast of the boundary between the Piedmont and Coastal Plain provinces. The Atlantic Coastal Plain province borders the Atlantic Ocean and consists of gravel, sand, silt and clay. The layers form geologic formations that range in age from Cretaceous to Holocene. The geologic units underlying the site are the Patuxent Formation, Arundel Clay, and the Patapsco Formation, these formations, consisting of alternating beds of sand, silt and clay form the Potomac Group. Aquifers are formed in the sand layers of the formations, with silt and clay layers forming confining beds. The aquifers found in the Potomac Group consist of multiple sand layers within the Patapsco and Patuxent Formations and include (from shallowest to deepest) the upper Patapsco aquifer, lower Patapsco aquifer, upper Patuxent aquifer and lower Patuxent aquifer. The lower Patapsco and upper Patuxent aquifers are separated by the Arundel Clay. Near the surface, the site is underlain by recent marsh deposits and mudflats of the Anacostia River and other alluvial deposits including thin sands. The depth to the Patuxent aquifer beneath the site is estimated to be 140 to 180 feet. Groundwater directly underlying the site is expected to flow laterally towards the adjacent Anacostia River (Refs. 17 and 18).

4.2 GROUNDWATER TARGETS

There are no potential groundwater drinking water targets located within a 4-mile radius of the site (Ref. 19). Based on the hydraulic gradients in the area, groundwater flows laterally from the site to the adjacent Anacostia River (Ref. 20).

4.3 GROUNDWATER CONCLUSIONS

There are no drinking water targets associated with the groundwater migration pathway. The site is located adjacent to surface waters (Anacostia River); therefore, the groundwater to surface water migration pathway is the primary concern associated with the groundwater migration pathway. The surface water targets are detailed in Section 5.0.

5.0 SURFACE WATER MIGRATION PATHWAY

This section describes the site's hydrologic setting, targets associated with the surface water migration pathway, and conclusions made for the surface water migration pathway.

5.1 HYDROLOGIC SETTING

The site is located adjacent to the Anacostia River, all overland flow eventually discharges into the Anacostia River. The Anacostia River flows for approximately 5 miles prior to discharging into the Potomac River. The 15-mile downstream target distance limit (TDL) is completed in the Potomac River. A large storm water system with many discharges and outfalls is associated with this site. Pepco currently maintains an EPA National Pollution Discharge Elimination System (NPDES) permit. As part of Pepco's renewal application for their NPDES permit, a dye test was performed during a rain event to confirm mapped storm sewer connections and drainage areas on the site (Ref. 8). This dye test documented 33 separate runoff sub basins with 26 internal discharges and 11 outfalls where flow leaves the site. This test confirmed that all process water generated on the site is discharged into the main storm drain that runs across the site from the southeast corner to the northwest. This drain is 48 inches in the southeastern portion of the site and becomes 54 inches in the center of the site. This 54 inch pipe discharges through the main outfall leaving the facility, outfall 013. The overland flow from the former dewatering area would enter the on-site storm water system and eventually discharge from outfall 013. This outfall is located in the northwestern portion of the site. From this outfall the flow enters a pipe that leads under Anacostia Avenue and eventually discharges to the Anacostia River from a large storm water discharge pipe located in an inlet of the Anacotia River (Refs. 4 , 7 and 8). The storm water drain outfall is the probable point of entry (PPE) of hazardous substances migrating from the site into the nearest perennial surface waters. Figure 6 in Appendix A shows the 15-mile downstream surface water migration pathway.

Water that does not enter the 54-inch main storm drain, discharges through outfalls connected to pipes that discharge into the Anacostia River or enter the Washington D.C. storm water system. A map of the Washington D.C. storm water and sewer drainage system for this area indicates that these outfalls enter a separate storm water system and discharge through outfalls located on the Anacostia River (Refs. 4 and 9).

As part of Pepco's current NPDES permit, eight on-site storm water discharges are sampled quarterly. Samples are analyzed for pH, oil & grease, nitrogen, phosphorous, iron, cadmium, copper, lead, nickel, zinc, and PCBs (aroclor-1242, aroclor-1254 and aroclor-1260). Included in the discharges routinely sampled are the storm sewers most at risk for receiving PCB-contaminated runoff. These discharges include the T & D Holding Area (discharge 402),

Building 68 (hazardous and PCB waste storage building) (discharge 416), and the oil/water separators (discharge 003). In addition to the internal discharges, two outfalls are also sampled quarterly as part of the NPDES permit, the main outfall leaving the facility (outfall 013) and an outfall located along Foote Street that is connected to the Washington, D.C. storm water system (outfall 401). There have been no NPDES violations recorded for this facility. The latest NPDES monitoring results were obtained and reviewed by Tetra Tech, no exceedances were recorded and no PCBs were detected in any of the samples collected (Refs. 4, 8 and 10).

The USGS maintains a gauging station on the bank of the Anacostia River at the Aquatic Gardens, approximately 1/2 mile upstream of the site. The Anacostia River is tidal in this area with an average tidal range of approximately 3 feet (Refs. 20 and 21).

5.2 SURFACE WATER TARGETS

There are no drinking water supply intakes located within the 15-mile downstream TDL from the PPE (Ref. 19). The DC Water and Sewer Authority provides drinking water to the population residing in the vicinity of the site and maintains an intake on the Potomac River outside the 15-mile TDL (Ref. 22).

Other potential targets identified along the surface water migration pathway are human consumption of contaminated fish, critical habitat for federally-listed endangered or threatened species and wetlands. A fish consumption advisory has been issued for the Anacostia River due to elevated levels of PCBs; however, according to an EPA report completed in 1997, a large percentage of anglers who fish the Anacostia consumes fish species found to have high levels of contamination (Refs. 23 and 24). According to the US Fish and Wildlife Service, no federally-listed endangered or threatened species are known to occur within the 15-mile TDL; therefore, the only known sensitive environment located along the TDL are approximately 47,850 linear feet of wetlands (Appendix A, Figure 6) (Ref. 25). The nearest wetland to the site was constructed by Pepco Benning and is located along the western border of the site (Ref. 4).

5.3 SAMPLING LOCATIONS

During the SI sampling event, Tetra Tech collected 16 sediment samples and five surface water samples from the Anacostia River. The samples were collected in accordance with the approved August 29, 2008 sampling and analysis plan. All sampling locations (with the exception of PB-

SD-16 and PB-SW-03) were accessed from a boat approximately 10 to 15 feet from the eastern bank of the river. A Ponar dredge sampler was utilized to collect the sediments from the river bottom. All sampling locations are shown in Appendix A, Figure 3. Figures 7 and 8 in Appendix A provides the sampling locations and tables summarizing the metals and PAHs/PCBs detected in sediment samples. Table 4 summarizes the surface water and sediment sampling locations collected to assess the surface water migration pathway during the SI.

TABLE 4
SURFACE WATER MIGRATION PATHWAY SAMPLING SUMMARY

Sample Identifiers	Matrix	Date	Depth of Sediment (inches)	Sample Description
PB-SD-01	Sediment	9/3/08	0-6	Collected at most downstream location in Anacostia River. Medium-brown silt with large amount of organic matter.
PB-SD-02	Sediment	9/3/08	0-6	Collected downstream of E. Capitol Street Bridge. Medium brown silty-sand.
PB-SD-03	Sediment	9/3/08	0-6	Collected downstream of E. Capitol Street Bridge. Medium brown silty-sand.
PB-SD-04	Sediment	9/3/08	0-6	Collected between E. Capitol Street Bridge and Benning Road Bridge. Medium brown silty-sand.
PB-SD-05	Sediment	9/3/08	0-6	Collected directly downstream of Benning Road Bridge. Medium brown silt.
PB-SD-06	Sediment	9/3/08	0-6	Collected adjacent to Pepco Benning site. Medium brown silt with large amount of organics.
PB-SD-07	Sediment	9/3/08	0-6	Collected directly downstream of PPE. Medium-brown silty clay.
PB-SD-08	Sediment	9/3/08	0-6	Collected in front of small inlet where outfall No. 13 discharges (PPE). Medium brown sandy-silt.
PB-SD-09	Sediment	9/3/08	0-6	Medium brown silt with large amount of organics.

TABLE 4
SURFACE WATER MIGRATION PATHWAY SAMPLING SUMMARY (cont'd)

Sample Identifiers	Matrix	Date	Depth of Sediment (inches)	Sample Description
PB-SD-12	Sediment	9/3/08	0-6	Collected downstream of Kenilworth Park Landfill site. Medium brown silt.
PB-SD-13	Sediment	9/3/08	0-6	Collected at most upstream location in vicinity of Kenilworth Park Landfill site. Medium brown silt.
PB-SD-14	Sediment	9/3/08	0-6	Collected adjacent to Pepco Benning wetlands. Medium brown silt.
PB-SD-15	Sediment	9/3/08	0-6	Collected from wetlands adjacent to Pepco Benning. Medium brown silt with large amount of organics. Very large amount of garbage observed along river bank in this area.
PB-SD-16	Sediment	9/3/08	0-6	Collected from bank of small inlet where Outfall No. 13 discharges (PPE). Sediment had oil-staining and petroleum odor.
PB-SW-01	Surface water	9/3/08	NA	Surface water sample collected at same location as PB-SD-02. Duplicate sample is PB-SW-05.
PB-SW-02	Surface water	9/3/08	NA	Surface water sample collected at same location as PB-SD-14.
PB-SW-03	Surface water	9/3/08	NA	Surface water sample collected at same location as PB-SD-16.
PB-SW-04	Surface water	9/3/08	NA	Surface water sample collected at same location as PB-SD-11.
PB-SW-05	Surface water	9/3/08	NA	Surface water sample collected at same location as PB-SD-02. Duplicate sample is PB-SW-01.

5.4 ANALYTICAL RESULTS

All samples collected at the Pepco Benning site were analyzed by an EPA CLP laboratory in accordance with the EPA CLP Statement of Work for TCL VOCs, TCL SVOC, PCBs, pesticides, and TAL metals and cyanide. Analytical summary tables for the surface water and sediment samples collected during the SI are provided in Appendix B, Tables 6 through 11. Table 5 below summarizes the analytical data reported for the sediment samples collected from the Anacostia River and provides the EPA Region 3's Freshwater Sediment Screening Benchmarks developed by the Biological Technical Assistance Group (BTAG) and values

presented in the National Oceanic and Atmospheric Administration's (NOAA) Screening Quick Reference Tables (SQuiRTs).

TABLE 5
ANACOSTIA RIVER SAMPLING ANALYTICAL RESULTS SUMMARY

Hazardous Substance Detected	Maximum Upstream Concentration (µg/kg)	Range of Downstream Concentrations (µg/kg)	Average Downstream Concentration (µg/kg)	Sediment Screening Criteria	
				EPA (µg/kg)	NOAA (µg/kg)
Anthracene	ND	ND – 210	175	57.2	10/260
Benzo(a)anthracene	280	ND – 1,200	699	108	15.72/500
Benzo(b)fluoranthene	870	470 - 1,500	1,047	27.2	NA
Benzo(k)fluoranthene	240	190 -1,200	787.5	27.2	NA
Chrysene	320	350 – 1,300	1,190	166	26.83/800
Dibenzo(a,h)anthracene	ND	ND – 411	259	33	10/100
Fluorene	ND	ND – 950	211	77.4	10/300
Fluoranthene	570	360 – 2,300	1,748	423	31.46/1500
Indeno(1,2,3-cd)pyrene	ND	ND – 1,100	586	17	17.32/330
Pyrene	ND	310 – 2,200	1,205	195	44.27/1000
Aroclor-1254	40	ND - 1000	250	59.8	34.1/26
Aroclor-1260	ND	ND - 1700	285	59.8	34.1/26
Metal Detected	**Maximum Upstream Concentration (mg/kg)**	**Range of Concentrations (mg/kg)**	**Average Concentration (mg/kg)**	**Sediment Screening Criteria**	
				EPA (mg/kg)	**NOAA (mg/kg)**
Arsenic	ND	ND – 18.1	2.34	9.8	5.9/17
Cadmium	0.50	0.82 – 25.7	2.67	0.99	0.596/3
Chromium	26.5	10.6 – 78.7	39.32	43.4	37.3/95
Copper	28.7	28.9 – 422	90.39	31.6	35.7/86
Iron	6,900	9,650 – 27,600	20,578	20,000	4%
Lead	39.8	30.1 – 1,150	137.5	35.8	35/127
Mercury	0.098	ND – 0.13	0.26	0.18	0.174/0.560
Nickel	21.0	15.8 – 292	48.88	22.7	18/43
Vanadium	28.0	12.3 – 948	103	NA	NA
Zinc	119	57.9 – 2,030	216.6	121	123.1/520

As shown in Appendix B Table 6, several VOCs were detected at low concentrations in sediment samples collected from the Anacostia River. The concentrations detected were compared to the freshwater sediment screening criteria developed by EPA Region 3's Freshwater Sediment

Screening Benchmarks developed by BTAG and values presented in NOAA's SQuiRTs. The only VOC reported above a corresponding benchmark was carbon disulfide, which was detected at 7.2 ug/kg in PB-SD-06.

This sampling location had a large amount of organic matter present; therefore, this compound is not associated with the site.

The SVOC compounds detected in sediment samples are summarized in Appendix B, Table 7. The majority of SVOCs detected were PAH compounds. Every sediment sample collected during the sampling event, including samples collected upstream of the site had concentrations of PAHs above corresponding sediment screening criteria. The range of total PAH concentrations reported was 2,020 µg/kg in PB-SD-02 to a maximum concentration of 14,920 µg/kg in sample PB-SD-04. There was no distinct spatial distribution of the PAHs noted, rather it appears to be indicative of ubiquitous levels in this vicinity of the Anacostia River.

Appendix B, Table 8 summarizes the pesticides detected in sediment samples. Low levels of numerous pesticides were reported in all of the sediment samples collected from the Anacostia River. The maximum concentrations were reported in PB-SD-16 which was collected in the inlet that receives drainage from a large storm water outfall. This outfall receives drainage from Pepco's outfall 013 as well as neighboring properties, including the D.C. Benning Road Transfer Station.

As shown in Appendix B, Table 9, the PCBs Aroclor-1254 and Aroclor-1260 were detected in every sample collected from the Anacostia River. The lowest values of PCBs were reported in the three most upstream samples. Every downstream sediment sample contained PCBs above the EPA BTAG and NOAA screening concentrations. The maximum concentration was reported in PB-SD-16, with a concentration of Aroclor-1260 of 1,700 µg/kg detected. PB-SD-16 was collected in the inlet where the PPE is located. PB-SD-07 reported the second highest concentration of PCBs (Aroclor-1254 of 1,000 µg/kg and Aroclor-1260 of 1,100 µg/kg). PB-SD-07 was collected directly downstream of the inlet.

Appendix B, Table 10 summarizes the inorganic compounds detected in sediment samples collected from the Anacostia River during the SI. The maximum levels detected were reported in PB-SD-16, collected from the inlet. The levels of arsenic (18.1 mg/kg), cadmium (25.7

mg/kg), chromium (78.7 mg/kg), copper (422 mg/kg), iron (25,400 mg/kg), lead (1,150 mg/kg), manganese (769 mg/kg), mercury (1.3 mg/kg), nickel (292 mg/kg) and zinc (2,030 mg/kg) were all above the corresponding screening criteria.

No VOCs, SVOCs, pesticides or PCBs were reported above the CLP contract-required quantitaion limits (CRQL) in any of the five surface water samples collected during the SI. Appendix B, Table 11 summarizes the inorganic compounds detected in the surface water samples. The only compound detected three times above the upstream level was copper, detected at 12.4 micrograms per liter (µg/L) in PB-SW-03. This concentration was also slightly above the corresponding benchmark of 9 µg/L.

5.5 SURFACE WATER CONCLUSIONS

Analytical results obtained during this sampling event indicate that contaminates of concern associated with Anacostia River sediments are PAHs, PCBs and inorganic compounds. The results further indicate that contaminated sediments are located both upstream and downstream of the site's PPE. PAHs are essentially ubiquitous in sediments of the Anacostia River in the vicinity of the site. The PAH concentrations detected in downstream sediment samples were not three times the concentrations reported in upstream samples. Further evidence of the ubiquitous nature of PAH contamination in the Anacostia River is based on the results reported from other sampling events conducted in the vicinity of the site. In 1998 and 2000, sediment samples were collected from the Anacostia River as part of investigations completed at Kenilworth Park Landfill site for the National Park Service. The Kenilworth Park Landfill is located adjacent to the Anacostia River, approximately 1,000 feet upstream of the Pepco Benning site. Three sediment samples were collected greater than 1.5 miles upstream of the Pepco Benning site. These samples are above the expected tidal influence and are therefore representative of background concentrations. Total PAH concentrations detected in these samples were 5,500 µg/kg, 11,500 µg/kg and 1,500 µg/kg, indicating that sources of PAHs are located upstream of the Pepco Benning facility. These potential sources include numerous combined sewer storm water outfalls located upstream of the site.

PCBs, specifically, Aroclor-1254 and Aroclor-1260 were detected in every sediment sample collected from the Anacostia River; however, the concentrations detected at and downstream of the PPE were greater than three times the concentrations reported in upstream samples. The

concentrations reported upstream ranged from 40 µg/kg to 46 µg/kg, the concentrations detected at the PPE was 810 µg/kg (Aroclor-1254) and 1,700 µg/kg (Aroclor-1260). Directly downstream of the PPE, Aroclor-1254 was detected at 1,000 µg/kg and Aroclor-1260 was detected at 1,100 µg/kg. The results of this SI were also compared with sediment sampling results obtained during EPA's 1987 multi-media inspection of the Pepco Benning facility and also sediment sampling results reported from samples collected during investigations completed in 1998 and 2000 at the Kenilworth Park Landfill (Refs. 6 and 20). Results from all investigations reveal that PCB concentrations increase to above three times upstream (background) concentrations in sediments collected from the inlet where the storm water discharge pipe is located (the site's PPE) and downstream of this inlet. Sediment samples collected upstream of the PPE during these investigations contained PCB concentrations ranging from 40 µg/kg to 88.5 µg/kg. Concentrations detected in sediments collected from the inlet where the PPE is located or directly downstream, contained PCB concentrations ranging from 409 µg/kg to 413 µg/kg. The concentrations detected at the PPE and downstream are above three times the background conentrations indicating that the site is partially attributable to the PCB contamination documented in sediments of the Anacostia River. The levels of PCBs reported were above screening concentrations established by EPA BTAG and NOAA for aquatic life (Refs. 26 and 27). Figure 9 depicts the PCB results from this SI, and results obtained in 1987, 1998 and 2000.

Finally, inorganic compounds were also determined to be elevated in Anacostia River sediments. Comparison between levels reported in upstream samples (above the expected tidal influence) and downstream samples indicate the levels of inorganics to be three times the levels reported in upstream samples. The levels of arsenic, cadmium, chromium, copper, iron, lead, manganese, mercury, nickel, and zinc were also reported above corresponding screening concentrations established by EPA and NOAA for aquatic life.

6.0 SOIL EXPOSURE AND AIR MIGRATION PATHWAYS

This section provides information regarding targets associated with the soil exposure and air migration pathways. The analytical results for soil samples collected at the site were discussed in Section 3.3.

6.1 PHYSICAL CONDITIONS

The site is located adjacent to the Anacostia River and is relatively flat. Subsurface investigations conducted at the site indicate the presence of a silty-sand, sand and gravel. The saturated zone has been encountered on the site at 14 feet bgs (Ref. 15). The Soil Conservation Service soil survey map for this area identify the soils on the site as Urban Land. The Urban Land mapping unit consists of areas where more than 80 percent of the surface is covered by asphalt, concrete, buildings, or other impervious surfaces. The undeveloped areas surrounding the site are mapped as containing Udorthents. Udorthents are defined as heterogeneous, earthy fill material that has been placed on poorly drained to somewhat excessively drained soils on flood plains of the Coastal Plain and Piedmont to provide sites for buildings, roads, and other uses (Ref. 28).

6.2 SOIL AND AIR TARGETS

No residences, schools, or daycare centers are located within 200 feet of the site (Ref. 4). The site is active and therefore there is a potential for workers to be exposed to hazardous substances located in the former dewatering area. The population within a 4-mile radius of the site is summarized below in Table 6 (Ref. 29). Residential communities are located to the south of the facility. According to U.S. census data gathered in 2000, the population residing within the same zip code as the facility is 97.7 % African American. The percentage of people living below the poverty level within the District of Columbia is 19.9%, the second highest percentage in the country (Ref. 31). In addition to the human population other targets identified to the air migration pathway include approximately 206.9 acres of wetlands identified within a 4-mile radius of the site (Appendix A, Figure 10).

TABLE 6
POPULATION WITHIN 4 MILES OF SITE

Radial Distance from Site (miles)	Population (number of persons)
0.00 - 0.25	168
0.25 - 0.50	2,143
0.50 - 1.0	15,394
1.0 - 2.0	77,658
2.0 - 3.0	118,503
3.0 - 4.0	148,911

6.3 SOIL AND AIR CONCLUSIONS

The soil exposure and air migration pathways are not significant pathways associated with this site. Public access to the site is restricted and the contamination detected on the site does not pose a significant threat to the air migration pathway.

7.0 SUMMARY AND CONCLUSIONS

The Pepco Benning Road site consists of an active 77-acre facility used to manage all operations and maintain all equipment associated with their electrical distribution system. The power plant located on the site has been in operation since 1906. Currently, the management and handling of waste streams, including PCB-containing equipment and material is well-organized and supervised; however, sampling results obtained during this SI indicate that hazardous substances, including PAHs, PCBs and certain metals remain in the former sludge dewatering area. This area is not contained and therefore could release these compounds via overland flow from this area into the storm water system that eventually discharges into the Anacostia River. In addition, residue samples collected at the site during EPA's 1997 multi-media inspection documented the presence of cadmium, chromium, copper, lead, mercury, nickel, zinc and PCBs in the Pepco Benning storm water system. This indicates that historical releases of these hazardous substances from the site contributed to the contamination documented in Anacostia River sediments in the vicinity of the site.

The concentrations of PCBs, arsenic, cadmium, chromium, copper, iron, lead, manganese, mercury, nickel, and zinc were all detected in Anacostia River sediments above corresponding screening concentrations established by EPA and NOAA for aquatic life. In addition to metals and PCBs, PAHs were detected in Anacostia River sediment samples; however, the concentrations detected were not three times the concentrations detected in upstream samples.

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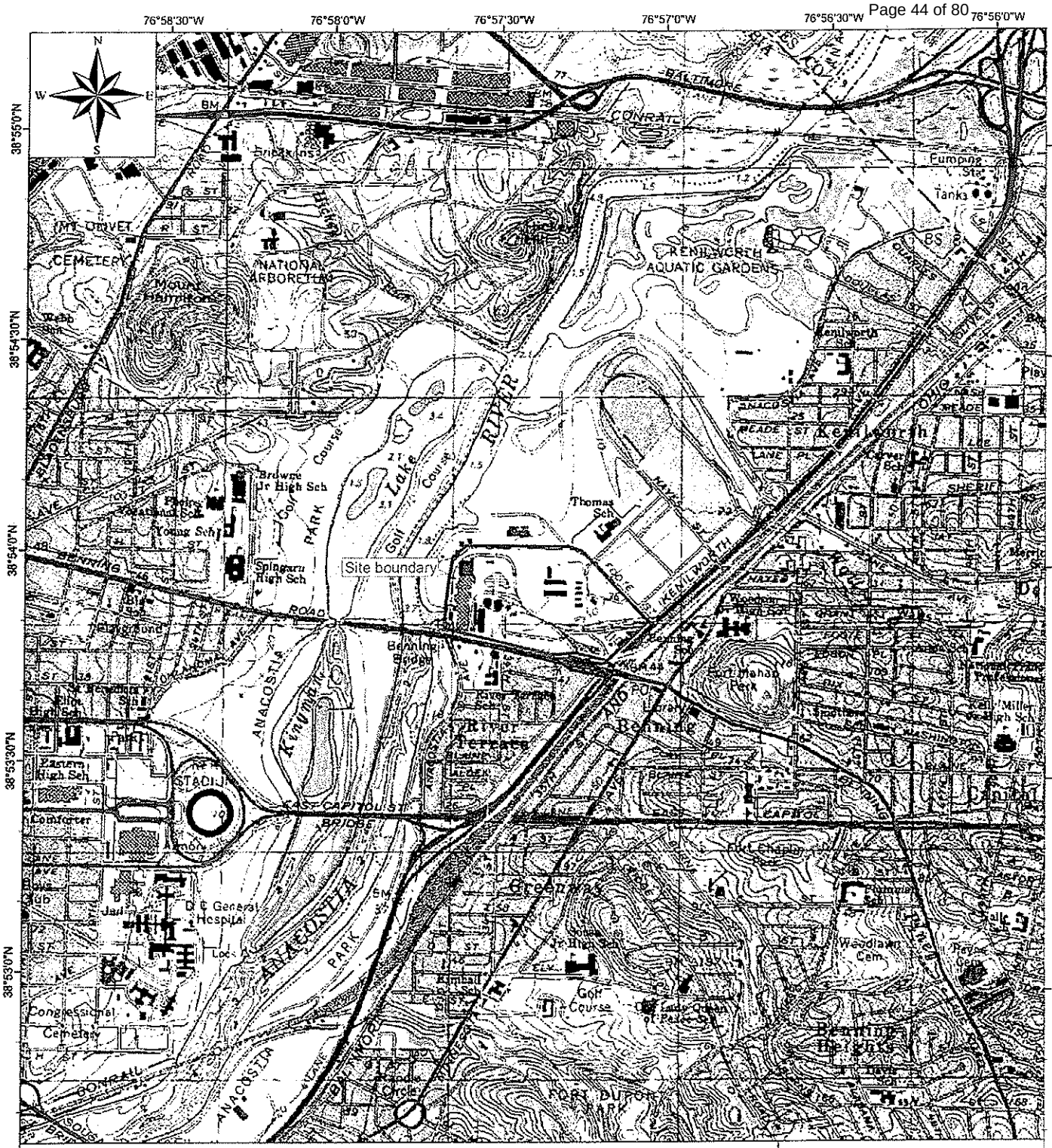
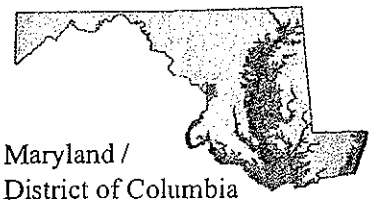
APPENDIX A

FIGURES



Quadrangle Location =

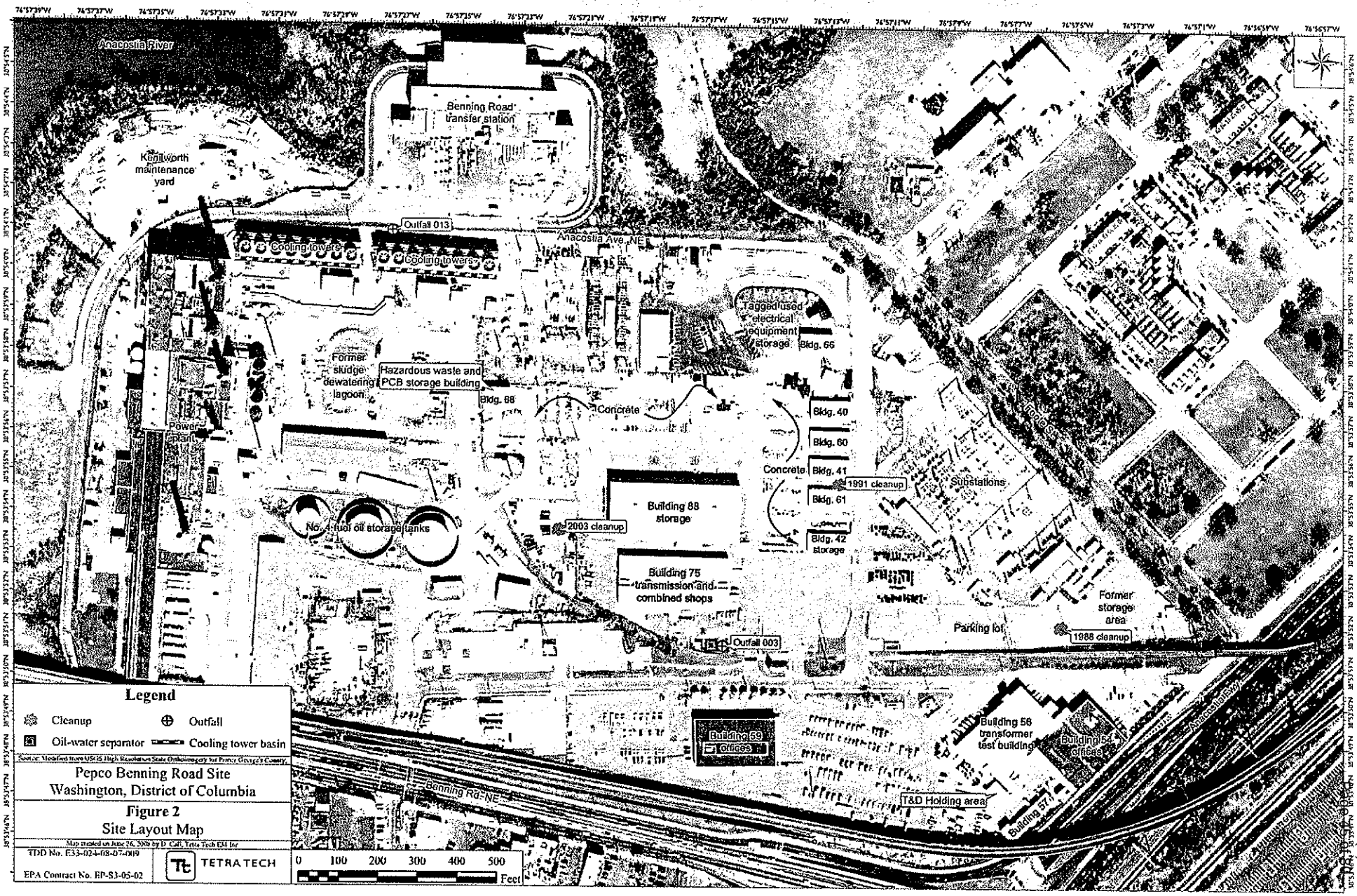


Maryland / District of Columbia

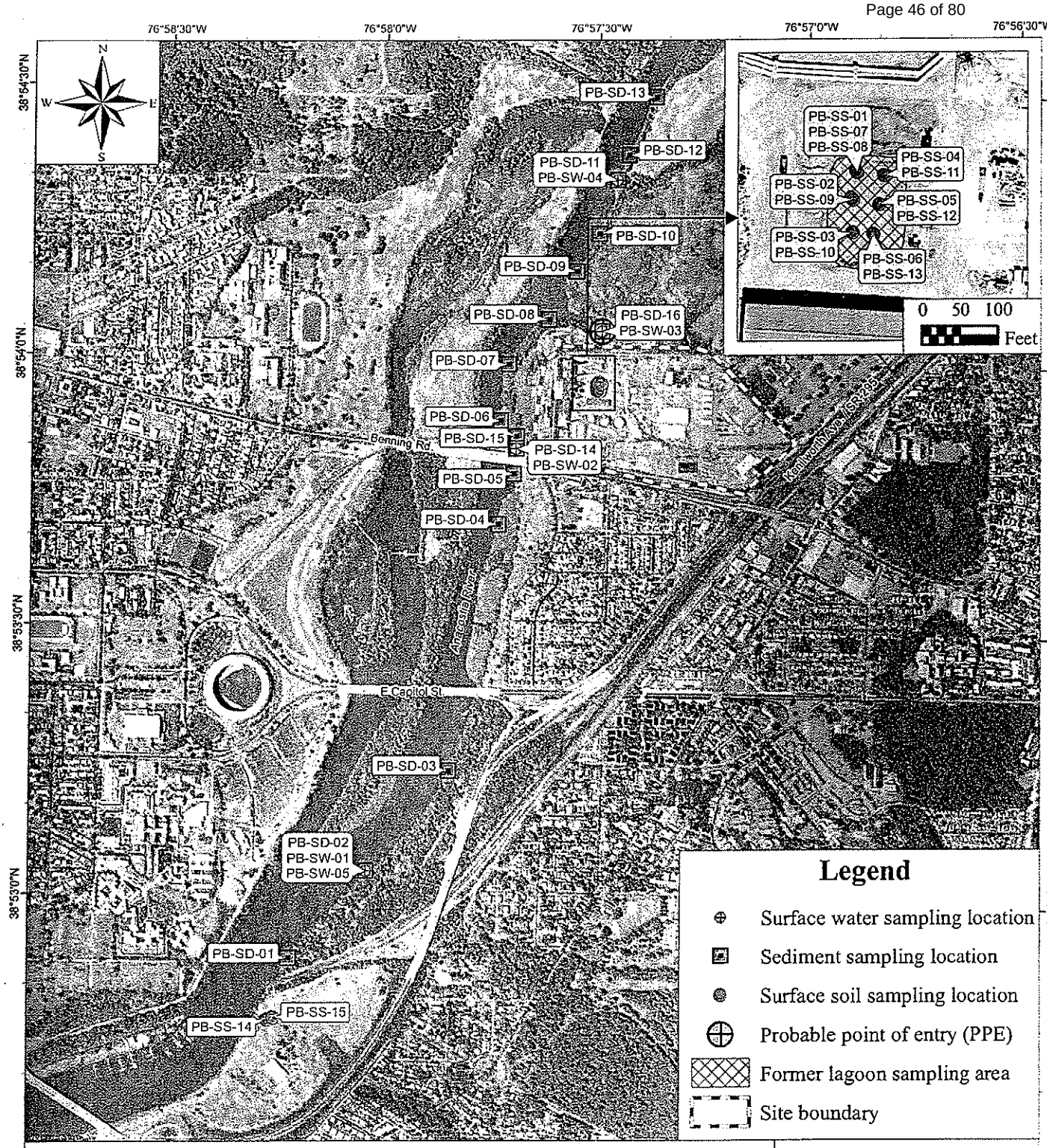
Pepco Benning Road Site
Washington, District of Columbia

Figure 1
Site Location Map

TDD No. E33-024-08-07-009 EPA Contract No. EP-S3-05-02	Map created on June 26, 2008 by D. Call, Tetra Tech EM Inc.	TETRA TECH

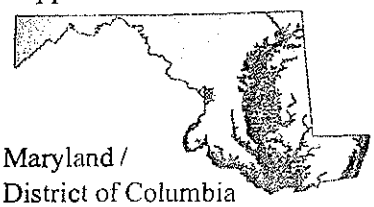

Anacostia River
Kenilworth maintenance yard
Benning Road transfer station
Outfall 013
Cooling towers
Cooling towers
Anacostia Ave. NE
Former sludge dewatering lagoon
Hazardous waste and PCB storage building
Bldg. 66
Concrete
Tagged used electrical equipment storage
Bldg. 65
Bldg. 40
Bldg. 60
Concrete
Bldg. 41
1991 cleanup
Bldg. 61
Bldg. 42 storage
Power plant
No. 4 fuel oil storage tanks
2003 cleanup
Building 88 storage
Building 75 transmission and combined shops
Outfall 003
Substations
Parking lot
Former storage area
1988 cleanup
Building 59 offices
Building 58 transformer test building
Building 57 offices
T&D Holding area
Benning Rd. NE
Legend
Cleanup
Outfall
Oil-water separator
Cooling tower basin
Source: Modified from USGS High Resolution State Orthoimagery for Prince George's County
Pepco Benning Road Site
Washington, District of Columbia
Figure 2
Site Layout Map
Map created on June 26, 2009 by D. Call, Tetra Tech EM Inc
TDD No. E33-024-08-07-0019
EPA Contract No. EP-S3-05-02
TETRA TECH
0 100 200 300 400 500
Feet

PEPCO (K)-2



Source: Modified from DigitalGlobe aerial photography, June 2007.

Approximate Site Location =



Maryland /
District of Columbia

Pepco Benning Road Site
Washington, District of Columbia

Figure 3
Sampling Location Map

TDD No. E33-024-08-07-009
EPA Contract No. EP-S3-05-02

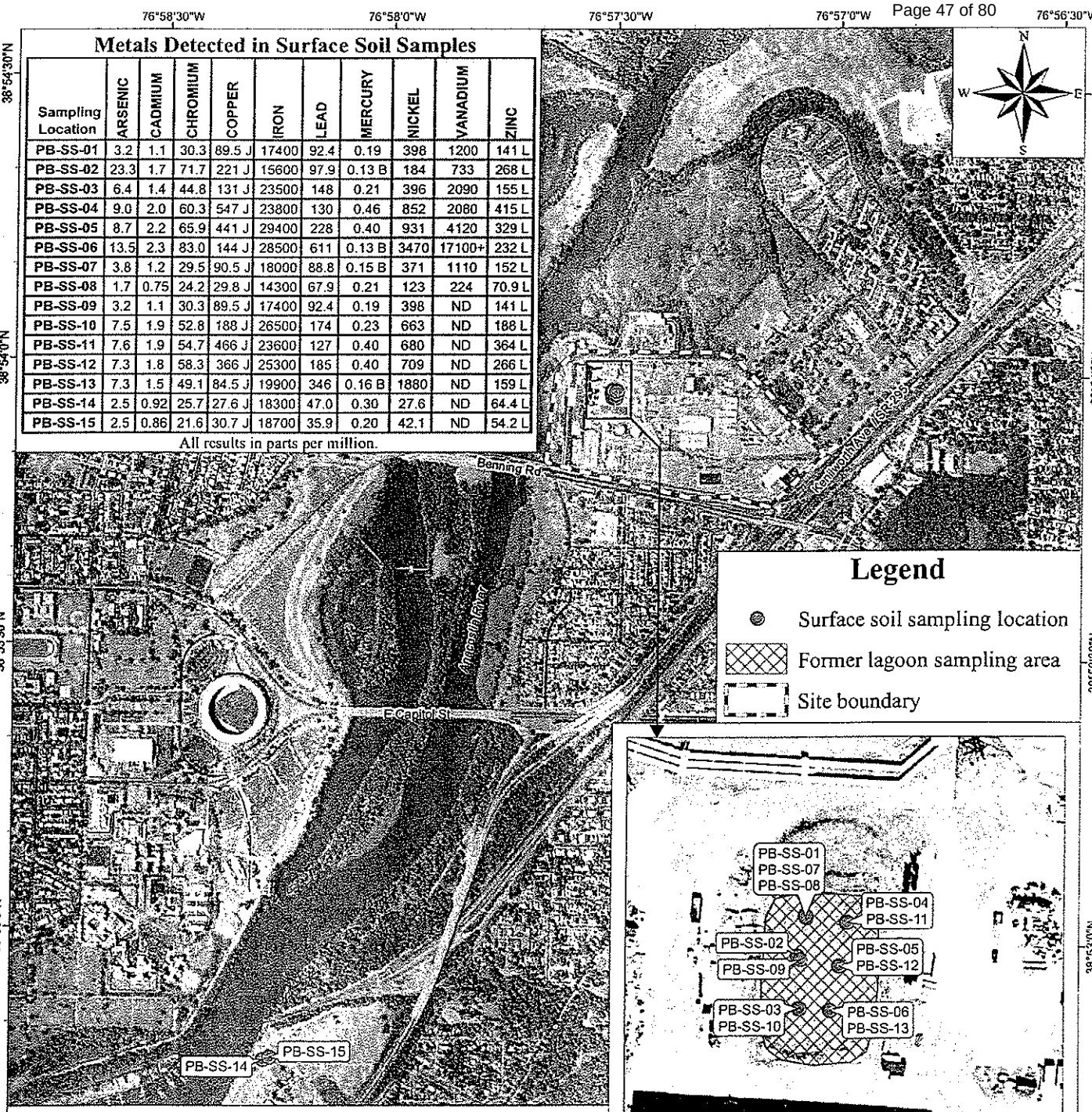
Map created on January 19, 2009
by D. Call, Tetra Tech EM Inc.

TETRA TECH

Metals Detected in Surface Soil Samples

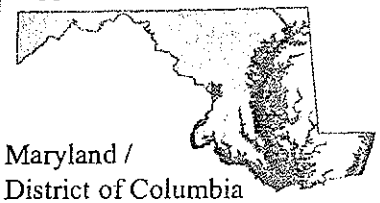
Sampling Location	ARSENIC	CADMIUM	CHROMIUM	COPPER	IRON	LEAD	MERCURY	NICKEL	VANADIUM	ZINC
PB-SS-01	3.2	1.1	30.3	89.5 J	17400	92.4	0.19	398	1200	141 L
PB-SS-02	23.3	1.7	71.7	221 J	15600	97.9	0.13 B	184	733	268 L
PB-SS-03	6.4	1.4	44.8	131 J	23500	148	0.21	396	2090	155 L
PB-SS-04	9.0	2.0	60.3	547 J	23800	130	0.46	852	2080	415 L
PB-SS-05	8.7	2.2	65.9	441 J	29400	228	0.40	931	4120	329 L
PB-SS-06	13.5	2.3	83.0	144 J	28500	611	0.13 B	3470	17100+	232 L
PB-SS-07	3.8	1.2	29.5	90.5 J	18000	88.8	0.15 B	371	1110	152 L
PB-SS-08	1.7	0.75	24.2	29.8 J	14300	67.9	0.21	123	224	70.9 L
PB-SS-09	3.2	1.1	30.3	89.5 J	17400	92.4	0.19	398	ND	141 L
PB-SS-10	7.5	1.9	52.8	188 J	26500	174	0.23	663	ND	188 L
PB-SS-11	7.6	1.9	54.7	466 J	23600	127	0.40	680	ND	364 L
PB-SS-12	7.3	1.8	58.3	366 J	25300	185	0.40	709	ND	266 L
PB-SS-13	7.3	1.5	49.1	84.5 J	19900	346	0.16 B	1880	ND	159 L
PB-SS-14	2.5	0.92	25.7	27.6 J	18300	47.0	0.30	27.6	ND	64.4 L
PB-SS-15	2.5	0.86	21.6	30.7 J	18700	35.9	0.20	42.1	ND	54.2 L

All results in parts per million.



Source: Modified from DigitalGlobe aerial photography, June 2007.
Notes: In data table:
ND = Not detected.
+ = Concentration reported from diluted sample.
B = Reported concentration not significantly higher than level reported in blank sample.
J = Estimated concentration.
L = Reported concentration is estimated low, actual value is expected to be higher.

Approximate Site Location =



Maryland / District of Columbia

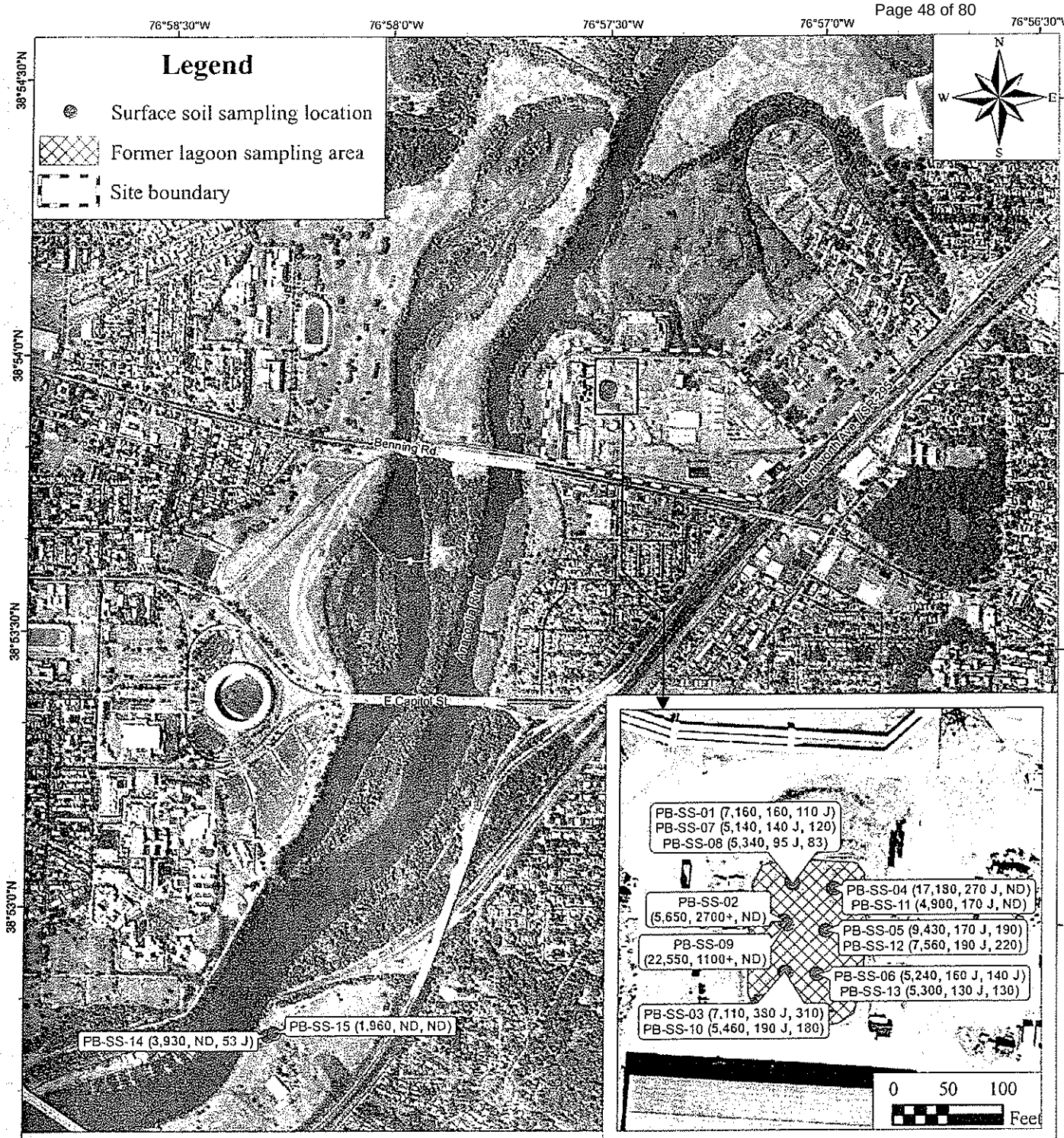
Pepco Benning Road Site
Washington, District of Columbia

Figure 4
Surface Soil Metals Concentrations

TDD No. E33-024-08-07-009
EPA Contract No. EP-S3-05-02

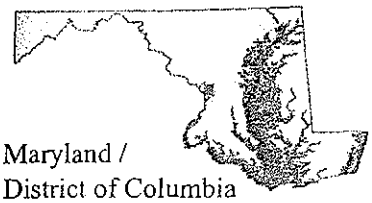
Map created on May 29, 2009
by D. Call, Tetra Tech EM Inc.

TETRA TECH



Source: Modified from DigitalGlobe aerial photography, June 2007.
Note: Concentrations are given in parentheses after each sampling location ID. Total Polycyclic Aromatic Hydrocarbons (PAH) results are given first in green text, followed by Aroclor-1254 result in red text, then Aroclor-1260 result in blue text. All results reported in parts per billion. ND = Not detected. J = Estimated concentration. + = Concentration reported from diluted sample.

Approximate Site Location =



Maryland / District of Columbia

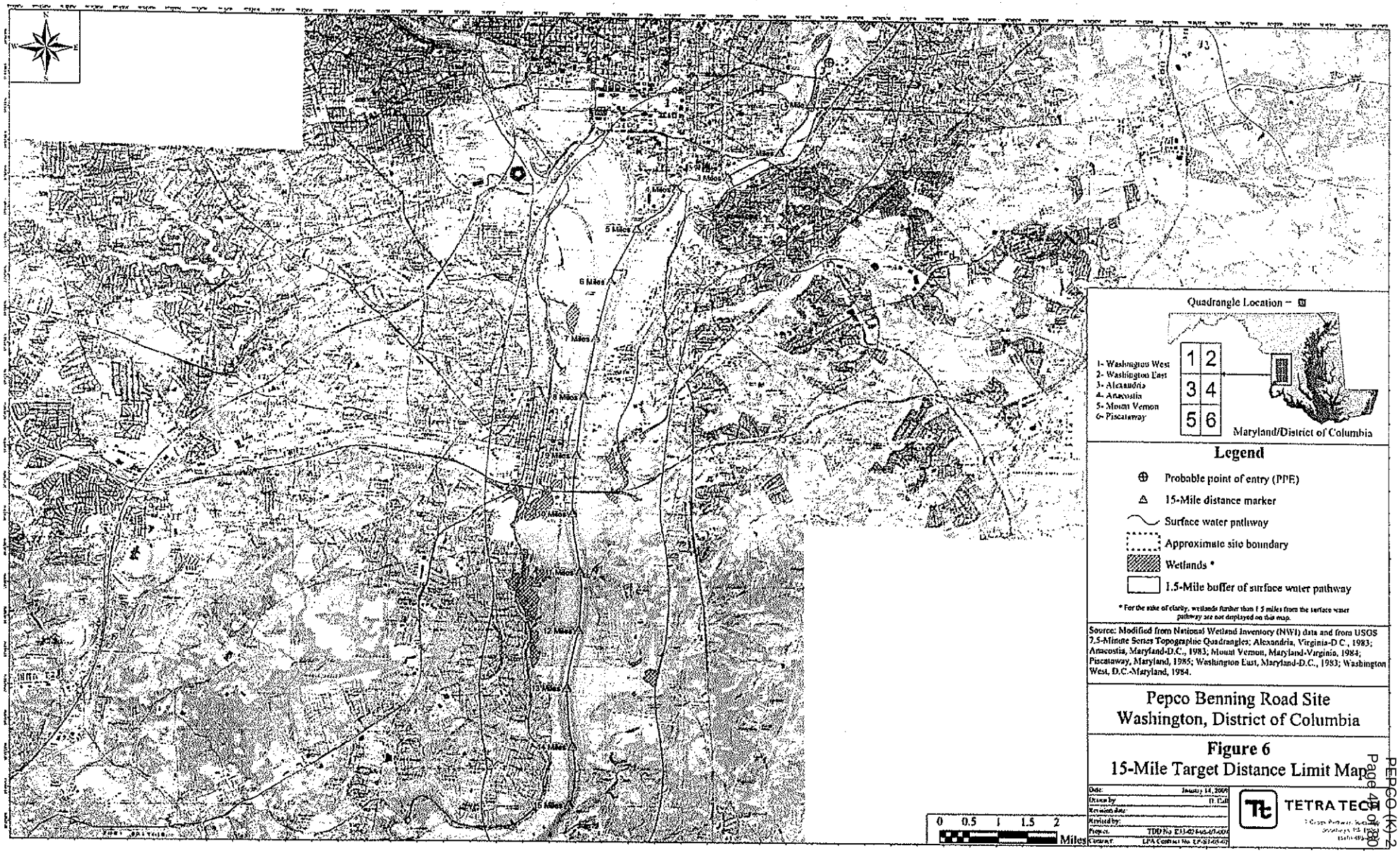
Pepco Benning Road Site
Washington, District of Columbia

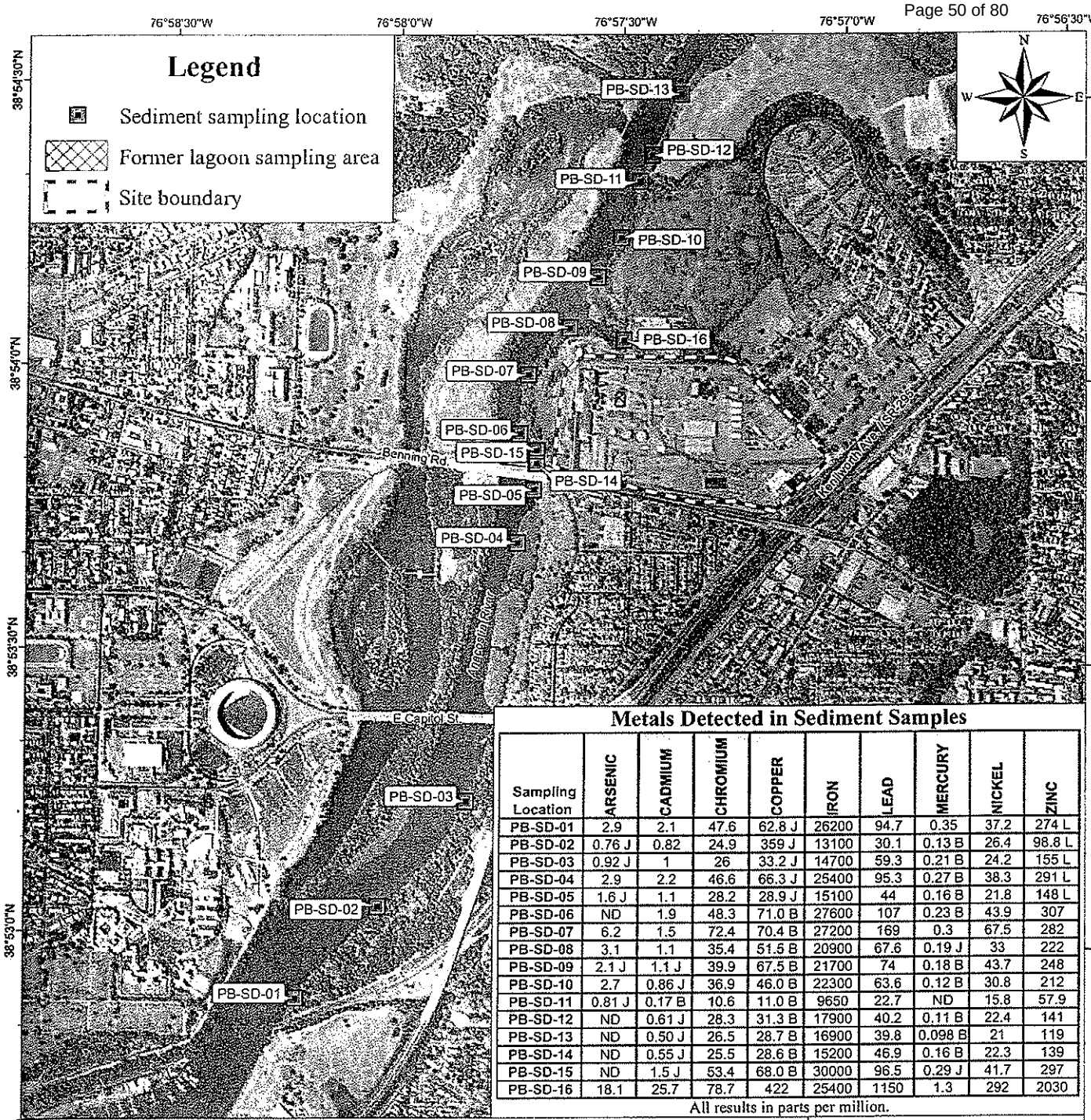
Figure 5
Surface Soil Total PAH/Aroclor Concentrations

TDD No. E33-024-08-07-009
EPA Contract No. EP-S3-05-02

Map created on May 29, 2009
by D. Call, Tetra Tech EM Inc.

TETRA TECH


Quadrangle Location
1- Washington West
2- Washington East
3- Alexandria
4- Anacostia
5- Mount Vernon
6- Piscataway
1 2
3 4
5 6
Maryland/District of Columbia
Legend
Probable point of entry (PPE)
15-Mile distance marker
Surface water pathway
Approximate site boundary
Wetlands *
1.5-Mile buffer of surface water pathway
* For the sake of clarity, wetlands further than 1.5 miles from the surface water pathway are not displayed on this map.
Source: Modified from National Wetland Inventory (NWI) data and from USGS 7.5-Minute Series Topographic Quadrangles; Alexandria, Virginia-D.C., 1983; Anacostia, Maryland-D.C., 1983; Mount Vernon, Maryland-Virginia, 1984; Piscataway, Maryland, 1985; Washington East, Maryland-D.C., 1983; Washington West, D.C.-Maryland, 1984.
Pepco Benning Road Site
Washington, District of Columbia
Figure 6
15-Mile Target Distance Limit Map
Date: January 14, 2009
Drawn by: D. Call
Revision date:
Revised by:
Project: TDD No. E03-024-05-07-004
Contract: LPA Contract No. EP-S7-05-07
TETRA TECH
0 0.5 1 1.5 2
Miles
1 Mile
2 Miles
3 Miles
4 Miles
5 Miles
6 Miles
7 Miles
8 Miles
9 Miles
10 Miles
11 Miles
12 Miles
13 Miles
14 Miles
15 Miles



Metals Detected in Sediment Samples

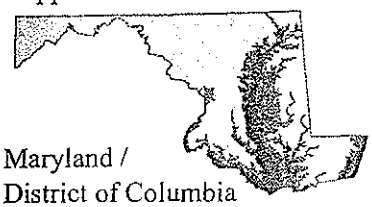
Sampling Location	ARSENIC	CADMIUM	CHROMIUM	COPPER	IRON	LEAD	MERCURY	NICKEL	ZINC
PB-SD-01	2.9	2.1	47.6	62.8 J	26200	94.7	0.35	37.2	274 L
PB-SD-02	0.76 J	0.82	24.9	359 J	13100	30.1	0.13 B	26.4	98.8 L
PB-SD-03	0.92 J	1	26	33.2 J	14700	59.3	0.21 B	24.2	155 L
PB-SD-04	2.9	2.2	46.6	66.3 J	25400	95.3	0.27 B	38.3	291 L
PB-SD-05	1.6 J	1.1	28.2	28.9 J	15100	44	0.16 B	21.8	148 L
PB-SD-06	ND	1.9	48.3	71.0 B	27600	107	0.23 B	43.9	307
PB-SD-07	6.2	1.5	72.4	70.4 B	27200	169	0.3	67.5	282
PB-SD-08	3.1	1.1	35.4	51.5 B	20900	67.6	0.19 J	33	222
PB-SD-09	2.1 J	1.1 J	39.9	67.5 B	21700	74	0.18 B	43.7	248
PB-SD-10	2.7	0.86 J	36.9	46.0 B	22300	63.6	0.12 B	30.8	212
PB-SD-11	0.81 J	0.17 B	10.6	11.0 B	9650	22.7	ND	15.8	57.9
PB-SD-12	ND	0.61 J	28.3	31.3 B	17900	40.2	0.11 B	22.4	141
PB-SD-13	ND	0.50 J	26.5	28.7 B	16900	39.8	0.098 B	21	119
PB-SD-14	ND	0.55 J	25.5	28.6 B	15200	46.9	0.16 B	22.3	139
PB-SD-15	ND	1.5 J	53.4	68.0 B	30000	96.5	0.29 J	41.7	297
PB-SD-16	18.1	25.7	78.7	422	25400	1150	1.3	292	2030

All results in parts per million.

Source: Modified from DigitalGlobe aerial photography, June 2007.
Notes: In data table:
ND = Not detected.
B = Reported concentration not significantly higher than level reported in blank sample.
J = Estimated concentration.
L = Reported concentration is estimated low, actual value is expected to be higher.

0 1,000 2,000 Feet

Approximate Site Location =



Maryland / District of Columbia

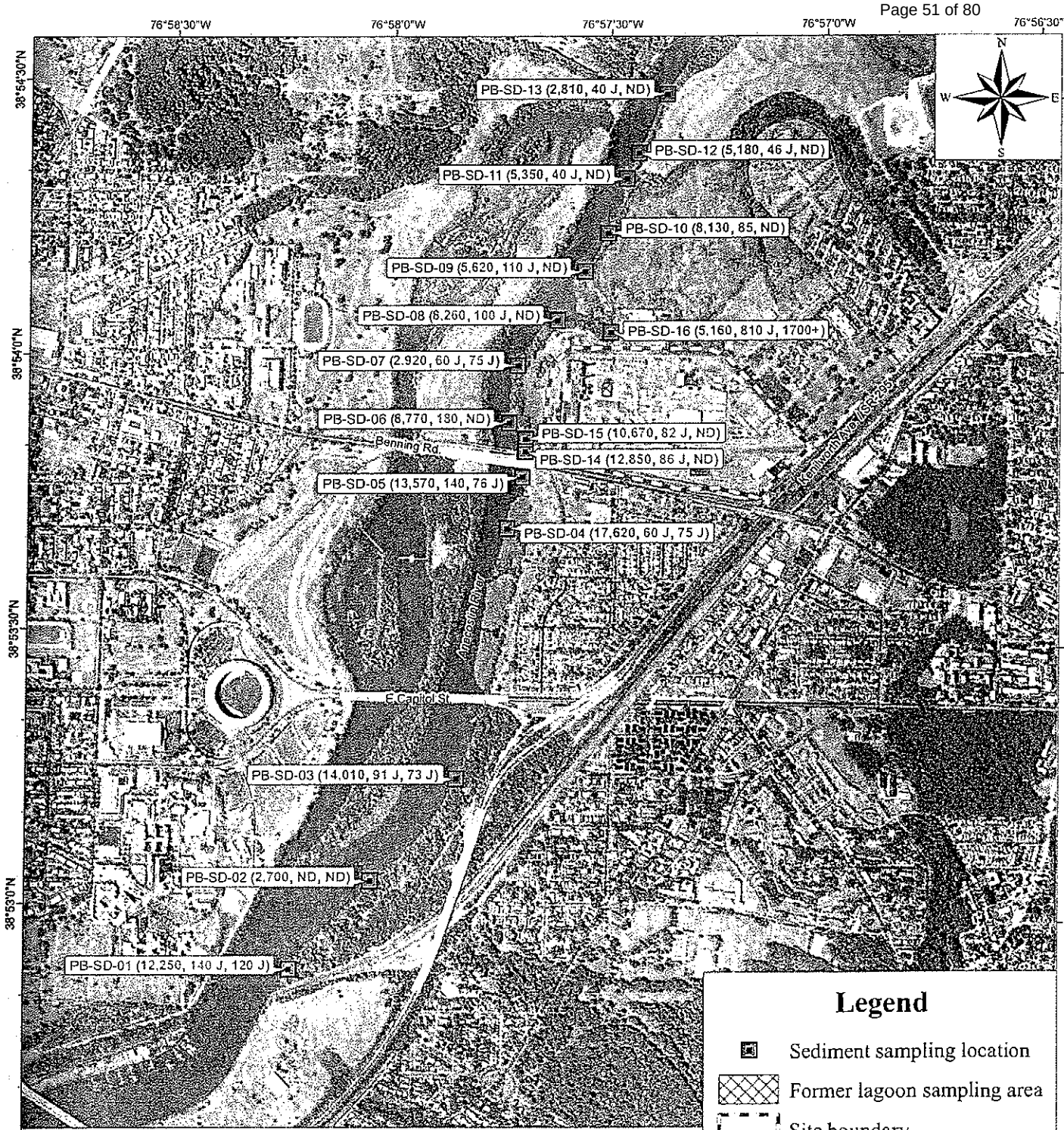
Pepco Benning Road Site
Washington, District of Columbia

Figure 7
Sediment Metals Concentrations

TDD No. E33-024-08-07-009
EPA Contract No. EP-S3-05-02

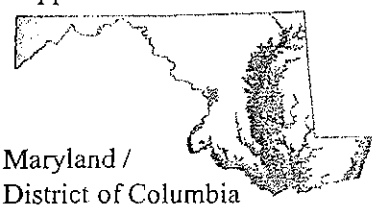
Map created on May 29, 2009
by D. Call, Tetra Tech EM Inc.

TETRA TECH



Source: Modified from DigitalGlobe aerial photography, June 2007.
Note: Concentrations are given in parentheses after each sampling location ID. Total Polycyclic Aromatic Hydrocarbons (PAH) results are given first in green text, followed by Aroclor-1254 result in red text, then Aroclor-1260 result in blue text. All results reported in parts per billion. ND = Not detected. J = Estimated concentration. + = Concentration reported from diluted sample.

Approximate Site Location = ▣



Maryland / District of Columbia

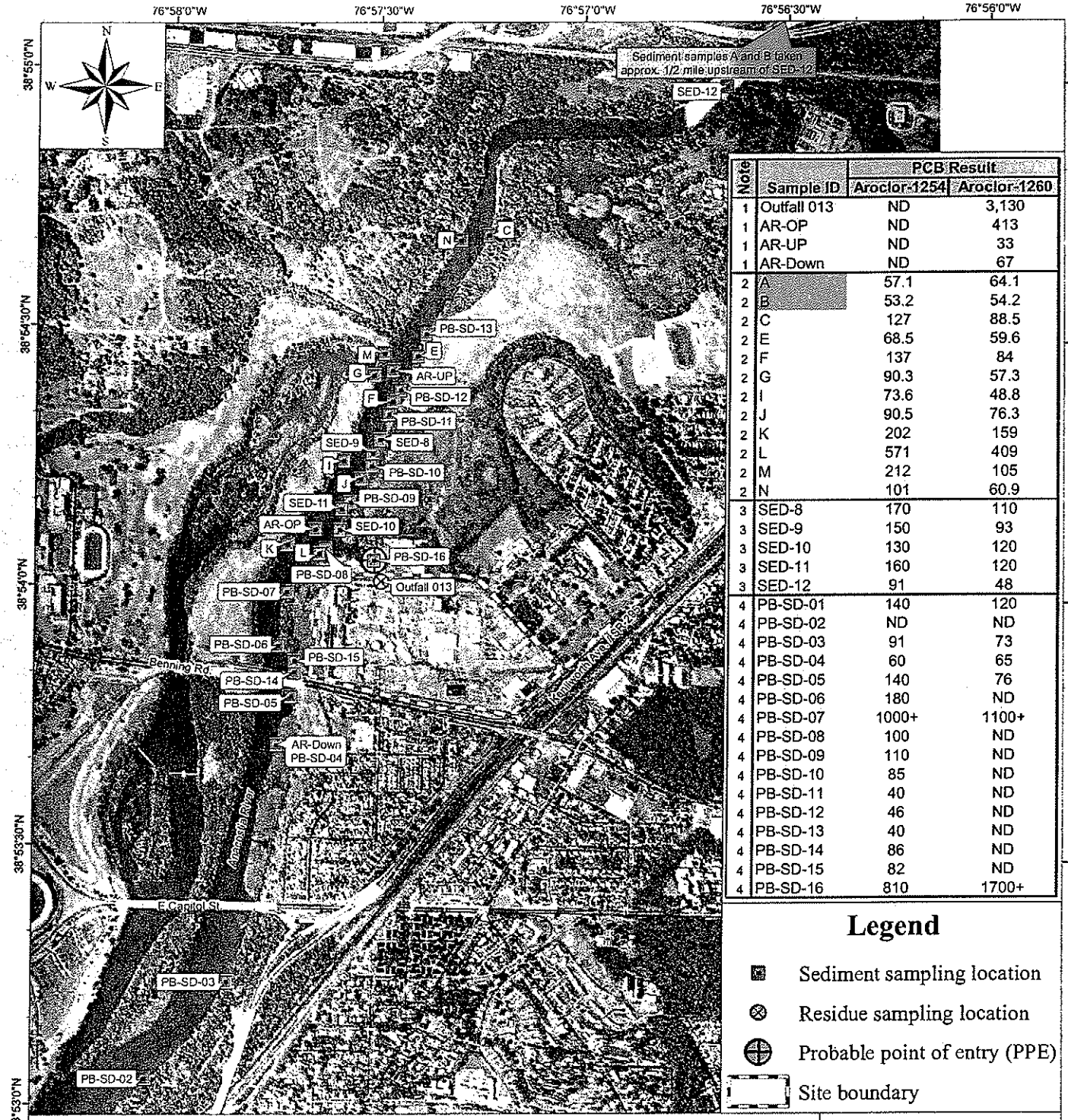
Pepco Benning Road Site
Washington, District of Columbia

Figure 8
Sediment Total PAH/Aroclor Concentrations

TDD No. E33-024-08-07-009
EPA Contract No. EP-S3-05-02

Map created on May 29, 2009
by D. Call, Tetra Tech EM Inc.

TETRA TECH



Note	Sample ID	PCB Result Aroclor-1254	PCB Result Aroclor-1260
1	Outfall 013	ND	3,130
1	AR-OP	ND	413
1	AR-UP	ND	33
1	AR-Down	ND	67
2	A	57.1	64.1
2	B	53.2	54.2
2	C	127	88.5
2	E	68.5	59.6
2	F	137	84
2	G	90.3	57.3
2	I	73.6	48.8
2	J	90.5	76.3
2	K	202	159
2	L	571	409
2	M	212	105
2	N	101	60.9
3	SED-8	170	110
3	SED-9	150	93
3	SED-10	130	120
3	SED-11	160	120
3	SED-12	91	48
4	PB-SD-01	140	120
4	PB-SD-02	ND	ND
4	PB-SD-03	91	73
4	PB-SD-04	60	65
4	PB-SD-05	140	76
4	PB-SD-06	180	ND
4	PB-SD-07	1000+	1100+
4	PB-SD-08	100	ND
4	PB-SD-09	110	ND
4	PB-SD-10	85	ND
4	PB-SD-11	40	ND
4	PB-SD-12	46	ND
4	PB-SD-13	40	ND
4	PB-SD-14	86	ND
4	PB-SD-15	82	ND
4	PB-SD-16	810	1700+

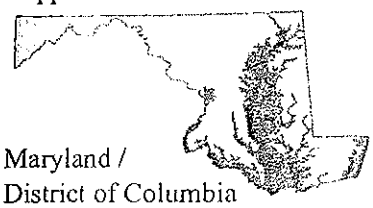
Legend

- Sediment sampling location
- Residue sampling location
- Probable point of entry (PPE)
- Site boundary

Source: Modified from DigitalGlobe aerial photography, June 2007.
Map Note: Samples A and B were collected approximately 1/2 mile upstream of SED-12 and are not displayed on this map.
Results Table Notes: All results reported in µg/kg. 1= Samples collected by EPA in 1987. 2= Samples collected in 2000 during completion of PA/SI of Kenilworth Park Landfill. 3= Samples collected in 1998 during investigation of Kenilworth Park Landfill. 4= Samples collected during the 2008 EPA SI.

0 1,000 2,000 Feet

Approximate Site Location =



Maryland / District of Columbia

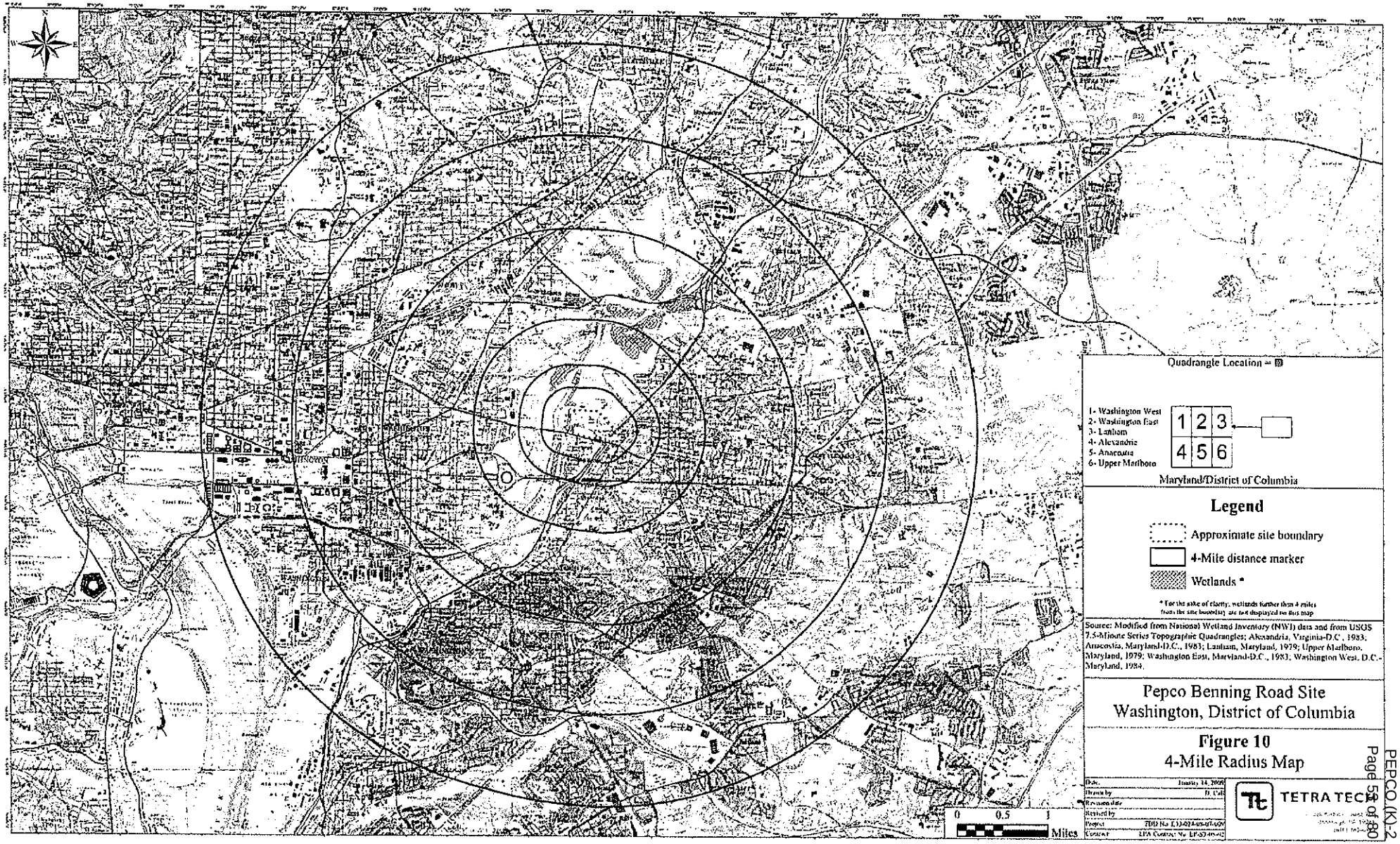
Pepco Benning Road Site
Washington, District of Columbia

Figure 9
Sampling Results Map

TDD No. E33-024-08-07-009
EPA Contract No. EP-S3-05-02

Map created on January 19, 2009
by D. Call, Tetra Tech EM Inc.

TETRA TECH


Quadrangle Location =
1- Washington West
2- Washington East
3- Lanham
4- Alexandria
5- Anacostia
6- Upper Marlboro
1 2 3
4 5 6
Maryland/District of Columbia
Legend
Approximate site boundary
4-Mile distance marker
Wetlands *
* For the sake of clarity, wetlands further than 4 miles from the site boundary are not displayed on this map
Source: Modified from National Wetland Inventory (NWI) data and from USGS 7.5-Minute Series Topographic Quadrangles; Alexandria, Virginia-D.C., 1983; Anacostia, Maryland-D.C., 1983; Lanham, Maryland, 1979; Upper Marlboro, Maryland, 1979; Washington East, Maryland-D.C., 1983; Washington West, D.C.-Maryland, 1984.
Pepco Benning Road Site
Washington, District of Columbia
Figure 10
4-Mile Radius Map
Date
Drawn by
Revision date
Revised by
Project
Contract
TETRA TECH
0 0.5 1
Miles

APPENDIX B

ANALYTICAL SUMMARY TABLES

TABLE 1
PEPCO BENNING ROAD SITE
SOIL SAMPLE
VOLATILE ORGANIC COMPOUNDS
ANALYTICAL RESULTS

Sample Number :			C00H6		C00G0		C00G8		C00G9		C00H0RE		C00H1		C00H2		C00H3	
Sampling Location :			PB-SS-01		PB-SS-02		PB-SS-03		PB-SS-04		PB-SS-05		PB-SS-06		PB-SS-07		PB-SS-08	
Field QC :			Dup of PB-SS-07												Dup of PB-SS-01			
Matrix :		EPA	Soil		Soil		Soil		Soil		Soil		Soil		Soil		Soil	
Units :		Region 3 SSL	ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		Industrial Soil	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Volatile Organic Compound	CRQL	µg/Kg	Result	Q	Result	Q	Result	Q	Result	Q							Result	Q
Acetone	10.0	6.1 E+08							25	B							36	B
Chloroform	5.0	1500															30	L
Trichloroethene	5.0	1.4 E+4			5.0	B			7.8	B								

Notes:
Only compounds reported above the CRQL included in table.
Empty cell indicated substance not reported above the CRQL.
ug/Kg = Micrograms per kilogram
B = Analyte not detected substantially above the level reported in laboratory or field blanks.
CRQL = Contract Required Quantitation Limit
Dup = Duplicate sample
L = Analyte present. Reported value may be biased low. Actual value is expected to be higher.
PB = Pepco Benning
Q = Laboratory analytical data qualifier
SS = Surface soil
SSL = Soil Screening Level

TABLE 1
PEPCO BENNING ROAD SITE
SOIL SAMPLE
VOLATILE ORGANIC COMPOUNDS
ANALYTICAL RESULTS

Sample Number :			C00H4		C00G3		C00G2		C00G4		C00G5		C00G6		C00G7	
Sampling Location :			PB-SS-09		PB-SS-10		PB-SS-11		PB-SS-12		PB-SS-13		PB-SS-14		PB-SS-15	
Field QC :													Background		Background	
Matrix :		EPA	Soil		Soil		Soil		Soil		Soil		Soil		Soil	
Units :		Region 3 SSL	ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		Industrial Soil	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Volatile Organic Compound	CRQL	µg/Kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q		
Acetone	5.0	6.1 E+08	21	B												
Chloroform	5.0	1500	30	L												
Trichloroethene	5.0	1.4 E+4					6.5	B	6.1	B						

Notes:
Only compounds reported above the CRQL included in table.
Empty cell indicated substance not reported above the CRQL.
ug/Kg = Micrograms per kilogram
B = Analyte not detected substantially above the level reported in laboratory or field blanks.
CRQL = Contract Required Quantitation Limit
Dup = Duplicate sample
L = Analyte present. Reported value may be biased low. Actual value is expected to be higher.
PB = Pepco Benning
Q = Laboratory analytical data qualifier
SS = Surface soil
SSL = Soil Screening Level

TABLE 2
PEPCO BENNING ROAD SITE
SOIL SAMPLE
SEMIVOLATILE ORGANIC COMPOUND ANALYTICAL RESULTS

Sample Number :			C00H6		C00G0		C00G8		C00G9		C00H0RE		C00H1		C00H2		C00H3	
Sampling Location :			PB-SS-01		PB-SS-02		PB-SS-03		PB-SS-04		PB-SS-05		PB-SS-06		PB-SS-07		PB-SS-08	
Field QC :			Dup of PB-SS-07												Dup of PB-SS-01			
Matrix :		EPA	Soil		Soil		Soil		Soil		Soil		Soil		Soil		Soil	
Units :		Region 3 SSL	ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		Industrial Soil	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Semivolatile Compound	CRQL	µg/Kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
2-Methylnapthalene	170	4.1 E+06									200	J						
Dimethylnapthalene	170	NA																
Acenaphthene	170	3.3 E+07																
Dibenzofuran	170	NA																
Fluorene	170	2.2 E+07																
Phenanthrene	170	NA	630		400		520		1300		790		360		380		480	
Anthracene	170	1.7 E+08					150	J	490		240							
Carbazole	170	NA																
Fluoranthene	170	2.2 E+07	1200		840		1100		4400+		1300		820		860		860	
Pyrene	170	1.7 E+07	990		900		900		2800		1200		730		790		890	
Butylbenzylphthalate	170	NA					310				690		24000+					
Benzo(a)anthracene	170	2100	640		630		630		[illegible]		740		580		480		560	
Chrysene	170	2.1 E+05	760		570		740		2500		940		490		480		500	
Bis(2-ethylhexyl)phthalate	170	1.2 E+05	170	B	1300	J	190	B	340	B			460	J	260	B	220	B
Benzo(b)fluoranthene	170	2,100	820	J	620	J	890	J	[illegible]	J	820	J	640	J	610	J	500	J
Benzo(k)fluoranthene	170	21,000	560		550		440		940		620		450		380		490	
Benzo(a)pyrene	170	210	[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		[illegible]	
Indeno(1,2,3-cd)pyrene	170	2100	450		310		460		[illegible]		750		370		330		290	
Dibenzo(a,h)anthracene	170	210					170	J	[illegible]		[illegible]							
Benzo(g,h,i)perylene	170	NA	470		290		490		1600		850		380		350		290	

Notes:

+ = Reported value obtained from diluted sample.
Empty cell indicated substance not reported above detection limit.
Only compounds reported above the CRQL included in table.
Shaded cell indicates value above corresponding SSL.
ug/Kg = Micrograms per kilogram
B = Analyte not detected substantially above the level reported in laboratory or field blanks.
CRQL = Contract Required Quantitation Limit
Dup = Duplicate sample

J = Analyte present. Reported value may not be accurate or precise.
L = Analyte present. Reported value may be biased low. Actual value is expected to be higher.
NA = Not applicable, SSL not established for this substance
PB = Pepco Benning
Q = Laboratory analytical data qualifier
SS = Surface soil
SSL = Soil Screening Level

TABLE 2
PEPCO BENNING ROAD SITE
SOIL SAMPLE
SEMIVOLATILE ORGANIC COMPOUND ANALYTICAL RESULTS

Sample Number :			C00H4		C00G3		C00G2		C00G4		C00G5		C00G6		C00G7	
Sampling Location :			PB-SS-09		PB-SS-10		PB-SS-11		PB-SS-12		PB-SS-13		PB-SS-14		PB-SS-15	
Field QC :													Background		Background	
Matrix :		EPA	Soil		Soil		Soil		Soil		Soil		Soil		Soil	
Units :		Region 3 SSL	ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		Industrial Soil	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Semivolatile Compound	CRQL	µg/Kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
2-Methylnapthalene	170	4.1 E+06														
Dimethylnapthalene	170	NA					540									
Acenaphthene	170	3.3 E+07	340													
Dibenzofuran	170	NA	190	J												
Fluorene	170	2.2 E+07	340													
Phenanthrene	170	NA	2200		400		300		820		340		490		270	
Anthracene	170	1.7 E+08	850						200							
Carbazole	170	NA	470													
Fluoranthene	170	2.2 E+07	2600		850		690		1300		780		660		430	
Pyrene	170	1.7 E+07	2100		710		610		1100		660		550		350	
Butylbenzylphthalate	170	NA	2400								870					
Benzo(a)anthracene	170	2100	1600		500		520		720		420		380		230	
Chrysene	170	2.1 E+05	1600		530		430		650		430		360		220	
Bis(2-ethylhexyl)phthalate	170	1.2 E+05	1600	J												
Benzo(b)fluoranthene	170	2,100	1600	J	610	J	580	J	810	J	470	J	420	J	260	J
Benzo(k)fluoranthene	170	2.1E+4	1100		530		250		350		380		270			
Benzo(a)pyrene	170	210	[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		200	
Indeno(1,2,3-cd)pyrene	170	2100	930		400		310		430		270		220			
Dibenzo(a,h)anthracene	170	210	[illegible]						170	J						
Benzo(g,h,i)perylene	170	NA	890		420		250		450		290		230			

Notes:

Empty cell indicated substance not reported above detection limit.
Only compounds reported above the CRQL included in table.
Shaded cell indicates value above corresponding SSL.
ug/Kg = Micrograms per kilogram
B = Analyte not detected substantially above the level reported in laboratory or field blanks.
CRQL = Contract Required Quantitation Limit
Dup = Duplicate sample

J = Analyte present. Reported value may not be accurate or precise.
L = Analyte present. Reported value may be biased low. Actual value is expected to be higher.
NA = Not applicable, SSL not established for this substance
PB = Pepco Benning
Q = Laboratory analytical data qualifier
SS = Surface soil
SSL = Soil Screening Level

TABLE 3
PEPCO BENNING ROAD SITE
SOIL SAMPLE
PESTICIDE COMPOUNDS ANALYTICAL RESULTS

Sample Number :			C00H6		C00G0		C00G8		C00G9		C00H0RE		C00H1		C00H2		C00H3	
Sampling Location :			PB-SS-01		PB-SS-02		PB-SS-03		PB-SS-04		PB-SS-05		PB-SS-06		PB-SS-07		PB-SS-08	
Field QC :			Dup of PB-SS-07												Dup of PB-SS-01			
Matrix :		EPA	Soil		Soil		Soil		Soil		Soil		Soil		Soil		Soil	
Units :		Region 3 SSL	ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		Industrial Soil	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Pesticide Compounds	CRQL	µg/Kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
Heptachlor	1.7	380							4.5	J								
Heptachlor epoxide	1.7	190			140	J												
Endosulfan I	1.7	3.7 E+06	2.0	J	8.5	J												
Dieldrin	3.3	110			28	J												
4,4'-DDE	3.3	5,100	7.0		55	J											5.5	J
Endrin	3.3	1.8 E+05	4.1		34	J												
Endosulfan II	3.3	3.7 E+08			5.6	J												
4,4'-DDD	3.3	7,200					4.4	J										
Endosulfan sulfate	3.3	NA													4.7	J		
4,4'-DDT	3.3	7,000	6.1	J	230+		7.0	J	9.6	J	8.3	J	5.8	J	4.5	J	3.9	J
Endrin ketone	3.3	1.8 E+05									3.8	J						
Endrin aldehyde	3.3	1.8 E+05			4.8	J												
alpha-Chlordane	1.7	6,500	3.4	J	4.5	J	3.8		17		1.9	J	2.9		3.4		5.0	
gamma-Chlordane	1.7	6,500	4.6	J	5.9	J	3.1	J	16	J	1.8	J	2.4	J	3.1	J	4.3	J

Notes:

+ = Reported value obtained from diluted sample.
Empty cell indicated substance not reported above detection limit.
Only compounds reported above the CRQL included in table.
Shaded cell indicates value above corresponding SSL.
ug/Kg = Micrograms per kilogram
CRQL = Contract Required Quantitation Limit
Dup = Duplicate sample

J = Analyte present. Reported value may not be accurate or precise.
NA = Not applicable, SSL not established for this substance
PB = Pepco Benning.
Q = Laboratory analytical data qualifier
SS = Surface soil
SSL = Soil Screening Level

TABLE 3
PEPCO BENNING ROAD SITE
SOIL SAMPLE
PESTICIDE COMPOUNDS ANALYTICAL RESULTS

Sample Number :			C00H4		C00G3		C00G2		C00G4		C00G5		C00G6		C00G7	
Sampling Location :			PB-SS-09		PB-SS-10		PB-SS-11		PB-SS-12		PB-SS-13		PB-SS-14		PB-SS-15	
Field QC :													Background		Background	
Matrix :		EPA	Soil		Soil		Soil		Soil		Soil		Soil		Soil	
Units :		Region 3 SSL	ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		Industrial Soil	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Pesticide Compounds	CRQL	µg/Kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
Heptachlor	1.7	380					2.5	J								
Heptachlor epoxide	1.7	190	26	J												
Endosulfan I	1.7	3.7 E+06	2.2	J												
Dieldrin	3.3	110	5.8													
4,4'-DDE	3.3	5,100	3.5	J												
Endrin	3.3	1.8 E+05	19	J												
Endosulfan II	3.3	3.7 E+06														
4,4'-DDD	3.3	7,200														
Endosulfan sulfate	3.3	NA	5.4												7.8	
4,4'-DDT	3.3	7,000	33	J	7.5	J	8.9	J	11	J						
Endrin ketone	3.3	1.8 E+05							4.0	J						
Endrin aldehyde	3.3	1.8 E+05									1400+	J				
alpha-Chlordane	1.7	6,500	3.1	J	3.4		7.1		2.4							
gamma-Chlordane	1.7	6,500	7.7	J	3.0	J	5.9	J	2.3	J						

Notes:

+ = Reported value obtained from diluted sample.
Empty cell indicated substance not reported above detection limit.
Only compounds reported above the CRQL included in table.
Shaded cell indicates value above corresponding SSL.
ug/Kg = Micrograms per kilogram
CRQL = Contract Required Quantitation Limit
Dup = Duplicate sample

J = Analyte present. Reported value may not be accurate or precise.
NA = Not applicable, SSL not established for this substance
PB = Pepco Benning
Q = Laboratory analytical data qualifier
SS = Surface soil
SSL = Soil Screening Level

TABLE 4
PEPCO BENNING ROAD SITE
SOIL SAMPLE
AROCLOR COMPOUNDS ANALYTICAL RESULTS

Sample Number :			C00H6		C00G0		C00G8		C00G9		C00H0RE		C00H1		C00H2		C00H3	
Sampling Location :			PB-SS-01		PB-SS-02		PB-SS-03		PB-SS-04		PB-SS-05		PB-SS-06		PB-SS-07		PB-SS-08	
Field QC :			Dup of PB-SS-07												Dup of PB-SS-01			
Matrix :		EPA	Soil		Soil		Soil		Soil		Soil		Soil		Soil		Soil	
Units :		Region 3 SSL	ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		Industrial Soil	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Aroclor Compounds	CRQL	µg/Kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
Aroclor-1254	33	740	160		[redacted]		380	J	270	J	170	J	160	J	140	J	95	J
Aroclor-1260	33	740	110	J			310				190		140	J	120		83	

Sample Number :			C00H4		C00G3		C00G2		C00G4		C00G5		C00G6		C00G7	
Sampling Location :			PB-SS-09		PB-SS-10		PB-SS-11		PB-SS-12		PB-SS-13		PB-SS-14		PB-SS-15	
Field QC :													Background		Background	
Matrix :		EPA	Soil		Soil		Soil		Soil		Soil		Soil		Soil	
Units :		Region 3 SSL	ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		Industrial Soil	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Aroclor Compounds	CRQL	µg/Kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
Aroclor-1254	33	740	[redacted]		190	J	170	J	190	J	130	J				
Aroclor-1260	33	740			180				220		130		53	J		

Notes:

+ = Reported value obtained from diluted sample.
Only compounds reported by laboratory included in table.
Empty cell indicated substance not reported above the CRQL.
ug/Kg = Micrograms per kilogram
CRQL = Contract Required Quantitation Limit
Dup = Duplicate sample

J = Analyte present. Reported value may not be accurate or precise.
PB = Pepco Benning
Q = Laboratory analytical data qualifier
Shaded cell indicates value above corresponding SSL.
SS = Suface soil
SSL = Soil Screening Level

TABLE 5
PEPCO BENNING ROAD SITE
SOIL SAMPLE
INORGANIC COMPOUNDS ANALYTICAL RESULTS

Sample Number :			MC00H6		MC00G0		MC00G8		MC00G9		MC00H0RE		MC00H1		MC00H2		MC00H3	
Sampling Location :			PB-SS-01		PB-SS-02		PB-SS-03		PB-SS-04		PB-SS-05		PB-SS-06		PB-SS-07		PB-SS-08	
Field QC :			Dup of PB-SS-07												Dup of PB-SS-01			
Matrix :		EPA Region 3 SSL	Soil		Soil		Soil		Soil		Soil		Soil		Soil		Soil	
Units :			mg/Kg		mg/Kg		mg/Kg		mg/Kg		mg/Kg		mg/Kg		mg/Kg		mg/Kg	
Date Sampled :		Soil	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Analyte	CRQL	mg/kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
ALUMINUM	20	9.9 E+05	10800		12000		11800		14300		12800		9480		10400		9050	
ANTIMONY	6	410									1.2	J	5.4	J				
ARSENIC	1	1.6	9.2		23.3		6.4		9.0		8.7		13.5		3.8		1.7	
BARIUM	20	1.9 E+05	108		259		129		125		179		271		118		88.7	
BERYLLIUM	0.5	2000	0.54	J	0.56	J	0.51	J	0.51	J	0.48	J			0.48	J	0.46	J
CADMIUM	0.5	NA	1.1		1.7		1.4		2.0		2.2		2.3		1.2		0.75	
CALCIUM	500	NA	39400		79800		36400		38400		31000		23600		42200		41700	
CHROMIUM (total)	1	1.4 E+03	30.3		71.7		44.8		60.3		65.9		83.0		29.5		24.2	
COBALT	5	300	15.6		19.6		20.2		26.9		33.5		72.8		15.7		8.7	
COPPER	2.5	4.1 E+04	89.5	J	221	J	131	J	547	J	441	J	144	J	90.5	J	29.8	J
IRON	10	7.2 E+05	17400		15600		23500		23800		29400		28500		18000		14300	
LEAD*	1	400*	92.4		97.9		148		130		228		611		88.8		67.9	
MAGNESIUM	500	NA	5490		5850		5460		6660		5710		3780		5250		5140	
MANGANESE	1.5	2.3 E+04	499	J	1910	J	816	J	629	J	1280	J	593	J	542	J	299	J
MERCURY	0.1	28	0.19		0.13	B	0.21		0.46		0.40		0.13	B	0.15	B	0.21	
NICKEL	4	2.0 E+04	398		184		396		852		931		3470		371		123	
POTASSIUM	500	NA	1480		1560		1970		994		1430		1080		1700		1510	
SELENIUM	3.5	5,100									1.2	B	4.1	B				
SILVER	1	5,100																
SODIUM	500	NA	209	B	234	B	311	B	323	B	333	B	656		213	B	178	B
THALLIUM	2.5	66	3.7		2.1	B	5.4		5.0		10.9		38.5		3.2	B		
VANADIUM	5	7,200	1200		733		2090		2080		4120		17100 +		1110		224	
ZINC	6	3.1 E+05	141	L	268	L	155	L	415	L	329	L	232	L	152	L	70.9	L
Cyanide	2.5	2.0 E+04	0.13	J													0.31	J

Notes:
+ = Reported value obtained from diluted sample.
* = No SSL established for lead, for screening purposes EPA recommends a concentration of 400 mg/kg be used for residential soils.
Empty cell indicated substance not reported above detection limit.
mg/Kg = Milligrams per kilogram
Shaded cell indicates value above corresponding benchmark.
B = Analyte not detected substantially above the level reported in lab or field blanks.
CRDL = Contract Required Quantitation Limit
Dup = Duplicate sample

J = Analyte present. Reported value may not be accurate or precise.
L = Analyte present. Reported value may be biased low. Actual value is expected to be higher.
NA = Not applicable, SSL not established for this substance
PB = Pepco Benning
SS = Surface soil
SSL = Soil Screening Level
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TABLE 5
PEPCO BENNING ROAD SITE
SOIL SAMPLE
INORGANIC COMPOUNDS ANALYTICAL RESULTS

Sample Number :			MC00H4		MC00G3		MC00G2		MC00G4		MC00G5		MC00G6		MC00G7	
Sampling Location :			PB-SS-09		PB-SS-10		PB-SS-11		PB-SS-12		PB-SS-13		PB-SS-14		PB-SS-15	
Field QC :													Background		Background	
Matrix :		EPA	Soil		Soil		Soil		Soil		Soil		Soil		Soil	
Units :		Region 3 SSL	mg/Kg		mg/Kg		mg/Kg		mg/Kg		mg/Kg		mg/Kg		mg/Kg	
Date Sampled :		Soil	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Analyte	CRQL	mg/kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
ALUMINUM	20	9.9 E+05	10800		14200		14700		12700		9150		8870		8270	
ANTIMONY	6	410		R	1.3	J	0.92	J	1.6	J	3.3	J				
ARSENIC	1	1.6	3.2		7.5		7.6		7.3		7.3		2.5		2.5	
BARIUM	20	1.9 E+05	108		160		115		150		187		93.6		74.8	
BERYLLIUM	0.5	2000	0.54	J	0.50	J	0.53	J	0.52	J		UL	0.76		0.69	
CADMIUM	0.5	NA	1.1		1.9		1.9		1.8		1.5		0.92		0.86	
CALCIUM	500	NA	39400		29500		38500		72800		39000		4630		3260	
CHROMIUM (total)	1	1.4 E+03	30.3		52.8		54.7		58.3		49.1		25.7		21.6	
COBALT	5	300	15.6		29.3		22.3		26.0		40.6		9.5		9.5	
COPPER	2.5	4.1 E+04	89.5	J	188	J	466	J	366	J	84.5	J	27.6	J	30.7	J
IRON	10	7.2 E+05	17400		26500		23600		25300		19900		18300		18700	
LEAD*	1	400+	92.4		174		127		185		346		47.0		35.9	
MAGNESIUM	500	NA	5490		4320		5770		5770		4460		3290		4750	
MANGANESE	1.5	2.3 E+04	499	J	1110	J	553	J	940	J	417	J	264	J	227	J
MERCURY	0.1	28	0.19		0.23		0.40		0.40		0.16	B	0.30		0.20	
NICKEL	4	2.0 E+04	398		663		680		709		1880		27.6		42.1	
POTASSIUM	500	NA	1480		1870		1070		1460		977		1560		1340	
SELENIUM	3.5	5,100									2.1	B				
SILVER	1	5,100											0.61	J	0.28	J
SODIUM	500	NA	209	B	344	B	325	B	295	B	442	B	88.3	B	79.5	B
THALLIUM	2.5	66	3.7		8.5		4.1		8.8		20.1					
VANADIUM	5	7,200	1200		3390		1710		3290		7690		32.4		27.1	
ZINC	6	3.1 E+05	141	L	188	L	364	L	266	L	159	L	64.4	L	54.2	L
Cyanide	2.5	2.0 E+04	0.13	J	0.23	J	0.15	J	0.18	J	0.19	J		UL		UL

Notes:

+ = Reported value obtained from diluted sample.

* = No SSL established for lead, for screening purposes EPA recommends a concentration of 400 mg/kg be used for residential soils.

Empty cell indicated substance not reported above detection limit.

mg/Kg = Milligrams per kilogram

Shaded cell indicates value above corresponding benchmark.

B = Analyte not detected substantially above the level reported in lab or field blanks.

CRDL = Contract Required Quantitation Limit

Dup = Duplicate sample

J = Analyte present. Reported value may not be accurate or precise.

L = Analyte present. Reported value may be biased low. Actual value is expected to be higher.

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PB = Pepco Benning

SS = Surface soil

SSL = Soil Screening Level

Q = Laboratory analytical data qualifier

TABLE 6
PEPCO BENNING ROAD SITE
SEDIMENT SAMPLE
VOLATILE ORGANIC COMPOUNDS
ANALYTICAL RESULTS

Sample Number :		Sediment Screening Criteria		C00H9		C00J0		C00J1RE		C00J2		C00J3		C00J4		C00J5		C00J6	
Sampling Location :				PB-SD-01		PB-SD-02		PB-SD-03		PB-SD-04		PB-SD-05		PB-SD-06		PB-SD-07		PB-SD-08	
Matrix :				Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment	
Units :				ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		EPA*	NOAA**	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Volatile Organic Compound	CRQL	ug/Kg	ug/Kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
Acetone	10.0	NA	NA	35	B			17	B	66	B	34	B	140	B	46	B	95	B
Carbon Disulfide	5.0	0.851	NA											[redacted]	J				
2-Butanone	10.0	NA	NA							28	K			56	J	16	J	47	J
Trichloroethene	5.0	96.9	NA	6.1	B									9.8	J			6	J
Tetrachloroethene	5.0	468	NA																

Notes:
* = Screening benchmark established by EPA Region 3 for freshwater sediments.
** = Screening concentrations for contaminants in freshwater sediments developed by NOAA.
Only compounds reported above the CRQL included in table.
Empty cell indicated substance not reported above detection limit.
Shaded cell indicates value above corresponding benchmark.
ug/Kg = Micrograms per kilogram
CRQL = Contract Required Quantitation Limit
B = Analyte not detected substantially above the level reported in laboratory or field blanks.
J = Analyte present. Reported value may not be accurate or precise.
K = Analyte present. Reported value may be biased high. Actual value is expected to be lower.
NA = Not applicable, screening criteria not established for this substance
NOAA = National Oceanic and Atmospheric Administration
Q = Laboratory analytical data qualifier

TABLE 6
PEPCO BENNING ROAD SITE
SEDIMENT SAMPLE
VOLATILE ORGANIC COMPOUNDS
ANALYTICAL RESULTS

Sample Number :		Sediment Screening Criteria		C00J7RE		C00L1		C00L2		C00K0		C00K1RE		C00K2		C00K3		C00K4	
Sampling Location :				PB-SD-09		PB-SD-10		PB-SD-11		PB-SD-12		PB-SD-13		PB-SD-14		PB-SD-15		PB-SD-16	
Matrix :				Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment	
Units :				ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		EPA*	NOAA**	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Volatile Organic Compound	CRQL	µg/Kg	µg/Kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
Acetone	5.0	NA	NA	28	B			15	B	43	B	31	B	76	B	61	B		
Carbon Disulfide	5.0	0.851	NA																
2-Butanone	10.0	NA	NA			36	J			29		16	J	41	J	34		120	J
Trichloroethene	5.0	96.9	NA			7.8	J							5.8	J			19	J
Tetrachloroethene	5.0	468	NA															8.2	J

Notes:
* = Screening benchmark established by EPA Region 3 for freshwater sediments.
** = Screening concentrations for contaminants in freshwater sediments developed by NOAA.
Only compounds reported above the CRQL included in table.
Empty cell indicated substance not reported above detection limit.
Shaded cell indicates value above corresponding benchmark.
ug/Kg = Micrograms per kilogram
CRQL = Contract Required Quantitation Limit
B = Analyte not detected substantially above the level reported in laboratory or field blanks.
J = Analyte present. Reported value may not be accurate or precise.
NA = Not applicable, screening criteria not established for this substance
NOAA = National Oceanic and Atmospheric Administration
Q = Laboratory analytical data qualifier

TABLE 7
PEPCO BENNING ROAD SITE
SEDIMENT SAMPLE
SEMIVOLATILE ORGANIC COMPOUND ANALYTICAL RESULTS

Sample Number :		Sediment Screening Criteria		C00H9		C00J0		C00J1		C00J2		C00J3		C00J4		C00J5		C00J6	
Sampling Location :				PB-SD-01		PB-SD-02		PB-SD-03		PB-SD-04		PB-SD-05		PB-SD-06		PB-SD-07		PB-SD-08	
Matrix :				Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment	
Units :				ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		EPA*	NOAA**	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Semivolatile Compound	CRQL	µg/Kg	µg/Kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
Benzaldehyde	170	NA	NA																
Acetophenone	170	NA	NA																
4-Methylphenol	170	670	NA																
Naphthalene	170	176	14.65 / 600																
Caprolactam	170	NA	NA																
2-Methylnapthalene	170	20	NA																
Acenaphthene	170	6.7	NA / 290																
Fluorene	170	77.4	10 / 300																
Phenanthrene	170	204	18.73 / 800	[illegible]				950		810		810		[illegible]				[illegible]	
Anthracene	170	57.2	10 / 260					[illegible]	J	[illegible]	J	170	J						
Carbazole	170	NA	NA																
Di-n-butylphthalate	170	6470	NA / 110							200	J	[illegible]	J	[illegible]	J	[illegible]	J		
Fluoranthene	170	423	31.46 / 1500	[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		[illegible]	L	[illegible]	L	[illegible]	L
Pyrene	170	195	44.27 / 1000	[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		[illegible]	L	[illegible]	L	[illegible]	L
Butylbenzylphthalate	170	10900	NA									170	J						
Benzo(a)anthracene	170	108	15.72 / 500	[illegible]		[illegible]	J	[illegible]		[illegible]		[illegible]						[illegible]	L
Chrysene	170	166	26.83 / 800	[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		[illegible]	L	[illegible]	L	[illegible]	L
Bis(2-ethylhexyl)phthalate	170	180	NA	[illegible]	J	[illegible]	J	[illegible]	J	[illegible]	J	[illegible]	J	[illegible]	J	[illegible]	J	[illegible]	J
Benzo(b)fluoranthene	170	27.2	NA	[illegible]	J	[illegible]	J	[illegible]	J	[illegible]	J	[illegible]	J	[illegible]	L	[illegible]	J	[illegible]	J
Benzo(k)fluoranthene	170	27.2	NA	[illegible]		[illegible]	J	[illegible]		[illegible]		[illegible]		[illegible]	J	[illegible]	J	[illegible]	J
Benzo(a)pyrene	170	150	32.4 / 700	[illegible]		[illegible]	J	[illegible]		[illegible]		[illegible]		[illegible]	J	[illegible]		[illegible]	L
Indeno(1,2,3-cd)pyrene	170	17	17.32 / 330	[illegible]				[illegible]		[illegible]		[illegible]		[illegible]	J			[illegible]	J
Dibenzo(a,h)anthracene	170	33	10 / 100	[illegible]	J			[illegible]	J	[illegible]		[illegible]	J						
Benzo(g,h,i)perylene	170	170	NA / 300	[illegible]		[illegible]	J	[illegible]		[illegible]		[illegible]							
[illegible]				[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		[illegible]	

Notes:

* =Screening benchmark established by EPA Region 3 for freshwater sediments.

** = Screening concentrations for contaminants in sediments developed by NOAA. Lower Threshold Effects value provided (if established) / followed by Upper Threshold Effects value.

Only compounds reported above the CRQL included in table.

Empty cell indicated substance not reported above detection limit.

Shaded cell indicates value above corresponding benchmark.

ug/Kg = Micrograms per kilogram

B = Analyte not detected substantially above the level reported in laboratory or field blanks.

CRQL = Contract Required Quantitation Limit

J = Analyte present. Reported value may not be accurate or precise.

L = Analyte present. Reported value may be biased low. Actual value is expected to be higher.

NA = Not applicable, screening criteria not established for this substance

NOAA = National Oceanic and Atmospheric Administration

PB = Pepco Benning

Q = Laboratory analytical data qualifier

SD = Sediment

TABLE 7
PEPCO BENNING ROAD SITE
SEDIMENT SAMPLE
SEMIVOLATILE ORGANIC COMPOUND ANALYTICAL RESULTS

Sample Number :		Sediment Screening Criteria		C00J7		C00L1		C00L2		C00K0		C00K1		C00K2		C00K3		C00K4	
Sampling Location :				PB-SD-09		PB-SD-10		PB-SD-11		PB-SD-12		PB-SD-13		PB-SD-14		PB-SD-15		PB-SD-16	
Matrix :				Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment	
Units :				ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		EPA*	NOAA**	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Semivolatile Compound	CRQL	µg/Kg	µg/Kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
Benzaldehyde	170	NA	NA																
Acetophenone	170	NA	NA																
4-Methylphenol	170	670	NA																
Naphthalene	170	176	14.65 / 600																
Caprolactam	170	NA	NA																
2-Methylnapthalene	170	20.2	NA											230	J	280	J	270	J
Acenaphthene	170	6.7	NA / 290																
Fluorene	170	77.4	10 / 300																
Phenanthrene	170	204	18.73 / 800			[illegible]		[illegible]		[illegible]		[illegible]	J	[illegible]		[illegible]		[illegible]	
Anthracene	170	57.2	10 / 260																
Carbazole	170	NA	NA																
Di-n-butylphthalate	170	6470	NA/110																
Fluoranthene	170	423	31.46 / 1500	[illegible]	L	[illegible]	J	[illegible]		[illegible]	L	[illegible]	J	[illegible]	J	[illegible]	J	[illegible]	J
Pyrene	170	195	44.27 / 1000	[illegible]	L	[illegible]		[illegible]		[illegible]	L			[illegible]		[illegible]		[illegible]	
Butylbenzylphthalate	170	10900	NA																
Benzo(a)anthracene	170	108	15.72 / 500	[illegible]	L	[illegible]		[illegible]		[illegible]	L	[illegible]	J	[illegible]		[illegible]		[illegible]	J
Chrysene	170	166	26.83 / 800	[illegible]	L	[illegible]		[illegible]	J	[illegible]	J	[illegible]		[illegible]	J	[illegible]		[illegible]	
Bis(2-ethylhexyl)phthalate	170	180	NA	[illegible]	J	[illegible]		[illegible]	B	[illegible]		[illegible]	B	[illegible]		[illegible]	J	[illegible]	B
Benzo(b)fluoranthene	170	27.2	NA	[illegible]	L	[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		[illegible]	J
Benzo(k)fluoranthene	170	27.2	NA	[illegible]	J	[illegible]	J	[illegible]	J	[illegible]	J	[illegible]	J	[illegible]	J	[illegible]	J	[illegible]	J
Benzo(a)pyrene	170	150	32.4 / 700	[illegible]	L	[illegible]		[illegible]		[illegible]		[illegible]	J	[illegible]		[illegible]		[illegible]	J
Indeno(1,2,3-cd)pyrene	170	17	17.32 / 330	[illegible]	J	[illegible]		[illegible]		[illegible]				[illegible]		[illegible]	J	[illegible]	J
Dibenzo(a,h)anthracene	170	33	10 / 100												J				
Benzo(g,h,i)perylene	170	170	NA / 300			[illegible]		[illegible]				[illegible]	J	[illegible]		[illegible]	J	[illegible]	J
[illegible]				[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		[illegible]		[illegible]	

Notes:

* =Screening benchmark established by EPA Region 3 for freshwater sediments.

** = Screening concentrations for contaminants in sediments developed by NOAA. Lower Threshold Effects value provided (if established) / followed by Upper Threshold Effects value.

Only compounds reported above the CRQL included in table.

Empty cell indicated substance not reported above detection limit.

Shaded cell indicates value above corresponding benchmark.

ug/Kg = Micrograms per kilogram

B = Analyte not detected substantially above the level reported in laboratory or field blanks.

CRQL = Contract Required Quantitation Limit

Dup = Duplicate sample

J = Analyte present. Reported value may not be accurate or precise.

L = Analyte present. Reported value may be biased low. Actual is expected to be higher.

NA = Not applicable, SSL not established for this substance

NOAA = National Oceanic and Atmospheric Administration

PB = Pepco Benning

Q = Laboratory analytical data qualifier

SD = Sediment

TABLE 8
PEPCO BENNING ROAD SITE
SEDIMENT SAMPLE
PESTICIDE COMPOUND ANALYTICAL RESULTS

Sample Number :				C00H9		C00J0		C00J1		C00J2		C00J3		C00J4		C00J5		C00J6	
Sampling Location :				PB-SD-01		PB-SD-02		PB-SD-03		PB-SD-04		PB-SD-05		PB-SD-06		PB-SD-07		PB-SD-08	
Field QC :																			
Matrix :		Sediment Screening Criteria		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment	
Units :				ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		EPA*	NOAA**	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Pesticide Compounds	CRQL	µg/Kg	µg/Kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
Heptachlor	1.7	68.0	NA / 10													2.4	J		
Aldrin	1.7	2.0	NA / 40													7.2	J		
Heptachlor epoxide	1.7	2.470	0.6 / 30											4.4	J	32			
Endosulfan I	1.7	2.9	NA																
Dieldrin	3.3	1.9	2.85 / 300													18		3.2	J
4,4'-DDE	3.3	3.16	1.42 / 50	4.0	J					3.3	J	3.9	J	9.3	J	25	J	7.3	J
Endrin	3.3	2.22	NA													5.4	J		
Endosulfan II	3.3	14	NA																
4,4'-DDD	3.3	4.88	3.54 / 60			2.9	J	5.4	J	4.3	J	5.1	J	13	J	19	J	11	J
Endosulfan sulfate	3.3	5.4	NA	10.0	J			3.3	J										
4,4'-DDT	3.3	4.16	NA / 50					16.0	J			6.9	J	11	J	56	J	10	J
Methoxychlor	17.0	18.7	NA																
Endrin ketone	3.3	NA	2.67 / 500													16	J		
Endrin eldehyde	3.3	NA	2.67 / 500													28			
alpha-Chlordane	1.7	3.24	4.5 / 30	4.7	J	2.5	J	3.6	J	3.9	J	7.8		13	J	9.5	J	10.0	J
gamma-Chlordane	1.7	3.24	4.5 / 30	6.1	J	2.7	J	4.4	J	3.5	J	7.1	J	9.9	J	7.3	J	7.4	J

Notes:

* =Screening benchmark established by EPA Region 3 for freshwater sedments.

** = Screening concentrations for contaminants in freshwater sediments developed by NOAA.
Threshold Effects value provided (if established) / followed by Upper Threshold Effects value.

Only compounds reported above the CRQL included in table.

Empty cell indicated substance not reported above detection limit.

Shaded cell indicates value above corresponding benchmark.

ug/Kg = Micrograms per kilogram

CRQL = Contract Required Quantitation Limit

J = Analyte present. Reported value may not be accurate or precise.

NA = Not applicable, SSL not established for this substance

NOAA = National Oceanic and Atmospheric Administration

PB = Pepco Benning

Q = Laboratory analytical data qualifier

SD = Sediment

TABLE 8
PEPCO BENNING ROAD SITE
SEDIMENT SAMPLE
PESTICIDE COMPOUND ANALYTICAL RESULTS

Sample Number :				C00J7		C00L1		C00L2		C00K0		C00K1		C00K2		C00K3		C00K4	
Sampling Location :				PB-SD-09		PB-SD-10		PB-SD-11		PB-SD-12		PB-SD-13		PB-SD-14		PB-SD-15		PB-SD-16	
Field QC :																			
Matrix :		Sediment Screening Criteria		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment	
Units :				ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		EPA*	NOAA**	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Pesticide Compounds	CRQL	µg/Kg	µg/Kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
delta-BHC	1.7	6,400	NA																
Heptachlor	1.7	68.0	NA / 10															12	J
Aldrin	1.7	2.0	NA / 40															2.6	J
Heptachlor epoxide	1.7	2.470	0.6 / 30															2.1	J
Endosulfan I	1.7	2.9	NA																
Dieldrin	3.3	1.9	2.85 / 300				J											2.2	J
4,4'-DDE	3.3	3.16	1.42 / 50		J		J						J		J		J		
Endrin	3.3	2.22	NA																J
Endosulfan II	3.3	14	NA															3.8	J
4,4'-DDD	3.3	4.88	3.54 / 60		J		J		J	3.1	J		J		J		J		
Endosulfan sulfate	3.3	5.4	NA		J										J		J		J
4,4'-DDT	3.3	4.16	NA / 50		J		J	2.9	J	3.1	J				J				J
Methoxychlor	17.0	18.7	NA																J
Endrin ketone	3.3	NA	2.67 / 500																J
Endrin aldehyde	3.3	NA	2.67 / 500							3.4	J								
alpha-Chlordane	1.7	3.24	4.5 / 30				J	3.8	J				J				J		J
gamma-Chlordane	1.7	3.24	4.5 / 30		J		J	2.9	J		J		J		J		J		J

Notes:

* =Screening benchmark established by EPA Region 3 for freshwater sedments.

** = Screening concentrations for contaminants in sediments developed by NOAA. Threshold Effects value provided (if established) / followed by Upper Threshold Effects value.

+ = Result reported from diluted analysis.

Only compounds reported above the CRQL included in table.

Empty cell indicated substance not reported above detection limit.

Shaded cell indicates value above corresponding benchmark.

ug/Kg = Micrograms per kilogram

CRQL = Contract Required Quantitation Limit

J = Analyte present. Reported value may not be accurate or precise.

NA = Not applicable, screening criteria not established for this substance

NOAA = National Oceanic and Atmospheric Administration

Q = Laboratory analytical data qualifier

SD = Sediment

TABLE 9
PEPCO BENNING ROAD SITE
SEDIMENT SAMPLE
ARCLOR COMPOUND
ANALYTICAL RESULTS

Sample Number :				C00H9		C00J0		C00J1		C00J2		C00J3		C00J4		C00J5		C00J6	
Sampling Location :				PB-SD-01		PB-SD-02		PB-SD-03		PB-SD-04		PB-SD-05		PB-SD-06		PB-SD-07		PB-SD-08	
Field QC :																			
Matrix :		Sediment Screening Criteria		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment	
Units :				ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		EPA*	NOAA**	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Aroclor Compounds	CRQL	µg/Kg	µg/Kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
Aroclor-1254	33	59.8	34.1 / 26	140	J			91	J	60	J	140		180		1000 +	J	100	J
Aroclor-1260	33	59.8	34.1 / 26	120	J			73	J	65	J	76	J			1100+	J		

Sample Number :				C00J7		C00L1		C00L2		C00K0		C00K1		C00K2		C00K3		C00K4	
Sampling Location :				PB-SD-09		PB-SD-10		PB-SD-11		PB-SD-12		PB-SD-13		PB-SD-14		PB-SD-15		PB-SD-16	
Field QC :																			
Matrix :		Sediment Screening Criteria		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment	
Units :				ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg		ug/Kg	
Date Sampled :		EPA*	NOAA**	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Aroclor Compounds	CRQL	µg/Kg	µg/Kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
Aroclor-1254	33	59.8	34.1 / 26	110	J	85		40	J	46	J	40	J	86	J	82	J	810	J
Aroclor-1260	33	59.8	34.1 / 26															1700+	

Notes:
* =Screening benchmark established by EPA Region 3 for freshwater sedments.
** = Screening concentrations for contaminants in sediments developed by NOAA. Threshold Effects value provided (if established) / followed by Upper Threshold Effects value.
+ = Result reported from diluted analysis.
Only compounds reported above the CRQL included in table.
Empty cell indicated substance not reported above detection limit.
Shaded cell indicates value above corresponding benchmark.

ug/Kg = Micrograms per kilogram
CRQL = Contract Required Quantitation Limit
J = Analyte present. Reported value may not be accurate or precise.
NA = Not applicable, screening criteria not established for this substance
NOAA = National Oceanic and Atmospheric Administration
Q = Laboratory analytical data qualifier
SD = Sediment

TABLE 10
PEPCO BENNING ROAD SITE
SEDIMENT SAMPLE
INORGANIC COMPOUNDS ANALYTICAL RESULTS

Sample Number :				MC00H9		MC00J0		MC00J1		MC00J2		MC00J3		MC00J4		MC00J5		MC00J6	
Sampling Location :				PB-SD-01		PB-SD-02		PB-SD-03		PB-SD-04		PB-SD-05		PB-SD-06		PB-SD-07		PB-SD-08	
Field QC :																			
Matrix :		Sediment Screening Criteria		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment	
Units :				mg/Kg		mg/Kg		mg/Kg		mg/Kg		mg/Kg		mg/Kg		mg/Kg		mg/Kg	
Date Sampled :		EPA*	NOAA**	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Analyte	CRDL	mg/kg	mg/kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
ALUMINUM	20	NA	NA	12100		5700		5450		11200		5610		11500		15100		8310	
ANTIMONY	6	2	NA/3									1.3	B			1.3	B		
ARSENIC	1	9.8	5.9/17	2.9		0.76	J	0.92	J	2.9		1.6	J			6.2		3.1	
BARIUM	20	NA	NA	108		198		68.6		108		66.8		107	L	115	L	78.9	L
BERYLLIUM	0.5	NA	NA	1.3		0.49	J	0.62	J	1.3		0.76	J	1.3		1.5		0.98	
CADMIUM	0.5	0.99	0.596/3	2.1		0.82		1.0		2.2		1.1		1.9		1.5		1.1	
CALCIUM	500	NA	NA	2840		9820		2280		2880		2310		3060	B	1610	B	2500	B
CHROMIUM	1	43.4	37.3/95	47.6		24.9		26.0		46.6		28.2		48.3		72.4		35.4	
COBALT	5	50	NA	18.3		8.0		11.7		18.3		12.2		20.0		18.8		16.7	
COPPER	2.5	31.6	35.7/86	62.8	J	359	J	33.2	J	66.3	J	28.9	J	71.0	B	70.4	B	61.5	B
IRON	10	20000	4%	26200		13100		14700		25400		15100		27600		27200		20900	
LEAD	1	35.8	35/127	94.7		30.1		59.3		95.3		44.0		107		169		67.6	
MAGNESIUM	500	NA	NA	3350		3470		2440		3480		2050		3330	B	2790	B	2990	B
MANGANESE	1.5	460	NA/1100	286	J	185	J	153	J	297	J	211	J	344		229		213	
MERCURY	0.1	0.18	0.174/0.560	0.35		0.13	B	0.21	B	0.27	B	0.16	B	0.23	B	0.30		0.19	J
NICKEL	4	22.7	18/43	37.2		26.4		24.2		38.3		21.8		43.9		67.6		33.0	
POTASSIUM	500	NA	NA	1510		997		1200		1530		1120		1390	B	1460	B	1360	B
SELENIUM	3.5	2	NA	2.0	B														
SILVER	1	1	NA/4.5																
SODIUM	500	NA	NA	237	B	178	B	194	B	230	B	212	B	310	B	258	B	261	B
THALLIUM	2.5	NA	NA			1.6	B												
VANADIUM	5	NA	NA	46.9		28.3		26.9		46.7		27.0		60.6		169		42.7	
ZINC	6	121	123.1/520	274	L	98.8	L	155	L	291	L	148	L	307		282		222	
Cyanide	2.5	0.1	NA					0.39	J							0.33	B		

Notes:

* =Screening benchmark established by EPA Region 3 for freshwater sediment.

** = Screening concentrations for contaminants in sediments developed by NOAA. Threshold Effects value provided (if established) / followed by Upper Threshold Effects value.

Only compounds reported above the CRQL included in table.

Empty cell indicated substance not reported above detection limit.

mg/kg = milligrams per kilogram

B = Analyte not detected substantially above the level reported in laboratory or field blanks.

CRQL = Contract Required Quantitation Limit

J = Analyte present. Reported value may not be accurate or precise.

L = Analyte present. Reported value may be biased low. Actual is expected to be higher.

NA = Not applicable, screening criteria not established for this substance

NOAA = National Oceanic and Atmospheric Administration

PB = Pepco Benning

Q = Laboratory analytical data qualifier

SD = Sediment

TABLE 10
PEPCO BENNING ROAD SITE
SEDIMENT SAMPLE
INORGANIC COMPOUNDS ANALYTICAL RESULTS

Sample Number :				MC00J7		MC00L1		MC00L2		MC00K0		MC00K1		MC00K2		MC00K3		MC00K4	
Sampling Location :				PB-SD-09		PB-SD-10		PB-SD-11		PB-SD-12		PB-SD-13		PB-SD-14		PB-SD-15		PB-SD-16	
Field QC :																			
Matrix :		Sediment Screening Criteria		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment		Sediment	
Units :				mg/Kg		mg/Kg		mg/Kg		mg/Kg		mg/Kg		mg/Kg		mg/Kg		mg/Kg	
Date Sampled :		EPA*	NOAA**	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
Analyte	CRDL	mg/kg	mg/kg	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
ALUMINUM	20	NA	NA	8040		8050		1770		6680		6310		5080		12700		17600	
ANTIMONY	6	2	NA/3															12.5	J
ARSENIC	1	9.8	5.9/17	2.1	J	2.7		0.81	J									18.1	
BARIUM	20	NA	NA	82.4	L	81.0	L	20.8	B	62.9	L	65.7	L	57.0	L	117	L	265	L
BERYLLIUM	0.5	NA	NA	0.99	J	1.0	J	0.34	J	0.84		0.80	J	0.71	J	1.4	J	0.97	J
CADMIUM	0.5	0.99	0.596/3	1.1	J	0.86	J	0.17	B	0.61	J	0.50	J	0.55	J	1.5	J	25.7	
CALCIUM	500	NA	NA	2640	B	3110	B	1580	B	2030	B	2430	B	1990	B	3000	B	5840	B
CHROMIUM	1	43.4	37.3/95	39.9		36.9		10.6		28.3		26.5		25.5		53.4		78.7	
COBALT	5	50	NA	22.1		18.3		5.1	J	13.1		14.5		12.2		20.5		26.0	
COPPER	2.5	31.6	35.7/86	57.5	B	46.0	B	11.0	B	31.3	B	28.7	B	28.8	B	68.0	B	422	
IRON	10	20000	4%	21700		22300		9650		17900		16900		15200		30000		25400	
LEAD	1	35.8	35/127	74.0		63.6		22.7		40.2		39.6		46.9		96.6		1150	
MAGNESIUM	500	NA	NA	2650	B	2880	B	1670	B	2440	B	1780	B	2000	B	3520	B	4400	B
MANGANESE	1.5	460	NA/1100	262		242		89.7		199		333		188		289		765	
MERCURY	0.1	0.18	0.174/0.560	0.18	B	0.12	B			0.11	B	0.098	B	0.16	B	0.29	J	1.3	
NICKEL	4	22.7	18/43	43.7		30.8		15.8		22.4		21.0		22.3		41.7		292	
POTASSIUM	500	NA	NA	1110	B	1240	B	402	B	1200	B	778	B	1050	B	1550	B	995	B
SELENIUM	3.5	2	NA			3.1	J									4.2	B		
SILVER	1	1	NA/4.5															15.4	
SODIUM	500	NA	NA	293	B	243	B	129	B	189	B	188	B	224	B	387	B	767	B
THALLIUM	2.5	NA	NA															3.2	J
VANADIUM	5	NA	NA	63.0		37.9		12.3		29.3		28.0		27.7		54.9		948	
ZINC	6	121	123.1/520	248		212		57.9		141		119		139		297		2030	
Cyanide	2.5	0.1	NA			0.23	B									0.94	B	0.40	B

Notes:

* =Screening benchmark established by EPA Region 3 for freshwater sediment.

** = Screening concentrations for contaminants in sediments developed by NOAA. Threshold Effects value provided (if established) / followed by Upper Threshold Effects value.

Only compounds reported above the CRQL included in table.

Empty cell indicated substance not reported above detection limit.

Shaded cell indicates value above corresponding benchmark.

mg/kg = milligrams per kilogram

B = Analyte not detected substantially above the level reported in laboratory or field blanks.

CRQL = Contract Required Quantitation Limit

J = Analyte present. Reported value may not be accurate or precise.

L = Analyte present. Reported value may be biased low. Actual is expected to be higher.

NA = Not applicable, screening criteria not established for this substance

NOAA = National Oceanic and Atmospheric Administration

PB = Pepco Benning

Q = Laboratory analytical data qualifier

SD = Sediment

TABLE 11
PEPCO BENNING ROAD SITE
SURFACE WATER SAMPLES
INORGANIC COMPOUND
ANALYTICAL RESULTS

Sample Number :					MC00K5		MC00K6		MC00K7		MC00K8		MC00K9		MC00H8	
Sampling Location :					PB-SW-01		PB-SW-02		PB-SW-03		PB-SW-04		PB-SW-05		PB-FB-01	
Field QC :					Dup of PB-SW-05								Dup of PB-SW-05			
Matrix :			Freshwater Screening Criteria													
Units :					ug/L		ug/L		ug/L		ug/L		ug/L		ug/L	
Date Sampled :		MCL	EPA*	NOAA**	9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008		9/3/2008	
ANALYTE	CRQL	ug/L	ug/L	ug/L	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q	Result	Q
ALUMINUM	200	NA	87	87	210	B	327		307		348		212		42.1	J
ANTIMONY	60	6.0	30	88/30												
ARSENIC	10	10	5	150												
BARIUM	200	2000	4	3.9	56.7	B	61.1	B	68.2	B	60.2	B	55.1	B	35.3	J
BERYLLIUM	5	4.0	66	0.66												
CADMIUM	5	5.0	0.25	0.25												
CALCIUM	5000	NA	NA	NA	34200	B	32800	B	32800	B	30400	B	32900	B	38700	
CHROMIUM	10	NA	85	NA	2.1	B	1.9	B	1.8	B	2.7	B	2.3	B		
COBALT	50	NA	23	3	0.39	B	0.74	B	0.90	B	0.77	B	0.37	B		
COPPER	25	1300	9	9	2.0	B	2.7	B	[illegible]	B	3.3	B	2.2	B	278	
IRON	100	NA	300	1000	709		1060		1750		1170		696		14.8	B
LEAD	10	15.0	2.5	2.5			3.3	J	3.7	J	3.6	J	2.1	J		
MAGNESIUM	5000	NA	82000	NA	9390	B	8680	B	8100	B	7870	B	8930	B	9950	
MANGANESE	15	NA	120	80	86.8		107		181		123		85.5		0.79	B
MERCURY	0.2	2.0	0.026	0.77	0.064	B	0.051	B	0.059	B	0.059	B	0.041	B	0.038	J
NICKEL	40	NA	52	52	2.2	B	2.6	B	6.1	J	3.1	B	2.1	B		
POTASSIUM	5000	NA	53000	NA	4000	B	4270	B	4660	B	4240	B	3810	B	4660	J
SELENIUM	35	50.0	1	5												
SILVER	10	NA	3.2	0.36	1.8	J										
SODIUM	5000	NA	680000	NA	24000	B	25900	B	30900	B	26300	B	23100	B	11300	
THALLIUM	25	2.0	0.8	0.03												
VANADIUM	50	NA	20	NA	3.2	B	2.1	B	8.4	J	2.3	B	2.0	B	1.3	J
ZINC	60	NA	120	120	5.4	B	9.3	B	25.6	B	14.0	B	8.8	B	15.8	J
CYANIDE	10.0	200.0	5	5.2	4.3	B	6.0	B		UL		UL	4.9	B	9.3	B

Notes:

* =Screening benchmark established by EPA Region 3 for freshwater.

** = Screening concentrations for contaminants in freshwater developed by NOAA. Value shown is is for chronic exposure level.

Only compounds reported above the CRQL included in table.

Empty cell indicated substance not reported above detection limit.

Shaded cell indicates value above corresponding benchmark.

ug/L = Micrograms per liter

B = Analyte not detected substantially above the level reported in laboratory or field blanks.

CRQL = Contract Required Quantitation Limit

Dup = Duplicate sample

J = Analyte present. Reported value may not be accurate or precise.

NA = Not applicable, screening criteria not established for this substance

NOAA = National Oceanic Atmospheric Administration

Q = Laboratory analytical data qualifier

APPENDIX C

PHOTO DOCUMENTATION LOG

Photographic Documentation

Site Name: Pepco Benning Road Site
Location: Washington, D. C.

Prepared by: Tetra Tech EM Inc.
Photographer: Donna Davies

Photograph No. 1

Photograph Date: September 3, 2008

Description: View of sample collection of PB-SW-03 at inlet to Anacostia River.

Photograph No. 2

Photograph Date: September 3, 2008

Description: View of sample collection of PB-SD-16 at inlet to Anacostia River.

Photographic Documentation

Site Name: Pepco Benning Road Site
Location: Washington, D. C.

Prepared by: Tetra Tech EM Inc.
Photographer: Donna Davies

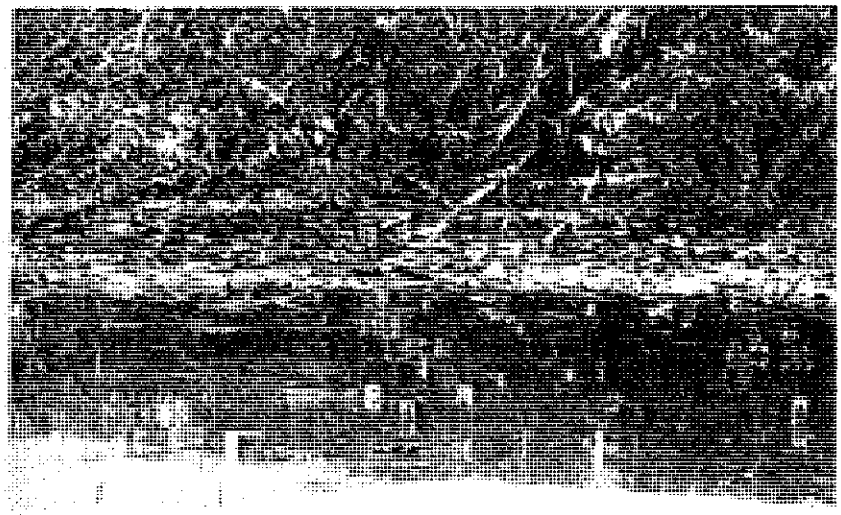
Photograph No. 3

Photograph Date: September 3, 2008

Description: View of storm water discharge point into Anacostia River. This is the PPE identified for the site.

Photograph No. 4

Photograph Date: September 3, 2008



Description: View of garbage located along Anacostia River bank.

Photographic Documentation

Site Name: Pepco Benning Road Site
Location: Washington, D. C.

Prepared by: Tetra Tech EM Inc.
Photographer: Donna Davies

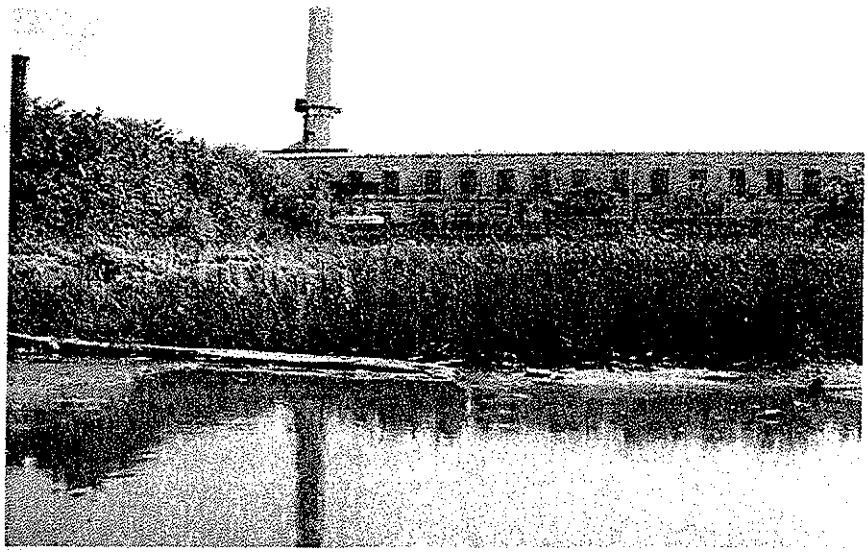
Photograph No. 5

Photograph Date: September 3, 2008

Description: View of wetland adjacent to Pepco facility. Photo taken on river.

Photograph No. 6

Photograph Date: September 3, 2008



Description: View of wetland adjacent to Pepco facility. Pepco site in background.

Photographic Documentation

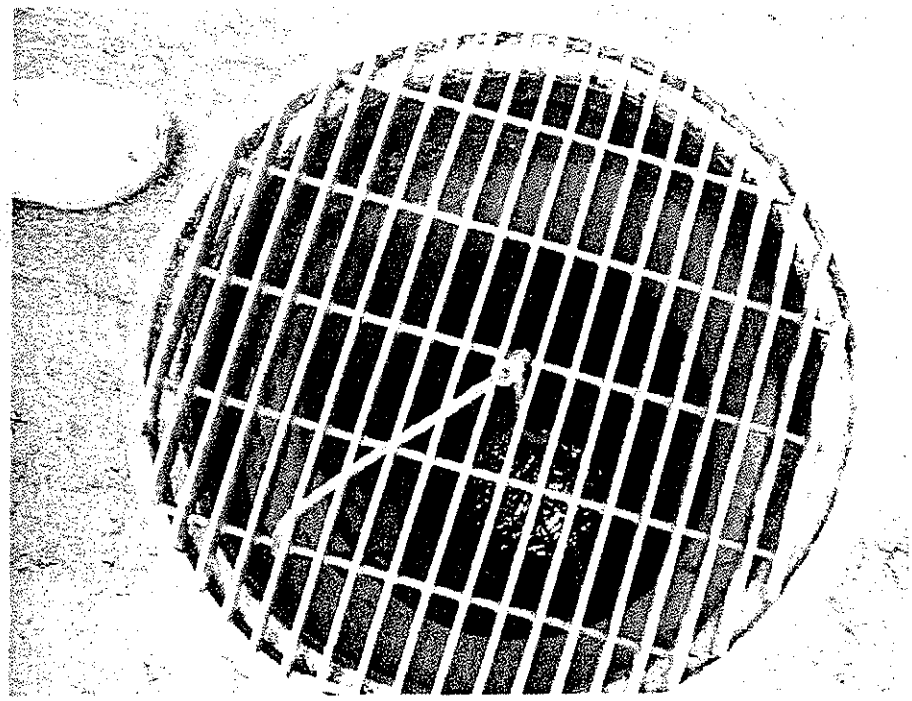
Site Name: Pepco Benning Road Site
Location: Washington, D. C.

Prepared by: Tetra Tech EM Inc.
Photographer: Donna Davies

Photograph No. 7

Photograph Date: June 10, 2008

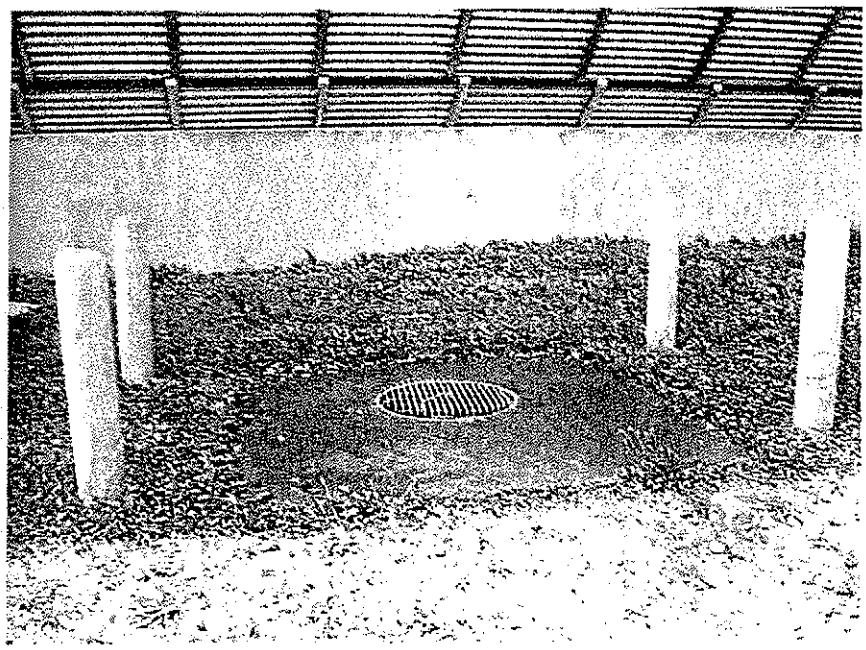
Description: View of NPDES sampling location for Outfall 013.



Photograph No. 8

Photograph Date: June 10, 2008

Description: Outfall 013 sampling location. Cooling tower in background.



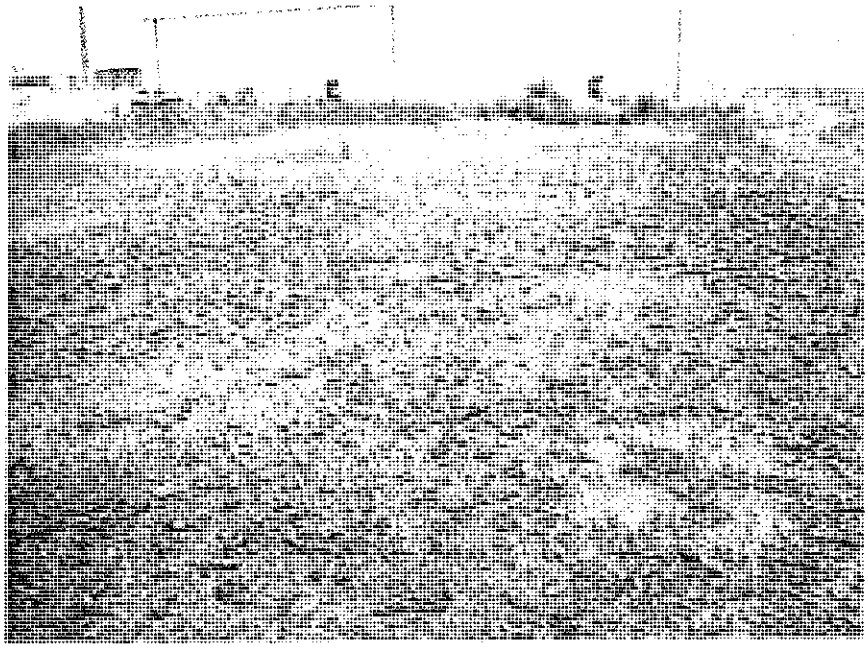
Photographic Documentation

Site Name: Pepco Benning Road Site
Location: Washington, D. C.

Prepared by: Tetra Tech EM Inc.
Photographer: Donna Davies

Photograph No. 9

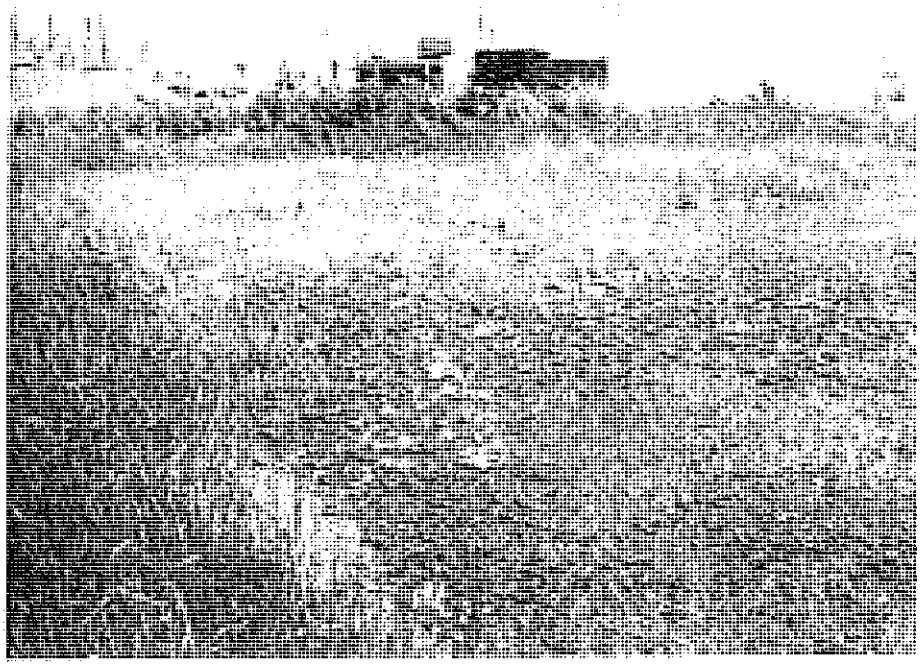
Photograph Date: June 10, 2008



Description: View of former lagoon used to dewater sludge dredged from cooling tower basins. Location where surface soil samples collected for analysis.

Photograph No. 10

Photograph Date: June 10, 2008



Description: View of former lagoon used to dewater sludge from cooling tower basins where surface soil samples collected for analysis.

T.D. Sanford
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (K) – 3

UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

DISTRICT OF COLUMBIA, Plaintiff, v. POTOMAC ELECTRIC POWER COMPANY, *et al.*, Defendants.	Civil Action No. 11-00282 (BAH)

MEMORANDUM OPINION

The District of Columbia brought this action against Pepco, a power generation company, pursuant to federal and D.C. environmental statutes. The District alleges that, between 1985 and 2003, there were six documented releases of toxic polychlorinated biphenyls ("PCBs") at a Pepco facility located at 3400 Benning Road, N.E., Washington, D.C. The District alleges that, over time, these environmentally damaging PCBs have seeped into sediment of the Anacostia River. The District and Pepco have reached a settlement that calls for Pepco to conduct a Remedial Investigation and Feasibility Study as the initial step in remedying the contamination. The parties have moved the Court to enter a consent decree that memorializes their settlement. Three environmental organizations – the National Resources Defense Council, the Anacostia River-keeper, and the Anacostia Watershed Society – have moved to intervene in this action or, in the alternative, for leave to participate as amici curiae. These organizations oppose entry of the consent decree in its current form. For the reasons explained below, the Court denies the motion to intervene but grants the proposed intervenors' request for leave to participate as amici curiae. In addition, the Court approves entry of the consent decree upon certain conditions outlined below.

I. BACKGROUND

The District of Columbia, through the District Department of the Environment (the "District," "DDOE," or the "plaintiff"), filed the Complaint in this action on February 1, 2011 against Potomac Electric Power Company and Pepco Energy Services, Inc. (collectively, "Pepco" or the "defendant"). Compl. at 1. The Complaint alleges claims under Section 7002(a)(1)(B) of the Resource Conservation and Recovery Act ("RCRA"), under Section 107 of the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), and under Section 401(a)(2) of the District of Columbia Brownfield Revitalization Act of 2000 ("DCBRA"). Compl. ¶ 1.

Pepco and its affiliated companies constitute one of the largest energy delivery companies in the mid-Atlantic region. *Id.* ¶ 2. The plaintiff alleges that from 1985 to 2003 six documented releases of toxic PCBs occurred at Pepco's facility at 3400 Benning Road, N.E., Washington, D.C. (the "Facility"). *Id.*¶ 4. The Complaint alleges that these PCBs have migrated into the sediment of the Anacostia River via the storm water system, overland flow, or groundwater discharge. *Id.* PCBs meet the definition of solid waste under RCRA and a hazardous substance under CERCLA and DCBRA. *Id.* Thus, the plaintiff alleges that "Pepco's discharge of PCBs into the Anacostia has contributed to conditions which may pose an imminent and substantial endangerment to aquatic life in the Anacostia River, and to human health." *Id.* The plaintiff alleges that the "conditions at the Facility result from Pepco's generation, management and disposal of hazardous substances, and Pepco, as a 'generator,' may be liable for the costs of abating such conditions." *Id.*

The plaintiff and Pepco have reached a settlement pursuant to which Pepco has agreed to conduct a remedial investigation and feasibility study ("RI/FS") to study the conditions at the Facility and the adjacent areas of the river, to determine the link between the Facility and the PCBs in the river, and to assess clean-up options. The parties have memorialized this agreement in a

proposed consent decree. The proposed consent decree was originally published for public comment on February 4, 2011, shortly after this action was filed. Pl.'s Mem. in Supp. of Pl.'s Mot. To Enter Consent Decree, ECF No. 24-1, at 1. On March 11, 2011, the plaintiff received comments on the proposed consent decree from the Natural Resources Defense Council, the Anacostia Watershed Society, and the Anacostia Riverkeeper. *Id.* at 1-2. On April 26, 2011, these three organizations (the "proposed intervenors") filed a motion to intervene as plaintiffs in this action. ECF No. 2.

The District considered the proposed intervenors' comments on the proposed consent decree and prepared a detailed written response. Pl.'s Mem. in Supp. of Pl.'s Mot. to Enter Consent Decree at 2. The District then revised the consent decree, including by incorporating some of the proposed intervenors critiques, and negotiated the revisions with Pepco. *Id.* The parties executed the revised consent decree on July 29, 2011 and filed it with the Court on August 17, 2011. *Id.*; *see* ECF No. 22.

The plaintiff has moved for the revised proposed consent decree to be entered. The proposed intervenors seek to intervene in this action and oppose entry of the consent decree. The plaintiff and Pepco oppose the motion to intervene. These motions are presently before the Court.

On November 22, 2011, the Court held oral argument on the motion to intervene and the motion to enter the consent decree. The proposed intervenors fully participated in oral argument on both motions. Following oral argument, the Court took the motions under advisement, but issued a Minute Order requesting that the parties submit a proposed order for entry of the consent decree. *See* Minute Order dated Nov. 22, 2011. The Court directed that the proposed order should indicate that acceptance of the proposed consent decree is contingent on two supplementary requirements relating to (1) ensuring public participation and access to information regarding the RI/FS and (2)

providing the Court with a status report on the progress of the timely implementation of the RI/FS. *Id.* These two supplementary requirements are discussed further below.

II. MOTION TO INTERVENE

A. Legal Standard

"Federal Rule of Civil Procedure 24 sets forth the requirements for both intervention as of right and permissive intervention." *Envtl. Def. v. Leavitt*, 329 F. Supp. 2d 55, 65 (D.D.C. 2004) (citing Fed. R. Civ. P. 24); *see also Fund for Animals, Inc. v. Norton*, 322 F.3d 728, 731 (D.C. Cir. 2003). Rule 24(a) provides for intervention as of right, stating that

> [o]n timely motion, the court must permit anyone to intervene who . . . is given an unconditional right to intervene by a federal statute [or] . . . claims an interest relating to the property or transaction that is the subject of the action, and is so situated that disposing of the action may as a practical matter impair or impede the movant's ability to protect its interests, unless existing parties adequately represent that interest.

Fed. R. Civ. P. 24(a). "As paraphrased by the D.C. Circuit, the rule indicates that an applicant's right to intervene depends on '(1) the timeliness of the motion; (2) whether the applicant claims an interest relating to the property or transaction which is the subject of the action; (3) whether the applicant is so situated that the disposition of the action may as a practical matter impair or impede the applicant's ability to protect that interest; and (4) whether the applicant's interest is adequately represented by existing parties.'" *Leavitt*, 329 F. Supp. at 65-66 (quoting *Fund for Animals*, 322 F.3d at 731); *see also Jones v. Prince George's County, Md.*, 348 F.3d 1014, 1017 (D.C. Cir. 2003) (listing the four elements of Rule 24(a) as "timeliness, interest, impairment of interest, and adequacy of representation"). "In addition, an applicant for intervention as of right must demonstrate that it has standing by showing injury-in-fact, causation, and redressability." *Leavitt*, 329 F. Supp. at 66 (citing *Fund for Animals*, 322 F.3d at 732-33). "Specifically, the applicant must have suffered an injury in fact, defined as a harm that is concrete and actual or imminent, not conjectural or hypothetical." *Id.* (citing *Byrd v. EPA*, 174 F.3d 239, 243 (D.C. Cir. 1999)). "Second,

the injury must be fairly traceable to the governmental conduct alleged." *Id.* "Finally, it must be likely that the requested relief will redress the alleged injury." *Id.*

"Alternatively, Rule 24(b) authorizes permissive intervention for an applicant who timely files a motion where a federal statute confers a conditional right to intervene or the applicant's claim or defense has a question of law or fact in common with the main action." *Id.* (citing Fed. R. Civ. P. 24(b)). "If a federal statute does not confer a conditional right to intervene, Rule 24(b)(2) requires a would-be intervenor to present '(1) an independent ground for subject matter jurisdiction; (2) a timely motion; and (3) a claim or defense that has a question of law or fact in common with the main action.'" *Id.* (citing *Equal Employment Opportunity Comm'n v. Nat'l Children's Ctr., Inc.*, 146 F.3d 1042, 1046 (D.C. Cir. 1998)). The decision to allow permissive intervention under Rule 24(b) is committed to the district court's discretion. *Id.* (citing *Nat'l Children's Ctr.*, 146 F.3d at 1046, 1048). In exercising its discretion to allow permissive intervention, the Court must consider whether the proposed intervention "will unduly delay or prejudice the adjudication of the original parties' rights." Fed. R. Civ. P. 24(b).

B. Intervention As A Matter Of Right Is Unwarranted

The proposed intervenors move to intervene as a matter of right or, in the alternative, via permissive intervention. Mot. to Intervene, or in the Alternative for Leave to Participate as Amici Curiae, and Mem. in Supp., ECF No. 2 ("Intervenor Mem.") at 2, 4, 10. In the alternative to either form of intervention, the proposed intervenors also seek leave to participate as amici curiae. *Id.* at 2.

The Court will deny the motion to intervene as a matter of right. Even assuming, *arguendo*, that all of the other prerequisites for intervention under Rule 24(a) were satisfied, the Court does not find that the proposed intervenors are "so situated that disposing of the action may as a practical matter impair or impede the [proposed intevenors'] ability to protect [their] interest[s]." Fed. R.

Civ. P. 24(a). In assessing this factor, the D.C. Circuit has instructed that courts must consider "the practical consequences of denying intervention, even where the possibility of [a] future challenge . . . remain[s] available." *Fund for Animals*, 322 F.3d at 735 (internal quotation omitted).

As a practical matter, denying intervention would not impair or impede the proposed intervenors' ability to protect their interests, which the proposed intervenors identify as interests "in protecting human health, including the health of their members, and in protecting and restoring the Anacostia River, including abatement of toxic contamination in the river." Intervenor Mem. at 7 (citing Proposed Intervenor Compl. ¶¶ 13-16). The District's claims in this action are proposed to be settled by consent decree. Even if the Court permits the proposed intervenors to intervene in this action, they would not be able to block entry of the consent decree. *See United States v. District of Columbia*, 933 F. Supp. 42, 47 (D.D.C. 1996) ("[I]f such a citizen were allowed to block entry of a consent decree merely by objecting to its terms it would wreak havoc upon government enforcement actions. Moreover, it is well settled that the right to have its objections heard does not, of course, give the intervenor the right to block any settlement to which it objects.") (internal citations, quotations, and alteration omitted).[1] Since the Court will grant the proposed intervenors leave to participate as amici curiae, as discussed below, the Court will have the opportunity to consider all of the proposed intervenors' objections to the proposed consent decree in evaluating whether to accept the consent decree. Thus, denying intervention here will not practically impair the proposed intervenors' ability to protect their interests because they will be able to present their critiques of the consent decree to the Court and because they could not block the consent decree even if intervention were granted.

[1] While intervenors may not be able to block entry of the consent decree between the District and Pepco, intervention would result in delaying settlement of this action because the consent decree here would not settle the claims in the proposed intervenors' complaint-in-intervention. Counsel for Pepco stated at oral argument that if intervention were granted, Pepco would enter into negotiations to attempt to resolve all claims in this action together. Thus, intervention would practically delay entry of the consent decree.

Courts have found that "disposing of [an] action may as a practical matter impair or impede" a proposed intervenor's interests when the disposition of the action would result in a substantial change in the status quo with respect to those interests. For example, in finding that intervention was warranted in *Fund for Animals*, the D.C. Circuit observed that "there is no question that the task of reestablishing the status quo if the [plaintiff] succeeds in this case will be difficult and burdensome." 322 F.3d at 735. The Court in that case also found that the proposed intervenor's "loss of revenues . . . would be substantial and likely irreparable." *Id.* (citing *Mova Pharm. Corp. v. Shalala*, 140 F.3d 1060, 1076 (D.C. Cir. 1998) (holding that danger of loss of market share due to denial of a preliminary injunction satisfied the third Rule 24(a)(2) factor)).

Here, the disposition of this action by consent decree will not create any irreparable results or alter the status quo in a way that is hard to reverse. The proposed consent decree provides, *inter alia*, that Pepco shall conduct and pay for an RI/FS to assess the contamination at the polluted site. Revised Consent Decree, ECF No. 22-1, ¶ 8. Pepco is also required to reimburse the District for its oversight costs. *Id.* ¶ 7. Importantly, the consent decree explicitly does not absolve Pepco of liability for subsequent remedial actions relating to contamination from the Facility. *See id.* ¶ 12, f, xi (stating that "[e]xcept for matters related to the RI/FS that are expressly resolved by this Consent Decree," the District reserves all available remedies arising out of "[a]ny liability, at any time, for additional response actions to address the Anacostia river."). Since the settlement of the claims in this action would not resolve the ultimate question of how the pollution will be cleaned up, the Court does not find that denial of intervention at this time would practically impair the proposed intervenors' ability to protect their interests. Intervention in or commencement of future actions remains a possible and practical avenue for the proposed intervenors to protect their interests. *Cf. Leavitt*, 329 F. Supp. 2d at 68 ("[N]othing in the decree would preclude [the proposed intervenor] from participating in the rulemaking or from challenging the final rule that emerges."). The RI/FS

that would result from settlement of this action would not substantially change the status quo at the Facility or in the river.

The proposed intervenors respond that "the RI/FS itself is a crucial part of the remediation process. . . [and] early decisions will affect every subsequent stage of the remediation process and may substantially determine whether an endangerment is found and, if so, how it is resolved." Reply in Supp. of Mot. to Intervene or for Leave to Participate as Amici Curiae at 4. Even if the Court accepts this premise, that does not require a finding that the disposition of this action, which is proposed to be settled by consent decree, will impair the proposed intervenors' ability to protect their interests. As noted above, the proposed intervenors will be able to present their critiques of the consent decree to the Court as amici curiae and they could not block the consent decree even if intervention were granted.

The proposed intervenors also argue that a future challenge in this case would be "difficult and burdensome" because RCRA bars independent citizen lawsuits where a state is "diligently prosecuting" an environmental matter. Intervenor Mem. at 7 (citing 42 U.S.C. § 6972(b)(2)(C)(i)). Specifically, the proposed intervenors argue that since the District's prosecution of this action "might constitute diligent state prosecution under RCRA that bars [them] from bringing a separate RCRA suit," denial of intervention here would practically impair their ability to protect their interests by filing their own lawsuit. *Id.* To the contrary, the fact that Congress has limited the ability of citizens to initiate environmental lawsuits where a state is already prosecuting a matter does not demonstrate that denial of intervention would practically impair the proposed intervenors' interests. Indeed, the same statute that establishes this "diligent prosecution" bar cited by the proposed intervenors also specifically addresses the circumstances in which intervention is appropriate. RCRA provides, in relevant part:

> In any action under subsection (a)(1)(B) of this section in a court of the United States, any person may intervene as a matter of right when the applicant claims an interest relating to

> the subject of the action and he is so situated that the disposition of the action may, as a practical matter, impair or impede his ability to protect that interest, unless the Administrator or the State shows that the applicant's interest is adequately represented by existing parties.

42 U.S.C. § 6972(b)(2)(E). Thus, RCRA itself provides that while a citizen may not initiate a new action on an environmental matter that the state is diligently prosecuting, a citizen may intervene in such an action, *if* the citizen "is so situated that the disposition of the action may, as a practical matter, impair or impede his ability to protect [his] interest. . . ." *Id.* If the mere existence of the diligent prosecution bar to initiating new actions were sufficient to show practical impairment, then the practical impairment requirement would effectively be nullified because it would be satisfied in every case.[2] Courts disfavor statutory interpretations that render part of the statute superfluous. *Nat'l Ass'n of Mortg. Brokers v. Bd. of Govs. of Fed. Reserve Sys.*, 773 F. Supp. 2d 151,168 (D.D.C. 2011) ("[I]t is a cardinal principle of statutory construction that the statute ought, upon the whole, be so construed that, if it can be prevented, no clause, sentence, or word shall be superfluous, void or insignificant.") (quoting *TRW, Inc. v. Andrews*, 534 U.S. 19, 21 (2001)). Disposition of this action by the proposed consent decree would not practically impair the proposed intervenors' ability to protect their interests for the reasons addressed above.[3]

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[2] The proposed intervenors treat Section 6972(b)(2)(E) as creating a "conditional right to intervene" that enables permissive intervention under Rule 24(b)(1)(A). *See* Intervenor Mem. at 10. Yet the language of Section 6792(b)(2)(E) purports to enable intervention "as a matter of right" and its requirements mirror the requirements for intervention of right under Rule 24(a)(2). The Court therefore finds that Section 6972(b)(2)(E) may best be read as clarifying the circumstances in which Rule 24(a) intervention of right is appropriate in a RCRA action. *See United States v. Hooker Chems. & Plastics Corp.*, 749 F.2d 968, 983 (2d Cir. 1984) ("[T]he requirements for intervention embodied in Rule 24(a)(2) must be read also in the context of the particular statutory scheme that is the basis for the litigation and with an eye to the posture of the litigation at the time the motion is decided."); *see also Litgo New Jersey, Inc. v. Jackson*, No. 06-2891, 2006 WL 3333486, at *4 (D.N.J. Nov. 16, 2006) (describing Section 6972(b)(2)(E) as enabling application "to intervene as a matter of right"). Ultimately, the Court would deny intervention regardless of whether this provision is analyzed under the rubric of permissive intervention or intervention of right.

[3] The District argues that RCRA's diligent prosecution bar to commencing a new action should also bar the proposed intevenors' complaint-in-intervention here because the complaint-in-intervention adds new claims that significantly expand the scope of this action, such that the complaint-in-intervention should be treated as the initiation of a new action rather than a true intervention. *See* Pl.'s Sur-Reply, ECF No. 13, at 3-5. Relatedly, the District argues that if the complaint-in-intervention is treated as commencing a new action, it is also barred because the proposed intervenors failed to comply with certain notice requirements for commencing a new RCRA action. *See id.* Since the Court is denying intervention for the reasons discussed herein, it need not reach these arguments.

C. Permissive Intervention Is Unwarranted

The Court also finds that permissive intervention is unwarranted in this case. Courts have "wide latitude" in exercising their discretion to allow or deny permissive intervention. *Nat'l Children's Ctr.*, 146 F.3d at 1046. "Reversal of a district court's denial of permissive intervention is a 'very rare bird indeed.'" *Id.* at 1048 (citation omitted). "District courts have the discretion . . . to deny a motion for permissive intervention even if the movant established an independent jurisdictional basis, submitted a timely motion, and advanced a claim or defense that shares a common question with the main action." *Id.* In exercising its discretion to allow permissive intervention, the Court must consider whether the proposed intervention "will unduly delay or prejudice the adjudication of the original parties' rights." Fed. R. Civ. P. 24(b).

Here, the Court finds that intervention is likely to unduly delay the adjudication of the original parties' rights. Indeed, the instant motion for intervention and the extensive briefing surrounding it has already delayed the Court's consideration of the revised consent decree. Intervention would likely delay the resolution of this action – and the associated RI/FS for the contaminated site – even further by triggering renewed negotiations over the terms of the consent decree in an attempt to resolve the proposed intervenors' claims simultaneously with the District's claims. In addition, allowing intervention would undermine part of the benefit of entering into a consent decree for the settling parties – namely, minimizing litigation and focusing on getting the RI/FS for the contaminated site underway expeditiously. Accordingly, permissive intervention is unwarranted.

D. The Proposed Intervenors May Participate As Amici Curiae In This Action

The Court has broad discretion to permit the proposed intervenors to participate as amici curiae. *See Nat'l Ass'n of Home Builders v. U.S. Army Corps of Eng'rs*, 519 F. Supp. 2d 89, 93

(D.D.C. 2007). Since the proposed intervenors are environmental organizations with relevant expertise and a stated concern for the issues at stake in this case, the Court finds that it may benefit from their input in evaluating the proposed consent decree. Therefore, the proposed intervenors are granted leave to participate as amici curiae and the Court will consider their comments in their written submissions and at oral argument in its assessment of the consent decree below.

III. MOTION TO ENTER CONSENT DECREE

A court reviewing a consent decree must "'determine that the settlement is fair, adequate, reasonable and appropriate under the particular facts and that there has been valid consent by the concerned parties.'" *Leavitt*, 329 F. Supp. 2d at 70 (quoting *Citizens for a Better Env't v. Gorsuch*, 718 F.2d 1117, 1126 (D.C. Cir. 1983)). A court must also assess whether the consent decree is in the public interest. *Id.* Upon evaluating the consent decree in consideration of these standards, and following oral argument and the submissions of the parties and the amici, the Court finds that the consent decree should be entered with the supplementary conditions discussed below and set forth in the Order that accompanies this Memorandum Opinion.

A. The Consent Decree Is Fair And In The Public Interest

"A review of the fairness of a proposed consent decree requires an assessment of the good faith of the parties, the opinions of the counsel, and the possible risks involved in litigation if the settlement is not approved." *Id.* (quotation omitted). "A consent decree is substantively fair if it incorporates concepts of corrective justice and accountability." *Id.* (internal quotation and citation omitted).

Both parties consent to the entry of the decree. The parties negotiated the settlement under a deadline imposed by the Environmental Protection Agency. Pl.'s Mem. in Supp. of Pl.'s Mot. to Enter Consent Decree ("Pl.'s Consent Decree Mem.") at 3. The EPA has been informed of the details of the agreement and "has not stated any objection or indicated that the Proposed Consent

Decree is insufficient in any way that would cause EPA to exercise its federal enforcement authorities with respect to the Facility." *Id.* Moreover, the consent decree is the product of a process that invited public input and it incorporates revisions adopted in response to the comments of the proposed intervenors. *Id.* at 5. Accordingly, the Court finds the consent decree to be procedurally fair.

The Court also finds that the decree is substantively fair. It requires Pepco, the suspected source of PCB contamination in the Anacostia River, to undertake the RI/FS and to reimburse the District for its oversight costs. At the same time, the District recognizes that there are other potential sources of pollution in the Anacostia River. *See id.* at 3-4. Therefore, the District submits that the "investigation will allows the Parties to determine what harm Pepco is responsible for, and if justified, for the District to seek remedial action for that harm." *Id.* Under the proposed consent decree, the District retains the right to sue Pepco to enforce any liability for future remedial actions to clean up the pollution at the Facility and in the river. *See* Revised Consent Decree ¶ 12, f, ix-xi. Indeed, counsel for the District noted at oral argument that a subsequent lawsuit was the likely avenue for enforcing the ultimate remediation requirements. Thus, the consent decree incorporates concepts of corrective justice and accountability.

B. The Consent Decree Is Adequate, Reasonable, And Appropriate

"The factors for determining the adequacy, reasonableness and appropriateness of a consent decree focus on the extent to which the decree is confined to the dispute between the parties and whether the decree adequately accomplishes its purported goal." *Leavitt*, 329 F. Supp. 2d at 71. "The role of the court in evaluating these factors, however, 'is not to impose its own judgments as to how it would prosecute and resolve a particular case.'" *Id.* (quoting *District of Columbia*, 933 F. Supp. 42 at 51). "Rather, the court must determine whether the proposed consent decree is reasonable from an objective point of view." *Id*. (internal quotation marks omitted).

The environmental group amici have raised two primary concerns about the adequacy and reasonableness of the consent decree. First, the amici argue that the consent decree is flawed because it fails to include a firm deadline for the completion of the RI/FS. *See* Opp'n to Mot. to Enter the Consent Decree ("Amici Opp'n") at 2. As a result, the amici contend that "Pepco could delay for years or even decades" before completing the RI/FS. *Id.* at 3. While it is true that the consent decree does not contain a binding final deadline for completion of the RI/FS, it does establish a process for scheduling the completion of the work. The consent decree provides that 60 days after entry of the consent decree, Pepco must submit a draft Statement of Work for the RI/FS. Revised Consent Decree ¶ 8(c). Then, 90 days after the District's approval of a final Statement of Work, Pepco must submit a draft work plan and other relevant documents, including a proposed schedule for the RI/FS. *Id.* Within 30 days after the District approves the final work plan, Pepco must initiate work on the RI/FS according to the schedule in the work plan. *Id.* The decree specifies that this schedule becomes binding, although it permits the District to extend the deadlines in its discretion. *Id.* More generally, the decree also provides that all work under the consent decree shall be performed "expeditiously." *Id.* ¶ 8(a). Thus, the danger of Pepco dragging the RI/FS process out for years, as amici fear, would contravene the intent of the consent decree and would appear to require that the District also fail to act in good faith by holding Pepco to reasonable, binding deadlines for the completion of the work.

Amici rely heavily on *Envtl. Tech. Council v. Browner*, No. 94-2119, 1995 WL 238328 (D.D.C. 1995), to argue that the Court should reject the consent decree for failure to include a binding deadline for completion of the RI/FS. In *Browner*, the plaintiffs sued the EPA for failure to issue certain regulations relating to hazardous waste. *Id.* at *1-2. The consent decree proposed in that case would have allowed the EPA and the settling plaintiffs to "stipulate to extensions of the deadlines for issuing the proposed and final rules without approval of the Court and without

showing good cause." *Id*. at *6. The *Browner* court found this arrangement insufficient to protect against unreasonable extensions of time and therefore rejected the consent decree. *Id.* at *7. As Pepco pointed out at oral argument, however, *Browner* is distinguishable from this case because, in *Browner*, the proposed consent decree would have relied upon a private party – the settling plaintiffs – to protect the public interest by ensuring that a government agency complied with its legal obligations to issue regulations. As Judge Hogan explained:

> While the settling plaintiffs may not ordinarily consent to an extension that they do not believe is justified, the Court harbors serious doubts that it is consistent with the public interest to leave the determination of good cause for an extension in the hands of the settling plaintiffs alone. The public interest in the promulgation of timely regulations appears to require the Court to carefully scrutinize any additional extensions of the rulemaking schedule when the EPA is already proposing to issue its final rule more than two years after the deadline imposed by Congress. The settling plaintiffs have other private interests that may affect their willingness to consent to an extension of a deadline. Absent an impartial determination as to the reasonableness of any extensions of time, the public interest is left unprotected.

Id. at *7. Here, the main concern is to ensure that Pepco will complete the RI/FS in a reasonable time frame. Since the DDOE is a public agency charged with protecting the public interest on environmental issues, the Court will assume that the DDOE will act in good faith and in the public interest in policing Pepco's responsibility to complete the RI/FS in a reasonable time frame. Unlike the settling plaintiffs in *Browner*, DDOE, as a public environmental agency, does not have "private interests that may affect [its] willingness to consent to an extension of a deadline." *Id.* Nonetheless, to ensure sufficient public and judicial oversight of the timeliness of the RI/FS process, the Court will require, as a condition of entry of the consent decree, that the parties file a status report with the Court within 18 months after the consented decree is entered.[4] This status report shall address the progress in implementation of the consent decree and any related plans for remediation of environmental contamination. If the RI/FS has not been completed by the reporting

[4] The parties explained at oral argument that 18 months was a reasonable time period for the completion of the RI/FS, barring any unforeseen challenges, and that two years represented the "outside date" estimate for completion.

date, the status report shall provide an explanation and showing of good cause for why it has not been completed and shall explain to the Court in detail how the parties plan to complete the RI/FS expeditiously.

The amici's second objection to the proposed consent decree is that it does not impose sufficient substantive requirements for the RI/FS. Specifically, the amici object that the consent decree itself embodies only a scope of work outline for the RI/FS, leaving a detailed statement of work, work plan, and community involvement plan, among other documents, to be fleshed out after the consent decree is entered. *See* Amici Opp'n at 4-6. The parties contend that it is acceptable to leave the more detailed elements of the RI/FS plan to be worked out after the entry of the decree. The parties note that the consent decree provides an outline for the structure of the full RI/FS plan and specifies that the "RI/FS will be conducted pursuant to relevant U.S. EPA guidelines and standards" – specifically, EPA OSWER Directive 9355.3-01, "Guidance for Conducting Remedial Investigations and Feasibility Studies under CERCLA." Ex. A to the Revised Consent Decree at 3.

The amici argue that the Court should follow the lead of *United States v. Telluride Company*, a District of Colorado case in which the court rejected a consent decree in part because the settling government plaintiff "relied on the defendant to develop much of the technical data upon which it relied in formulating the decree and remediation plan." 849 F. Supp. 1400, 1406 (D. Colo. 1994). The posture of this case is significantly different from that of *Telluride*, however. In *Telluride*, the consent decree concerned a proposed remediation plan that would have restored only approximately 15 acres of wetlands where the defendant had illegally destroyed 45 to 47 acres. *Id.* at 1405-1406. The *Telluride* court also found the government to be dismissive of public comments, despite having received forty letters regarding the proposed consent decree. *Id.*

Here, the consent decree concerns only the RI/FS evaluation of the contaminated site and does not address any remedial actions, which are reserved for a subsequent lawsuit. Further, unlike

in *Telluride*, the DDOE in this case provided detailed written responses to the public comments from amici, *see* ECF No. 21-1, and, in some instances, has negotiated changes to the consent decree based on those comments. *See id.* In the circumstances of this case, the Court finds that the consent decree is reasonable, adequate, and appropriate. This conclusion is especially true in light of the Court's view that it is important to begin the RI/FS process promptly. Indeed, as the *Telluride* court noted, "[t]he need for the expeditious cleanup of an environmental violation can weigh in favor of approval of a proposed consent decree." *Telluride*, 849 F. Supp. at 1405. Given that important details of the RI/FS process do remain to be elaborated by the parties, however, it is critical to ensure robust opportunities for public access, review, and comment upon the implementation of the consent decree. Accordingly, the Court will approve the consent decree only upon the understanding – accepted by the parties at oral argument – that Paragraphs 37 and 38 of the proposed consent decree, relating to the opportunity for public participation and the publication of the administrative record, require the District timely to publicize Pepco's draft plans and other submissions under Paragraph 8(c) of the proposed consent decree. These paragraphs also require the timely publication of all final plans and other documents approved by the District under the terms of the proposed consent decree. These publication requirements will enable the public to review and comment upon Pepco's draft proposals for the RI/FS components prior to the District's approval of those proposals. Thus, the District will be able to take public comments into account before deciding whether to accept a particular proposal from Pepco. At oral argument, the District urged the Court to enter the consent decree in part because of its view that more robust engagement with the public regarding the RI/FS would be possible after this litigation is settled. Thus, the Court fully expects the District will pursue a process of active public engagement and will seriously consider all the public comments provided in response to Pepco's draft proposals.

IV. CONCLUSION

For the reasons explained above, the Court denies the motion to intervene and grants the motion to enter the consent decree, subject to the conditions described above. An appropriate Order will accompany this Memorandum Opinion.

DATED: December 1, 2011

/s/ Beryl A. Howell
BERYL A. HOWELL
United States District Judge

T.D. Sanford
Direct Exhibit
DC. P.S.C - - May, 2019

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District of Columbia

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MINUTE ORDER (paperless) ISSUING, upon consideration of the [50] Joint Status Report and [51] Proposed Order, the following SCHEDULING ORDER: (1) by September 6, 2019, the parties shall file a joint status report; (2) by February 3, 2020, the final Remedial Investigation Report shall be completed; and (3) by September 16, 2021, the final Feasibility Report shall be completed. Signed by Chief Judge Beryl A. Howell on March 11, 2019. (lcbah1)

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EXECUTIVE SUMMARY – PHILLIP S. BARNETT

This testimony describes the Long Range Planning (LRP) processes used by Potomac Electric Power Company (Pepco or the Company). This testimony also supports Pepco's Operation and Maintenance (O&M) costs for (1) 11 PHI Service Company (PHISCO) responsibility areas and for certain PHISCO Depreciation and Amortization expenses; (2) Pepco's Exelon Business Service Company (BSC) costs; and (3) Pepco's customer and sales growth forecast which is used to develop Pepco's revenue forecast. This testimony, in conjunction with that of other Company witnesses addressing O&M costs, demonstrates how the LRP process and Pepco's O&M costs benefit customers by allowing the Company to provide safe and reliable electric distribution service in the District of Columbia.

LRP Processes: This testimony provides details regarding the Company's LRP methodology, which is used to determine the Company's forward-looking budget upon which aspects of its proposed Multiyear Rate Plan (MRP) are based. The LRP provides O&M costs from 2018-2022. A number of Pepco witnesses are using these projections to support the O&M costs for 2020-2022. This section of testimony describes the methodologies used to develop the cost requests of the Pepco witnesses.

PHISCO O&M Costs: This testimony supports Pepco's projections for 2019-2022 for PHISCO O&M costs for the Communications, Controllership, Executive Management, Finance, Government & External Affairs, Human Resources, Legal, Regulatory, Supply, and Treasury/ Bank Fees responsibility areas, including depreciation and amortization.

BSC O&M Costs: This testimony supports Pepco's projections for 2019-2022 of BSC O&M costs.

Table 1 – O&M Costs[1]

	Historical	Bridge	Projections		
	2018	2019	2020	2021	2022
Pepco	$478,639,194	$496,760,22444	$483,012,834	$483,378,41	$485,325,894
PHISCO	$72,225,581	$71,668,962	$69,866,041	$68,972,744	$68,922,770
BSC O&M	$56,660,701	$50,732,269	$49,004,823	$48,480,126	$48,106,343

In preparing its O&M projections for 2020-2022, the Company analyzed historical spending levels, considered underlying major cost drivers and developed an assessment of future requirements. The LRP process is designed to determine the level of spending necessary to maintain the safe and reliable operations of the distribution system. To the extent that new or more extensive activities may be necessary to provide safe and reliable distribution service, the funding requirements for these new or more extensive elements are discussed in this testimony or in the testimony of other Pepco witnesses. This testimony also demonstrates that, on an overall basis, Pepco's O&M costs are projected to decrease from 2019 levels over the term of the MRP. Also, the Compounded Annual Growth Rate (CAGR) for Pepco's O&M costs from 2018-2022 is 0.3%, which is lower than the inflation rate.[2]

Customer and Sales Growth Forecast: This testimony describes the methods used to determine Pepco's customer and sales growth forecast. The testimony also explains that the customer and sales growth forecast, apply the currently effective Bill Stabilization Adjustment (BSA) in order to develop a revenue forecast for the Company.

[1] Table 1 contains O&M costs for Pepco, including operations in the District of Columbia and Maryland. Please see the testimony of Company Witness Wolverton, which contains the allocation and direct billing of O&M costs between Pepco's District of Columbia and Maryland operations.

[2] The CAGR is a business and financial term describing an exponential growth rate on an annual basis.

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF PHILLIP S. BARNETT
FORMAL CASE NO. 1156

I. INTRODUCTION

A. Witness Qualifications

Q1. Please state your name and position.

A1. My name is Phillip S. Barnett. I am the Senior Vice President, Chief Financial Officer and Treasurer of Pepco Holdings, LLC (PHI). I am testifying on behalf of Pepco.

Q2. Please describe your responsibilities as Senior Vice President, Chief Financial Officer and Treasurer of PHI.

A2. I am responsible for all financial matters related to PHI and its three utility subsidiaries, Pepco, Atlantic City Electric Corporation (ACE), and Delmarva Power & Light Company (Delmarva Power). I have oversight and coordination responsibilities for PHI's accounting and financial, tax, treasury, investor relations, and risk management activities. I also ensure that PHI performs with strong financial management discipline and solid financial internal controls.

Q3. Please describe your education and professional experience.

A3. I received a bachelor's degree in business administration with a concentration in accounting from Marquette University and a master's degree in management from Northwestern University. I began my professional career as an auditor at Arthur Andersen; worked at Itel Corporation in various financial planning and reporting roles; and was then employed at GE Capital for approximately 11 years, rising through the ranks to the position of chief financial officer of three of GE Capital's business units. I have worked for Exelon

Corporation (Exelon) in various roles for the past 16 years before Exelon merged with PHI in 2016. Before assuming my current position in 2018, I served as the Chief Financial Officer (CFO) for PECO Energy Company (PECO), another Exelon subsidiary. PECO is a regulated electric and gas utility company serving customers in Philadelphia and the surrounding counties.

Q4. Have you previously submitted testimony in proceedings before the Public Service Commission of the District of Columbia (Commission)?

A4. No.

Q5. Have you previously submitted testimony in proceedings before other state or federal commissions or agencies?

A5. Yes. I have previously submitted testimony on behalf of PECO in multiple rate proceedings before the Pennsylvania Public Utility Commission.

B. Purpose of Testimony and Exhibit List

Q6. What is the purpose of your Direct Testimony in this proceeding?

A6. The purpose of my Direct Testimony in this proceeding is as follows: (1) to explain how PHI's LRPs are developed;[3] (2) to discuss actual and projected O&M levels billed or allocated to Pepco from non-operational departments of PHISCO; (3) to discuss actual and projected O&M costs billed or allocated to Pepco from the BSC other than Information Technology (IT), which will be discussed by Company Witness Calabrese; and (4) to discuss Pepco's customer and sales growth projection process and forecast for the District of Columbia.

[3] The LRP process develops five-year budgets for all PHI companies.

My testimony and the accompanying exhibits were prepared by me or under my direct supervision and control. The sources for my testimony and exhibits are Company records and public documents. I also rely upon my personal knowledge and experience.

Q7. Are you sponsoring any exhibits in this proceeding?

A7. Yes. I am sponsoring PEPCO (L)-1 through PEPCO (L)-22.

Q8. Please summarize each of the exhibits that you are sponsoring.

A8. PEPCO (L)-1 through PEPCO (L)-22 contain 2018-2022 LRP documentation for various PHI and Exelon responsibility areas. The exhibits listed below contain data and information regarding the corresponding responsibility area's major business functions within PHI, the responsibility area's major activities, and the responsibility area's actual O&M costs attributable to Pepco for 2018 and Pepco O&M budgets for 2019-2022.

- PEPCO (L)-1 is a narrative description of the PHI Communications responsibility area.
- PEPCO (L)-2 contains the 2018-2022 O&M costs for PHI Communications
- PEPCO (L)-3 is a narrative description of the PHI Controllership responsibility area.
- PEPCO (L)-4 contains the 2018-2022 O&M costs for PHI Controllership.
- PEPCO (L)-5 is a narrative description of the PHI Executive Management responsibility area.
- PEPCO (L)-6 contains the 2018-2022 O&M costs for PHI Executive Management.
- PEPCO (L)-7 is a narrative description of the PHI Finance responsibility area.
- PEPCO (L)-8 contains the 2018-2022 O&M costs for PHI Finance.

- PEPCO (L)-9 is a narrative description of the PHI Government and External Affairs responsibility area.
- PEPCO (L)-10 contains the 2018-2022 O&M costs for PHI Government and External Affairs.
- PEPCO (L)-11 is a narrative description of the PHI Human Resources responsibility area.
- PEPCO (L)-12 contains the 2018-2022 O&M costs for PHI Human Resources.
- PEPCO (L)-13 is a narrative description of the PHI Legal responsibility area.
- PEPCO (L)-14 contains the 2018-2022 O&M costs for PHI Legal.
- PEPCO (L)-15 is a narrative description of the PHI Regulatory responsibility area.
- PEPCO (L)-16 contains the 2018-2022 O&M costs for PHI Regulatory.
- PEPCO (L)-17 is a narrative description of the PHI Supply responsibility area.
- PEPCO (L)-18 contains the 2018-2022 O&M costs for PHI Supply.
- PEPCO (L)-19 contains the 2018-2022 O&M costs for PHI Treasury/Bank Fees.
- PEPCO (L)-20 contains the 2018-2022 O&M costs for Depreciation and Amortization.
- PEPCO (L)-21 contains the 2018-2022 O&M costs for BSC (excluding IT costs).

- PEPCO (L)-22 is a copy of PHISCO's Alternate Integration Plan submitted and approved in Formal Case No. 1119.[4]

C. Description of Exelon's Corporate Structure

Q9. Please explain how PHI, Pepco, and PHISCO are related to Exelon.

A9. Exelon and PHI merged in 2016 with the Commission's authorization in Order No. 18148 in Formal Case No. 1119. PHI is a limited liability company and an indirect, wholly-owned subsidiary of Exelon. PHI is comprised of PHISCO and three regulated utilities: Pepco, Delmarva Power, and ACE.

PHISCO is a subsidiary of PHI. PHISCO provides a variety of shared services pursuant to service agreements with PHI's three regulated subsidiaries, Pepco, ACE, and Delmarva Power. Exelon also operates BSC, a separate shared service company. Like PHISCO, BSC provides services to PHISCO, Pepco, ACE, and Delmarva Power pursuant to a service agreement. BSC is a subsidiary of Exelon. PEPCO (L)-22, the Alternate Integration Plan, contains a list of functions performed by PHISCO and by BSC. After approving the PHI-Exelon merger, the Commission also approved the Alternate Integration Plan, which delineates the services Pepco receives from both service companies (PHISCO

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[4] Pepco filed its Alternate Integration Plan in compliance with Merger Commitment No. 88, which is set forth in Attachment B of Order No. 18148, and addresses the integration of PHISCO, which provides certain services to Pepco and other utility subsidiaries of PHI, into the BSC. Merger Commitment No. 88 directed:

> Immediately following the Merger close, PHISCo will remain as a subsidiary of PHI and will continue to perform functions and to maintain related assets currently involved in providing services exclusively to the PHI utilities. Other functions that are currently provided by PHISCo, including those that are provided to PHI utilities and to other current PHI subsidiaries, will be transferred to EBSC or another Exelon affiliate in a phased transition over a period of time following the Merger closing. To address concerns that there would be two service companies under the proposed Merger, Exelon will file a plan within six (6) months after the Merger's close for Commission approval to integrate PHISCo within EBSC and other entities. The plan to integrate PHISCo with EBSC shall not include any net transfer of PHISCo employees located in the District of Columbia pre-Merger to any location outside of the District, subject to the provisions of Paragraph 19.

and BSC).[5] The Alternate Integration Plan contains a detailed attachment listing which services are provided by BSC and which are provided by PHISCO. PEPCO (L)-22 at page 12. Both PHISCO and BSC are also responsible for delivering specific, unique shared services to Pepco.

Q10. Please explain why Pepco incurs costs from PHISCO and BSC.

A10. PHISCO costs refer to Pepco's share of the costs of the specific services that PHISCO provides to the PHI utilities (Pepco, ACE, and Delmarva Power). PHISCO costs are incurred for the benefit of and allocated only to the PHI utilities rather than across Exelon or the Exelon Utilities. PHISCO costs are directly billed or allocated to Pepco using the methodology discussed in the direct testimony of Company Witness Giese.

BSC provides services to all of the Exelon companies, including Pepco. As such, Pepco is also allocated BSC costs for the functions BSC provides to Pepco. Certain BSC costs are directly billed or allocated to Pepco, while other BSC costs are directly billed or allocated to PHISCO, and then to Pepco, as described in Company Witness Giese's testimony.

[5] When approving the Alternate Integration Plan, the Commission found that "the Alternative Plan provides a reasonable, lower-cost, and timely integration of PHISCo into EBSC, and is the preferred Plan of the Commission going forward. Furthermore, while we have indicated that two service companies will increase the need for regulatory oversight, reporting and auditing to ensure that Pepco and District ratepayers are being allocated the correct costs, we do realize, as pointed out by Pepco, regardless of which plan we choose, two service companies must and will still exist because of Commitment No. 73, which provides: PHI's CEO and other senior officers who directly report to the CEO will hold no positions with Exelon or Exelon affiliates other than PHI and PHI's subsidiaries."

Q11. Please explain how services provided by BSC differ from services provided by PHISCO.

A11. As determined by the Commission in Order No. 18674, the services provided by BSC and PHISCO differ and are not duplicative.[6] BSC services are performed to support all Exelon companies, including Pepco. In contrast, PHISCO services support PHI and its regulated utilities, including Pepco. For example, each of Exelon's subsidiaries, including PHI, are allocated accounting costs from BSC. The BSC accounting costs include, but are not limited to, accounting services for analyzing and adhering to changes in GAAP (*e.g.*, accounting for leases), pension accounting, and compensation accounting. These services support all Exelon companies. PHI's accounting service, on the other hand, performs services that solely support PHI and its utilities, such as revenue accounting.

II. DEVELOPMENT OF THE COMPANY'S LRP

A. Description of the LRP Process

Q12. What is the LRP?

A12. LRP stands for "Long Range Plan." The LRP includes five years of forecasted O&M costs and is used to plan for future expenditures and manage costs. Please note the LRP also includes capital spend, financial statements (e.g., income statement, balance sheet, cash flows) and financial metrics.

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[6] See Formal Case No. 1119, Order No. 18674, the Commission determined that "The structural differences [between PHISCO and BSC] largely reflect differences in the scope of shared services historically offered by each company. For example, PHISCo offers a broad set of operational and administrative and general (A&G) support services to each of its three PHI utility affiliates (Pepco, ACE and Delmarva), which are not handled within the individual operating company level. EBSC, however, is structured somewhat differently providing only limited A&G type functions that are not handled anywhere else. Order No. 18674 at ¶ 19.

Q13. Please briefly describe the Pepco LRP process.

A13. One of the key goals of the LRP process is to integrate and align Pepco's operational and financial plans. The operational plan includes goals that strive toward achieving industry-leading safety and operational performance for both reliability and customer satisfaction. In terms of the financial plan, spending targets are set in order to achieve operational goals, to comply with regulatory requirements, and to ensure that overall O&M expense increases are lower than the rate of inflation. These operational and financial goals align with Pepco's ultimate goal – to provide safe and reliable electric distribution service to customers in the District of Columbia.

Q14. Can you please provide more detail about the LRP process?

A14. Yes. The planning process for Pepco starts with a review and update of Pepco's operational performance indicators and regulatory requirements to determine if changes are required for the future. Any significant changes in such goals and initiatives are taken into consideration when the Company updates the LRP. The LRP is a five-year view and is updated with key assumptions and with detailed input provided by "responsibility areas," such as Technical Services or Support Services. Each "responsibility area" reviews its historic expense levels, performance assessments, regulatory requirements, operational goals, specific projects, and a myriad of other factors. The individual "responsibility area" LRPs are typically submitted to the Finance responsibility area in June of each year and are carefully analyzed for consistency, completeness, and appropriateness. Vice Presidents responsible for Pepco's operational responsibility areas are submitting individual testimony in this proceeding regarding the O&M costs incurred by Pepco in their specific "responsibility areas."

The responsibility area LRPs are then consolidated and delivered to PHI's senior management (*i.e.*, the Chief Executive Officer, the Chief Operating Officer, and the Chief Financial Officer) for review and approval. The PHI 2019 budgeted spending (*i.e.*, O&M and capital) plans and financing plan (*i.e.*, borrowing) are also approved by PHI's Board of Directors thereafter.

Q15. Does the Company regularly meet the budgeting goals established in the LRP process?

A15. The LRP process is, to some extent, aspirational in nature. The Company uses the LRP process to establish O&M budgets that will benefit customers by reflecting lower levels of costs. While the budgets developed through the LRP process are attainable, they are also somewhat aggressive. As a result, the Company does not always meet those budgeting goals. As I discuss below, in both 2017 and 2018, Pepco's actual O&M costs exceeded the budgeted costs developed through the LRP process by 3%.

Q16. Does the Company plan for some O&M efficiency savings?

A16. Yes. The Company develops an O&M cost challenge target to keep the O&M year-over-year increases at a rate lower than inflation.

Q17. Is the O&M challenge excluded from the requested O&M dollars and, if so, why?

A17. Yes. The O&M challenge dollars are excluded for two primary reasons:

(1) The challenge will help offset future unplanned cost increases (*e.g.*, emergent events, increasing cybersecurity protection).

(2) The challenge will help offset if the actual costs come in higher than estimated due to various issues (*e.g.*, aging infrastructure issues and unfavorable non-storm weather conditions).

B. Use of LRP to Develop Projected Costs

Q18. Please describe the process used to develop the O&M projected costs included in this rate filing.

A18. Each year Pepco performs its budget and planning process based on business needs, upcoming projects/existing or new initiatives, regulatory/legal requirements, and established targets. Responsibility area and project cost budgets are established and entered into the budget/long range planning software by each responsibility area Vice President at the resource level (e.g., labor, contracting). The Company determines what level of resources (e.g., labor, contracting) will be required to achieve and fund the above-stated business needs after analyzing historical spending levels, considering underlying major cost drivers and developing an assessment of future requirements. The Company also incorporates financial guidelines in its planning process to achieve operational efficiencies and other business-related savings through process improvements and optimizing plan execution into its plan and to keep O&M cost increases below the increase in the inflation rate.

Q19. Please describe the process used to develop the capital costs included in this filing.

A19. The process for developing the projected capital costs included in this filing is similar to the process outlined in the previous question with respect to O&M. Please refer to Company Witness Clark's Direct Testimony for a more extensive description of the Company's capital projects and costs.

Q20. Describe any recent actions taken by the Company to improve the LRP forecasting accuracy.

A20. The Company often reviews its budgets for accuracy in order to develop a careful approach to actual and forecasted expenditures. In response to the maintenance cost increases described above, the Company has increased the level of funding in its most recent LRP budgets for corrective maintenance to be more consistent with historical levels and better aligned with expected levels.

Q21. Does the Company's LRP process encourage efficiency and cost savings?

A21. Yes. Pepco's O&M costs are projected to be nearly flat, with increases lower than the rate of inflation.

III. DESCRIPTION OF PHISCO O&M COSTS

Q22. Are you supporting the projected O&M costs for all responsibility areas within PHISCO?

A22. No. I am only supporting the projected O&M costs for the following PHISCO non-operational responsibility areas:

1) IT Depreciation and Amortization;
2) Communications;
3) Controllership;
4) Executive Management;
5) Finance;
6) Government and External Affairs;
7) Human Resources;
8) Legal;

9) Regulatory;

10) Treasury/Bank Fees; and

11) Supply.

A number of other Company witnesses are supporting the O&M costs for the operational responsibility areas.

Q23. What is the total level of LRP O&M costs you are supporting in this case?

A23. See Table 2.

Table 2

	Historical	Bridge	Projections		
	2018	2019	2020	2021	2022
Pepco O&M	$478,639,194	$496,760,22	$483,012,834	$483,378,41	$485,325,894
PHISCO	$72,225,581	$71,688,962	$69,866,041	$68,972,744	$68,922,770
BSC O&M	$56,660,701	$50,732,269	$49,004,823	$48,480,126	$48,106,343

Q24. How does the above Pepco LRP O&M compare to this District of Columbia distribution rate case O&M?

A24. The testimony of Company Witness Wolverton provides details regarding Pepco's District of Columbia costs and revenue requirements.

Q25. What are the major cost drivers of the Pepco O&M cost increases from 2018 to 2019?

A25. O&M costs increased by $18 million (from about $478 million to about $496 million) or 3.8% from 2018 to 2019, driven primarily by $12.1 million for inflation (*e.g.*, merit increases) and $4.9 million in higher pension costs.

Q26. What are the major cost drivers of the Pepco O&M cost increases from 2018 to 2020?

A26. Costs increased by $4.3 million (from about $478.6 million to about $483 million) or 0.9% from 2018 to 2020 driven by $3.3 million from one-time items related to 2018,

$22.5 million for two years of inflation (*e.g.* merit increases), and $2.9 million in higher pension costs. These increases were partially offset by the expiration of the Control Center lease $15.2 million, lower BSC costs ($7.7 million), and other lower costs ($1.6 million). As I stated above, the one-time-recurring $3.3 million reduction in O&M costs in 2018 related to the establishment of a regulatory asset for Benning environmental costs.

Q27. Why are you comparing the 2018 costs to the 2020 costs?

A27. We are comparing 2018 to 2020 because 2018 includes historical costs and 2020 is the first year in the MRP.

Q28. What are the major cost drivers of the Pepco O&M cost increases from 2020 through 2022?

A28. Costs from 2020 through 2022 remain relatively flat; they increase only 0.5% from about $483 million to $485.3 million.

Q29. What is the projected overall annual percentage decrease in O&M costs for the non-operational PHISCO responsibility areas billed or allocated to Pepco from 2018-2020?

A29. Information regarding projected O&M cost decreases is set forth in Table 3:

Table 3

	Historical	Bridge	Projection		
	2018	2019	2020	2021	2022
PHISCO	$72,225,581	$71,668,962	$69,866,041	$68,972,744	$68,922,770
Annual %		-0.8%	-2.5%	-1.3%	-0.1%

These decreases are significantly below the annual rates of inflation during this time period.

Table 4 contains the O&M projections for each responsibility area discussed in my testimony. More detail regarding these projections is discussed in Sections B through L.[7]

Table 4

	Historical	Bridge	Projection		
	2018	**2019**	**2020**	**2021**	**2022**
Communications	$4,671,767	$3,374,224	$3,422,449	$3,460,476	$3,496,564
Controllership	$5,632,347	$5,339,445	$5,163,134	$5,065,142	$5,225,982
Executive Management	$2,313,317	$2,632,502	$2,654,909	$2,690,532	$2,742,609
Finance	$5,801,097	$4,671,749	$4,689,367	$4,783,192	$4,872,722
Government & External Affairs	$11,344,142	$12,477,367	$12,688,147	$12,888,869	$13,005,434
Human Resources	$3,241,143	$3,145,820	$3,246,111	$3,233,177	$3,281,285
Legal	$5,635,417	$4,646,026	$4,634,600	$4,651,915	$4,677,021
Regulatory	$13,557,485	$16,034,893	$16,341,925	$16,586,407	$16,901,624
Supply	$42,528,552	$1,596,786	$1,495,799	$1,591,539	$1,610,025
Treasury/Bank Fees	$495,156	$1,411,303	$1,455,039	$1,462,039	$1,469,039
Depreciation & Amortization	$17,005,156	$16,338,845	$14,074,561	$12,559,456	$11,640,465
PHISCO Total	**$72,225,581**	**$71,668,962**	**$69,866,041**	**$68,972,744**	**$68,922,770**

A. Communications Responsibility Area

Q30. Please describe the duties and activities of the Communications responsibility area.

A30. Communications is responsible for educating Pepco's customers about service offerings, safety considerations, rates and billing issues, and similar topics. The work done by the Communications responsibility area benefits customers by providing important information regarding electric distribution service in the District of Columbia. For example, the Communications responsibility area provides information to customers regarding service issues that may result from storms. To meet its responsibilities, the Communications responsibility area conducts the following business functions:

- Social Media and Digital Communications ensures PHI meets customers where they are – online. The business function manages content development and daily

[7] Further detail regarding the O&M projections for these responsibility areas are found in PEPCO (L)-2, 4, 6, 8, 10, 12, 14, 16, 18, and 20.

maintenance of the external PHI websites, social media channels, mobile apps, and The Source, PHI's digital story and content hub. The goal is to ensure digital content is informational, engaging, and digestible for the increasing number of customers who connect with us by laptop, tablet, or mobile phone.

- Leadership and Culture includes support of executive presentations for PHI Officers—with primary focus on the Chief Executive Officer and Chief Operating Officer leading the culture communication channels that connect our organization, including The Inside Source, Supervisor Updates, and partnering with Human Resources to ensure Pepco connects employees with key information and programs that engage employees across the organization.
- Media Engagement includes efforts to positively position PHI's work to drive innovation and deliver clean, safe, and reliable energy service for Pepco customers and communities.
- Strategic Project Management includes the integrated communications plans and programs that encompass our business priorities and pillars, including Capital Infrastructure Projects, Innovation, Health, Safety, and Environment, and Corporate Stewardship.
- Market Research conducts customer surveys to provide Pepco with information needed to enhance safe and reliable service and customer satisfaction.

Q31. What are the major cost drivers that are projected to contribute to the Communications responsibility area projections for 2018 to 2019?

A31. Communications costs are projected to be $1.3 million higher in 2018 primarily due to contracting spend, which was higher than planned in 2018 due to timing of accruals from 2017 that were booked in 2018.

Q32. What are the major cost drivers that are projected to contribute to the Communications responsibility area projections for 2018 to 2020?

A32. Communications costs are projected to be $1.2 million higher in 2018 primarily due to contracting spend, which was higher than planned in 2018 due to timing of accruals from 2017 that were booked in 2018.

Q33. What are the major cost drivers that are projected to contribute to the Communications responsibility area projections for 2020 to 2022?

A33. Communications costs are projected to remain relatively flat in 2020-2022.

B. Controllership Responsibility Area

Q34. Please discuss the Controllership responsibility area's duties and activities.

A34. Controllership oversees PHI's accounting operations and obligations. Controllership is also responsible for completing all PHI regulatory filings and ensuring compliance with all generally accepted accounting practices (GAAP) and Federal Energy Regulatory Commission (FERC) accounting requirements. The Controllership responsibility area consists of General Accounting, PHISCO Accounting, Plant Accounting and Project Governance, Revenue Accounting, and Regulatory Accounting.

The Controllership is responsible for the following key functions:

- Completing Securities and Exchange Commission (SEC) and FERC filings and support regulatory filings;
- Ensuring complete and accurate GAAP and FERC general ledgers;
- Evaluating and commenting on emerging accounting guidance;
- Engaging with Audit and Controls to ensure proper design and execution of financial controls;
- Ensuring clean external audit opinions and no restatement of financials; and
- Reviewing PHI accounting positions with external auditors and the Audit Committee.

Q35. What are the major cost drivers that are projected to contribute to the Controllership responsibility area's projection for 2018 to 2019?

A35. Payroll costs are projected to decrease in 2019 by about $0.3 million from 2018.

Q36. What are the major cost drivers that are projected to contribute to the Controllership responsibility area's projection for 2018 to 2020?

A36. Controllership costs are projected to decrease $0.5 million in 2020 compared to 2018.

Q37. What are the major cost drivers that are projected to contribute to the Controllership responsibility area's projection for 2020 to 2022?

A37. Controllership costs are projected to decrease in 2021 (about 2%) due to headcount reduction. Controllership costs are projected to increase slightly (about 1%) in 2022 due to annual merit increases.

C. Executive Management Responsibility Area

Q38. Please discuss the Executive Management responsibility area's duties and activities.

A38. Executive Management is responsible for leadership of PHI's overall performance associated with service, reliability, financial management, and regulatory and external affairs. The Executive Management responsibility area consists of the CEO, an Executive Assistant, a Chief of Staff, and four Business Analysts.

Q39. What are the major cost drivers that are projected to contribute to the Executive Management responsibility area's projection for 2018 to 2019?

A39. Executive Management costs are projected to be $0.4 million lower in 2018 compared with 2019, primarily due to Edison Electric Institute dues of $0.3 million being charged to the utility operations departments in 2018.

Q40. What are the major cost drivers that are projected to contribute to the Executive Management responsibility area's projection for 2018 to 2020?

A40. Executive Management costs are projected to be $0.4 million lower in 2018 compared with 2020 primarily due to Edison Electric Institute dues of $0.3 million being charged to the utility operations departments in 2018.

Q41. What are the major cost drivers that are projected to contribute to the Executive Management responsibility area's projection for 2020 to 2022?

A41. Executive Management costs are projected to increase slightly in 2021 (about 1%) and 2022 (about 2%) due to annual merit increases.

D. Finance Responsibility Area

Q42. Please discuss the Finance responsibility area's duties and activities.

A42. The Finance responsibility area consists of Financial Operations (FinOps), Financial Planning and Analysis (FP&A), and the Office of the CFO. Among other functions, FinOps provides governance and oversight of PHI's spending plan. FP&A provides timely, relevant, and reliable projected financial information and management reporting to various internal and external stakeholders.

Q43. What are the major cost drivers that are projected to contribute to the Finance responsibility area's projection for 2018 to 2019?

A43. Finance costs are projected to be $1.1 million higher in 2018 compared with 2019 primarily due to 2018 staff augmentation costs related to enterprise systems integration and headcount reductions in 2019.

Q44. What are the major cost drivers that are projected to contribute to the Finance responsibility area's projection for 2018 to 2020?

A44. Finance costs are projected to be $1.1 million higher in 2018 compared with 2020 primarily due to 2018 staff augmentation costs related to enterprise systems integration and higher headcount in 2018.

Q45. What are the major cost drivers that are projected to contribute to the Finance responsibility area's projection for 2020 to 2022?

A45. Finance costs are projected to increase slightly in 2021 (about 2%) and 2022 (about 2%) due to annual merit increases.

E. Government and External Affairs Responsibility Area

Q46. Please discuss the Government and External Affairs responsibility area's duties and activities.

A46. Government and External Affairs leads PHI's government relations and external affairs strategy. These efforts involve all stakeholders, including customers, regulators, and elected officials, and the department designs and implements Pepco's stakeholder relations and issues management programs. Specific Government and External Affairs responsibilities include:

- Design and implement Pepco's stakeholder relations and issues management programs; serve as Pepco's primary governmental, community, stakeholder, and political advisor.
- Lead legislative and public policy initiatives and support regulatory activities.
- Represent Pepco at the highest levels in government and political arena.
- Establish policies and procedures to ensure Pepco's compliance with all state and local lobbying, gifting and political contributions requirements.
- Manage, develop, and implement Corporate Relations philanthropic, volunteer, and sponsorship programs and budgets.
- Manage large customer and Large Commercial Services accounts (commercial and industrial) across all regions, including customer service inquiries, energy solutions, analytics and business development.
- Execute market research, customer opinion survey information, and analysis (e.g., residential, commercial, governmental surveys)

- Develop and implement programs designed to address customer issues and facilitate subsequent resolution.
- Develop and implement customers' energy assistance programs to help low- and moderate-income customers pay their energy bills.
- Develop and promote economic development programs to help attract business and grow jobs across all jurisdictions.

Q47. What are the major cost drivers that are projected to contribute to the Government and External Affairs projection for 2018 to 2019?

A47. Government and External Affairs costs are projected to be $1.1 million lower in 2018 compared with 2019 primarily due to open positions that are expected to be filled in 2019. The Government and External Affairs group plans to hire four additional employees in order to better serve customers.

Q48. What are the major cost drivers that are projected to contribute to the Government and External Affairs projection for 2018 to 2020?

A48. Government and External Affairs costs are projected to be $1.3 million lower in 2018 compared with 2020 primarily due to open positions in 2018 that are expected to be filled before 2020.

Q49. What are the major cost drivers that are expected to contribute to the Government and External Affairs projection for 2020 to 2022?

A49. Government and External Affairs costs are projected to increase slightly in 2021 (about 1.5%) and 2022 (about 1%) due to annual merit increases.

F. Human Resources Responsibility Area

Q50. Please discuss the Human Resources responsibility area's duties and activities.

A50. The Human Resources responsibility area's primary duty is to support PHI's operational objectives and to positively influence employee engagement. Human Resources provides PHI's employees with development tools and support and helps employees understand their role in driving forward Pepco's objectives, including its service reliability and affordability objectives. The primary job functions include: 1) Management and Administration; 2) Talent Acquisition; 3) Diversity & Inclusion; 4) Talent Management and Leadership Development; and 5) Organizational Effectiveness.

Q51. What are the major cost drivers that are projected to contribute to the Human Resources projection for 2018 to 2019?

A51. Human Resources costs are projected to be essentially flat from 2018 to 2019.

Q52. What are the major cost drivers that are projected to contribute to the Human Resources projection for 2018 to 2020?

A52. Human Resources costs are projected to remain relatively flat from 2018 to 2020.

Q53. What are the major cost drivers that are projected to contribute to the Human Resources projection for 2020 to 2022?

A53. Human Resources costs are projected to remain relatively flat from 2020 to 2021. Costs are projected to increase slightly in 2022 (about 1.5%) due to annual merit increases.

G. Legal Responsibility Area

Q54. Please discuss the Legal responsibility area's duties and activities.

A54. The PHI Legal responsibility area provides legal advice, counseling, and services to all business units within Pepco Holdings. The Legal responsibility area delivers

solutions in legal and compliance matters by working in partnership with Pepco's business colleagues, applying legal expertise, developing relationships, and employing innovative ideas to enhance the services provided to customers. The PHI Legal responsibility area consists of lawyers and staff who focus primarily on regulatory matters and represent the utilities before the public service commissions in each jurisdiction and before the FERC. Regulatory matters range from representing the utilities in distribution and transmission rate cases, to advising on grid modernization and representing the utilities in grid modernization proceedings, to complying with jurisdictional statutes as well as commission orders and regulations, to providing any other necessary filings and information to the public service commissions.

Q55. What are the major cost drivers that are projected to contribute to the Legal projection for 2018 to 2019?

A55. Legal costs are projected to be $1.0 million higher in 2018 compared with 2019 primarily due to higher than budgeted outside counsel spend in 2018 for property tax appeals.

Q56. What are the major cost drivers that are projected to contribute to the Legal projection for 2018 to 2020?

A56. Legal costs are projected to be $1.0 million higher in 2018 compared with 2020 primarily due to higher than budgeted outside counsel spend in 2018 for property tax appeals.

Q57. What are the major cost drivers that are projected to contribute to the Legal projection for 2020 to 2022?

A57. Legal costs are projected to remain relatively flat from 2020 to 2022.

H. Regulatory Responsibility Area

Q58. Please discuss the Regulatory responsibility area's duties and activities.

A58. The Regulatory responsibility area is charged with developing and executing the overall regulatory strategic plan for PHI and managing all regulatory affairs related to PHI's utility business before the Public Service Commission of the District of Columbia, the Maryland Public Service Commission, the Delaware Public Service Commission, the New Jersey Board of Public Utilities, and FERC, including the grid modernization proceedings in each jurisdiction. The responsibility area works closely with all stakeholders to ensure that customer needs are met through the regulatory process. The primary job functions include: 1) Regulatory Affairs; 2) Regulatory Strategy and Revenue Policy; 3) Pricing and Regulatory Services; 4) Regulatory Analysis; 5) Power Procurement; 6) Load Research and Settlements; 7) Energy Supplier Services; 8) Supply Customer Energy Strategic Planning; and 9) Strategy.

Q59. What are the major cost drivers that are projected to contribute to the Regulatory responsibility area projection for 2018 to 2019?

A59. Regulatory costs are projected to be $2.5 million higher in 2019 due to payroll and contractor costs from the Strategy group which moved into Regulatory in the third quarter of 2018.

Q60. What are the major cost drivers that are projected to contribute to the Regulatory responsibility area projection for 2018 to 2020?

A60. Regulatory costs are projected to be $2.8 million higher in 2020 due to payroll and contractor costs from the Strategy group which moved into Regulatory in the third quarter of 2018 and annual merit increases from 2018 to 2020.

Q61. What are the major cost drivers that are projected to contribute to the Regulatory responsibility area projection for 2020 to 2022?

A61. Regulatory costs are projected to increase slightly in 2021 (about 2%) and 2022 (about 2%) due to annual merit increases.

I. Supply Responsibility Area

Q62. Please discuss the Supply responsibility area's duties and activities.

A62. The major business functions of Supply are Materials Management, including Warehousing, and Purchasing. The Material Availability department provides purchasing activities to ensure inventory is available at all PHI storerooms and for PHI projects. It also provides guidance for the control of emergency reserve inventory and slow-moving/obsolete materials. The Warehouse Operations department ensures that the receipt, storage, issuance, inventory accuracy, and delivery of materials are provided and secure in a manner to help prevent loss or damage. The General Shops department performs fabrication services for over one hundred stock items, fabricates steel structures for PHI substations, completes tool repair services for Pepco Operations, and performs rubber goods testing for Pepco Operations and Engineering.

Q63. What are the major cost drivers that are projected to contribute to the Supply responsibility area projection for 2018 to 2019?

A63. Supply O&M costs are projected to be $0.9 million higher in 2018 compared with 2019 primarily due to higher payroll and related overheads and higher inventory adjustments in 2018.

Q64. What are the major cost drivers that are projected to contribute to the Supply responsibility area projection for 2018 to 2020?

A64. Supply O&M costs are projected to be $1.0 million higher in 2018 compared with 2020 primarily due to higher payroll and related overheads and higher inventory adjustments in 2018.

Q65. What are the major cost drivers that are projected to contribute to the Supply responsibility area projection for 2020 to 2022?

A65. Supply O&M costs are projected to increase slightly in 2021 (about 0.1%). Supply Chain costs remain relatively flat in from 2021 to 2022.

J. Treasury/Bank Fees

Q66. Please discuss the Treasury/Bank Fees responsibility area's responsibilities and activities.

A66. Pepco's bank fees are related to transactions with the banks where Pepco has bank accounts. This includes Bank Fees, Trustee Fees, Utilization Fees, Capital Market Fees, and Credit Facility Fees.

Q67. What are the major cost drivers that are projected to contribute to the Treasury/Bank Fees projection for 2018 to 2019?

A67. Treasury/Bank Fees costs are projected to be $0.9 million higher in 2019 due to a shift between O&M and interest expense in 2018 actuals. In 2018, credit facility fees were booked to interest expense.

Q68. What are the major cost drivers that are projected to contribute to the Treasury/Bank Fees projection for 2018 to 2020?

A68. Treasury/Bank Fees costs are projected to be $1.0 million higher in 2020 due to a shift between O&M and Interest Expense in 2018 actuals. In 2018, credit facility fees were booked to Interest Expense.

Q69. What are the major cost drivers that are projected to contribute to the Treasury/Bank Fees projection for 2020 to 2022?

A69. Treasury/Bank Fee costs are projected to remain relatively flat in 2020-2022.

K. Depreciation and Amortization

Q70. Please describe the depreciation and amortization O&M costs you are supporting.

A70. Pepco's allocated share of depreciation expense for PHISCO assets include PHI's customer system, the IT systems (not the meters) supporting Advanced Metering Infrastructure (AMI), Personal Computers, Storage, and other IT equipment.

Q71. What are the major cost drivers that are projected to contribute to the depreciation and amortization projection for 2018 to 2019?

A71. The projected decrease in costs from $17,005,156 in 2018 to $16,338,845 in 2019 reflects the projected reduction in depreciation expense at the PHISCO level.

Q72. What are the major cost drivers that are projected to contribute to the depreciation and amortization projection for 2018 to 2020?

A72. The projected decrease in costs from $17,005,156 in 2018 to $14,074,561 in 2020 reflects the projected reduction in depreciation expense at the PHISCO level.

Q73. What are the major cost drivers that are projected to contribute to the depreciation and amortization projection for 2020 to 2022?

A73. The projected decrease in costs from $14,074,561 in 2020 to $11,640,465 in 2022 reflects the projected reduction in depreciation expense at the PHISCO level.

Q74. Would you like to discuss any element of the PHISCO O&M costs in more detail?

A74. Yes. The CAGR decrease from 2018 to 2020 is 1.6%, which is significantly lower than the average rate of inflation.

IV. DESCRIPTION OF BSC O&M COSTS

Q75. Please explain what you mean when you refer to BSC costs.

A75. As discussed above, BSC costs refer to the services Exelon BSC provides to the PHI utilities. BSC costs are distinct from PHISCO costs, as set forth in the Alternate Integration Plan. PEPCO (L)-22. BSC costs include, but are not limited to; IT, Internal Audit, Treasury, Tax, Accounts Payable, Employee Benefits, and Information Security.

Q76. What responsibilities are performed by BSC employees for which costs are directly billed or allocated to Pepco?

A76. These responsibilities include, but are not limited to: 1) Corporate Relations, 2) Corporate Strategy, 3) Treasury, 4) Internal Audit, 5) Tax, 6) External Financial Reporting, 7) Federal Government Affairs, 8) Payroll Processing, 9) Health and Benefits, 10) Compensation, 11) Talent Management, 12) Litigation, 13) Legal Compliance and Ethics, 14) Enterprise Risk Management, 15) Corporate and Information Security Services, 16) Strategic Sourcing, and 17) Accounts Payable. These areas perform activities that are unique to those performed by employees PHISCO, which is solely dedicated to the support of Pepco, ACE, and Delmarva Power. They are areas where Exelon has determined that it

is most cost effective to perform the activities on a more centrally lead basis for the benefit of all of the Exelon operating companies, with each department working to provide reliable and affordable services to its customers. BSC employees have the ability to perform activities for all Exelon operating companies as well as for specific operating companies, like Pepco, upon demand or request.

Q77. How are costs associated with BSC services tracked to ensure that Pepco receives an appropriate allocation of these costs?

A77. BSC costs are reviewed and approved as part of PHI's annual budget and LRP process and are developed using the LRP process described earlier in my testimony. They are also reviewed annually as part of the Service Level Agreement (SLA).[8] The costs for services provided specifically to Pepco are "directly assigned" to Pepco. In other instances, BSC provides services on behalf of more than one Exelon company. In such cases, the costs cannot be directly assigned but are instead allocated to Pepco and other entities using allocation methods described in the approved General Service Agreement applicable to Pepco and BSC. Cost allocation is described in the testimony of Company Witness Giese and is designed to assign the costs to the entity that caused the costs to be incurred and to ensure that Pepco's customers pay only for BSC services provided on their behalf. Each year during the budget and LRP process, PHI compares BSC costs to prior year to analyze any year-over-year changes and to the prior version of the LRP to analyze any plan-over-plan changes. Any changes are reviewed and discussed with BSC to justify PHI incorporating into its budget and LRP. During the year, monthly reporting is provided by

[8] The SLA is the operational document identifying the services being provided by BSC to Pepco. Pepco reviews the services provided by BSC at least once per year during the SLA approval process.

BSC to show actual costs to budgeted costs. Additionally, each month BSC provides PHI its full-year estimate of where BSC will be coming in versus the budget and versus the prior full-year estimate. For purposes of this MRP filing, the Company began its analysis with data from 2018, as it is the most recent and representative data available.

Q78. What O&M costs are you supporting associated with services provided by the BSC?

A78. I am supporting O&M costs associated with BSC services for 2018-2022.[9]

Table 5 - BSC O&M

	Historical	Bridge		Projections	
	2018	**2019**	**2020**	**2021**	**2022**
BSC O&M	$56,660,170	$50,732,269	$49,004,823	$48,480,126	$48,106,343
Annual %		-10.5%	-3.4%	-1.1%	-0.8%

In 2018, those costs total $56.6 million, as shown on PEPCO (L)-21. In 2019, I support an O&M cost level of $50.7 million, as shown on PEPCO (L)-21. Finally, in 2020, BSC O&M costs will be approximately $49 million, as shown on PEPCO (L)-21. These projections include costs associated with all of the BSC departments described above. As shown in Table 5, BSC O&M costs are projected to decline during the period of this MRP.

Q79. Would you like to discuss any element of the BSC O&M costs in more detail?

A79. The Compound Annual Growth Rate decrease from 2018 to 2020 is a decrease of 7.00%, which is significantly lower than the average rate of inflation.

[9] Further detail regarding the O&M projections for these responsibility areas are found in PEPCO (L)-21.

V. CUSTOMER AND SALES GROWTH FORECAST/REVENUE FORECAST

Q80. Please describe the three main areas for which the Company must provide projections.

A80. The Company is providing projections of capital costs and O&M costs. The third projection is our revenue projection. To develop the revenue projection, the Company begins with a forecast of its customer and sales growth and then applies the currently effective Bill Stabilization Adjustment (BSA). Company Witness Wolverton testifies regarding the level of Pepco's revenue forecast, but I am describing how Pepco makes its revenue forecast. Company Witness Blazunas uses the revenue forecast when designing the rates proposed in this proceeding.

Q81. Let's discuss the customer and sales growth forecast contained in Pepco's rate filing. Please describe how Pepco conducts econometric modeling to reflect the growth of its customer base.

A81. The Company has a team of economists responsible for maintaining econometric models that produce sales and customer forecasts. The models estimate statistical relationships between electric energy sales/customers and variables that are believed to explain sales/customer growth trends. The models are built in MetrixND statistical software with monthly historical data back to 1991. The primary variables included in the model to explain customer growth are regional economic variables - in particular, total nonfarm employment in Washington, DC, published by the US Bureau of Labor Statistics. Forecasts of employment prepared by IHS Economics serve as the basis for future employment growth used in the forecast of customer counts.

While the vast majority of Pepco's customer classes are included in the BSA, for which customer growth is the only driver of changes in revenues, a few customer classes are still based on volumetric rates. The electric energy sales models contain variables of the all-in real price of electricity (i.e., price including expectations of distribution, energy, and capacity price growth), weather measured by heating and cooling degree-days base 65 degrees (forecast is based on 20-year average normal weather), and the number of customers in the respective class. Energy sales forecasts are then adjusted for the estimated impacts of Energy Efficiency/Demand Side Management, Distributed Generation (Solar), and Electric Vehicle adoption.

Q82. How has Pepco applied its currently effective BSA rates to the customer forecast to develop an annual revenue forecast?

A82. The Company prepares base distribution revenue forecasts using the UI Planner Financial Modelling Software. BSA revenues are calculated by multiplying customer forecasts based on the econometric modeling times current BSA targets. Non-BSA and surcharge revenues are calculated by multiplying energy sales forecasts based on the econometric modeling times current volumetric energy rates. When developing the revenue forecast, the Company excludes the rate relief requested in this proceeding.

VI. CONCLUSION

Q83. Does this conclude your Direct Testimony?

A83. Yes, it does.

P.S. Barnett
Direct Exhibit
DC. P.S.C - - May, 2019

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2018-2022 Long Range Plan Documentation

VP Area: PHI Communications

Vice President:

I – Approvals

This document has been checked for errors in calculations and content.

Prepared By: Date: February 22, 2019
Senior Manager

Approved By: Date: February 22, 2019
Director

Approved By: Date: February 22, 2019
Vice President

II – Major Business Functions

PHI Communications is a key PHI business function. Our team is dedicated to supporting the business objectives of PHI and its utilities, while highlighting how we are delivering on our company's purpose to power a cleaner and brighter future for our customers and communities.

Our Primary Goals

- Creating awareness among customers, media, elected officials and other key stakeholders about PHI's services, initiatives and industry leadership
- Fostering an understanding and support of PHI's business strategy among all PHI employees and customers

The below provides an overview of the major business functions PHI Communications uses to carry out its primary goals.

Social and Digital Communications
Social Media and Digital Communications ensures the PHI brand meets customers where they are – online. We manage content development and daily maintenance of the external PHI websites, social media channels, mobile apps, and The Source, PHI's digital story and content hub. Our goal is to ensure digital content is engaging and digestible for the increasing number of customers who connect with us by laptop, tablet, or mobile phone.

Marketing Communications
Marketing Communications includes the ongoing development and positioning of the PHI brand with customers and stakeholders, increasing awareness through the strategic use of external (advertising, collateral and customer communications) and internal communication channels.

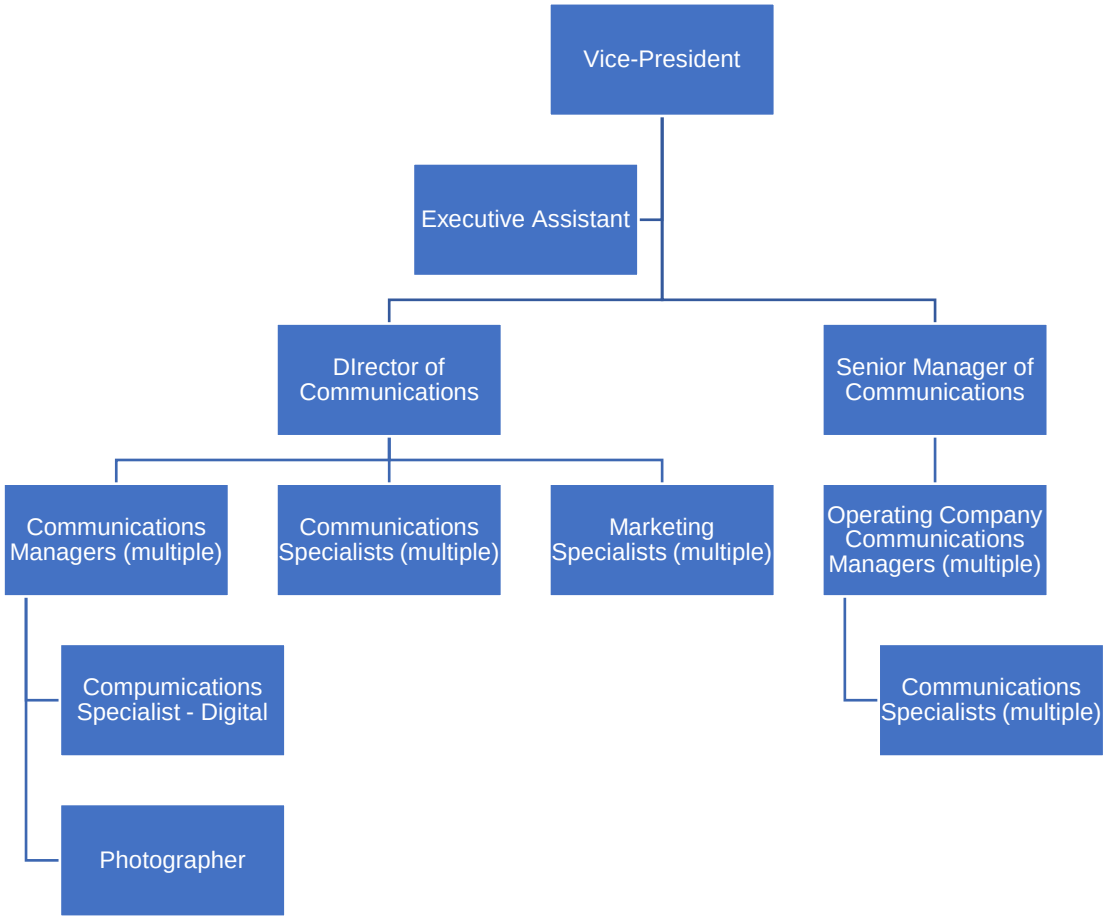
Leadership and Culture
Leadership and Culture includes support of executive presentations for PHI Officers—with primary focus on the CEO and COO; leading the culture communication channels that connect our organization including The Inside Source, Supervisor Updates, and more; and partnering with HR to ensure we connect employees with key information and programs that engage employees across the organization.

Media Engagement
Media Engagement includes efforts to positively position PHI's work to drive innovation and deliver clean, safe, reliable and affordable energy service for customers and communities served by Atlantic City Electric, Delmarva Power and Pepco. To accomplish this, PHI's staff is available around-the-clock to respond to media inquiries and engages routinely with members of the media to create relationships and ensure a clear understanding of company initiatives.

Strategic Project Management
Strategic Project Management includes the integrated communications plans and programs that encompass our business priorities and pillars, including Capital Infrastructure Projects, our Innovation Agenda, Health, Safety, and Environment, and Corporate Stewardship.

III – Home Center Hierarchy

The below chart represents a high-level view of the PHI Communications organization.



IV – Major Programs

PHI Communications is the primary lead for coordinating the efforts to drive stakeholder awareness and engagement for Atlantic City Electric, Delmarva Power and Pepco. This effort includes:

- Coordination, development and placement of advertising campaigns, which requires agency support and engagement for both traditional and multicultural campaigns
- Development and implementation of social and digital media strategies and agency and platform support for social channel management, monitoring, and measurement
- Development of marketing materials and direct customer communications, including bill inserts, customer newsletters, graphics, videos, collateral, and other material
- Media engagement and strategy development, implementation and measurement
- Executive and internal communications support

P.S. Barnett
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2018-2022 Long Range Plan Documentation

VP Area: PHI Communications

Vice President:

PHI Communications

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	PHI Communications has 18 total FTEs in 2019. 2 FTEs are dedicated to ACE, 2 are dedicated to DPL and 2 are dedicated to Pepco. The remaining 12 FTEs support PHI, Pepco, ACE and DPL as needed	930,903	972,519	1,000,603	1,021,704	1,043,898
2	Overtime	Administrative wages that exceed base payroll	13,057	-	-	-	-
3	Incentive	Formulaic based on key performance indicators in Annual Incentive Plans	187,082	196,937	204,397	208,621	214,475
4	Pension and OPEB	Function of payroll based on actuarial study	260,298	235,422	228,375	224,742	223,283
5	Fringe Benefits	Function of payroll based on headcount	163,691	144,334	150,702	157,242	164,005
6	Other Premium	Primarily long-term incentive plan for key managers and above; also includes other awards such as retention and signing bonuses	190,192	107,950	110,945	111,006	111,006
7	Stock Compensation	Payroll costs not directly associated with hours worked. Includes Pshares, Restricted Stock, and Stock Option compensation costs	3,827	-	-	-	-
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	Function of payroll: includes federal unemployment, federal social security, state unemployment	79,300	93,873	96,500	98,535	100,676
10	Materials	Office supplies, especially technology accessories such as headsets, computer memory, etc.	7,904	26,656	26,656	26,656	26,656
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	Agency support, advertising, bill inserts and design work, social and digital channel management and support	63,634	-	-	-	-
13	Contracting - Non-Ops	Agency support, advertising, bill inserts and design work, social and digital channel management and support	2,421,160	1,326,336	1,331,341	1,336,478	1,336,478
14	Contracting - Outsourced	Agency support, advertising, bill inserts and design work, social and digital channel management and support	8,098	-	-	-	-
15	Staff Augmentation	Used for costs associated with contractors performing functions that are typically performed by Exelon employees	55,023	-	-	-	-
16	Insurance	N/A	-	-	-	-	-
17	Regulatory Fees/Permits	N/A	-	-	-	-	-
18	Licensing and Telecom	Cost of software maintenance fees, application licenses, as well as charges for cell phones, PDAs, blackberries, pagers and other personal telecommunication devices	7,380	8,949	8,949	8,949	8,949
19	BSC Services	N/A	-	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	Seminars and training for professional development and industry peer workshops and meetings	1,994	15,232	15,232	15,232	15,232
23	Travel & Entertainment	Includes business travel related expenses, such as mileage reimbursement, car rental, railways, taxi, travel booking fees, etc. This account also includes meal expenses, tuition reimbursement, and costs associated with employee relocation	93,976	64,022	64,022	64,022	64,022
24	Memberships / Dues	Cost of industry and professional memberships for employees and the company (e.g., Utilities Enterprise Membership)	4,743	4,760	4,760	4,760	4,760
25	Charity / Contributions	Charitable contributions	3,444	-	-	-	-
26	Lobbying	N/A	-	-	-	-	-
27	Office Expense	Office supplies	3,137	-	-	-	-
28	Other Expenses	Other miscellaneous costs not specifically accounted for in other operating expense subaccounts	14,335	-	-	-	-
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	N/A					
31	CIAC / CIAM	N/A	-	-	-	-	-
32	Facilities, Rentals, Utils	Allocated based on factors such as square footage and location	151,386	168,785	170,582	172,768	173,048
33	Transportation / Fleet	Costs related to vehicle charges, rental car costs, and allocation of overhead fleet service costs	7,203	8,448	9,385	9,762	10,076
34	Depreciation & Amort	N/A	-	-	-	-	-
35	**Total Expense**		**$ 4,671,767**	**$ 3,374,224**	**$ 3,422,449**	**$ 3,460,476**	**$ 3,496,564**

PHI Communications

VI - Headcount

Instructions:

List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt					
Pepco Non-Exempt					
Pepco Union					
Total Pepco	**-**	**-**	**-**	**-**	**-**
PHISCO Exempt	15	16	16	16	16
PHISCO Non-Exempt	1	2	2	2	2
PHISCO Union	-	-	-	-	-
Total PHISCO	**16**	**18**	**18**	**18**	**18**

P.S. Barnett
Direct Exhibit
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2018-2022 Long Range Plan Documentation

VP Area: PHI Controllership

Vice President:

I – Approvals

This document has been checked for errors in calculations and content.

Prepared By: Date: February 22, 2019
Director

Approved By: Date: February 22, 2019
Vice President

II – Major Business Functions

The PHI Controllership is responsible for the following key functions:

- Complete PHI SEC and FERC filings and support regulatory filings
- Ensure complete and accurate GAAP and FERC general ledgers
- Evaluate and comment on emerging accounting guidance
- Engage with Audit and Controls to ensure proper design and execution of financial controls
- Ensure clean external audit opinions and no restatement of financials
- Socialize PHI positions with external auditors and the Audit Committee

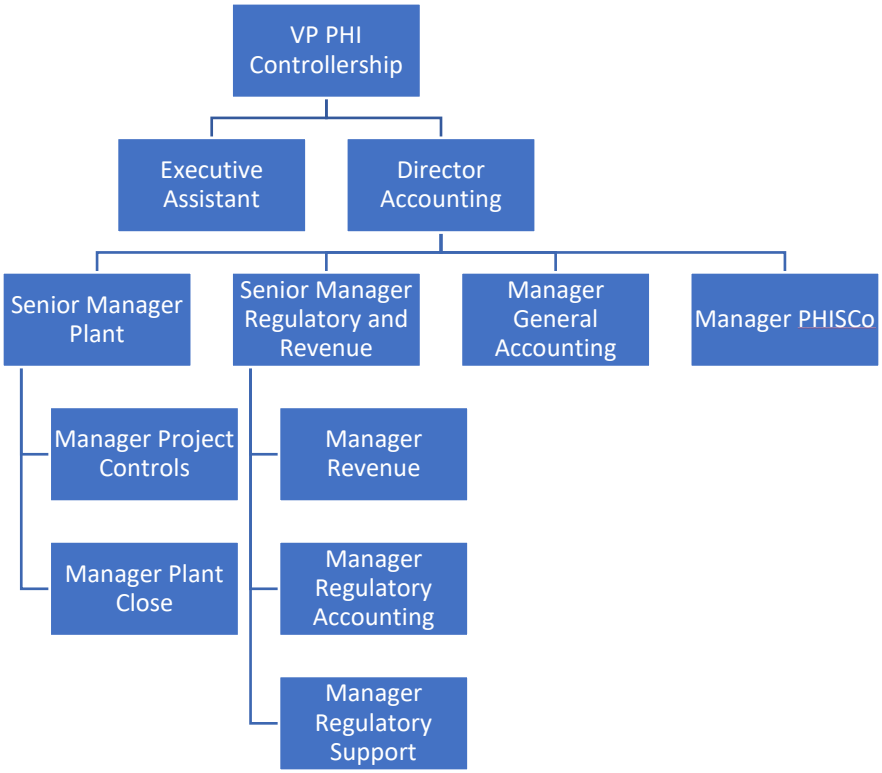
The PHI Controllership is made up of the following groups:

- General Accounting
    - Coordinate overall close process for PHI (coordination with corporate and Finance, monitor account reconciliations and manual journal entries)
    - Coordinate and record financial impacts of periodic reviews of inventory obsolescence, environmental reserves, and public claims
    - Record financial impacts of legal reserves and real estate transactions
    - Support incurred but not reported (IBNR) assessments for public claims and workers compensation
    - Coordinate with Finance to calculate and submit monthly allocation rates (labor burdens, rates x quantity) for PHI Utilities
    - Monitor and resolve issues within intercompany accounts and transactions
- PHISCo Accounting
    - Coordinate with Finance to calculate and submit monthly allocation rates (labor burdens, rates x quantity) for PHISCo
    - Prepare PHISCo service company bills for PHI utilities
    - Perform annual goodwill assessment
    - Prepare monthly close package for all of PHI
    - Compile and file annual PHISCo FERC Form 60
- Plant Accounting and Project Governance
    - Provide capital vs O&M determinations, oversight of real estate and fixed asset processing
    - Prepare journal entries and account reconciliations for plant assets, depreciation, AFUDC, asset retirement obligations (ARO), and Contributions in Aid of Construction (CIAC)
    - Attend authorization meetings to gain awareness of projects and ensure proper accounting
    - Coordinate and support depreciation studies and prepare annual update of depreciation rates for non-regulated plant assets
    - Coordinate and support periodic ARO studies and quarterly monitoring
    - Support tax repairs and tax filing processes
    - Verify projects are approved, reviewed and characterization of costs is appropriate and in compliance with accounting policy
    - Monitor projects for proper in-service dates/extended lookahead and high Construction Work-in-Progress (CWIP) reviews
    - Close out projects within 120 days of in-service date (validate charges, facilitate necessary adjustments)
    - Perform final classification of assets and retirements within Power Plan (various processes and responsibilities exist within this line item)
    - Facilitate blanket project reviews (review actual costs charged to blanket projects for proper capital / O&M treatment)

- Revenue Accounting
    - Calculate and assess reasonableness of bad debt expense reserve and unbilled estimates
    - Record financial impacts of purchased power recovery mechanisms for each utility and jurisdiction (default service, standard offer service, provider of last resort)
    - Record financial impacts of recovery mechanisms in each utility and jurisdiction (purchase of receivables, uncollectible costs, renewable energy contracts, DC Plug, etc.)
    - Record financial impacts of natural gas inventory and storage
    - Work closely with Regulatory to monitor and account for rate changes due to distribution rate case orders, surcharge filings, and other rate-making activities (e.g., tax reform, interim rates, revenue subject to refund, rate credits)
    - Work with IT around billing system issues
    - Account for O&M special billing
- Regulatory Accounting
    - Record financial impacts for transmission formula rate filings and electric and gas distribution base rate orders
    - Record financial impacts of recovery mechanisms including energy procurement and energy efficiency programs
    - Record and monitor regulatory assets and liabilities including recovery, amortization, netting, and current and noncurrent classification
    - Coordinate and document monthly meetings with Regulatory and Legal
    - Review rate making orders, assess accounting implications, and prepare accounting issue memos and material (FERC and state regulators)
    - Subset of this team is dedicated to providing rate case support without close responsibilities
        - Write testimony for Accounting Witnesses in distribution rate cases
        - Coordinate and manage data requests
        - Oversee Cost Allocation Manual (CAM) and affiliate audits
        - Interface with Regulatory around rate-making activities

III – Home Center Hierarchy

The below diagram depicts the PHI Controllership organization.



IV – Major Programs

The majority of PHI Controllership labor is O&M. We do have a team that supports the closing of capital projects where the labor is capitalized. We also incur significant External Audit Fees which are managed centrally at the Exelon Corporate level.

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2018-2022 Long Range Plan Documentation

VP Area: PHI Controllership

Vice President:

PHI Controllership

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	PHI Controllership is made up of the following groups: General Accounting (14%), PHISCo Accounting (10%), Plant Accounting (32%), Revenue Accounting (20%), and Regulatory Accounting (24%)	2,443,168	2,609,646	2,540,178	2,490,917	2,543,328
2	Overtime	Administrative wages that exceed base payroll	4,011	-	-	-	-
3	Incentive	Formulaic based on key performance indicators in Annual Incentive Plans	564,116	486,236	477,371	468,113	488,095
4	Pension and OPEB	Function of payroll based on actuarial study	680,196	632,658	580,615	548,728	553,116
5	Fringe Benefits	Function of payroll based on headcount	432,698	387,863	383,141	383,920	406,273
6	Other Premium	Primarily long-term incentive plan for key managers and above; also includes other awards such as retention and signing bonuses	175,986	137,660	157,649	187,896	187,896
7	Stock Compensation	Payroll costs not directly associated with hours worked. Includes Pshares, Restricted Stock, and Stock Option compensation costs	79,475	957	-	-	-
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	Function of payroll: includes federal unemployment, federal social security, state unemployment	206,061	252,269	245,339	240,581	249,393
10	Materials	Office supplies, especially technology accessories such as headsets, computer memory, etc.	1,964	-	-	-	-
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	External consulting costs for Goodwill Impairment Study, Depreciation Study, and Bad Debt Loss Factor Study	24,643	-	-	-	-
13	Contracting - Non-Ops	External consulting costs for Goodwill Impairment Study, Depreciation Study, and Bad Debt Loss Factor Study	164,425	322,084	268,115	235,237	285,174
14	Contracting - Outsourced	External consulting costs for Goodwill Impairment Study, Depreciation Study, and Bad Debt Loss Factor Study	5,620	-	-	-	-
15	Staff Augmentation	Used for costs associated with contractors performing functions that are typically performed by Exelon employees	518,465	95,200	97,580	100,020	102,520
16	Insurance	N/A	-	-	-	-	-
17	Regulatory Fees/Permits	N/A	-	-	-	-	-
18	Licensing and Telecom	Cost of software maintenance fees, application licenses, as well as charges for cell phones, PDAs, blackberries, pagers and other personal telecommunication devices	3,542	9,710	9,330	8,758	8,758
19	BSC Services	N/A	-	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	Seminars and training for professional development and industry peer workshops and meetings	808	17,600	16,910	15,875	15,875
23	Travel & Entertainment	Includes business travel related expenses, such as mileage reimbursement, car rental, railways, taxi, travel booking fees, etc. This account also includes meal expenses, tuition reimbursement, and costs associated with employee relocation	51,346	97,889	94,891	90,392	90,392
24	Memberships / Dues	Cost of industry and professional memberships for employees and the company (e.g., Utilities Enterprise Membership)	1,887	3,884	3,732	3,503	3,503
25	Charity / Contributions	N/A	-	-	-	-	-
26	Lobbying	Lobbying expense	21	-	-	-	-
27	Office Expense	Supplies	3,791	10,924	10,496	9,853	9,853
28	Other Expenses	Other miscellaneous costs not specifically accounted for in other operating expense sub accounts	17,163	-	-	-	-
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	N/A	-	-	-	-	-
31	CIAC / CIAM	N/A	-	-	-	-	-
32	Facilities, Rentals, Utils	Allocated based on factors such as square footage and location	252,961	274,863	277,789	281,349	281,806
33	Transportation / Fleet	N/A	-	-	-	-	-
34	Depreciation & Amort	N/A	-	-	-	-	-
35	**Total Expense**		**$ 5,632,347**	**$ 5,339,445**	**$ 5,163,134**	**$ 5,065,142**	**$ 5,225,982**

PHI Controllership

VI - Headcount

Instructions:
List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt					
Pepco Non-Exempt					
Pepco Union					
Total Pepco	**-**	**-**	**-**	**-**	**-**
PHISCO Exempt	46	50	48	45	45
PHISCO Non-Exempt	1	1	1	1	1
PHISCO Union	-	-	-	-	-
Total PHISCO	**47**	**51**	**49**	**46**	**46**

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PEPCO _____ (L) – 5

2018-2022 Long Range Plan Documentation

PHISCO Area: Executive Management

President and CEO:

I – Approvals

This document has been checked for errors in calculations and content.

Prepared By: Date: February 21, 2019
Business Analyst

Approved By: Date: February 21, 2019
Chief of Staff to the CEO

Approved By: Date: February 21, 2019
President and CEO

II – Major Business Functions

The Chief Executive Officer (CEO) is responsible for leadership of Pepco Holdings' overall performance associated with service, reliability, financial management and regulatory and external affairs.

Pepco Holdings (PHI) employs more than 4,600 people, owns more than $21 billion in assets and generates approximately $4.8 billion in annual revenue. PHI serves more than 2 million customers as the parent company of:

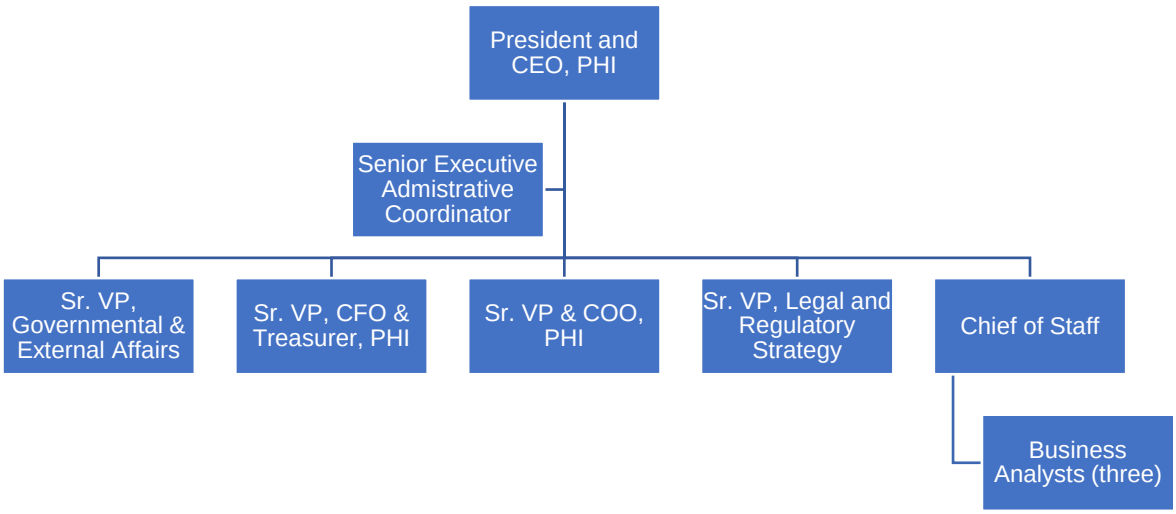
- Pepco, an electric utility serving Washington DC and suburban Maryland
- Delmarva Power & Light, an electric and gas utility serving Delaware and portions of the Delmarva Peninsula
- Atlantic City Electric, an electric utility serving Southern New Jersey

The CEO is supported by an Executive Assistant, a Chief of Staff and three Business Analysts. The Chief of Staff organization is responsible for:

- Benchmarking
- Business Planning
- Key Performance Indicator processes
- Supporting fulfillment of CEO responsibilities

III – Home Center Hierarchy

The below chart depicts the office of the CEO:



IV – Major Programs

The majority of O&M expenses are related to labor for the full-time employees supporting the CEO.

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2018-2022 Long Range Plan Documentation

VP Area: Executive Management

President & CEO:

Executive Management

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	FTE's include – President and CEO, Executive Admin, Chief-of-Staff, Business Planning Lead, Benchmarking Lead, KPI Lead and KPI Lead Assistant	609,955	605,759	623,227	636,309	650,444
2	Overtime	Administrative wages that exceed base payroll	9,832	15,708	16,148	16,148	16,584
3	Incentive	Formulaic based on key performance indicators in Annual Incentive Plans	284,385	315,103	327,046	333,857	343,372
4	Pension and OPEB	Function of payroll based on actuarial study	169,399	147,501	143,079	140,790	139,943
5	Fringe Benefits	Function of payroll based on headcount	108,787	90,430	94,417	98,505	102,791
6	Other Premium	Primarily long-term incentive plan for key managers and above; also includes other awards	21,649	32,807	23,800	23,800	23,800
7	Stock Compensation	Payroll costs not directly associated with hours worked. Includes Pshares, Restricted Stock, & Stock Option compensation costs	605,336	433,659	405,827	393,025	393,025
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	Function of payroll: includes federal unemployment, federal social security, state unemployment	52,840	58,815	60,458	61,727	63,099
10	Materials	Laptop, monitors from zones	684	-	-	-	-
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	Contains contracting activity of the skilled labor nature that supports normal business operations	-	5,712	5,872	6,030	6,181
13	Contracting - Non-Ops	Benchmarking survey, Employee engagement pulse survey	56,904	55,264	56,811	58,345	59,804
14	Contracting - Outsourced	Executive recruiting costs and used in 2018 to recruit leadership positions	8,323	-	-	-	-
15	Staff Augmentation	Beeline/Pontoon invoice correction	(1,652)	-	-	-	-
16	Insurance	N/A	-	-	-	-	-
17	Regulatory Fees/Permits	N/A	-	-	-	-	-
18	Licensing and Telecom	BSC pass-through charges	3,697	-	-	-	-
19	BSC Services	N/A	-	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	Seminars and training for professional development and industry peer workshops and meetings	1,076	10,948	11,255	11,558	11,847
23	Travel & Entertainment	Includes business travel related expenses, such as mileage reimbursement, car rental, railways, taxi, travel booking fees, etc. This account also includes meal expenses, tuition reimbursement, and costs associated with employee relocation	91,077	125,950	129,476	132,972	136,296
24	Memberships / Dues	Cost of industry and professional memberships for employees and the company (e.g., Utilities Enterprise Membership)	22,866	444,822	457,277	469,623	481,364
25	Charity / Contributions	N/A	-	2,856	2,936	3,015	3,091
26	Lobbying	N/A	-	-	-	-	-
27	Office Expense	Office supplies, toner, ink, paper, binders, shipping supplies, FedEx and UPS	5,650	18,183	18,692	19,197	19,677
28	Other Expenses	Other miscellaneous costs not specifically accounted for in other operating expense sub accounts	157,343	148,512	152,670	156,792	160,712
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	N/A	-	-	-	-	-
31	CIAC / CIAM	N/A	-	-	-	-	-
32	Facilities, Rentals, Utils	Allocated based on factors such as square footage and location	74,147	79,404	80,291	81,371	81,570
33	Transportation / Fleet	Costs related to vehicle charges, rental car costs, and allocation of overhead fleet service costs	31,019	41,069	45,627	47,467	49,009
34	Depreciation & Amort	N/A	-	-	-	-	-
35	**Total Expense**		**$ 2,313,317**	**$ 2,632,502**	**$ 2,654,909**	**$ 2,690,532**	**$ 2,742,609**

Executive Management

VI - Headcount

Instructions:
List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt					
Pepco Non-Exempt					
Pepco Union					
Total Pepco	**-**	**-**	**-**	**-**	**-**
PHISCO Exempt	7	7	7	7	7
PHISCO Non-Exempt					
PHISCO Union					
Total PHISCO	**7**	**7**	**7**	**7**	**7**

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2018-2022 Long Range Plan Documentation

VP Area: Finance

Manager/Director:

I - Approvals

This document has been checked for errors in calculations and content.

Prepared By:		Date:	2/21/2019
Approved By:	Vice President	Date:	2/21/2019
Approved By:	Sr. Vice President / CFO	Date:	2/21/2019

II – Major Business Functions

The two major business functions/departments within Finance are Financial Operations (FinOps) and Financial Planning and Analysis (FP&A). Both the FinOps and FP&A teams are led by the PHI Chief Financial Officer (CFO) who has governance and oversight of all financial matters, including holding the business accountable for making cost-conscious spending decision. The functions / duties provided by FinOps and FP&A are as follows:

FinOps:

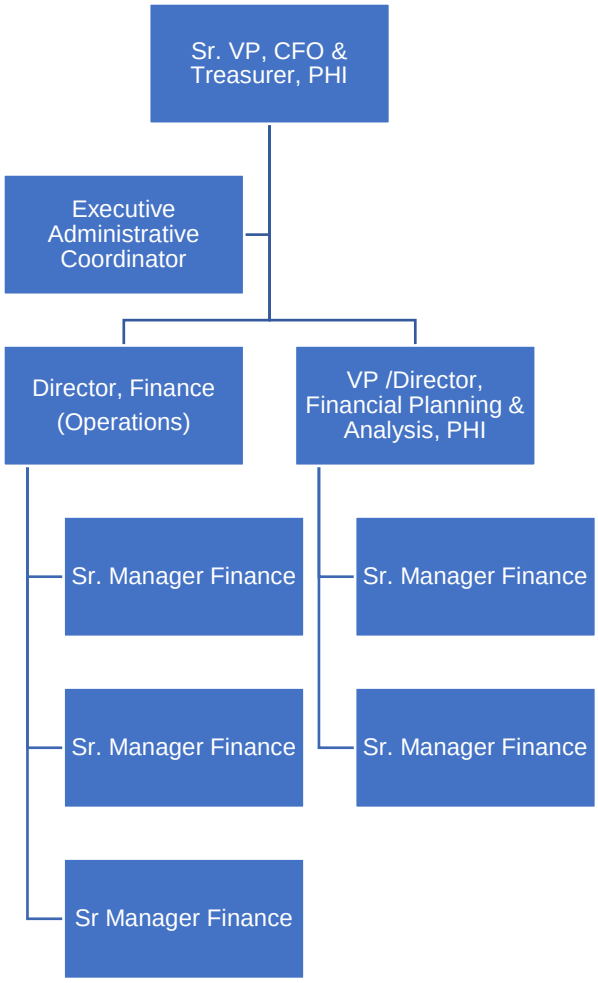
- Provides governance, oversight & development of PHI spending plan (Operating and Maintenance Expense and Capital Plan) which is a 5-year plan and the basis for each year's budget
    - Includes providing financial targets to departmental Vice Presidents to achieve PHI's overall financial goals
- Performs monthly financial reporting to PHI Senior Management:
    - Includes variances of actual costs to budgeted costs, including drivers of the variances
- Provides governance, oversight & development of monthly Latest Estimate of full year costs. The Latest Estimate is a full year reforecast of the budget, taking into account the monthly actual activities and future monthly changes and updates to the Budget.
- Partner with FP&A, Regulatory and Controller's group in achieving PHI's financial goals / targets
- Provide financial reporting and analysis to support business leaders in managing their budgets
- Partner with the business during the monthly accounting close process to assure all accruals and accounting entries are performed with accuracy and completeness
- Assist with full compliance of merger commitments
- Supports Rate Cases (filings and data requests)

FP&A:

- Provides governance, oversight & development of PHI's 5-year Long Range Plan
    - Includes P&L, Balance Sheet and Cash Flows
- Assures Key Financial Metrics are achieved in the Long-Range Plan
- Perform and provides monthly financial reporting to PHI Senior Management
    - Includes variances and drivers for net income, cash flow and Key Financial Metrics
- Develops and provides Senior Management with full year Latest Estimate or Net Income, Balance Sheet, Cash Flows and Key Financial Metrics
- Works with treasury to develop financing plan and support debt issuance process
- Oversight and coordination of financial reporting packages for internal and external stakeholders"
- Performs ad hoc analysis and scenario planning
- Supports Rate Cases (filings and data requests)

III - Home Center Hierarchy

The below diagram provides a high-level overview of the Finance department:



IV - Major Programs

There are no major O&M programs in the Finance department.

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2018-2022 Long Range Plan Documentation

VP Area: Finance

Senior Vice President:

Finance

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	Budgeted 29 FTE for Fin Ops, 15 FTE for FPNA, and 2 FTE for supporting CFO group	2,610,316	2,260,167	2,270,533	2,319,093	2,368,208
2	Overtime	Overtime hours for non-exempt employees	7,442	-	-	-	-
3	Incentive	Formulaic based on key performance indicators in Annual Incentive Plans	624,643	423,345	428,942	438,114	450,006
4	Pension and OPEB	Function of payroll based on actuarial study	725,387	550,828	521,712	513,563	509,953
5	Fringe Benefits	Function of payroll based on headcount	461,044	337,705	344,272	359,317	374,569
6	Other Premium	Primarily long-term incentive plan for key managers and above; also includes other awards such as retention and signing bonuses	215,452	171,718	182,605	195,011	195,011
7	Stock Compensation	Payroll costs not directly associated with hours worked. Includes Pshares, Restricted Stock, and Stock Option compensation costs	(1,476)	163,771	162,328	162,328	162,328
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	Function of payroll: includes federal unemployment, federal social security, state unemployment	220,359	219,640	220,450	225,164	229,932
10	Materials	These are for office expense, computer memory, skype headsets, etc.	7,665	3,422	3,516	3,610	3,701
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	Accrual from 2017 reversed in January 2018	(11,606)	-	-	-	-
13	Contracting - Non-Ops	These are for UI contractors hired for ESI integration from SAP to Hyperion	53,554	34,106	35,038	35,963	36,924
14	Contracting - Outsourced	Financial advisory services	8,668	-	-	-	-
15	Staff Augmentation	Used for costs associated with contractors performing functions that are typically performed by Exelon employees	500,632	65,493	75,044	76,623	80,199
16	Insurance	N/A	-	-	-	-	-
17	Regulatory Fees/Permits	N/A	-	-	-	-	-
18	Licensing and Telecom	Cost of software maintenance fees, application licenses, as well as charges for cell phones, PDAs, blackberries, pagers and other personal telecommunication devices	6,821	23,927	24,512	25,075	25,665
19	BSC Services	N/A	-	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	Seminars and training for professional development and industry peer workshops and meetings	2,288	20,815	21,384	21,950	22,529
23	Travel & Entertainment	Includes business travel related expenses, such as mileage reimbursement, car rental, railways, taxi, travel booking fees, etc. This account also includes meal expenses, tuition reimbursement, and costs associated with employee relocation	107,285	168,688	166,619	171,646	176,907
24	Memberships / Dues	Cost of industry and professional memberships for employees and the company (e.g., Utilities Enterprise Membership)	20,565	19,648	20,140	20,644	21,162
25	Charity / Contributions	N/A	-	-	-	-	-
26	Lobbying	N/A	-	-	-	-	-
27	Office Expense	Office supplies	7,539	6,896	7,079	7,265	7,464
28	Other Expenses	Accrual for unapproved credit card transactions	25,258	-	-	-	-
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	N/A	-	-	-	-	-
31	CIAC / CIAM	N/A	-	-	-	-	-
32	Facilities, Rentals, Utils	Allocated based on factors such as square footage and location	209,262	201,580	205,194	207,826	208,165
33	Transportation / Fleet	N/A	-	-	-	-	-
34	Depreciation & Amort	N/A	-	-	-	-	-
35	**Total Expense**		**$ 5,801,097**	**$ 4,671,749**	**$ 4,689,367**	**$ 4,783,192**	**$ 4,872,722**

Finance

VI - Headcount

Instructions:
List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt					
Pepco Non-Exempt					
Pepco Union					
Total Pepco	**-**	**-**	**-**	**-**	**-**
PHISCO Exempt	45	41	40	40	40
PHISCO Non-Exempt	1	1	1	1	1
PHISCO Union					
Total PHISCO	**46**	**42**	**41**	**41**	**41**

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2018-2022 Long Range Plan Documentation

SVP Area: Governmental and External Affairs

Senior Vice President:

I - Approvals

This document has been checked for errors in calculations and content.

Prepared By: Date: 2/20/2019

Approved By: Date: 2/20/2019
Senior Vice President

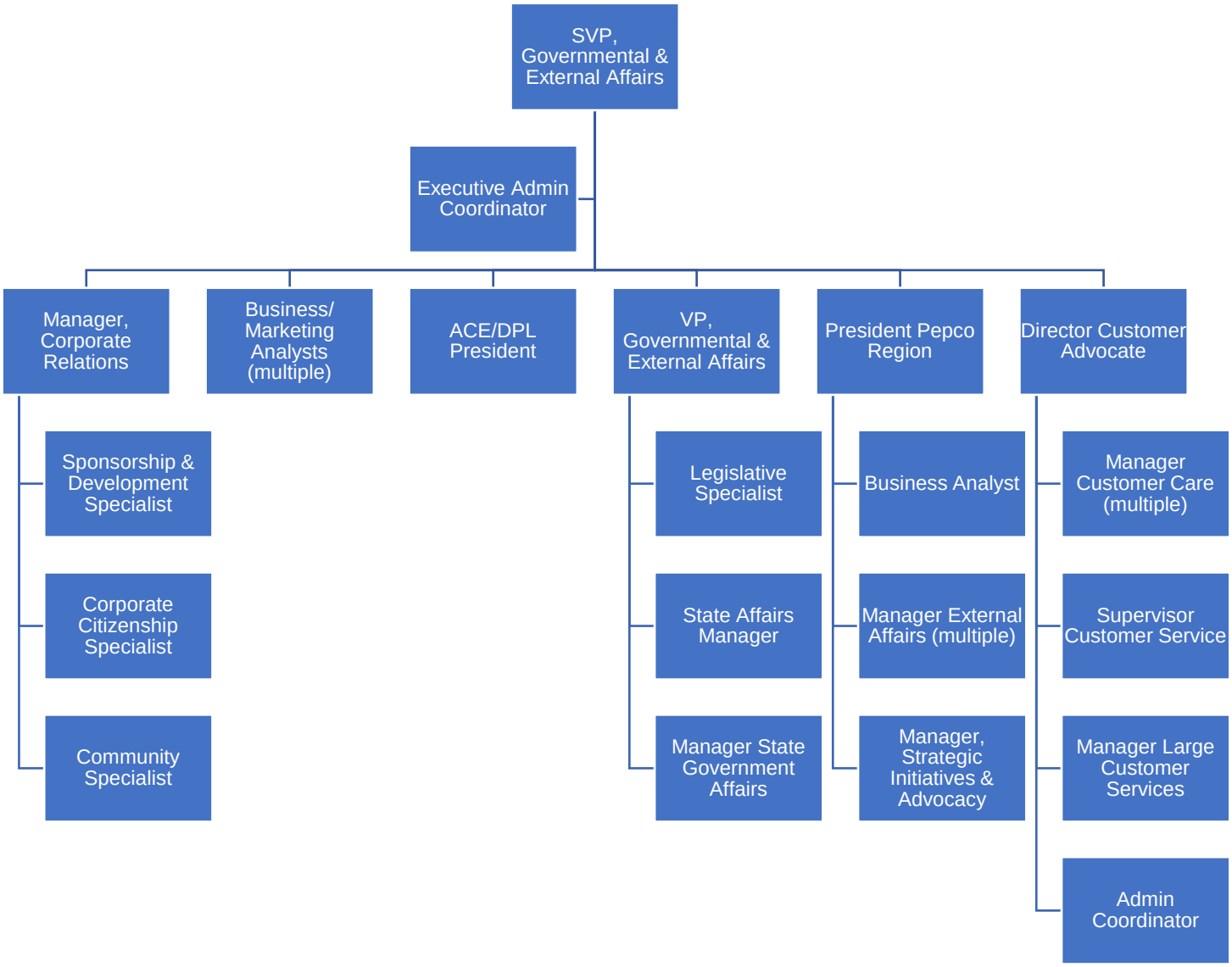
II – Major Business Functions

Governmental and External Affairs is responsible for leading government relations and external affairs strategy. Specific responsibilities include:

- Design and implement Pepco's stakeholder relations and issues management programs, serve as Pepco's primary governmental, community, stakeholder, and political advisor.
- Lead legislative and public policy initiatives and support regulatory activities.
- Represent Pepco at the highest levels in government and political arena.
- Establish policies and procedures to assure Pepco's compliance with all state and local lobbying, gifting and political contributions requirements.
- Manage, develop, and implement Corporate Relations philanthropic, volunteer and sponsorship programs and budgets.
- Manage large customer and key accounts (commercial and industrial) across all regions, including billing, energy solutions, analytics and business development.
- Execute market research, customer opinion survey information, and analysis (i.e., Residential, Commercial, Governmental surveys, etc.).
- Develop and implement programs designed to address customer issues and facilitate subsequent resolution.
- Develop and implement customers energy assistance programs to help low- and moderate-income customers pay their energy bills.
- Develop and promote economic development programs to help attract business and grow jobs across all jurisdictions.

III - Home Center Hierarchy

The below chart represents a high-level view of the Governmental and External Affairs department.



IV - Major Programs

Market Research—Market Strategies, Inc (MSI): Customer Satisfaction Research: $221,833
MSI provides customer satisfaction data across the Pepco residential and commercial customer segments. Customer satisfaction is an Exelon utility-wide key performance indicator (KPI). The costs include data collection on an ongoing basis (daily), identification of performance trends, quarterly reports and access to an online portal to view results. On an annual basis, a key driver analysis is conducted to better understand any changes in the drivers of customer satisfaction. All six Exelon utilities utilize MSI, and work together to achieve cost savings and efficiencies. Beyond the annual incentive plan, KPI customer satisfaction results are used to provide data during rate cases, testimony and other regulatory proceedings. The data are used internally to measure messaging and advertising impacts, customer satisfaction across the spectrum of customer services, identify problem areas, and measure performance. Data are communicated across a variety of internal leadership groups, customer communications, and customer operations.

Market Research—Transactional Research: $215,800
MSI conducts transactional research to assess customer satisfaction with specific transaction types. MSI conducts a call center study for all Exelon utilities to provide data for the call center satisfaction KPI. The costs include data collection on an ongoing basis (daily), an online portal to view results, monthly and quarterly reporting, and identification of performance trends. Both residential and commercial customers who contact the call center are included. These data are tracked and reported monthly to the call center. The data are used to identify performance trends and any need for improvement. Data may be used for rate cases, testimony, and other regulatory proceedings.

Large Customer Services—Pepco Low Income Assistance: $91,000
Staff Augmentation—1 FTE assists the Senior Community Relations Specialist staff at community meetings, community events and sign-up events in distributing energy assistance information as well as assisting customers in signing-up for available energy assistance programs.

Large Customer Services—Schneider/Televent: $224,250 (approximately)
Energy Profiler Online (EPO) is a cloud-hosted energy management information and demand response system for end use customers of utilities. EPO allows both utilities and their customers to view accurate, detailed energy usage data, which can help identify cost savings opportunities and support participation in automated demand response programs. It also helps utilities to meet government energy efficiency mandates and easily manage peak demands-no installation required.

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2018-2022 Long Range Plan Documentation

VP Area: Governmental and External Affairs

Senior Vice President:

Governmental and External Affairs

V - Major Cost Drivers by Cost Type

Instructions:
List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	Total 2018 headcount is 66 FTEs; ~50% from Government Affairs, 25% from Customer Relations and 25% from Key Accounts	4,401,720	5,083,366	5,229,687	5,339,118	5,455,840
2	Overtime	Administrative wages that exceed base payroll	53,375	12,159	12,159	12,698	12,698
3	Incentive	Formulaic based on key performance indicators in Annual Incentive Plans	502,958	408,680	422,190	431,974	444,008
4	Pension and OPEB	Function of payroll based on actuarial study	443,728	1,063,234	1,004,186	948,347	884,455
5	Fringe Benefits	Function of payroll based on headcount	994,351	1,022,879	1,063,458	1,106,722	1,154,044
6	Other Premium	Primarily long-term incentive plan for key managers and above; also includes other awards	279,194	110,964	113,903	298,103	135,422
7	Stock Compensation	Payroll costs not directly associated with hours worked. Includes Pshares, Restricted Stock, and Stock Option compensation costs	266,960	160,920	168,726	-	162,681
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	Function of payroll: includes federal unemployment, federal social security, state unemployment	80,878	115,112	118,332	120,822	123,477
10	Materials	Office supplies, especially technology accessories such as headsets, computer memory, LED monitors, etc.	45,565	11,262	11,408	11,563	11,588
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	Contracting activity of the skilled labor nature that supports normal business operations	835,658	47,673	48,618	49,591	49,591
13	Contracting - Non-Ops	Print media that are used for internal or external communications, public policy, legal and regulatory consultants, customer satisfaction research and message testing. Provides art, text and geo-mapping for target mail campaign directed at low income customers. Provides updates, review and analysis of changes to N.J.A.C.	1,794,970	2,515,880	2,526,191	2,558,174	2,553,476
14	Contracting - Outsourced	Pepco Montgomery County construction survey (KCW Engineering Technologies)	5,448	-	-	-	-
15	Staff Augmentation	Contractors to assist with PHI Community foundation and Energy assistance outreach work. Duties included educating customers on available assistance, manning tables at resource fairs and assisting at other energy assistance events in the Pepco Region	127,732	62,482	63,723	64,998	64,998
16	Insurance	N/A	-	-	-	-	-
17	Regulatory Fees/Permits	Lobbying compliance costs charged here	1,755	-	-	-	-
18	Licensing and Telecom	Cost of software maintenance fees, application licenses, as well as charges for cell phones, PDAs, blackberries, pagers and other personal telecommunication devices	156,376	233,014	233,864	235,105	235,163
19	BSC Services	N/A	-	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	Seminars and training for professional development and industry peer workshops and meetings	24,597	34,783	35,330	35,891	35,979
23	Travel & Entertainment	Includes business travel related expenses, such as mileage reimbursement, car rental, railways, taxi, travel booking fees, etc. This account also includes meal expenses, tuition reimbursement, and costs associated with employee relocation	531,089	661,708	678,540	696,278	696,333
24	Memberships / Dues	Cost of industry and professional memberships for employees and the company (e.g., Utilities Enterprise Membership)	95,709	55,649	56,766	57,901	57,901
25	Charity / Contributions	These are reclassified against the charitable commitment obligation at the end of each accounting month	1,049	35,278	35,776	36,291	36,291
26	Lobbying	Consultant charges for lobbying specific to company initiatives	46,162	-	-	-	-
27	Office Expense	Supplies	55,989	72,213	73,323	74,551	74,556
28	Other Expenses	Other miscellaneous costs not specifically accounted for in other operating expense sub accounts	95,553	233,507	236,490	239,509	239,627
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	N/A	-	-	-	-	-
31	CIAC / CIAM	N/A	-	-	-	-	-
32	Facilities, Rentals, Utils	Allocated based on factors such as square footage and location	454,545	480,803	493,484	506,746	510,731
33	Transportation / Fleet	Costs related to vehicle charges, rental car costs, and allocation of overhead fleet service costs	48,783	55,800	61,992	64,488	66,576
34	Depreciation & Amort	N/A	-	-	-	-	-
35	**Total Expense**		**$ 11,344,142**	**$ 12,477,367**	**$ 12,688,147**	**$ 12,888,869**	**$ 13,005,434**

Governmental and External Affairs

VI - Headcount

Instructions:
List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt	31	36	36	36	36
Pepco Non-Exempt	-	-	-	-	-
Pepco Union	-	-	-	-	-
Total Pepco	**31**	**36**	**36**	**36**	**36**
PHISCO Exempt	35	38	38	38	38
PHISCO Non-Exempt		-	-	-	-
PHISCO Union					
Total PHISCO	**35**	**38**	**38**	**38**	**38**

P.S. Barnett
Direct Exhibit
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Introduced as:
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An Exelon Company

2018-2022 Long Range Plan Documentation

VP Area: Human Resources

Vice President:

I – Approvals

This document has been checked for errors in calculations and content.

Prepared By: Date: 09/21/18
Vice President

Approved By: Date: 2/14/19
Vice President

II – Major Business Functions

PHI's Human Resources department's primary responsibility is to support operational objectives with day-to-day resource needs and to positively influence employee engagement. This is done by providing developmental tools and support for all employees, and by helping employees to better understand their role in driving this process.

We are also focused on initiatives designed to make the employee experience, from hire to retire, one that is rewarding for our employees and one that adds value to the company.

HR Management and Administration

- Manage policies and programs to ensure compliance with external agencies
- Maintain compliance of on-boarding, off-boarding, and cross-boarding processes
- Maintain compliance of contractor management process
- Manage distribution of statutory compliance notices and postings
- Maintain the HR records/file management program
- Provide subject matter expertise for non-compliance/non-mandatory workforce policies
- Maintain compliance of HR management model documents
- Maintain compliance to HR system requirements
- Partner with Exelon Business Services Company (BSC) and peers on strategy development, program evaluation and development (as part of peer group work) to ensure operations expectations are met
- Support HR/payroll processes and programs and help employees and leaders through education and issue resolution

Talent Acquisition

- Establish and execute enterprise-wide recruiting programs strategies that help the operating companies achieve their recruiting pipeline development, including but not limited to the professional pipeline intern program, the military, national diversity and disability strategies
- Oversee adherence to staffing policies and procedures
- Develop and manage relationships with local recruiting related vendors, negotiate contracts
- Post jobs to sourcing sites; select, interview, test, and hire talent
- Train leaders on interviewing and selection processes
- Oversee relocation policies between vendor and new hires
- Support tuition reimbursement program
- Adhere to and maintain talent acquisition and management systems

Diversity & Inclusion (D&I)

- Establish diversity and inclusion strategies
- Counsel and support executive and business unit implementation of D&I strategies, including business plan integration
- Communicate corporate wide D&I messages; provide subject matter expertise in the development of diversity communications (disbursement through Communications group)
- Provide D&I management support, including education; provide subject matter expertise for diversity training/educational materials and D&I education modules in all leadership development programs
- Develop and support D&I council and Employee Resource Group (ERG) activities
- Develop and support D&I outreach (recruiting, community, and vendors) in partnership with Corporate Relations, Supplier Diversity, External Affairs, and Talent Acquisition
- Develop and implement D&I metrics and reporting at operating company and executive levels; monitor/test diversity efforts and alignment with policies and procedures
- Ensure alignment regarding D&I strategies, goals and results; advise and consult management on diversity issues and lead executive leadership discussions

- Manage Affirmative Action Plans (AAP), provide training for HR teams, and work with Legal and practice areas to respond to AAP audits

Talent Management and Leadership Development

- Develop leadership core competencies and implement standards and expectations
- Design organizational development, performance development, talent management, and learning strategies; and implement Exelon programs
- Maintain organizational development methodologies, processes and tools for succession planning and performance reviews
- Design and maintain oversight of leadership/management development programs and tools
- Design and maintain oversight of employee development programs and tools
- Develop and maintain leadership training programs/materials with subject matter expertise
- Procure leadership training and negotiate contracts
- Conduct leadership training, as appropriate
- Manage leadership training, organizational development and learning vendors and consultants
- Deliver and coordinate numerous leadership and executive leadership programs
- Identify and manage Hi-Po (high potential) programs and processes
- Oversee and maintain succession planning processes

Organizational Effectiveness

- Build and execute strategies designed to improve effectiveness of the organization and HR function

HR Analytics

- Complete annual external benchmarking surveys as required per our corporate memberships as needed
- Oversee and execute related HR Metrics
- Oversee and execute the Employee Engagement Survey Process including: development and delivery of tools, processes and resources; supporting analysis and reporting; and the action planning process

HR Project Management

- Provide governance and oversight of HR strategic initiatives and continuous process improvement consulting support for HR
- Conduct talent assessments
- Support overall strategy design, vendor management, technology enablement and ongoing strategic support and oversight to operating company HR teams for the following assessments:
    - Leadership
    - Individual contributor
    - 360s
    - Exit interviews, Stay interview

Labor Relations

- Develop and manage business-unit-specific strategies in partnership with BSC
- Respect employee's legal right to be non-union, strive to retain that status and maintain a direct relationship between management and employees
- Educate First Line Supervisors on labor expectations
- Consulting / Contract Administration:
    - Analyze impact of business unit initiatives on employee relations by advising management on labor/employee relations issues;
    - Interpret collective bargaining agreements (CBAs), arbitration implications, and strategy formation

- Develop and provide training/education to management concerning pertinent CBA matters and other labor relations issues
- Respond to union/exempt employee questions related to labor communications
- Support discipline/termination consensus calls for represented employees with HR Operations and Legal
- Conduct frequent interactions with Union Leadership
- Provide guidance on improved employee relations
- Provide contract interpretation for line management
- Administer and lead protocol strategy meetings
- Support negotiations including and grievance and arbitration procedures

Compensation and Benefits

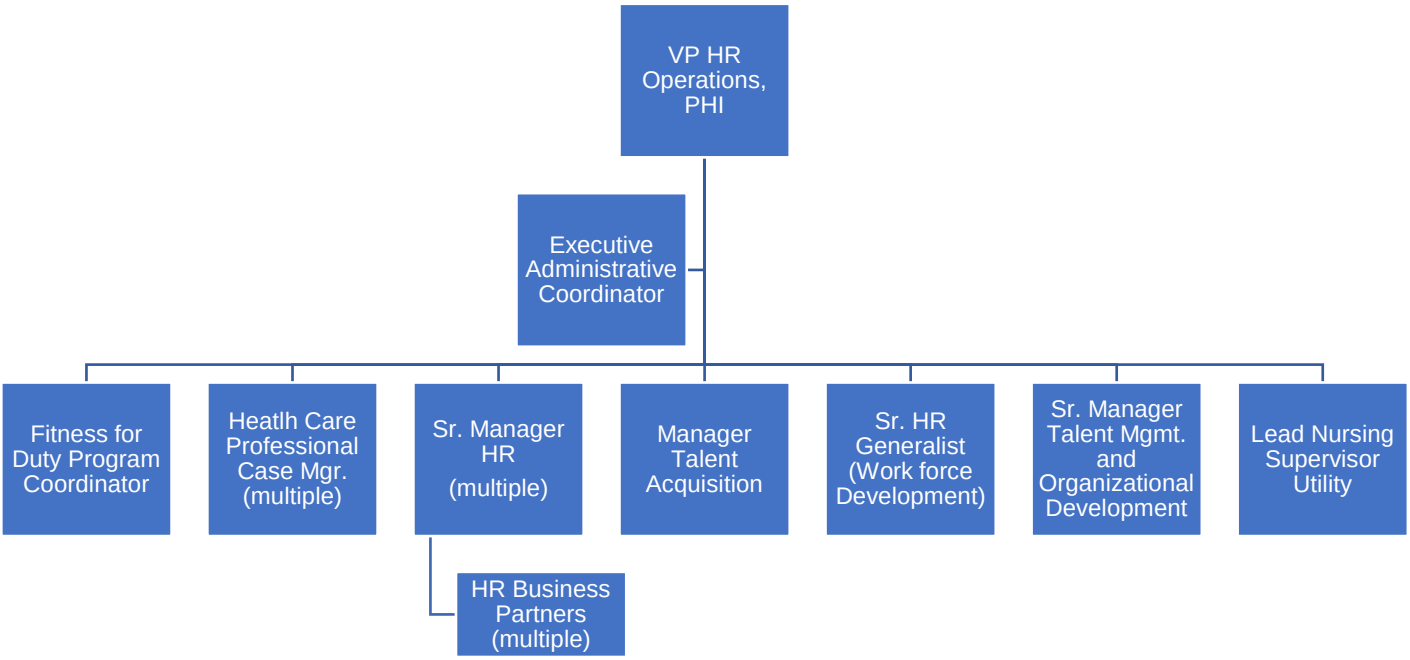
- Provide on the ground support, oversight, and education for employees and leaders on all compensation and benefits programs

Health Services (OHS)

- Provide medical programs oversight, management, and education for Short-Term Disability Case Management, Regulatory Medical Testing, Workplace Clinical Services, and Data Systems Administration
- Implement interventions to help control cost, reduce lost time, and increase productivity
- Maintain compliance to meet the requirements of medical disability plans, Workers' Compensation statutes, and federal and state legislation and delivery of clinical services to minimize time away from the job

III – Home Center Hierarchy

The below diagram represents a high-level overview of the Human Resources department.



IV – Major Programs

O&M initiatives are not significant in cost and used for programs such as diversity and inclusion, talent acquisition, and talent management.

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2018-2022 Long Range Plan Documentation

VP Area: Human Resources

Vice President:

Human Resources

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	Talent Acquisition and Onboarding - 20%, Talent Management/Leadership Development - 18%, Employee Relations - 18%, OHS & Fitness for Duty - 15%, Labor Grievances - 15%, Special Projects 14%	1,414,699	1,474,709	1,517,441	1,549,756	1,582,398
2	Overtime	Administrative wages that exceed base payroll	5,164	-	-	-	-
3	Incentive	Formulaic based on key performance indicators in Annual Incentive Plans	338,768	142,183	147,714	150,728	154,839
4	Pension and OPEB	Function of payroll based on actuarial study	396,504	357,514	346,845	341,398	338,961
5	Fringe Benefits	Function of payroll based on headcount	249,623	219,187	228,879	238,861	248,973
6	Other Premium	Primarily long-term incentive plan for key managers and above; also includes other awards such as retention or signing bonuses	139,943	131,932	177,564	117,545	117,545
7	Stock Compensation	Payroll costs not directly associated with hours worked. Includes Pshares, Restricted Stock, and Stock Option compensation costs	-	-	-	-	-
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	Function of payroll: includes federal unemployment, federal social security, state unemployment	119,418	142,557	146,560	149,681	152,834
10	Materials	Materials for Fitness for Duty and other Occupational Health Services related testing supplies	29,505	44,847	44,847	44,847	44,847
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	Other contracting costs. Credit in 2018 is due to a reclass of costs to Non-Ops	(11,345)	-	-	-	-
13	Contracting - Non-Ops	Costs for Occupational Heath Services related services and workforce planning development survey	51,850	69,264	69,264	69,264	69,264
14	Contracting - Outsourced	Other contracting	270	-	-	-	-
15	Staff Augmentation	Used for costs associated with contractors performing functions that are typically performed by Exelon employees	67,151	107,633	107,633	107,633	107,633
16	Insurance	N/A	-	-	-	-	-
17	Regulatory Fees/Permits	N/A	-	-	-	-	-
18	Licensing and Telecom	Cost of software maintenance fees, application licenses, as well as charges for cell phones, PDAs, blackberries, pagers and other personal telecommunication devices	15,813	16,743	16,743	16,743	16,743
19	BSC Services	N/A	-	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	Seminars and training for professional development and industry peer workshops and meetings	5,916	-	-	-	-
23	Travel & Entertainment	Includes business travel related expenses, such as mileage reimbursement, car rental, railways, taxi, travel booking fees, etc. This account also includes meal expenses, tuition reimbursement, and costs associated with employee relocation	79,094	89,694	89,694	89,694	89,694
24	Memberships / Dues	Cost of industry and professional memberships for employees and the company (Ex. Utilities Enterprise Membership)	2,270	5,980	5,980	5,980	5,980
25	Charity / Contributions	Donations to charitable organizations.	483	11,959	11,959	11,959	11,959
26	Lobbying	N/A	-	-	-	-	-
27	Office Expense	Office supplies	13,297	14,949	14,949	14,949	14,949
28	Other Expenses	Other miscellaneous costs not specifically accounted for in other operating expense sub accounts	34,743	-	-	-	-
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	N/A	-	-	-	-	-
31	CIAC / CIAM	N/A	-	-	-	-	-
32	Facilities, Rentals, Utils	Allocated based on factors such as square footage and location	266,529	316,668	320,039	324,140	324,667
33	Transportation / Fleet	N/A	-	-	-	-	-
34	Depreciation & Amort	N/A	-	-	-	-	-
35	**Total Expense**		**$ 3,219,695**	**$ 3,145,820**	**$ 3,246,111**	**$ 3,233,177**	**$ 3,281,285**

Human Resources

VI - Headcount

Instructions:
List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt					
Pepco Non-Exempt					
Pepco Union					
Total Pepco	**-**	**-**	**-**	**-**	**-**
PHISCO Exempt	23	22	22	22	22
PHISCO Non-Exempt	1	1	1	1	1
PHISCO Union					
Total PHISCO	**24**	**23**	**23**	**23**	**23**

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2018-2022 Long Range Plan Documentation

VP Area: Legal

Senior Vice President:

I – Approvals

This document has been checked for errors in calculations and content.

Prepared By: Date: 2/24/2019
Senior Vice President

Approved By: Date: 2/24/2019
Senior Vice President

II – Major Business Functions

The PHI Legal department provides legal advice, counseling and services to all business units within Pepco Holdings. The department consists of attorneys who are admitted to practice law in the PHI jurisdictions as well as paralegals and other support professionals who work together to efficiently deliver legal services to the company. Legal services are delivered both directly by members of the department, and through the retention of outside counsel who work directly with, and are supervised by, in-house lawyers.

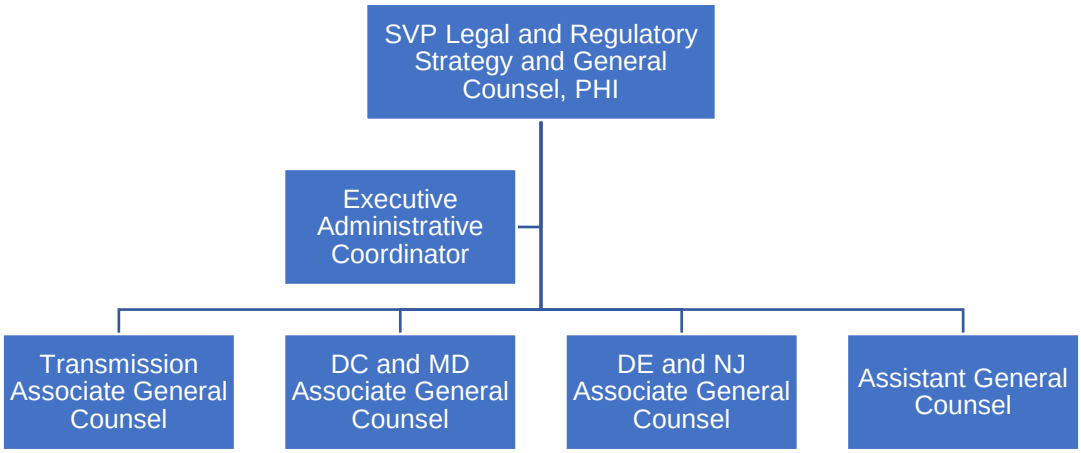
The PHI Legal department consists of lawyers and staff who focus primarily on regulatory matters and represent the utilities before the public service commissions in each jurisdiction and before the Federal Energy Regulatory Commission. Regulatory matters range from representing the utilities in distribution and transmission rate cases to complying with jurisdictional statutes as well as commission orders and regulations to providing any other necessary filings and information to the public service commissions.

The PHI Legal department also works closely with attorneys and support staff in the Exelon Business Services Corp., who provide expertise and legal services on a broad range of other areas of the law, including areas such as labor and employment, environmental, corporate and commercial transactions.

The department is committed to delivering value-added solutions in legal and compliance matters by working in partnership with our business colleagues, applying our legal expertise, developing relationships, and employing innovative and creative ideas.

III – Home Center Hierarchy

The below chart provides an overview of the Legal department:



IV – Major Programs

The major O&M costs of the department are attributed to direct labor costs comprised of salary, benefits, and overheads for the employees in the department, and the cost of outside counsel.

Outside counsel is retained to provide legal support on specific matters as the business need arises. In each case, a lawyer within the department is responsible for retaining the outside counsel, supervising the work, and working collaboratively with the outside lawyers and the business unit, and approving outside counsel invoices for work performed on behalf of the utility.

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2018-2022 Long Range Plan Documentation

VP Area: Legal

Senior Vice President:

Legal

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	The PHI Legal department consists of lawyers and staff who focus primarily on regulatory matters and represent the utilities before the public service commissions in each jurisdiction and before the Federal Energy Regulatory Commission	1,414,367	1,462,882	1,505,250	1,537,245	1,569,589
2	Overtime	Administrative wages that exceed base payroll	6,287	5,204	5,355	5,469	5,585
3	Incentive	Formulaic based on key performance indicators in Annual Incentive Plans	315,794	383,515	398,163	406,497	417,555
4	Pension and OPEB	Function of payroll based on actuarial study	394,801	352,549	342,023	336,638	334,228
5	Fringe Benefits	Function of payroll based on headcount	249,779	216,143	225,697	235,530	245,496
6	Other Premium	Primarily long-term incentive plan for key managers and above; also includes other awards such as retention and signing bonuses.	327,632	275,491	276,359	272,165	272,165
7	Stock Compensation	Payroll costs not directly associated with hours worked. Includes Pshares, Restricted Stock, & Stock Option compensation costs	21,648	5,637	-	-	-
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	Function of payroll: includes federal unemployment, federal social security, state unemployment	113,445	140,577	144,522	147,594	150,699
10	Materials	Office supplies, especially technology accessories such as headsets, computer memory, etc.	3,754	-	-	-	-
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	Other Contracting costs that were reclassed to other cost types	(54,588)	(68,109)	(77,861)	(88,583)	(84,548)
13	Contracting - Non-Ops	Outside counsel legal costs for various regulatory proceedings	2,475,623	1,569,086	1,510,686	1,493,306	1,459,986
14	Contracting - Outsourced	Legal governance and shareholder service contracting including stock plan adminstration, transfer agent fees and shareholder mailing costs	396	5,474	5,474	5,474	5,474
15	Staff Augmentation	Used for costs associated with contractors performing functions that are typically performed by Exelon employees	19,974	-	-	-	-
16	Insurance	Cost of company insurance for casualty damages	5,375	-	-	-	-
17	Regulatory Fees/Permits	Regulatory fees	181	-	-	-	-
18	Licensing and Telecom	Cost of software maintenance fees, application licenses, as well as charges for cell phones, PDAs, blackberries, pagers and other personal telecommunication devices	3,922	3,998	3,998	3,998	3,998
19	BSC Services	N/A	-	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	Seminars and training for professional development and industry peer workshops and meetings	5,159	5,498	5,498	5,498	5,498
23	Travel & Entertainment	Includes business travel related expenses, such as mileage reimbursement, car rental, railways, taxi, travel booking fees, etc. This account also includes meal expenses, tuition reimbursement, and costs associated with employee relocation	113,005	51,445	51,445	51,445	51,445
24	Memberships / Dues	Cost of industry and professional memberships for employees and the company (e.g., Utilities Enterprise Membership)	7,380	14,708	14,708	14,708	14,708
25	Charity / Contributions	N/A	-	-	-	-	-
26	Lobbying	N/A	-	-	-	-	-
27	Office Expense	Office supplies	34,292	24,990	24,990	24,990	24,990
28	Other Expenses	Other miscellaneous costs not specifically accounted for in other operating expense sub accounts	15,373	-	-	-	-
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	N/A	-	-	-	-	-
31	CIAC / CIAM	N/A	-	-	-	-	-
32	Facilities, Rentals, Utils	Allocated based on factors such as square footage and location	161,818	196,938	198,293	199,941	200,152
33	Transportation / Fleet	N/A	-	-	-	-	-
34	Depreciation & Amort	N/A	-	-	-	-	-
35	**Total Expense**		**$ 5,635,417**	**$ 4,646,026**	**$ 4,634,600**	**$ 4,651,915**	**$ 4,677,021**

Legal

VI - Headcount

Instructions:
List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt					
Pepco Non-Exempt					
Pepco Union					
Total Pepco	**-**	**-**	**-**	**-**	**-**
PHISCO Exempt	10	12	12	12	12
PHISCO Non-Exempt	7	8	8	8	8
PHISCO Union					
Total PHISCO	**17**	**20**	**20**	**20**	**20**

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2018-2022 Long Range Plan Documentation

VP Area: Regulatory

Vice President:

I – Approvals

This document has been checked for errors in calculations and content.

Prepared By: Date: 2/19/19

Approved By: Date: 2/21/19

Approved By: Date: 2/21/19
Vice President

II – Major Business Functions

The Regulatory department is responsible for developing and executing the overall regulatory strategic plan for PHI and managing all regulatory affairs related to PHI's utility business before the Maryland Public Service Commission (MD PSC), the Delaware Public Service Commission (DE PSC), the Public Service Commission of the District of Columbia (DC PSC), the New Jersey Board of Public Utilities (NJ BPU), and the Federal Energy Regulatory Commission (FERC). The regulatory department consists of the Regulatory, Energy Acquisition and Utility of the Future groups.

The Regulatory group activities include:

- Working with PHI leadership and Exelon Utilities to develop the annual regulatory strategic plan;
- Developing, enhancing and maintaining PHI's and Exelon Utilities' regulatory relationship with the regional Commissions, its Staff and Stakeholders;
- Developing and managing all distribution and transmission rate case filings;
- Managing all regulatory strategic initiatives and tariff-related filings;
- Monitoring all regulatory assets and liabilities;
- Interacting with Financial Planning, Investor Relations and Corporate Communications to provide all required financial information;
- Working with all other business units of the company on regulatory matters, strategies, policies and special projects.

The Energy Acquisition group provides customers with the lowest available energy prices and meets suppliers' expectations through high quality settlements, superior services, innovation in procurement processes and transformational leadership.

The PHI Utility of the Future (UOTF) group is focused on development of strategy and policy enabling effective integration of technologies and services which will define the energy services platform in the near future. The UOTF group examines opportunities which will deliver value to our customers while maintaining the reliability and safety of the electric distribution grid. The UOTF group also consists of the Utility OpCo Compliance team, which is responsible for regulatory compliance reporting and support of various regulatory proceedings.

See below for a further detailed description of each department/main areas of responsibility within Regulatory:

Regulatory Affairs – This group is responsible for ensuring regulatory compliance including maintaining and operating the Regulatory Compliance System, coordination with internal personnel on the development of compliance filings; including the case management of base rate case filings and making the appropriate regulatory filings. In addition, the team develops and maintains cooperative and effective relationships with the MD PSC, the DE PSC, the DC PSC, the NJ BPU, and the FERC.

Regulatory Strategy and Revenue Policy – The Regulatory Strategy and Revenue Policy group oversees, develops, and recommends strategies for various regulatory initiatives and product lines and manages Electric Distribution Rate Cases and Gas Rate Cases with DC PSC, MD PSC, DE PSC, and NJ BPU as well as Transmission Rate Cases with FERC. Specifically, the team develops, communicates and implements short-term and long-term regulatory strategies, actively participates in various Commission rulemaking and policies, develops long-term strategies on various issues to ensure appropriate cost recovery, and initiates and manages rate cases.

Pricing and Regulatory Services – The Pricing and Regulatory Services team oversees, develops and maintains all non-distribution related rates for Pepco, Delmarva Power (DPL), and

Atlantic City Electric (ACE). In this role, it provides central Company oversight for the application and administration of non-distribution related rate case proceedings and ensures timely recovery of deferred balances. The team is also responsible for Sarbanes-Oxley related activity on the Regulatory team.

Regulatory Analysis – The Regulatory Analysis team evaluates the requirements of future rate cases to ensure financial health of Pepco, DPL, and ACE. The team works closely with cross-functional teams in the development of business strategies and the preparation of business case analysis for presentations to senior management, ensuring regulatory aspects are fully addressed. This group also is involved in external reporting on regulatory matters, including coordination, development and primary certification of SEC reports on regulatory matters, information developed for quarterly earnings calls, development of regulatory information for ratings agencies, and similar requests for regulatory information. The team also supports the Policy Witness in Base Rate Case filings, works closely with the Financial Operations team on the Pepco, DPL, and ACE long-range plans (LRPs), and performs various financial ad hoc analysis as requested.

Power Procurement – This group is responsible for managing the electricity auction process in each PHI jurisdiction.

Gas Procurement – Gas Procurement is primarily responsible for procuring natural gas and interstate pipeline transportation and storage capacity to provide gas services to customers in accordance with the applicable Gas Service Tariff.

Load Research and Settlements – Load Research and Settlements is responsible for comprehensive analysis and execution of energy supply services related to Standard Offer Service (SOS), Basic Generation Service Contracts (BGS) and PJM invoices for Pepco, DPL and ACE, as well as the verification and validation process for PHI's zonal load for its three operating companies' zones (Pepco, DPL and ACE).

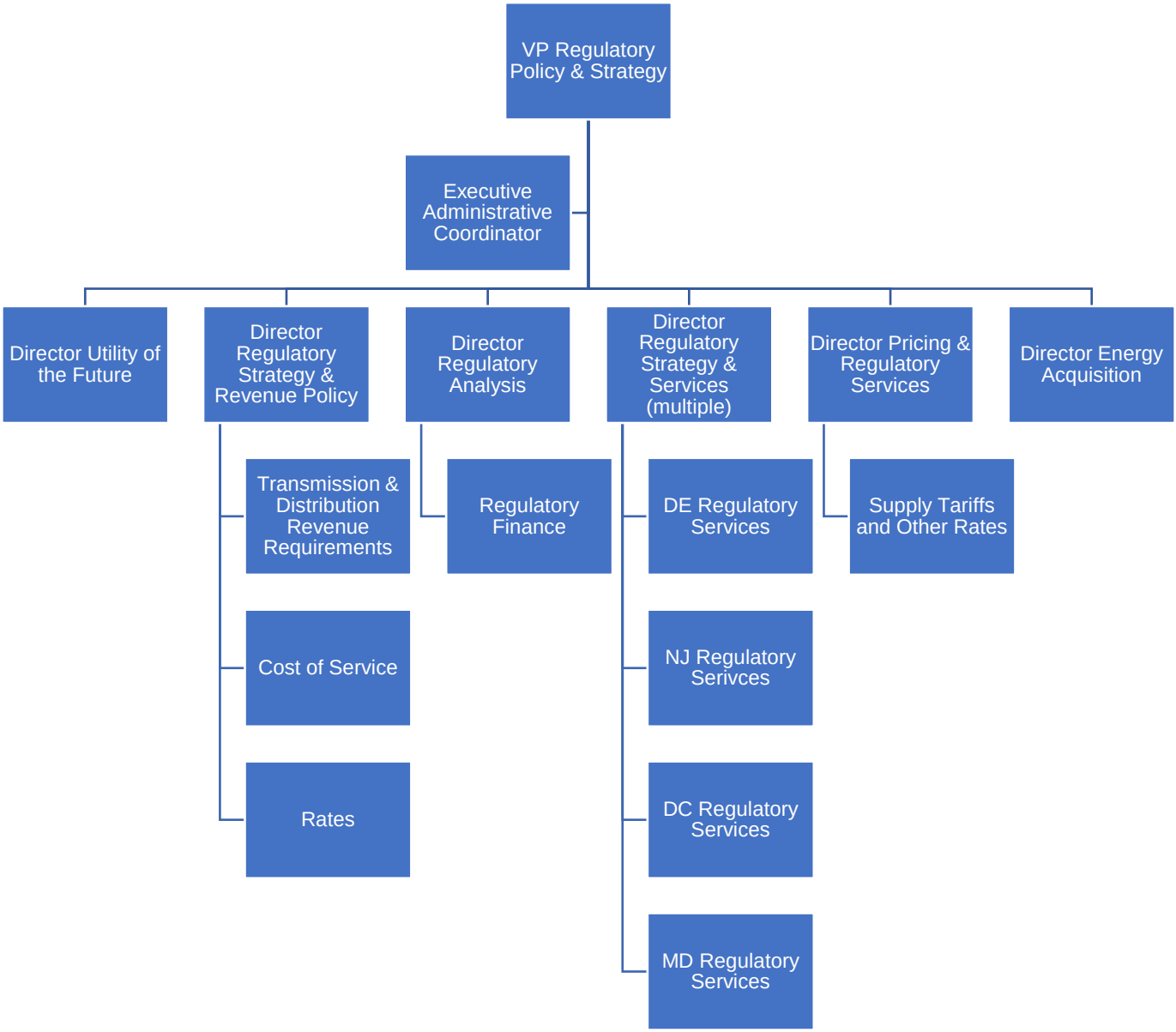
Energy Supplier Services – Energy Supplier Services establishes and maintains retail third party supplier relationships, administers Supplier Agreements and Creditworthiness, responds to internal and external inquiries (telephone hotline, state/brand specific email boxes); manages issue/dispute resolution process, manages retail supplier communication (proactive/reactive), acts as subject matter experts in support of regulatory initiatives (working groups, proceedings, filings), and implements regulatory directives/orders.

Supply Customer Energy Strategic Planning – This group is responsible for DPL Delaware's Renewable Portfolio Standards (RPS), procuring Renewable Energy Credits (RECs) for all distribution customers, completing the Delaware IRP (Integrated Resource Plan) every 2 years, investigating all potential opportunities for diverse and reliable supply, including those that create environmental benefits for Delaware, seeking to meet its customer's energy supply needs "at the lowest reasonable cost" and "at a minimal cost," coordinating dispatch of PHI's Demand Response Programs, managing Non-Utility Generation Contracts, and managing the Qualified Fuel Cell Program (Bloomenergy).

Utility of the Future – This group's objective, although new to PHI's organizational structure, plans to leverage the existing Exelon Utilities framework for the move to an efficient and evolving electric power system. In addition, the group will identify and examine disruptors that will transform the business, research/evaluate the business potential and opportunity for new technologies and service offerings, provide guidance and support on developing strategic plans to appropriate business areas for execution, and support various regulatory filings.

III – Home Center Hierarchy

The below diagram provides a high-level overview of the Regulatory organization.



IV – Major Programs

Pepco's Regulatory department has budgeted roughly $2.3 million in contractor related expenses mainly related to legal contractor costs used for reviewing and providing input to data requests and testimony and professional consulting costs used for hiring outside witnesses, such our Cost of Capital witness, to support the Pepco DC and MD Base Rate Case initiatives anticipated to occur in 2018/2019, as well as our Transmission formula rate filing. Base Rate Cases are vital to the Company's success as they are filed to recover investments made toward maintaining and improving the electric distribution infrastructure and other costs essential in providing safe and reliable service to customers.

The Utility of the Future group budgeted $400,000 of contractor related costs to support the Systems Dynamic Pricing Model. The Systems Dynamic Pricing Model is an application used to address challenges of understanding and planning for the Utility of the Future environment, as the traditional utility business model has rapidly been evolving.

Pepco's Energy Acquisition department has budgeted $1 million to support advertising for Demand Response Programs. These programs provide an opportunity for customers to play an important role in the operations of the electric grid by reducing or shifting their electricity during peak periods, which helps control the supply and demand of electricity.

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2018-2022 Long Range Plan Documentation

VP Area: Regulatory

Vice President:

Regulatory

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	Approx. 52% work on filings; 31% on supply activities (power procurement, load settlements, gas procurement), 11% on Utility of the Future, and 6% on other regulatory activities	5,165,174	6,137,046	6,314,506	6,437,668	6,583,694
2	Overtime	Administrative wages that exceed base payroll	6,053	13,849	13,860	13,860	13,860
3	Incentive	Formulaic based on key performance indicators in Annual Incentive Plans	1,070,699	1,025,652	1,063,762	1,084,476	1,116,053
4	Pension and OPEB	Function of payroll based on actuarial study	1,218,264	1,446,254	1,394,161	1,357,031	1,330,644
5	Fringe Benefits	Function of payroll based on headcount	969,299	1,007,330	1,050,366	1,093,354	1,141,331
6	Other Premium	Primarily long-term incentive plan for key managers and above; also includes other awards	358,620	393,487	404,638	393,801	393,801
7	Stock Compensation	Payroll costs not directly associated with hours worked. Includes Pshares, Restricted Stock, & Stock Option compensation costs	297,908	210,346	174,171	162,328	162,328
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	Function of payroll: includes federal unemployment, federal social security, state unemployment	351,748	476,269	489,609	499,200	510,482
10	Materials	Office supplies, especially technology accessories such as headsets, computer memory, etc.	12,832	842	858	881	891
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	Contains contracting activity of the skilled labor nature that supports normal business operations	39,139	12,410	12,737	13,071	13,418
13	Contracting - Non-Ops	Consultant and expert witnesses for regulatory proceedings (including external legal fees, audit fees, Public Service Commission fees), Other Services (FedEX, Intercall, Media expense, etc.) and Advertising for Demand Response Programs	2,385,280	4,019,381	4,101,026	4,181,596	4,265,929
14	Contracting - Outsourced	N/A	37,294	-	-	-	-
15	Staff Augmentation	Used for costs associated with contractors performing functions that are typically performed by Exelon employees and also includes dollars budgeted for interns	33,756	83,648	85,482	87,365	89,300
16	Insurance	N/A	-	-	-	-	-
17	Regulatory Fees/Permits	Costs related to DC Deposit Orders	250	-	-	-	-
18	Licensing and Telecom	Cost of software maintenance fees, application licenses, as well as charges for cell phones, PDAs, blackberries, pagers and other personal telecommunication devices that are passed through from BSC.	106,992	98,572	101,140	104,070	106,777
19	BSC Services	N/A	-	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	Seminars and training for professional development and industry peer workshops and meetings	38,508	59,529	61,114	63,363	65,034
23	Travel & Entertainment	Includes business traveling related expenses, such as mileage reimbursement, car rental, railways, taxi, travel booking fees, etc. This account also includes meal expenses, tuition reimbursement, and costs associated with employee relocation	205,521	260,395	265,630	272,367	277,850
24	Memberships / Dues	Cost of industry and professional memberships for employees and the company (Ex. Utilities Enterprise Membership)	27,581	25,519	28,421	25,581	25,612
25	Charity / Contributions	N/A	-	-	-	-	-
26	Lobbying	N/A	-	-	-	-	-
27	Office Expense	Supplies	175,814	116,371	119,481	122,939	126,227
28	Other Expenses	Other miscellaneous costs not specifically accounted for in other operating expense sub accounts	500,323	23,856	24,513	25,131	25,799
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	N/A	-	-	-	-	-
31	CIAC / CIAM	N/A	-	-	-	-	-
32	Facilities, Rentals, Utils	Allocated based on factors such as square footage and location	533,967	600,284	610,279	621,546	624,477
33	Transportation / Fleet	Costs related to vehicle charges, rental car costs, and allocation of overhead fleet service costs	22,465	23,853	26,172	26,778	28,114
34	Depreciation & Amort	Remaining amortization of Lodestar system	-	-	-	-	-
35	**Total Expense**		**$ 13,557,485**	**$ 16,034,893**	**$ 16,341,925**	**$ 16,586,407**	**$ 16,901,624**

Regulatory

VI - Headcount

Instructions:

List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt	11	13	13	13	13
Pepco Non-Exempt					
Pepco Union					
Total Pepco	**11**	**13**	**13**	**13**	**13**
PHISCO Exempt	88	96	96	96	96
PHISCO Non-Exempt					
PHISCO Union					
Total PHISCO	**88**	**96**	**96**	**96**	**96**

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An Exelon Company

2018-2022 Long Range Plan Documentation

VP Area: Supply Operations

Director:

I – Approvals

This document has been checked for errors in calculations and content.

Prepared By: Date: February 22, 2019

Approved By: Date: February 22, 2019
Director

II – Major Business Functions

Supply Operations — Materials Management including Warehousing and Purchasing

- **Material Availability** provides purchasing activities to ensure inventory is available at all PHI storerooms and for PHI projects. Also provides guidance for the control of emergency reserve inventory and slow-moving/obsolete materials. The department utilizes processes and tools to ensure appropriate inventory levels. Activities include:
    - Purchasing material needed for projects or replenishment in the warehouses via a blanket purchase order or a straight purchase order if not a reoccurring purchase
    - Management of the inventory levels for each warehouse—safety stock level and maximum to keep on hand to address any emergent jobs that must be addressed by Operations
    - Coordination with warehouse personnel on the identification and removal of obsolete material
    - Purchase of seasonal readiness material

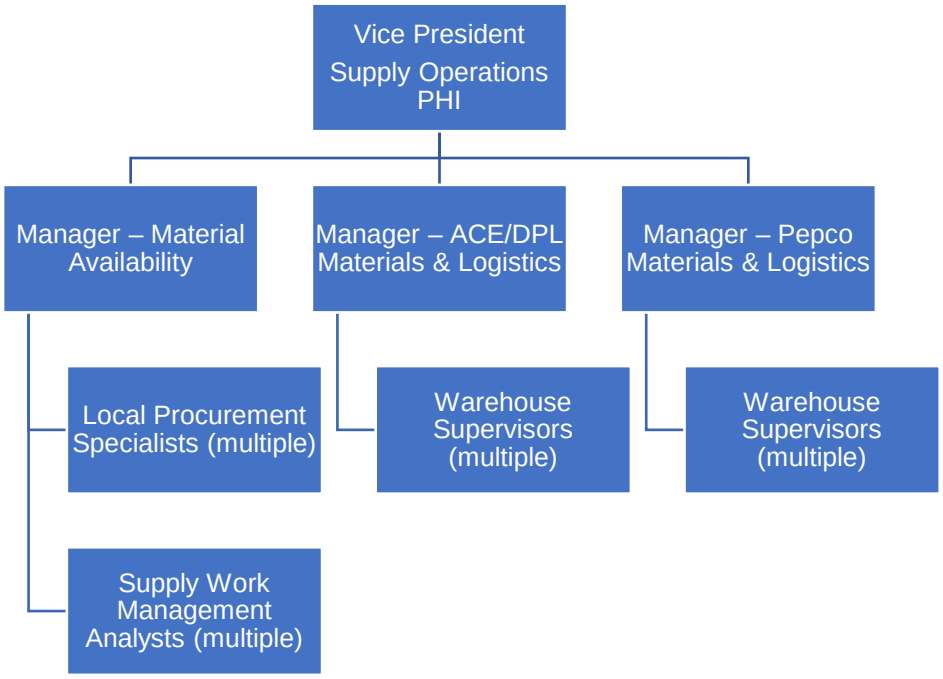
- **Warehouse Operations** assures that the receipt, storage, issuance, inventory accuracy, and delivery of materials are accomplished and secure in a manner to help prevent loss or damage.

  The following processes address the business partner needs through the implementation of:
    - **Material Issuance** – process for picking and issuing construction materials for company and contractor construction crews.
    - **Material Storage** – process for storage and inventory of utility materials and to ensure compliance in respect to the safe storage of hazardous and other materials.
    - **Material Return** - process used to ensure that previously issued materials are returned to the warehouse in a controlled manner and ensure that credits are appropriately applied. Disposition of returned materials includes return to stock, identification as surplus, or as obsolete equipment.
    - **Seasonal Readiness** – material preparation to enhance customer service and operations during the summer and winter periods
    - **Emergency Response** – planning and actions to ensure that the right materials/services are available at the right time and in the right place in response to emergency conditions.
    - **Material Delivery**- process used to load, secure and transport materials to and from PHI warehouses and/or job sites. Includes emergency delivery, job site delivery, and warehouse replenishments.

- **General Shops** performs fabrication services for over one hundred stock items, fabricates steel structures for PHI substations, completes tool repair services for Pepco Operations, and performs rubber goods testing for Pepco Operations and Engineering.

III – Home Center Hierarchy

The below diagram depicts a high-level overview of the Supply Operations department.



IV – Major Programs

There are two significant O&M programs related to Supply Operations:

1. Central Procurement Team – this organization within Supply will be created to support commodities across all six Exelon utilities to streamline processes. The end state will be a reduction of five FTE's across Exelon.

2. Storeroom Productivity – due to better material planning from the business and vendor efficiencies, we expect productivity efficiency reductions across the PHI storerooms.

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2018-2022 Long Range Plan Documentation

VP Area: Supply Operations

Director:

Supply Operations

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	Material issuance/receiving (30%), Material Delivery (20%), Material Ordering (15%), Inventory Counts (10%), SOX/Environmental Compliance (10%), Material Fabrication (8%), Special Projects/Administrative (5%) Rubber goods testing (2%)	991,099	816,883	747,695	668,577	682,599
2	Overtime	Administrative wages that exceed base payroll	87,861	-	-	-	-
3	Incentive	Formulaic based on key performance indicators in Annual Incentive Plans	56,572	38,884	35,527	31,938	32,782
4	Pension and OPEB	Function of payroll based on actuarial study	57,027	163,799	136,232	110,861	100,532
5	Fringe Benefits	Function of payroll based on headcount	237,240	178,865	165,304	150,597	156,889
6	Other Premium	Primarily long-term incentive plan for key managers and above; also includes other awards such as retention or signing bonuses	(40,454)	-	-	-	-
7	Stock Compensation	Payroll costs not directly associated with hours worked. Includes Pshares, Restricted Stock, & Stock Option compensation costs	-	-	-	-	-
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	Function of payroll: includes federal unemployment, federal social security, state unemployment	(2,236)	-	-	-	-
10	Materials	Material costs are related to safety gear, material handling equipment, and costs for storage materials (i.e., pallet racks); also includes credits that the shops receive when they credit material they fabricate into the inventory	70,277	(180,000)	(180,000)	32,568	32,568
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	Contractor costs are primarily related to specialized crane and rigging/hauling services when large pieces of material are received or transported	28,527	-	-	-	-
13	Contracting - Non-Ops	Contractor costs are primarily related to specialized crane and rigging/hauling services when large pieces of material are received or transported	64,275	60,000	60,000	60,000	60,000
14	Contracting - Outsourced	Other Contracting	558	-	-	-	-
15	Staff Augmentation	Used for costs associated with contractors performing functions that are typically performed by Exelon employees	(2,800)	-	-	-	-
16	Insurance	N/A	-	-	-	-	-
17	Regulatory Fees/Permits	N/A	-	-	-	-	-
18	Licensing and Telecom	Cost of software maintenance fees, application licenses, as well as charges for cell phones, PDAs, blackberries, pagers and other personal telecommunication devices	4,231	4,800	4,800	4,800	4,800
19	BSC Services	N/A	-	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	Seminars and training for professional development and industry peer workshops and meetings	-	-	-	-	-
23	Travel & Entertainment	Includes business travel related expenses, such as mileage reimbursement, car rental, railways, taxi, travel booking fees, etc. This account also includes meal expenses, tuition reimbursement, and costs associated with employee relocation	9,973	5,400	5,400	5,400	5,400
24	Memberships / Dues	Cost of industry and professional memberships for employees and the company (e.g., Utilities Enterprise Membership)	902	-	-	-	-
25	Charity / Contributions	N/A	-	-	-	-	-
26	Lobbying	N/A	-	-	-	-	-
27	Office Expense	Office supplies	903	2,400	2,400	2,400	2,400
28	Other Expenses	Other miscellaneous costs not specifically accounted for in other operating expense sub accounts	5,656	-	-	-	-
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	N/A	-	-	-	-	-
31	CIAC / CIAM	N/A	-	-	-	-	-
32	Facilities, Rentals, Utils	Allocated based on factors such as square footage and location	871,359	450,711	458,477	463,540	469,239
33	Transportation / Fleet	Costs related to vehicle charges, rental car costs, and allocation of overhead fleet service costs	87,583	55,046	59,964	60,858	62,817
34	Depreciation & Amort	N/A	-	-	-	-	-
35	**Total Expense**		**$ 2,528,552**	**$ 1,596,786**	**$ 1,495,799**	**$ 1,591,539**	**$ 1,610,025**

Supply Operations

VI - Headcount

Instructions:
List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt	5	5	5	5	5
Pepco Non-Exempt					
Pepco Union	45	48	43	38	38
Total Pepco	**50**	**53**	**48**	**43**	**43**
PHISCO Exempt	13	11	8	8	8
PHISCO Non-Exempt	1	1	1	1	1
PHISCO Union					
Total PHISCO	**14**	**12**	**9**	**9**	**9**

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2018-2022 Long Range Plan Documentation

VP Area: Treasury Operations

Vice President:

Treasury Operations

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	N/A	-	-	-	-	-
2	Overtime	N/A	-	-	-	-	-
3	Incentive	N/A	-	-	-	-	-
4	Pension and OPEB	N/A	-	-	-	-	-
5	Fringe Benefits	N/A	-	-	-	-	-
6	Other Premium	N/A	-	-	-	-	-
7	Stock Compensation	N/A	-	-	-	-	-
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	N/A	-	-	-	-	-
10	Materials	N/A	-	-	-	-	-
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	N/A	-	-	-	-	-
13	Contracting - Non-Ops	N/A	-	-	-	-	-
14	Contracting - Outsourced	N/A	-	-	-	-	-
15	Staff Augmentation	N/A	-	-	-	-	-
16	Insurance	N/A	-	-	-	-	-
17	Regulatory Fees/Permits	N/A	-	-	-	-	-
18	Licensing and Telecom	N/A	-	-	-	-	-
19	BSC Services	N/A	-	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	N/A	-	-	-	-	-
23	Travel & Entertainment	N/A	-	-	-	-	-
24	Memberships / Dues	N/A	-	-	-	-	-
25	Charity / Contributions	N/A	-	-	-	-	-
26	Lobbying	N/A	-	-	-	-	-
27	Office Expense	Supplies	47	-	-	-	-
28	Other Expenses	Bank fees	495,108	1,411,303	1,455,039	1,462,039	1,469,039
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	N/A	-	-	-	-	-
31	CIAC / CIAM	N/A	-	-	-	-	-
32	Facilities, Rentals, Utils	N/A	-	-	-	-	-
33	Transportation / Fleet	N/A	-	-	-	-	-
34	Depreciation & Amort	N/A	-	-	-	-	-
35	**Total Expense**		**$ 495,156**	**$ 1,411,303**	**$ 1,455,039**	**$ 1,462,039**	**$ 1,469,039**

Treasury Operations

VI - Headcount

Instructions:
List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt					
Pepco Non-Exempt					
Pepco Union					
Total Pepco	-	-	-	-	-
PHISCO Exempt					
PHISCO Non-Exempt					
PHISCO Union					
Total PHISCO	-	-	-	-	-

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2018-2022 Long Range Plan Documentation

VP Area: Depreciation and Amortization

Manager/Director:

Depreciation and Amortization

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	N/A	-	-	-	-	-
2	Overtime	N/A	-	-	-	-	-
3	Incentive	N/A	-	-	-	-	-
4	Pension and OPEB	N/A	-	-	-	-	-
5	Fringe Benefits	N/A	-	-	-	-	-
6	Other Premium	N/A	-	-	-	-	-
7	Stock Compensation	N/A	-	-	-	-	-
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	N/A	-	-	-	-	-
10	Materials	N/A	-	-	-	-	-
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	N/A	-	-	-	-	-
13	Contracting - Non-Ops	N/A	-	-	-	-	-
14	Contracting - Outsourced	N/A	-	-	-	-	-
15	Staff Augmentation	N/A	-	-	-	-	-
16	Insurance	N/A	-	-	-	-	-
17	Regulatory Fees/Permits	N/A	-	-	-	-	-
18	Licensing and Telecom	N/A	-	-	-	-	-
19	BSC Services	N/A	-	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	N/A	-	-	-	-	-
23	Travel & Entertainment	N/A	-	-	-	-	-
24	Memberships / Dues	N/A	-	-	-	-	-
25	Charity / Contributions	N/A	-	-	-	-	-
26	Lobbying	N/A	-	-	-	-	-
27	Office Expense	N/A	-	-	-	-	-
28	Other Expenses	N/A	-	-	-	-	-
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	N/A	-	-	-	-	-
31	CIAC / CIAM	N/A	-	-	-	-	-
32	Facilities, Rentals, Utils	N/A	-	-	-	-	-
33	Transportation / Fleet	N/A	-	-	-	-	-
34	Depreciation & Amort	Depreciation and amortization expense	17,005,156	16,338,845	14,074,561	12,559,456	11,640,465
35	**Total Expense**		**$ 17,005,156**	**$ 16,338,845**	**$ 14,074,561**	**$ 12,559,456**	**$ 11,640,465**

Depreciation and Amortization

VI - Headcount

Instructions:
List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt					
Pepco Non-Exempt					
Pepco Union					
Total Pepco	-	-	-	-	-
PHISCO Exempt					
PHISCO Non-Exempt					
PHISCO Union					
Total PHISCO	-	-	-	-	-

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2018-2022 Long Range Plan Documentation

VP Area: Business Services Company – Non-IT

Manager/Director:

Business Services Company – Non-IT

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	BSC - Exelon Utilities	Utility-focused corporate governance and oversight function to facilitate collaboration among the utilities to achieve the highest standards of organizational effectiveness, operational excellence, financial discipline and efficiency, customer and stakeholder satisfaction, and NERC Compliance	6,765,326	6,873,145	7,443,314	7,528,294	6,650,548
2	Communications	Enables Exelon and its operating companies to successfully pursue business goals and objectives by developing and providing strategic direction, management and support. This partnership helps strengthen and sustain communications and understanding among employees, customers, policymakers and the communities we serve through execution of external and internal communications initiatives and programs.	2,118,591	2,144,366	1,378,690	1,402,342	1,477,527
3	Corporate Strategy	Strategic support for senior leadership; program leadership for Exelon's sustainable business strategy; and corporate-wide governance, oversight and support for the innovation, environment and safety functions	1,553,584	1,630,700	1,657,580	1,674,824	1,693,763
4	Development	Expertise and governance in the evaluation and execution of merger and acquisition opportunities, evaluate company assets for divesture opportunities, and provide financial and transactional support for complex transactions and restructuring projects.	507,865	662,229	670,622	679,939	685,136
5	Executive Services	Strategy, policy, governance and oversight of overall business performance to optimize overall business value while improving and enhancing customer experience and allowing business unit autonomy and accountability.	5,466,884	4,723,114	4,231,383	3,892,451	3,572,771
6	Finance	Create collaborative processes between business units on business strategy and financial decisions; align finance functions through a common structure and standard policies, practices and processes; drive cost savings through the elimination of redundant and non-value added work; provide governance and risk management; and provide financial analysis and decision support to our business partners	14,830,853	13,822,790	13,842,471	14,147,054	14,506,067
7	Govt Affairs and Public Policy	Advance policies, regulatory initiatives and market designs that enhance Pepco's customer value and also build sustainable business value. Key initiatives focus on providing energy to customers that is clean, affordable, reliable, and resilient. We also pursue policies that foster innovation and enhance the ability of Pepco to offer additional services	1,814,863	1,555,842	1,506,673	1,527,978	1,543,685
8	Human Resources	Centralizes and consolidates HR governance and oversight as well as aligns HR strategies, practices and services with customer and business requirements. Enables the design and implementation of common policies, systems and processes that: support the strategic objectives of the company, drive high performance and employee engagement, enhance workforce effectiveness, and build a platform for success through operational effectiveness and superior talent	6,030,433	5,986,930	5,914,109	5,935,896	5,938,744
9	Investments	Services include: determining the investment strategy and asset allocation of Exelon's pension funds, VEBA post retirement funds and nuclear decommissioning funds; staffing investment managers; managing daily investment activities; due diligence and monitoring; operational and back office activities; and maintaining a well diversified investment menu for the Employee Savings Plans	291,995	238,965	196,931	177,572	179,832
10	Legal	Provide governance, management and support services, including services for Subsidiaries' boards of directors, as required, legal counseling for securities matters and corporate finance; manage the Ethics and Compliance Program, including the Audit Committee's process for receiving and investigating concerns about potential violations of the Code of Business Conduct; manage the shareholder service function; coordinate the development of corporate policies and the Management Model; and coordinate records management, subsidiary management and the FERC Interlock processes	3,457,546	2,515,046	2,580,805	2,621,214	2,656,533
11	Other BSC	Taxes, interest on intercompany loans, severance, overall billings revenue adjustment	4,016,051	**2,280,743**	**2,514,394**	**2,823,807**	**3,081,526**
12	Risk	Provide governance and oversight of enterprise risk management and credit risk management	1,049,859	1,043,017	1,061,845	1,068,731	1,080,883
13	Security Baseline	Will be known as BSC Corporate & Information Security Services ("CISS") moving forward and this practice area provides governance and functional oversight for physical and cyber security controls and services.	3,696,465	4,501,753	4,583,779	4,670,549	4,724,528
14	Supply	Provide strategic sourcing, supply operational support, accounts payable invoice processing, the credit card program (expense reimbursements), and supply business operations and technical services	801,427	476,662	465,696	494,453	504,949
15	Transportation	Provide private flight transportation to authorized personnel	2,809	89,988	87,099	78,272	72,680
16	EGB	Coordinates with and supports the business to accelerate adoption of emerging technologies and business models to drive productivity, efficiency, and cost savings.	728,748	818,232	825,557	825,557	825,557
17	Security Controls	Governance and oversight of physical and cyber security controls	476,792	550,149	256,754	208,988	208,988
18	Security Projects	Planning, design, and implementation of physical and cyber security projects	280,853	192,560	259,212	218,563	207,355
19	CTAs	Costs to achieve are integration costs that are related to PHI during the Exelon integration efforts and are necessary in order to achieve synergy savings.	1,530,855	-	-	-	-
20	CTO	Costs to optimize are one-time costs that enable cost optimization	2,601,361	2,087,989	1,031,705	15,350	15,350
21	**Gross Total**		**$ 58,023,158**	**$ 52,194,219**	**$ 50,508,620**	**$ 49,991,835**	**$ 49,626,422**
22	Excl Amount Capitalized		(1,362,457)	(1,461,950)	(1,503,797)	(1,511,709)	(1,520,079)
23	**Net Total**		**$ 56,660,701**	**$ 50,732,269**	**$ 49,004,823**	**$ 48,480,126**	**$ 48,106,343**

Business Services Company – Non-IT

VI - Headcount

Instructions:
List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt					
Pepco Non-Exempt					
Pepco Union					
Total Pepco	-	-	-	-	-
PHISCO Exempt					
PHISCO Non-Exempt					
PHISCO Union					
Total PHISCO	-	-	-	-	-

P.S. Barnett
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (L) – 22

pepco.
An Exelon Company

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September 26, 2016

Ms. Brinda Westbrook-Sedgwick
Commission Secretary
Public Service Commission
of the District of Columbia
1325 G Street N.W., Suite 800
Washington, DC 20005

Re: Formal Case No. 1119

Dear Ms. Westbrook-Sedgwick:

Enclosed please find a revised PHI Service Company Integration Plan ("Plan") in the referenced proceeding. There was an error identified in Attachment 1 to the filing made on September 23, 2016. Attached is a corrected Plan, including the revised Attachment 1.

Please contact me if you have any questions.

Sincerely,

Dennis P. Jamouneau

DPJ/mda

Enclosure

cc: All Parties of Record

PHI SERVICE COMPANY INTEGRATION PLAN

The following describes the proposal of Exelon Corporation ("Exelon") and Potomac Electric Power Company ("Pepco" or the "Company") to address Commitment No. 88 of Attachment B of Order No. 18148[1] in Formal Case No. 1119. Commitment No. 88 addresses the integration of the PHI Service Company ("PHISCo"), which provides certain services to Pepco and other utility subsidiaries of Pepco Holdings LLC,[2] into the Exelon Business Service Company, LLC ("EBSC") and reads as follows:

> Immediately following the Merger close, PHISCo will remain as a subsidiary of PHI and will continue to perform functions and to maintain related assets currently involved in providing services exclusively to the PHI utilities. Other functions that are currently provided by PHISCo, including those that are provided to PHI utilities and other current subsidiaries, will be transferred to EBSC or another Exelon affiliate in a phased transition over a period of time following the Merger closing. To address concerns that there would be two service companies under the proposed Merger, Exelon will file a plan within six (6) months after the Merger's close for Commission approval to integrate PHISCo within EBSC and other entities. The plan to integrate PHISCo with EBSC shall not include any net transfer of PHISCo employees located in the District of Columbia pre-Merger to any location outside of the District, subject to the provisions of Paragraph 19.

Commitment No. 88 is focused on addressing concerns identified by the Commission in Order No. 17947, which initially denied the merger.[3] Specifically, in Order No. 17947, the Commission noted that the proposed merger would add a second service company, EBSC, even though the Commission and parties have already raised concerns about complexities surrounding the ability to verify the appropriate cost allocations from PHISCo to Pepco.[4] The Commission stated that "ensuring the proper allocation of service company costs … will require increased time and scrutiny on the part of the Commission and all of the companies involved."[5] Pepco and Exelon heard these concerns, and Commitment No. 88 is meant to address them.

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[1] *In the Matter of the Joint Application of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and New Special Purpose Entity, LLC for Authorization and Approval of Proposed Merger Transaction*, Formal Case No. 1119 (Mar. 23, 2016). The Commission issued Order 18148 (March 23, 2016) approving the merger with condition, and subsequently issued Order No. 18160 (April 4, 2016), correcting certain errors in Order No. 18148 and in Attachment B. Order No. 18160 however did not modify Commitment No. 88.

[2] Pepco Holdings LLC ("PHI") is also the parent company of Delmarva Power & Light Company that serves customers in Maryland and Delaware and Atlantic City Electric Company that serves customers in New Jersey.

[3] Order No. 17947 (Aug. 27, 2015).

[4] Order No. 17947 at P 195.

[5] *Id.*

In this filing, Pepco and Exelon present a plan for integration of nearly all PHISCo employees into EBSC ("Integration Plan") and an alternative option for Commission consideration to integrate only PHISCo employees in certain corporate functions into EBSC ("Alternative Plan"). EBSC is the Exelon Corporate Shared Service Company that provides, among other services, corporate management and administrative services to the Exelon affiliates.

In order to meet the requirements of another merger commitment, Commitment No. 73, it is not possible to completely eliminate PHISCo as a service company for PHI and the PHI utilities. Under Commitment No. 73, the PHI CEO and PHI senior officers who report directly to the PHI CEO may not hold positions as officers or employees of Exelon or an Exelon affiliate other than PHI, PHISCo, or the PHI utilities.[6] Therefore, a limited number of PHI executives will need to remain employed by PHISCo with the costs of their employment allocated to the PHI utilities.[7]

Under Pepco's proposed Integration Plan, nearly all functions currently being performed by PHISCo and employees related to those functions will be transferred to EBSC. The Integration Plan is consistent with the language of Commitment No. 88 and, following its implementation, nearly all service company costs allocated to Pepco will come from one service company, EBSC. However, the costs associated with the employees who must remain employed by PHISCo will be allocated from PHISCo to Pepco and the other PHI utilities.

The key aspects of the Integration Plan are explained in more detail in Section III of this filing. If approved, and as further explained in Section III, the following would occur:

- Transition employment of approximately 1,800 PHISCo employees
- Modify current EBSC allocation methods and billing ratios
- Potential transfer of PHISCo utility specific assets to PHI utilities, including to Pepco
- Potential transfer of PHISCo corporate assets to EBSC
- Change design and configuration of general ledger, work management, payroll and other IT systems

The timing of the completion of the Integration Plan will be dependent on the amount and types of integration activities required under this Plan, which are described more fully below, the timing of other integration projects, and receiving approval for the plan. Pepco and Exelon

[6] See Order No. 18148 in Case No. 1119, Paragraph 73 in Attachment B, Page No. 16, entered by the District of Columbia Public Service Commission on March 23, 2016; This is also a condition of the merger approval in Maryland, New Jersey and Delaware. See Order No. 86990 in Case No. 9361, Condition 30 in Appendix A, Page No. A - 32, entered by the Maryland Public Service Commission on May 15, 2015; See Stipulation of Settlement in Docket No. EM14060581, Paragraph 41, Page No. 15, entered by the New Jersey Board of Public Utilities on January 7, 2015. See the Amended Settlement Agreement as approved by Order No. 8746 in Docket No. 14-193, Paragraph 30, Page No. 8, entered by the Delaware Public Service Commission on June 2, 2015.

[7] This structure was also one of the facts relied upon in the nonconsolidation opinion provided in compliance with Condition No. 92. *See* "Non-Consolidation Opinion" letter, Formal Case No. 1119, page 4, P13 (July 5, 2016).

currently estimate that implementation would be complete by March 31, 2018 if Commission approval of the Integration Plan as presented is given by February 1, 2017 and no approvals from other jurisdictions are required.[8]

In addition to the proposed Integration Plan, Pepco also presents an Alternative Plan for Commission consideration. Under this Alternative Plan, only corporate shared service functions and related employees in PHISCo would be transferred to EBSC, while other functions that are more closely related to utility operations and the PHISCo employees dedicated to those functions would remain within PHISCo. The Alternative Plan presents various advantages including ease of integration, lower implementation costs, and alignment to EBSC and legacy Exelon utilities'[9] structure, and such alignment will facilitate benchmarking and operational comparisons between the utility companies.

As with the Integration Plan, the key aspects of this Alternative Plan are explained in more detail in this filing (Section IV). In order to effectuate the Alternative Plan, the following would occur:

- Transition employment of approximately 300 PHISCo employees to EBSC
- Modify some designs and configurations of general ledger, work management, payroll and other IT systems

Under the Alternative Plan, there would be limited or no transfers of assets from PHISCo and there would be minimal or no changes to the current cost allocation methods. The Alternative Plan, which aligns with the plans designed by the integration teams while the merger was pending and therefore initiated when the merger closed, could be completed by May 2017.

Under both the Integration Plan and the Alternative Plan, there will be no net transfer of PHISCo employees in the District of Columbia, and neither option prevents Pepco from fulfilling any of the other employee-related merger protections. In addition, the two plans do not affect employee physical work locations or utility-related job functions. Instead, the plans would transfer nearly all, or some, employees to a different corporate affiliate. Also, given that both plans would transfer at least some employees from PHISCo to EBSC, both plans would also necessitate changes to payroll and other Human Resource systems and records, and would move some employees outside of the ring-fenced entity, PH Holdco LLC.

Similarly, neither the Integration Plan nor the Alternative Plan completely eliminates the need for two service companies — and related allocations to Pepco from two service companies. The number of service company allocations to Pepco is expected to be the same under both plans. However, the Alternative Plan would structure the service companies such that core

[8] In either the Integration Plan or the Alternative Plan, some employees will be transferred by May 2017.

[9] Exelon's legacy electric distribution utilities are Commonwealth Edison Company ("ComEd"), which serves customers in Illinois; PECO Energy Company ("PECO"), serving customers in Pennsylvania; and Baltimore Gas and Electric Company ("BGE") which serves customers in Maryland.

utility support function costs allocated to Pepco would come from PHISCo and more general corporate function costs would come from EBSC, thus more clearly identifying the costs and potentially assisting in the understanding and review of the costs by external parties.

I. Current Structure of PHISCo

PHISCo provides shared operational and general and administrative support specific to PHI's three utilities (Atlantic City Electric Company, Pepco, and Delmarva Power & Light Company). These shared services span a variety of functions, including:

- Executive Management
- Procurement and Administrative Services
  - Includes security, vehicle and building maintenance, supply chain management, real estate services
- Financial Services
  - Includes accounts payable, payroll, asset and project accounting, budgeting, treasury and finance, risk management, financial and tax accounting
- Insurance Coverage and Services
- Human Resources
- Legal Services
- Audit Services
- Customer Services
  - Includes customer service centers, call centers, billing, credit and collections, metering services and systems, customer systems
- Information Technology
- Regulatory Affairs
- External Affairs
  - Includes corporate communications, employee communications, corporate contributions, governmental affairs
- Environmental Services
  - Includes oversight of environmental concerns relate to air, water, land, and waste and regulatory compliance
- Safety Services
- Regulated Electric and Gas Services
  - Includes system operations services, power procurement and planning, asset management, interconnection services, distribution/substation/transmission engineering, construction management, electric maintenance, and forestry

II. Current Structure of EBSC

EBSC is the Exelon shared service company that provides corporate management and administrative services to the Exelon affiliates including services such as:

- Executive Management
- Human Resources
- Financial Services
- Legal Services
- Corporate Strategy
- Insurance
- Information Technology, and
- Supply

Unlike PHISCo, EBSC does not provide services that are part of the direct utility operations of ComEd, PECO or BGE, such as customer services (call center operations, billing, and credit and collections) or shared regulated electric and gas services, as described above. The employees engaged in these operations for ComEd, PECO, and BGE are employees of the specific utility they support and the related costs are incurred directly by each utility and managed by each utility. Thus, the current EBSC structure facilitates comparison and benchmarking of ComEd, PECO, and BGE. The Alternative Plan best aligns to the current EBSC structure and would allow comparison and benchmarking for ComEd, PECO, BGE and PHI.

III. Integration Plan

The Integration Plan for PHISCo will include transferring nearly all employees and obligations[10] from PHISCo to EBSC. [11] The principal feature of this plan from an external perspective is that it would (with limited exceptions due to Commitment No. 73) distribute costs to Pepco from only one service company — EBSC. As stated above, the transfer of current PHISCo employees into EBSC will not conflict with the merger commitments related to employee benefits and will not result in a net transfer of PHI or PHISCo employees out of the District of Columbia.

[10] Such obligations include those related to current and past employees, such as pension and benefit obligations, as well as vendors performing services for PHISCo.

[11] The PHI CEO and senior officers of PHI who report directly to the PHI CEO must remain employed by PHISCo to fulfill Commitment No. 73 and the non-consolidation opinion.

The following are the key areas that will be impacted by this Integration Plan:

- Employee Impact:

  Approximately 1,800 employees,[12] which include approximately 350 union employees,[13] will be transferred from employment by PHISCo to employment by EBSC. This will require modifications to payroll and other Human Resource records and associated systems. This transfer will also result in a significant number of employees who directly support the operations of the PHI utilities to be moved outside of the ring-fenced entity, PH Holdco LLC, and into EBSC.

- PHISCo Structure:

  Following the integration, most service company costs allocated to Pepco will come from one service company, EBSC. However, PHISCo will be required to continue to have a small number of employees to fulfill the merger commitment that the PHI CEO and PHI senior officers who report directly to the PHI CEO may not be officers or employees of Exelon affiliates outside the ring-fencing structure. Because these employees will be supporting more than one PHI utility, PHISCo will continue as a shared service company and allocate a portion of these costs to Pepco.

- EBSC Structure:

  Following the integration, EBSC will continue to offer the same pre-merger corporate management and administrative services to all its affiliates. These EBSC "corporate services" will be expanded to include services to PHI. EBSC corporate services include areas that have consolidated tasks associated with all Exelon companies into one support team. For example, financial reporting, within the financial services area, is responsible for preparing Exelon's entire financial statement package. This team has been expanded to include PHI's information within this package.

  Additionally, EBSC will include a new area of services specific to the operations and support of only PHI's utilities. These PHI "operational services" would not be consolidated to include all Exelon affiliates. Comparable "operational services" are provided directly within Exelon's other operating utility affiliates (ComEd, PECO, and BGE). The PHI operational teams are dedicated to supporting efforts specifically relating to PHI. For example, Legal will have a team focused on supporting the regulatory issues for only PHI's utilities.

[12] As of January 1, 2016.
[13] Subject to any collective bargaining agreement modifications that are deemed necessary.

See Attachment 1, page 1, for a chart showing the future structure of PHISCo and EBSC under the Integration Plan.

This Integration Plan will result in an increase in activities billed within EBSC before being billed to PHI's utilities. This will not change the amount billed to Pepco, but will create a two-step billing process within EBSC. For example, corporate services such as IT will need to be billed to each of the EBSC PHI operational service areas within EBSC before the area costs are billed out to the PHI utilities. This intra-company billing is required so that the costs are assigned to and follow the PHI dedicated users of these IT services and because the PHI dedicated users of these IT services are in EBSC, while comparable users are within ComEd, BGE, PECO or other Exelon affiliates. This structure will limit the potential for Exelon's other utilities cross subsidizing PHI utilities.

- Asset Transfer and Regulatory:

  In addition to the integration of employees and other activity that will move to EBSC, assets that are recorded at PHISCo may need to be transferred to the respective PHI utilities or transferred to EBSC. These assets primarily consist of those related to Information Technology, the Customer Relationship Management and Billing platform, and office-related assets. If transfers of assets are required, Pepco will inform the Commission when such transfers are completed and will explain Pepco's District of Columbia share of the value of the assets. This filing would be made following Commission approval of the plan. For the other PHI utilities, transfers of assets may require regulatory approval. In addition, the commitments originally agreed upon by other PHI utilities contemplated PHISCo remaining in place and were approved prior to Order No. 18148. Accordingly, Exelon and PHI anticipate that the integration proposal in the District of Columbia will be addressed in the other jurisdictions and this filing will be provided to the other jurisdictions consistent with the requirements of those other jurisdictions.[14]

- Additional Impacts:

  This Integration Plan would also require additional system integration work that was not part of the initial integration activities that have occurred and are ongoing in the time period since the merger closed. The following IT systems would require additional design and configuration changes: General Ledger system, Accounts Payable and Supply systems, Payroll/HR systems, and other feeder systems such as Customer Billing and Work Management. Preliminary estimates of the incremental costs to perform the work outlined above are approximately $2 million.

[14] To the extent that another jurisdiction asserts approval authority for any changes to the structure of PHISCo approved by the Commission, timelines may need to be extended to accommodate that approval process.

- Timing

  Based on the amount and types of integration activities required under this Integration Plan, the timing of other integration projects, and the dependency of receiving approval for the plan, Pepco and Exelon currently estimate that implementation would be complete by March 31, 2018, if Commission approval of the Integration Plan as presented is given by February 1, 2017 and no approvals from other jurisdictions are required.

IV. Alternate Plan: Integration of Corporate Shared Services into EBSC

As an alternative to the Integration Plan described above, Pepco presents another option for the Commission's consideration. This Alternative Plan aligns with the initial integration plan that was implemented immediately following the consummation of the merger, and also aligns with the pre-merger corporate design for EBSC and ComEd, PECO and BGE.

Similar to the Integration Plan presented above, the Alternative Plan includes transferring only the current PHISCo corporate shared service areas to EBSC. These corporate shared service areas include the individuals of Human Resources, Finance, Legal, Corporate Strategy, Information Technology, and Supply who will now be responsible for supporting all Exelon affiliates. However, unlike the first option, the Alternative Plan leaves within PHISCo those operational functions that are dedicated to directly supporting only the PHI utilities such as customer service, billing, call centers, credit and collections, regulatory, and shared regulated electric and gas delivery services, including engineering, core systems, transmission, and asset and operational management. In addition, under this Alternative Plan, certain subsets of corporate shared services functions dedicated specifically to PHI would remain at PHISCo, including employees who are engaged in supporting the PHI utilities (but not other Exelon affiliates) in the areas of Legal, IT, Human Resources, Communications, Government Affairs, Finance, and Supply. This structure would align with the current structure of EBSC and its legacy utilities, ComEd, PECO, and BGE.

As explained below, while it is true that under this option Pepco would receive allocations of costs from two service companies, there are some advantages to this alternative structure, and no or minimal impact in terms of the amount and transparency of the costs being allocated to Pepco.

- Employee Impact:

  Only current PHISCo employees within shared service functions of EBSC supporting multiple Exelon affiliates (i.e., not dedicated to PHI) will become employees of EBSC as part of the overall system integration plan.

  It is estimated that approximately 300 employees[15] will be transferred to EBSC. The impact to employees is expected to be minimal and will result in approximately 1,500 employees remaining employed by PHISCo to provide services exclusively to the PHI utilities. Moreover, the merger commitments related to employee benefits and office locations will not be affected by the Alternative Plan. *See* Attachment 1, page 2 for a chart showing the impact to the future structure of PHISCo and EBSC under the Alternative Plan.

  The PHI executives who are required to remain employees of PHISCo under Commitment No. 73 will remain within the same legal entity as their employees. Those executives must remain employed at PHISCo under either alternative.

- PHISCO Structure:

  Under the Alternative Plan, PHISCo will remain as a service company under PHI. The services that will be provided by PHISCo will directly benefit only the PHI utilities. The plan to have two separate service companies will allow regulators and other stakeholders to identify the utility operations services specific to PHI's utilities being provided by PHISCo. This design also allows the employees of PHISCo who will support the PHI utilities to remain within the PHI holding company structure, which will emphasize that the roles and services provided are for the direct benefit of the PHI utilities, like Pepco, and will further limit the risk of cross subsidization of Exelon affiliates.

- EBSC Structure:

  EBSC will continue to offer the same pre-merger corporate management and administrative services to all its affiliates. EBSC's services will be consistently provided to all Exelon affiliates, including the PHI utilities.

[15] As of January 1, 2016.

- Asset Transfer and Regulatory:

  As discussed previously, no or minimal assets will be transferred under the Alternative Plan. As a result, PHISCo assets used in PHI utility operations will remain within the ring-fenced holding company structure. Also, the Alternative Plan is consistent with the initial post-merger integration plan that was developed and is currently being implemented. The Alternative Plan is also consistent with the plan discussed by the PHI utilities with their respective regulators in Delaware, New Jersey, and Maryland.

- Timing:

  The Alternative Plan would be implemented as part of the overall system integration project, which has an estimated completion date of May 2017.

PHI Service Company Structure
Department Changes Transfers Under Integration Plan

Function	Department	PHISCO	BSC
Executive	Executive Management	X	
Finance	Budget / Forecasting		X
	Accounts Payable		X
	Payroll Services		X
	Risk Management		X
	Controller Services -Reporting, Research		X
	Audit, Insurance, Tax, Treasury		X
Communications	Communications		X
Government Affairs	Government Affairs - Other		X
	Government Affairs - Federal		X
Human Resources	Human Resources - Administration, Corporate		X
	Human Resources - PHI		X
IT	IT Support/Systems - Customer Systems		X
	IT Support/Systems - Power Delivery		X
	IT Support/Systems - Corporate		X
Legal Services	Claims		X
	Legal Services - Regulatory		X
	Corporate Secretary		X
	Legal Services - Corporate		X
Regulatory Affairs	Regulatory Affairs		X
Operations	Asset Management		X
	Energy Supply		X
	Environmental Services		X
	Meter Services		X
	Customer Services		X
	Operations		X
	Performance Management		X
	Special Billing		X
	Support Services		X
	Vehicle Resource Management		X
Real Estate	Facilities / Real Estate Services		X
Security	Security Services - Corporate		X
	Security Services - PHI		X
Supply	Sourcing - Corporate		X
	Sourcing - PHI		X

PHI Service Company Structure
Department Changes Transfers Under Alternative Plan

Function	Department	PHISCO	BSC
Executive	Executive Management	X	
Finance	Budget / Forecasting	X	
	Accounts Payable		X
	Payroll Services		X
	Risk Management		X
	Controller Services -Reporting, Research		X
	Audit, Insurance, Tax, Treasury		X
Communications	Communications	X	
Government Affairs	Government Affairs - Other	X	
	Government Affairs - Federal		X
Human Resources	Human Resources - Administration, Corporate		X
	Human Resources - PHI	X	
IT	IT Support/Systems - Customer Systems	X	
	IT Support/Systems - Power Delivery	X	
	IT Support/Systems - Corporate		X
Legal Services	Claims	X	
	Legal Services - Regulatory	X	
	Corporate Secretary		X
	Legal Services - Corporate		X
Regulatory Affairs	Regulatory Affairs	X	
Operations	Asset Management	X	
	Energy Supply	X	
	Environmental Services	X	
	Meter Services	X	
	Customer Services	X	
	Operations	X	
	Performance Management	X	
	Special Billing	X	
	Support Services	X	
	Vehicle Resource Management	X	
Real Estate	Facilities / Real Estate Services	X	
Security	Security Services - Corporate		X
	Security Services - PHI	X	
Supply	Sourcing - Corporate		X
	Sourcing - PHI	X	

CERTIFICATE OF SERVICE

I hereby certify that a copy of a revised PHI Service Company Integration Plan, with a corrected attachment, was served this 26th day of September 2016 on all parties in Formal Case No. 1119 by electronic mail.

Ms. Brinda Westbrook-Sedgwick
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DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (M)

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EXECUTIVE SUMMARY - WILLIAM J. (BILL) SULLIVAN

This testimony presents the projected Operating and Maintenance (O&M) costs associated with operating the Potomac Electric Power Company (Pepco or the Company) electric distribution system in order to provide safe and reliable service to our customers. The electric distribution O&M costs are broken down according to cost drivers required to operate, construct, maintain and design the electric distribution system. The four (4) major cost drivers in the Electric Operations responsibility area, which comprise the majority of the overall projected costs are:

(1) Base payroll and associated benefits costs;

(2) Overtime;

(3) Field operations contracting support and facilities costs; and

(4) Leases.

These drivers are the result of the aggregate activity of work in each department in Pepco Electric Operations responsibility area. Table 1 shows the 2018 historical and budgeted and projected O&M costs for 2019 and 2020 through 2022 for the Pepco Electric Operations Responsibility Area.

ELECTRIC OPERATIONS RESPONSIBILITY AREA O&M SUMMARY

Table 1[1]

Historical	Bridge	Projection		
2018	**2019**	**2020**	**2021**	**2022**
$101,604,219	**$99,877,167**	**$87,154,987**	**$87,029,597**	**$87,227,128**

[1] The O&M costs reflected are total Pepco Company costs including the District of Columbia and Maryland. See the Direct Testimony of Company Witness Wolverton for the allocation of costs to the District of Columbia.

The Electric Operations responsibility area is divided into two sub-areas: Regional Electric Operations and Operations Control Center. There are six departments under the Regional Electric Operations sub-area. They are:

(1) The Benning Field Operations department;

(2) The Forestville Field Operations department;

(3) The Rockville Field Operations department;

(4) The Regional Engineering and Design department;

(5) The Work Management department; and

(6) The Business Planning and Support department.

In preparing its projections for the Multiyear Rate Plan (MRP) period 2020-2022, the Company analyzed its actual 2018 spending levels, considered underlying cost drivers and developed an assessment of future requirements. The Company also projected costs for 2019 which is a bridge year between 2018 historical costs and the MRP period.

In addition, this testimony identifies work requirements incremental to levels of historical spending and necessary to maintain the safe and reliable operations of the distribution system. Funding requirements for these new or more extensive work elements are forecasted based on historical spending plus incremental expense requirements for new or more extensive work elements.

POTOMAC EDISON POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF WILLIAM J. SULLIVAN
FORMAL CASE NO. 1156

I. INTRODUCTION

A. Witness Qualifications and Purpose of Testimony

Q1. Please state your name and position.

A1. My name is William J. (Bill) Sullivan and I am Vice President, Electric and Gas Operations of Pepco Holdings LLC (PHI). I am testifying on behalf of Pepco.

Q2. Please describe your professional experience and qualifications.

A2. I earned a bachelor's degree in Electrical Engineering and a master's degree in Engineering Management from Drexel University. Before joining Pepco Holdings in May 2017, I worked for PECO, Pennsylvania's largest electric and natural gas utility. I began my career in 1987 as a project engineer and advanced through numerous management positions in engineering, customer service, field services, meter services, accounts receivable, and electric operations. My most recent position, prior to my current role, was with Exelon Utilities as Director, Utility Performance and Integration, which I began in 2012. I also serve on the board of PECO Energy Benefits Association and am a 2003 graduate of Leadership Philadelphia.

Q3. What are your responsibilities as Vice President, Electric and Gas Operations of Pepco Holdings?

A3. I am responsible for the safe and reliable operation, design, construction and maintenance of the PHI electric distribution system. The Electric Operations responsibility area is divided into two sub-areas: Regional Electric Operations and Operations Control

Center. There are six departments under the Regional Electric Operations sub-area. The Pepco departments under my responsibility area include (1) Benning Field Operations, (2) Forestville Field Operations, (3) Rockville Field Operations, (4) Regional Engineering and Design, (5) Work Management, and (6) Business Planning and Support.

Q4. Have you previously submitted testimony to the Public Service Commission of the District of Columbia (Commission)?

A4. No.

Q5. Please state the purpose of your Direct Testimony.

A5. The purpose of my Direct Testimony is to support the O&M expenses for the Electric Operations responsibility area. As described later in this testimony, Pepco is expecting to hold ongoing O&M expenses relatively flat for the years 2018-2022, targeting efficiency improvements to offset a 2.5% escalation in corrective maintenance spending as well as increased spending in training, hiring and other activities.

As explained by Company Witness Wolverton, 2019 is a bridge year between 2018 historical costs and the MRP period beginning in 2020. The Company uses a projection for O&M expenditures for 2019 based upon its Long Range Plan (LRP). For 2020-2022, the MRP period, the Company also uses projections based on the LRP. My testimony provides an explanation of the Electric Operations responsibility areas 2018 actual O&M and expenses; and provides explanation of the key initiatives and cost drivers that impact O&M and are reflected in the LRP for Electric Operations for each of the years 2019 through 2022. My testimony and accompanying exhibits were prepared by me or under my direct supervision and control. The sources for my testimony and exhibits are Company records and public documents. I also rely upon my personal knowledge and experience.

Q6. How is your testimony organized?

A6. First, I will describe each department in the Electric Operations responsibility area. I will next discuss the key initiatives and undertakings that drove O&M costs for 2018. I will also discuss the key initiatives and efforts Electric Operations has planned for 2019 and the costs that are budgeted for 2019 to meet those initiatives. Finally, I will discuss the planned initiatives and projected costs for years 2020 through 2022.

Q7. Are you sponsoring any exhibits in this proceeding?

A7. Yes. I am supporting PEPCO (M)-1, which is a narrative description of the Electric Operations responsibility area and contains the Electric Operations Organizational Chart, and PEPCO (M)-2, which is the LRP documentation for the Electric Operations responsibility area. These exhibits provide details regarding the O&M cost levels I support in my testimony and provide greater understanding of the work performed by Electric Operations.

B. Description of Pepco's Electric Operations Responsibility Area

Q8. Please describe the role of Pepco's Electric Operations responsibility area?

A8. Pepco's Electric Operations responsibility area is tasked with safely and reliably operating, constructing and maintaining Pepco's electric distribution system. This effort encompasses:

1) Developing, implementing and administrating safety protocols - including industry safety best practices and Exelon's electric Lock-out, Tag-out (LOTO) program;
2) Hiring and training craft and technical personnel;
3) Designing and constructing portions of the electric distribution system;

4) Specifying, obtaining and maintaining specialized and industry standard tools, equipment and software; and

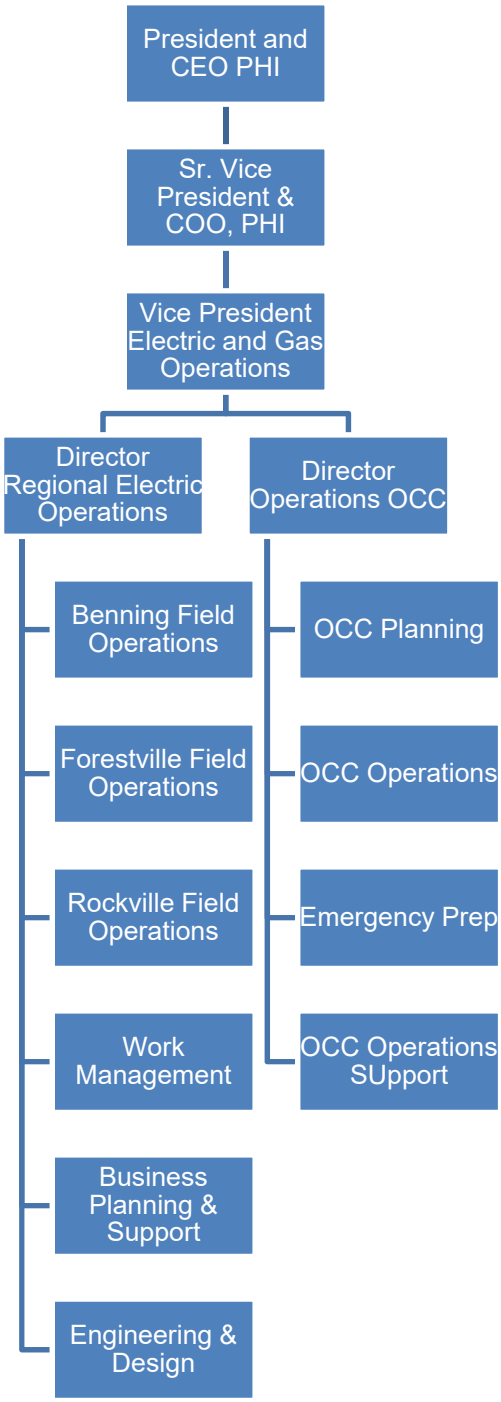
5) Developing safety and operating practices and standards to perform to a standard of excellence.

Q9. How is the Electric Operations responsibility area structured?

A9. The Electric Operations responsibility area is divided into two sub-areas: Regional Electric Operations and Operations Control Center. There are six departments under the Regional Electric Operations sub-area. They are: 1) Benning Field Operations, 2) Forestville Field Operations, 3) Rockville Field Operations, 4) Regional Engineering and Design, 5) Work Management, and 6) Business Planning and Support.

Table 2 provides a high-level overview of the Pepco Electric Operations responsibility area.

Table 2
Electric Operations Responsibility Area Organizational Chart



II. ELECTRIC OPERATIONS O&M ACTIVITIES

Q10. Please provide the 2018 actual and budgeted and projected Pepco O&M costs for 2019 and 2020 through 2022 for the Electric Operations responsibility area.

A10. Table 1[2] shows the 2018 historical and budgeted and projected O&M costs for 2019 and 2020 through 2022 for the Pepco Electric Operations responsibility area.

Table 1[3]
Pepco Electric Operations Responsibility Area
O&M Summary of Costs

Historical	Bridge	Projection		
2018	2019	2020	2021	2022
$101,604,219	$99,877,167	$87,154,987	$87,029,597	$87,227,128

Q11. Describe how Electric Operations O&M costs are developed in the LRP process.

Q11. As part of the LRP process, Electric Operations develops its budgeting goals. Generally, Electric Operations looks to historical cost levels and accounts for business needs, ongoing and new projects or initiatives, legal and regulatory requirements and established targets. These goals are entered into the long-range planning software and, in an iterative process, produce the totals summarized in Table 1.

Q12. Please explain the variation between the 2018 historical costs and the 2019 bridge year costs for the Electric Operations responsibility area?

A12. The principal variations between the 2018 historical costs and the 2019 bridge year are as follows:

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[2] Table 1 is duplicated in the Executive Summary.

[3] The O&M costs reflected are total Pepco Company costs including the District of Columbia and Maryland. See the Direct Testimony of Company Witness Wolverton for the allocation of costs to the District of Columbia.

- Base payroll increases from $24 million to $29 million 2018 to 2019 as a result of significant understaffing in 2018.[4] The Electric Operations responsibility area ran an average of 50 full time equivalents (FTEs) below budget level in 2018. In addition, 13 FTEs have been approved for addition to the base headcount in 2019 as a result of increased maintenance forecasts, increased new business work and an expectation of improved operational performance across a suite of Key Performance Indicators (KPIs).
- Operational contracting decreased from $24 million to $9 million as a result of transferring preventive maintenance inspection responsibilities from the Electric Operations responsibility area to the Technical Services responsibility area as well as improved efficiency in contracting activity.
- Non-Operations contracting will increase by $4.5 million as a result of an accounting treatment transferring costs for certain distribution claims work from a high level account to a more targeted subaccount.
- Fleet will increase by $1 million as a result of increased staffing of field quality control personnel in the Business Planning and Support department creating a requirement for additional vehicles.

Q13. Please explain the variation between the 2018 historical costs and the 2020 initial MRP year costs for the Electric Operations responsibility area?

A13. The principal variations between the 2018 historical costs and the MRP period are as follows:

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[4] See PEPCO (M)-2 at line 1.

- Facilities, Rentals, Leases and Utilities will reduce by $15 million as a result of the final payoff at the end of 2019 of a 25-year lease for the Energy Management System (EMS) and Operations Control Center building that houses Electric Operations.
- Non-Operations contracting will increase by $4.5 million as a result of an accounting treatment transferring costs for certain distribution claims work from a high-level account to a more targeted subaccount.
- Fleet will increase by $1 million as a result of increased staffing of field quality control personnel in the Business Planning and Support department creating a requirement for additional vehicles.

Q14. Why are you comparing the 2018 costs to the 2020 costs?

A14. We are comparing 2018 to 2020 because 2018 is historical and 2020 is the first year in the MRP.

Q15. What are the major cost drivers of the Pepco O&M cost increases from 2020 through 2022?

A15. Costs from 2020 through 2022 remain relatively flat; they increase a *de minimus* amount, only .08%, from about $87,154,987 to $87,227,128.

Q16. What challenges does the Electric Operations responsibility area face in the MRP period 2020-2022?

A16. The major challenges facing the Electric Operations responsibility area include hiring and training new craft and technical personnel to expand the work scopes performed by internal labor and support replacements due to employee turnover, including enhancing current training programs and supporting an improved safety culture; expanding preventive

and corrective maintenance programs on the overhead and underground electric distribution systems to maintain new equipment installations in good operating condition in order to continue to benefit from the reliability improvements they provide; implementing new software tools to expand the ability to remotely operate and restore the electric system downstream of traditional control points inside substations as well as to analyze and respond to real-time electric system conditions in increasingly efficient ways; and improving permitting requirements with local and federal jurisdictions to reduce wait times for new business customers and support the ongoing economic development of Pepco's service territory.

A. Electric Operations Sub-area Activities

Q17. Please describe the Electric Operations sub-area and its O&M costs and activities.

A17. The Electric Operations sub-area maintains configuration control over the distribution and transmission systems, directs real-time operations on the part of field personnel and contractors, administers the LOTO policy to ensure the electrical safety of field workers and monitors the electric system to address real time events and future risks. Included in the Electric Operations sub-area is the Emergency Preparedness group that conducts outreach to local Emergency Management Agencies (EMAs) and Law Enforcement Organizations (LEOs) to support regional readiness in response to natural and manmade events, maintains relationships with the Southeast Electric Exchange (SEE) and the North Atlantic Mutual Aid (NAMA) mutual assistance groups and supports weather forecast information across Electric Operations.

Q18. Please explain the key cost drivers for the Electric Operations sub-area.

A18. The largest cost driver in the Electric Operations sub-area during the MRP period will be the final satisfaction of Pepco's 1990's-era EMS installation (Lease Renewal), which Pepco repaid over a term of 25 years. The costs associated with paying of this expense are not reflective of future ongoing operations and will not be reallocated in the MRP. The next two key cost drivers during the MRP period will be the costs associated with hiring and training Electric Operators. These costs will be incurred as additional headcount base labor, as well as training premiums reflected in base labor and overtime.

Q19. How does the Electric Operations sub-area provide benefits to Pepco customers?

A19. The Electric Operations sub-area helps customers by controlling the electric distribution system configuration in a manner that reduces the likelihood of power outages and the duration of any power outages that do occur. The Company does this by working to limit the duration of outages that customers experience by directing the isolation of damage and then the restoration of load before completing repairs. The Company also endeavors to avoid potential outages or electric system events by responding to alarms on the electric system that signal abnormal electric system conditions that need to have corrective maintenance performed in order to avoid adverse customer or electric system impacts. By analyzing and continuously monitoring the system stresses such alarms represent, the Electric Operations sub-area deploys maintenance crews in response to those signals to make equipment adjustments to reduce the likelihood of power outages.

Electric Operations also provides benefits to Pepco customers by training emergency management agencies and law enforcement organizations on Pepco's protocols when responding to customer outages on the electric system and by arranging to receive

mutual assistance crews when forecasted major outage conditions warrant activation to reduce outage durations.

Q20. What accomplishments did Pepco's Electric Operations sub-area achieve in 2018?

A20. Pepco's Electric Operations sub-area had several achievements over the course of 2018 including implementing the Energy Management System upgrade successfully and hiring seven new Distribution Operators to support 24x7 operations. Additionally, in 2018 troubleshooting and restoration work coordinated by the Electric Operations sub-area led to Pepco's best Customer Average Interruption Duration Index (CAIDI) performance of 82. In 2018 Pepco Electric Operations also implemented a new line of demarcation between Distribution and Transmission Operations control in order to align with North American Electric Reliability Corporation (NERC) designations and enable future efficiency. These efforts are projected, consolidated Company operations which create efficiencies and save money.

1. Benning Field Operations Department Activities

Q21. Describe the Benning Field Operations department and its O&M costs and Activities.

A21. The Benning Field Operations department principally is responsible for safely conducting the day-to-day maintenance and construction principally of the underground electric system and manhole and conduit system, including implementing safety policies, supporting craft training and efficiently allocating resources to various work activities.

Q22. Please explain the key cost drivers for the Benning Field Operations department.

A22. The largest cost driver the Benning Field Operations department during the MRP period will be the costs associated with base payroll and benefits and overtime, driven by

expanding headcount in craft positions and training new employees. This cost will be partially offset by reductions in contracting spend.

Additional key cost drivers that flow from the Company's increased preventive and corrective maintenance include the costs associated with skills and safety training related to preventive and corrective maintenance and the costs associated with new tools and vehicles to carry out the functions and tasks that come from increased preventive and corrective maintenance efforts. These costs are principally labor costs that are derived from preventive and corrective maintenance associated with the Benning Field Operations department activities.

Q23. Why are increased labor costs associated with preventive and corrective maintenance a significant cost driver for the department?

A23. Through its increased preventative and corrective maintenance efforts, Pepco has improved customer reliability performance. The Company installed a variety of new equipment on the electric system, including underground sectionalizers, new network transformers and protectors and switches. On a going-forward basis, this equipment requires inspection and, when warranted, repair, to continue to contribute to current levels of outage frequency and duration performance.

Q24. How do skills and safety training add to cost for the Benning Field Operations department?

A24. These costs are principally labor costs that are derived from training activities associated with the Benning Field Operations department. In order to properly train personnel in the department, we have undertaken to construct new craft skills training facilities with splicing benches for eight students. These facilities will benefit customers

with new workers who are skilled with up-to-date technology and experience for Pepco's service requirements going forward.

Q25. Describe the placement of power lines underground in the District of the Columbia.

A25. Pepco's high proportion of underground equipment has evolved over many years as the result of local undergrounding ordinances, new business underground extension rules and an overhead–to-underground conversion initiative (District of Columbia Power Line Undergrounding (DC PLUG) Initiative).

Q26. Does placing power lines underground require the Electric Operations responsibility area to hire uniquely skilled labor?

A26. Yes. Placing power lines underground requires that the Electric Operations responsibility area hire employees that are specifically trained to construct the newly undergrounded infrastructure. In addition, the Electric Operations responsibility area is required to train sufficient underground line mechanics to operate and maintain the underground infrastructure without compromising SAIDI or similar reliability performance metrics. Both of these labor requirements drive costs. Also driving costs is the need to develop and maintain an adequate stock of materials to complete the infrastructure projects.

Q27. How does the Benning Field Operations department provide benefits to Pepco customers?

A27. The Benning Field Operations department helps customers by responding to outage conditions on the underground electric distribution system, by performing routine preventive and corrective maintenance on the underground electric system to reduce outage

conditions for customers and by providing hiring and training of craft personnel to efficiently maintain and operate the underground electric distribution system.

Q28. What accomplishments did Pepco's Benning Field Operations department achieve in 2018?

A28. Pepco's Benning Field Operations department had several achievements over the course of 2018, including constructing a new underground training area with eight splicing stations with video capabilities, a new classroom outfitted with 16 computers, and multiple hands-on practical stations (real field conditions). Additionally, the department invested in new splicing truck purchases with built-in air conditioning units to condition manholes, arc flash blankets and double fire-retardant materials (additional coveralls, hoods) purchased for all trucks and employees. The department also implemented remote cutting and cable identification procedures and purchased new pumps and cutters for all crews.

2. Forestville Field Operations Department Activities

Q29. Describe the Forestville Field Operations department and its O&M Activities and customer benefits.

A29. Forestville Field Operations principally is responsible for safely conducting the day-to-day maintenance and construction principally of the overhead and underground residential distribution (URD) electric system, including implementing safety policies, supporting craft training and efficiently allocating resources to various work activities.

Q30. Please explain the key cost drivers for the Forestville Field Operations department.

A30. The largest cost driver the Forestville Field Operations department during the MRP period will be the costs associated with base payroll and benefits and overtime, driven by expanding headcount in craft positions and training new employees. This cost will be

partially offset by reductions in contracting spend. These costs are associated with hiring and training specially-skilled overhead line mechanics to respond to outage events on the electric system and maintain newly installed equipment over the coming years as well as to maintain operational excellence in CAIDI and other KPIs.

Additional key cost drivers that flow from the Company's increased preventive and corrective maintenance include the costs associated with skills and safety training related to preventive and corrective maintenance and the costs associated with new tools and vehicles to carry out the functions and tasks that come from increased preventive and corrective maintenance efforts. These costs are principally labor costs that are derived from preventive and corrective maintenance and properly assigned to the Forestville Field Operations department activities.

Q31. Why is the variability of increased preventive and corrective maintenance a significant cost driver for the department?

A31. Through its increased preventative and corrective maintenance efforts, Pepco has improved customer reliability performance. These costs are principally labor costs that are derived from labor required to perform preventive and corrective maintenance and properly assigned to the Forestville Field Operations department activities.

Q32. What accomplishments did Pepco's Forestville Field Operations department achieve in 2018?

A32. Pepco's Forestville Field Operations department had several achievements over the course of 2018. These achievements include enhanced peer-to-peer safety inspections with a contact rate of 137% as well as hiring and/or promoting over 10% of the craft work force.

3. Rockville Field Operations Department Activities

Q33. Describe the Rockville Field Operations department and its O&M costs and activities and customer benefits.

A33. The Rockville Field Operations department is responsible for responding to outages on the electric distribution system and performing routine corrective maintenance and construction work to ensure that the system remains in good operating condition. This work includes hiring and training employees as well as obtaining tools and equipment to support their work activities.

Q34. Please explain the key cost drivers for the Rockville Field Operations department.

A34. The largest cost driver the Rockville Field Operations department during the MRP period will be the costs associated with base payroll and benefits and overtime, driven by expanding headcount in craft positions and training new employees. This cost will be partially offset by reductions in contracting spend.

Additional key cost drivers that flow from the Company's increased preventive and corrective maintenance include the costs associated with skills and safety training related to preventive and corrective maintenance and the costs associated with new tools and vehicles to carry out the functions and tasks that come from increased preventive and corrective maintenance efforts. These costs are principally labor costs that are derived from preventive and corrective maintenance and properly assigned to the Rockville Field Operations department activities.

Q35. What accomplishments did Pepco's Rockville Field Operations department achieve in 2018?

A35. Pepco's Rockville Field Operations department had several achievements over the course of 2018. These achievements include enhanced peer-to-peer safety inspections with a contact rate of 117%, as well as historically low numbers of responsible vehicle accidents and serious injuries. The Rockville Field Operations department also completed the Stage 2 International Standards Organization (ISO) 14001 certification audit with no major or minor items of nonconformance. The ISO 14001 standard is an environmental management system standard that is broadly used across the country to help companies and organizations support environmental policy. Finally, the department implemented hands-on craft skills training for 26 new apprentices at the Rockville training yard.

4. Regional Engineering and Design Department Activities

Q36. Describe the Regional Engineering and Design department and its O&M costs and activities.

A36. The Regional Engineering and Design department completes detailed design drawings for all New Business projects (e.g., customer service connections and customer requested relocations), for regional reliability improvement projects, and for non-centrally managed capacity expansion projects.

Q37. Please explain the key cost drivers for the Regional Engineering and Design department.

A37. The largest cost driver in the Regional Engineering and Design department during the MRP period will be design and customer service labor associated with new business/residential customer upgrades as well as field survey data expansions the

Company has undertaken to improve the quality of its geographic information systems (GIS) data. Pepco is working to implement an Advanced Distribution Management System (ADMS) that will model, in real time, distribution system configuration. When developed, the ADMS will calculate real time arc-flash ratings and support real-time distribution system information to support safety protocol requirements and reliability performance. The system will also improve confidence in electric system configuration models downstream of primary devices. This improved confidence will be achieved through the validation of or updates to the underlying GIS model as a result of field surveys of existing electric system conditions. For the MRP period, the Regional Engineering and Design department contemplates substantial work on the GIS including expanded field surveys to confirm and enhance the accuracy of GIS data.

Additional departmental cost drivers during the MRP period include the costs associated with software training and licensing for new IT tools which will improve the accuracy of load modeling and forecasting associated with improving GIS data. Pepco intends to leverage Exelon Utilities (EU) North Star IT solutions as part of its progress toward developing is ADMS. As Pepco leverages EU North Star, the licensing costs of new software is expected to decrease. However, these changes require tools and business process training to fully implement new design and estimation processes to continue to perform core functional responsibilities.

Also, skills, safety, and technical training in this area will add labor costs to the department.

Q38. How does the Regional Engineering and Design department provide benefits to Pepco customers?

A38. The Regional Engineering and Design department helps customers by designing facilities to provide multiple paths of supply so that customers are restored rapidly in outage conditions, by analyzing circuit configurations to ensure outage events on the distribution system impact as few customers as possible and by supporting growth in the District of Columbia by enabling customers to build their homes and businesses with sufficient electrical capacity to meet their needs.

Q39. What accomplishments did Pepco's Regional Engineering and Design department achieve in 2018?

A39. Pepco's Regional Engineering and Design department had several achievements over the course of 2018. Along with the rest of the Company, the department implemented the ESI software to improve budgeting and forecasting alignment with the rest of the EU, and the department hired eight new personnel. The Regional Engineering and Design department also implemented business performance reporting to track the component durations of design projects to improve efficiency and improve new business customer satisfaction.

5. Work Management Department Activities

Q40. Describe the Work Management department and its O&M costs and activities.

A40. The Work Management department schedules planned corrective maintenance and new construction projects, prioritizes emergent corrective maintenance work and measures project schedule adherence. The department also collects and analyzes data regarding the efficiency of our work crews and tracks the different types of work being completed to

optimize resource allocation and spend. Work Management also assists in creating projections related to corrective maintenance work costs and completion rates.

Q41. Please explain the key cost drivers for the Work Management department.

A41. The major cost driver for the Work Management department is internal labor as a result of hiring. Efficiencies realized by the Work Management department result in lower overtime and operational contractor spend in the field operations departments as work is planned and executed with better oversight and productivity.

- **Skills, safety and technical training:** The Work Management department expects rising incremental costs related to technical training to promote a safe work environment and develop personnel.
- **Software licensing and training for new IT tools:** The Work Management department has recently led the Pepco transition into two new software packages to increase operational efficiency and decrease downtime costs. These software packages also allow for better oversight of our field crews, and increased cost control related to downtime and poor resource allocation. The Work Management department expects to incur incremental costs related to the licensing of these software packages. The Work Management department also expects rising incremental costs related to training our employees in the new software, as we work towards developing a more mature and technically skilled team.
- **Increase resource for scheduling:** As the Work Management department grows in scope and we develop new processes for supporting our operations, we expect increasing incremental costs related to hiring new personnel. As a newly created department, the Work Management department has been operating with the

smallest possible complement. The Work Management department expects an increase in personnel to continue effectively serving our customers and internal stakeholders.

Q42. How does skills, safety and technical training add to costs for the Work Management department?

A42. In order to properly train personnel in the department, the Work Management department has undertaken to provide training seminars related to new software. As needed, the Work Management department will also provide training and seminars related to technical skills such as our new reporting tool and excel. The Work Management department will also provide safety training and safety equipment to all of our personnel that go into the field.

Q43. Why is software training and licensing for new IT tools a significant cost driver for the department?

A43. Work Management is reliant on various scheduling software packages to schedule and plan work. Ensuring that the software licenses are paid and that its personnel are adequately trained in leveraging the software is instrumental in securing departmental effectiveness and customer satisfaction.

Q44. How does the Work Management department provide benefits to Pepco customers?

A44. The Work Management department helps customers by efficiently scheduling corrective maintenance and project-driven work to efficiently use scheduled resources and reduce cost as a result of call out or overtime activities and operational contracting.

Q45. What accomplishments did Pepco's Work Management department achieve in 2018?

A45. The Work Management Process is new to PHI and was rolled out in 2017. The Work Management department has successfully aided in the implementation of the new scheduling protocols across all of Pepco and has ensured increased operational efficiency and productivity. The Work Management process has helped provide the required visibility for Company employees on how work is executed and planned on a weekly basis. The process provides a platform for more accountability from all departments as jobs progress through engineering to construction and allows field operations to better plan their work ahead of execution. This planning process supports the Pepco Electric Operations Responsibility Area since it translates to a reduction of operational down-time and faster completion rates, resulting in downstream cost-savings for customers, and reduced waiting times for new business work.

6. Business Planning and Support Department Activities

Q46. Describe the Business Planning and Support department and its O&M costs and activities.

A46. The Business Planning and Support department oversees field contractors performing non-centrally managed construction and maintenance work and oversees regional budget performance, invoicing and KPI reporting.

Q47. Please explain the key cost drivers for the Business Planning department.

A47. The largest cost driver in the Business Planning department during the MRP period will be costs associated with Operational Contracting, associated with new business construction work as well as streetlight maintenance.

Another cost driver for the Business Planning department is costs associated with Undergrounding Contract Management. Pepco has contracted with a variety of contractors as part of its undergrounding project to move significant facilities underground to promote reliability and safety. The Business Planning department is responsible for improving contractor efficiency and adherence to Not-to-Exceed contract awards versus time and materials arrangements, reducing project overruns. These efforts add costs for this department.

In addition, the following contribute to upward incremental cost changes:

- Skills and safety training;
- Increased hiring to ensure improved quality assurance from contractors working to expand the electric system; and,
- New tools and vehicles to support workforce efficiency.

Q48. How will increased hiring serve as a significant cost driver for the department?

A48. Additional craft oversight personnel are being hired to support quality control and efficiency expectations from Contractors of Choice performing work on the electric distribution system. These new employees will have salaries and benefits impacting overall departmental spend.

Q49. How does the Business Planning department provide benefits to Pepco customers?

A49. The Business Planning department helps customers by supplementing internal construction crews to upgrade the Pepco electric system in a cost-effective manner. These upgrades support the reliability improvements that are reflected in Pepco's System Average Interruption Duration Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance.

In addition, as shown in Table 3, Pepco Business Planning & Support coordinated 696 Mutual Assistance resources for 10 weather events in 2018.

Table 3
2018 Mutual Assistance Deployments

Event	Date	Resources Sent
Nor'Easter	03/20/18	134 PEPCO to ACE
Thunderstorm	07/03/18	26 PEPCO to PECO
Thunderstorm	07/22/18	15 PEPCO to PECO
Thunderstorm	07/24/18	53 PEPCO to BGE
Thunderstorm	07/27/18	33 PEPCO to BGE
Hurricane Michael	10/08/18	197 PEPCO to Dominion
Winter Storm	11/16/18	30 PEPCO to Jersey Central Power & Light (JCPL)
Winter Storm Bruce	11/26/18	132 PEPCO to ComEd
Winter Storm	12/09/18	41 PEPCO to Duke/Dominion
Winter Storm	12/31/18	35 PEPCO to National Grid

Q50. What accomplishments did Pepco's Business Planning department achieve in 2018?

A50. As shown in Table 4, Pepco's Business Planning department trained a significant number of personnel through the Electric Operations responsibility area:

Table 4
2018 Business Planning Personnel Trained

Training Area	Number of Personnel Trained
TOA Trained:	16
Lock-Out-Tag-Out Trained:	71
Badged:	446
Mobil Data Terminal/Storm Training:	19 of 22 Sr. Contract Coordinators and SPCM's

III. CONCLUSION

Q51. Does this conclude your Direct Testimony?

A51. Yes, it does.

W. Sullivan
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (M) – 1

2018-2022 Long Range Plan Documentation

VP Area: Electric Operations and Operations Control Center

Vice President:

I – Approvals

This document has been checked for errors in calculations and content.

Prepared By: Date: 9-21-18

Approved By: Date: 2-21-19
Director

Approved By: Date: 2-21-19
Director

Approved By: Date: 2-21-19
Vice President

II – Major Business Functions

Pepco Electric Operations (EO) organization is responsible for the safe, reliable and efficient operation and overall performance of the electric distribution systems in the District of Columbia. The team coordinates emergency preparation and response efforts, responds to emergencies, maintains/improves the system, ensures compliance to all regulations and standards, and supports system expansion and the connection of new customers.

Pepco EO is committed to strong financial management and immediate response to customer issues. The organization – composed of a diverse, talented workforce – champions ongoing employee engagement and education.

Pepco EO organization is responsible for:

- Constructing new electric facilities to serve new or additional customer load
- Operating and repairing the electric system to restore service to customers
- Performing preventative and corrective maintenance

Pepco EO service territory is indicated by the green coloring below:

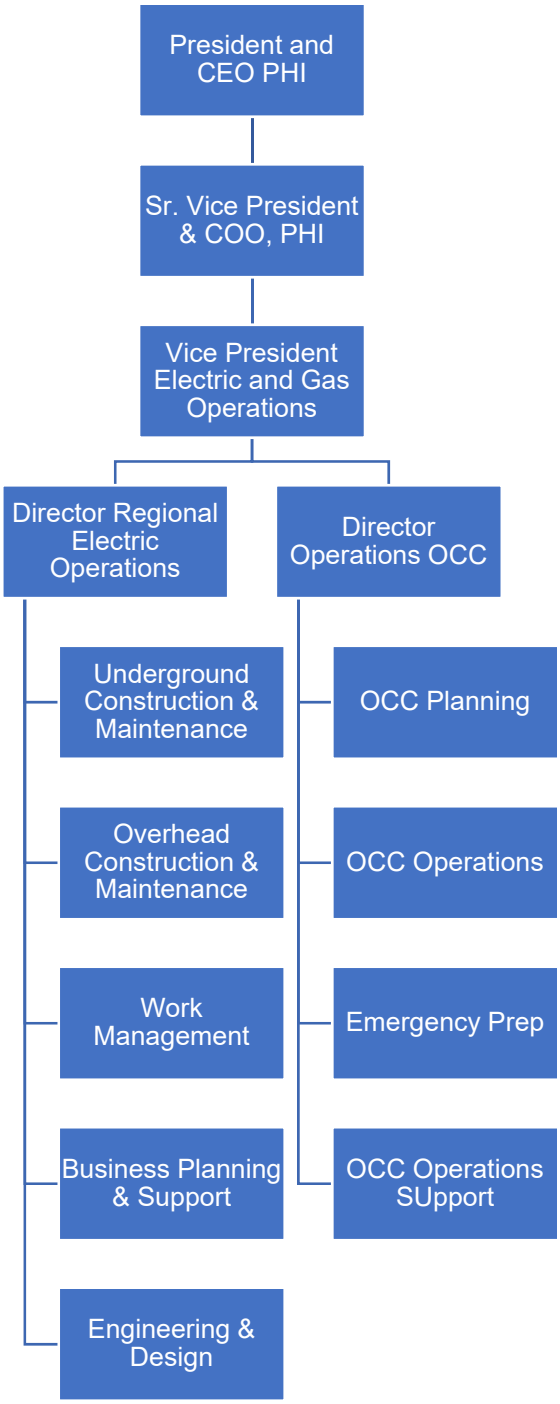
Pepco DC EO organization is comprised of the following departments:

Pepco DC Electric Operations	Responsibilities
Underground Construction and Maintenance	Plans, directs, coordinates and supervises craft personnel engaged in the construction, operation and maintenance of company underground electric facilities. Supervises resources in a manner that ensures the safe, efficient, economical, and expeditious completion of work with high regard for customer satisfaction to accomplish desired results
Overhead Construction and Maintenance	Plans, directs, coordinates and supervises craft personnel engaged in the construction, operation and maintenance of company overhead electric facilities. Supervises resources in a manner that ensures the safe, efficient, economical, and expeditious completion of work with high regard for customer satisfaction to accomplish desired results
Work Management	Prioritizes, schedules, plans, prepares and executes all regional corrective, preventative and predictive maintenance tasks, projects, switching evolutions and tests associated with all work disciplines.
Business Planning and Support	Develops and drives short-term and long-range business planning. Conducts complex modeling, forecasting, trending, variance analysis, business case development, and other financial operational analysis. Oversees and manages prioritization, scheduling, planning and execution of all work assigned to Contractors of Choice. Manage the tasks being performed by external construction resources to maximize productivity, safety, quality, diversity, and cost savings.
Engineering and Design	Performs engineering tasks associated with critical engineering projects or small projects with many complex features. Develops studies, plans, criteria, specifications, calculations, evaluations, design documents, performance assessments, integrated systems analysis, cost estimates, and budgets associated with the planning, design, licensing, construction, operation, and maintenance of Pepco DC electric distribution facilities/systems. Provides consultation and recommendations to the Company within and to other business units and/or customers as a result of studying company or customer-owned systems, processes, equipment, or facilities. Reviews financial data from budget and actual costs of projects.

Pepco OCC Operations	Responsibilities
Operations Control Center (OCC) Planning	Directs and is responsible for optimizing the practices, policies, procedures and programs to operate the electric distribution system in a safe, reliable and efficient manner with the welfare of employees, customers, the public and shareholders in mind. Manages the Operations Control Center training, planning and clearance activities. Focuses on operational excellence in establishing switching routines for scheduled and emergent work, system monitoring and loading, and system restoration during emergency events.
OCC Operations	Follows established policies, procedures and guidelines on distribution system operations. Maintains the system integrity, reliability and security of the distribution system in a safe, reliable and efficient manner. Gathers and analyzes system data to determine the feasibility of switching requests. Verifies the safe and efficient operation of the electrical system.
Emergency Prep	Coordinates disaster response or crisis management activities and provides disaster preparedness training, emergency plans, and procedures for natural disasters (e.g., hurricanes, floods). Prepares and analyzes damage assessments following disasters or emergencies. Maintains and updates resource materials associated with emergency preparedness plans.
OCC Operations Support	Maintains active involvement in the operations organization as required to maintain a high-performance organization, reliable delivery services, and optimize the practices, policies, procedures and programs to operate the transmission and distribution systems in a safe, reliable and efficient manner with the welfare of employees, customers, the public, and shareholders in mind. Responsible for the continuous assessment of the organization in the areas of productivity, resource utilization, labor strategy, adherence to standards and work practices, implementation of root cause investigation corrective actions, and performance indicator analysis.

III – Home Center Hierarchy

The below diagram provides a high-level overview of the Pepco Electric Operations and Operations Control Center Organizations.



IV – Major Programs

Pepco Electric Operations	O&M Programs/Initiatives
Pepco DC Electric Operations	The Pepco Field Operations areas have the responsibility for maintaining the overhead and underground distribution and transmission equipment. This entails engineering projects for customer growth, reliability improvement, and load level expansions, in addition to the inspection and corrective maintenance programs of the electric system assets. For operating and maintenance of the electric system, the group has scheduled inspection and equipment maintenance programs, such as overhead feeder lines inspections, and underground manhole inspection/maintenance. The group also responds to equipment repair incidents as well as customer outage/restoration events, either single customer or group outages such as that witnessed during a storm event. .
Pepco DC OCC	The Pepco OCC organization's primary responsibility is to ensure the proper operations of the electric distribution and transmission system for the Pepco service area. Among the activities and programs that support this effort are: • Monitoring and regulation of load and voltage levels at supply points, such as substations and transformers • Interaction with regional transmission organizations to analyze load levels and make adjustments to preserve integrity of the operating system • Assistance and coordination with field operations areas for switching operations and scheduling of outages for necessary capital and maintenance work • Dispatching of field crews for customer outage incidents including during a major restoration event The activities and responsibilities listed above constitute the majority of the O&M costs incurred by Pepco OCC on an annual basis.

W. Sullivan
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (M) – 2

2018-2022 Long Range Plan Documentation

VP Area: Electric Operations and Operations Control Center

Vice President:

Electric Operations

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	Majority of base payroll costs are for electric system operating and maintenance program costs, in addition to control center operations, managerial and administrative support	24,142,892	29,176,321	30,027,743	30,759,126	31,475,140
2	Overtime	Administrative wages that exceed base payroll	6,584,846	6,532,423	6,782,423	6,672,423	6,672,423
3	Incentive	Formulaic based on key performance indicators in Annual Incentive Plans	1,679,127	1,561,511	1,607,407	1,652,908	1,700,568
4	Pension and OPEB	Function of payroll based on actuarial study	1,493,737	5,904,018	5,541,609	5,194,332	4,765,556
5	Fringe Benefits	Function of payroll based on headcount	5,684,971	6,187,664	6,431,836	6,714,223	7,010,869
6	Other Premium	Primarily long-term incentive plan for key managers and above; also includes other awards	968,218	217,061	152,252	152,180	152,180
7	Stock Compensation	N/A	-	-	-	-	-
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	Function of payroll: includes federal unemployment, federal social security, state unemployment	111,419	216,818	222,877	227,558	232,610
10	Materials	Primarily electric system operating and maintenance program materials, for repairs, inspections, truck stock supplies, replacement of equipment	5,742,586	4,823,859	4,795,844	4,797,619	4,798,696
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	Supplemental labor for electric distribution maintenance programs	23,891,972	8,709,333	10,009,119	9,914,798	10,112,806
13	Contracting - Non-Ops	Consulting support for engineering and professional services	1,479,927	5,968,516	5,604,858	5,609,062	5,613,372
14	Contracting - Outsourced	N/A	3,386,507	3,412,396	3,412,396	3,412,396	3,412,396
15	Staff Augmentation	Contractor staff to augment business needs throughout the business cycle	702,887	249,802	249,798	249,798	249,798
16	Insurance	N/A	-	-	-	-	-
17	Regulatory Fees/Permits	Cost to obtain maintenance activity and permit fees, occupancy and steel plate permits	118,321	-	-	-	-
18	Licensing and Telecom	Cost of software maintenance fees, application licenses, as well as charges for cell phones, PDAs, blackberries, pagers and other personal telecommunication devices	534,056	579,656	589,421	573,940	574,719
19	BSC Services	N/A	-	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	Seminars and training for professional development and industry peer workshops and meetings	60,286	59,326	59,355	48,502	48,582
23	Travel & Entertainment	Includes business travel related expenses, such as mileage reimbursement, car rental, railways, taxi, travel booking fees, etc. This account also includes meal expenses, tuition reimbursement, and costs associated with employee relocation	906,821	734,464	736,541	722,355	724,943
24	Memberships / Dues	Cost of industry and professional memberships for employees and the company (e.g., Utilities Enterprise Membership)	9,570	2,460	2,460	2,460	2,460
25	Charity / Contributions	N/A	-	-	-	-	-
26	Lobbying	N/A	-	-	-	-	-
27	Office Expense	Supplies	218,203	628,443	628,478	581,817	581,863
28	Other Expenses	Other miscellaneous costs not specifically accounted for in other operating expense sub accounts	407,453	(326,421)	(656,520)	(1,676,657)	(2,676,638)
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	Utility Services and Intercompany Oper Costs	135,287	-	-	-	-
31	CIAC / CIAM	N/A	-	12,000	12,000	1,000	1,000
32	Facilities, Rentals, Utils	Control Center Lease Expense. Other rent allocated based on factors such as square footage and location	17,329,028	17,814,565	2,670,354	2,765,586	2,802,359
33	Transportation / Fleet	Costs related to vehicle charges, rental car costs, and allocation of overhead fleet service costs	6,016,104	7,412,952	8,273,735	8,654,171	8,971,424
34	Depreciation & Amort	N/A	-	-	-	-	-
35	**Total Expense**		**$ 101,604,219**	**$ 99,877,167**	**$ 87,153,987**	**$ 87,029,597**	**$ 87,227,128**

Electric Operations

VI - Headcount

Instructions:

List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt	165	180	180	180	180
Pepco Non-Exempt	3	3	3	3	3
Pepco Union	473	534	534	534	534
Total Pepco	**641**	**717**	**717**	**717**	**717**
PHISCO Exempt	32	40	40	40	40
PHISCO Non-Exempt	2	2	2	2	2
PHISCO Union					
Total PHISCO	**34**	**42**	**42**	**42**	**42**

M.A. Ortega
Direct Testimony
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (N)

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EXECUTIVE SUMMARY- MIGUEL A. ORTEGA

Table 1[1]
Technical Services Responsibility Area O&M Summary

Historical	Bridge	Projections		
2018	2019	2020	2021	2022
$48,377,955	$51,185,386	$53,960,305	$54,357,412	$55,976,314

This testimony presents Potomac Electric Power Company's (Pepco or the Company) Technical Services responsibility area Operation and Maintenance (O&M) costs. Pepco's Technical Services responsibility area is responsible for the overall management of Pepco's electric distribution system assets' material condition and performance. The Technical Services responsibility area oversees distribution system performance, distribution capacity planning, reliability and maintenance programs, smart grid and innovation, vegetation management and investment strategy for all regions, covering more than 8,800 square miles of territory.

The O&M costs associated with the duties assigned to this responsibility area are broken down according to the five departments:

(1) Central Engineering;

(2) Distribution Planning, Smart Grid, and Innovation;

(3) Core Business Applications;

(4) Business Planning and Support; and

(5) Investment Strategy.

[1] The O&M costs reflected are total Pepco costs, including the District of Columbia and Maryland. See the Direct Testimony of Company Witness Wolverton for the allocation of costs to the District of Columbia.

Of these five departments, one – Central Engineering - comprises nearly 81% of the projected costs for the Multiyear Rate Plan (MRP) period 2020–2022. Central Engineering is responsible for both Vegetation Management and Asset Performance and Reliability, two important areas for the Company and its customers.

In preparing its projections for the MRP period (2020-2022), the Company analyzed its actual 2018 spending levels, considered underlying cost drivers, and developed an assessment of future requirements. The Company also projected costs for 2019, which is a bridge year between 2018 historical costs and the MRP period.

In addition, this testimony identifies major programs and initiatives incremental to levels of historical spending and that are necessary to maintain the safe and reliable operation of the distribution system. Funding requirements for these new or more extensive work elements are projected based on historical spending levels plus incremental expense requirements for new or ongoing work efforts.

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF MIGUEL A. ORTEGA
FORMAL CASE NO. 1156

I. INTRODUCTION

Q1. Please state your name and position.

A1. My name is Miguel A. Ortega. I am Vice President of Technical Services for Pepco Holdings LLC (PHI). I am testifying on behalf of Pepco.

A. Qualifications and Experience

Q2. Please describe your professional experience and qualifications.

A2. I earned a bachelor's degree in Electrical Engineering from the Illinois Institute of Technology. I have been in the energy industry for 36 years and have held leadership positions in various areas. Prior to joining PHI, I served as Director, External Affairs at Commonwealth Edison Company (ComEd), where I led the successful implementation of new technology programs. I also have led efforts to improve the Transmission & Distribution systems' material condition and operational performance, including managerial roles in transmission, substation and distribution testing, engineering, operations, construction, maintenance, and generation. A recent role at ComEd focused on improving customers' experiences through innovative use of customer-facing technologies in the customer service area.

Q3. What are your responsibilities in your role as Vice President of Technical Services of Pepco Holdings?

A3. I am responsible for the overall management of Pepco Holdings' electric distribution system assets' material condition and performance. I oversee distribution

system performance, distribution capacity planning, reliability and maintenance programs, smart grid and innovation, vegetation management and investment strategy for all regions, covering more than 8,800 square miles of territory.

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

Q4. Have you previously provided testimony to the Public Service Commission of the District of Columbia (Commission)?

A4. No.

B. Purpose of the Testimony

Q5. Please state the purpose of your Direct Testimony.

A5. The purpose of my Direct Testimony in this proceeding is to provide the following information related to Pepco's application to establish a MRP in the District of Columbia: (1) information explaining the structure and operation of the Technical Services responsibility area and how its departments benefit District of Columbia customers; (2) an explanation of how those benefits are funded through Pepco's O&M budget as reflected in Pepco's Long Range Plans (LRPs); (3) an explanation of the Technical Services responsibility area's 2018 historical O&M expenses; and (4) an explanation of the key initiatives and cost drivers that impact O&M costs and are reflected in the LRP for the Technical Services responsibility area for 2019 and 2020 through 2022.

Q6. How is your testimony organized?

A6. First, I will describe each department in the Technical Services responsibility area. I will next discuss the key initiatives and undertakings that drove O&M costs for 2018. I

will also discuss the key initiatives and efforts the Technical Services responsibility area has planned for 2019 and the major planned initiatives that will drive projected costs for years 2020 through 2022.

Q7. Are you sponsoring any exhibits in this proceeding?

A7. Yes. I am supporting PEPCO (N)-1 and PEPCO (N)-2. These exhibits provide details regarding the O&M cost levels my testimony supports and provide greater understanding of the work performed by the Technical Services responsibility area.

II. THE TECHNICAL SERVICES RESPONSIBILITY AREA

A. Structure and Organization

Q8. Please describe the Technical Services responsibility area.

A8. The Technical Services responsibility area provides overall management of Pepco Holdings' distribution system assets' material condition and performance. It oversees electric distribution system performance, distribution capacity planning, reliability and maintenance programs, smart grid and innovation, vegetation management, and investment strategy for all regions, including the District of Columbia. The Technical Services responsibility areas' functions differ from those of the Electric Operations responsibility area, which is responsible for safely and reliably operating, constructing, and maintaining Pepco's electric distribution system, as discussed by Company Witness Sullivan (PEPCO (M)).

Q9. How is your responsibility area organized?

A9. There are five departments within the Technical Services responsibility area:

(1) Central Engineering;

(2) Distribution Planning, Smart Grid, and Innovation;

(3) Core Business Applications;

(4) Business Planning and Support; and

(5) Investment Strategy.

Q10. How do your departments help Pepco's customers?

A10. The departments under my direction help customers in many ways. Generally, Pepco's Technical Services responsibility area is responsible for the identification, initiation, and oversight of programs on the Pepco distribution system that promote the safe and reliable delivery of energy to Pepco customers. The Technical Services responsibility area also is responsible for developing the material, equipment, and design standards used for distribution system programs.

Together, my departments have provided top decile reliability for District of Columbia customers for both duration and frequency of outages. The Technical Services responsibility area manages planning for distribution system enhancement programs, ensuring the Company can continue meeting the energy needs of Pepco customers in the District of Columbia.

B. Pepco Technical Services Responsibility Area O&M

Q11. Describe the Technical Services responsibility area O&M activities.

A11. The Technical Services responsibility area is responsible for planning, managing, and overseeing distribution system capacity programs as well as implementing smart grid and other innovative programs while maintaining the reliability of the distribution system, including through vegetation management. It also oversees the Company's investment strategy. These activities require the experience and skills of engineers, engineering tech specialists, office support personnel, supervisors, and management.

The Technical Services responsibility area is responsible for:

- Tree trimming;
- Inspecting and maintaining the electrical distribution system;
- Analyzing and improving reliability;
- Developing and implementing innovative new technology;
- Ensuring our electrical infrastructure meets the current and future energy needs of residents and businesses in the District;
- Maintaining critical software systems that manages Pepco's distribution system; and
- Initiating and managing programs that promote the reliable delivery of energy to Pepco customers.

The individuals who carry out these responsibilities require training, materials, service vehicles, office materials and supplies and have costs associated with compensation that comprise the O&M expenses for the Technical Services responsibility area.

Table 1[2] provides the Technical Services responsibility area's historical and projected O&M costs for the period 2018-2022.

Table 1[3]
Technical Services Responsibility Area O&M Summary

Historical	Bridge	Projections		
2018	2019	2020	2021	2022
$48,377,955	$51,185,386	$53,960,305	$54,357,412	$55,976,314

[2] Table 1 is repeated in the Executive Summary of this testimony.
[3] The O&M costs reflected are total Pepco costs, including the District of Columbia and Maryland. See the Direct Testimony of Company Witness Wolverton for the allocation of costs to the District of Columbia.

1 **Q12. Please explain the variation between the 2018 historical costs and the 2019 bridge year**
2 **costs for the Technical Services responsibility area.**
3 A12. The key cost variances from 2018 to 2019 across all Technical Services
4 departments were storm restoration expenses, contracting costs related to specialists that
5 were retained for management and program-related activities and base payroll expenses.
6 Specifically, while contracting costs associated with storm restoration expenses increased,
7 those costs were offset, in part, by reductions in base payroll that occurred due to the
8 realignment of personnel from Technical Services to other responsibility areas within the
9 Company.
10 **Q13. Please explain the variation between 2018 historical costs and the 2020 initial MRP**
11 **year costs for the Technical Services responsibility area.**
12 A13. The key cost variances from 2018 to 2020 across all Technical Services
13 responsibility area departments are generally the same as they were for 2018 to 2019.
14 Namely, storm restoration expenses, contracting costs related to specialists that were
15 retained for management and program-related activities, and base payroll costs. While
16 contracting costs associated with storm restoration expenses are budgeted to increase, those
17 costs are expected to be offset slightly by base payroll reductions. Overall, the Company
18 anticipates a modest increase when 2018 is compared to 2020.
19 **Q14. Why are you comparing the 2018 costs to the 2020 costs?**
20 A14. We are comparing 2018 to 2020 because 2018 is historical costs and 2020 is the
21 first year in the MRP.

Q15. What are the major cost drivers of the Pepco O&M cost increases from 2020 through 2022?

A15. Costs from 2020 through 2022 remain relatively flat; they increase only 3.736% from about $53,960,305 to $55,976,314.

1. Central Engineering Activities

Q16. What are the key initiatives and activities that will drive costs for the Central Engineering department during the MRP period?

A16. The Pepco Central Engineering department is responsible for overall management of Pepco's electric distribution system assets. The department oversees distribution system performance, reliability, maintenance programs, and distribution standards for Pepco's service area. The department also provides engineering and distribution system maintenance expertise and helps deliver safe and reliable electricity to customers. Central Engineering is responsible for Pepco's Vegetation Management efforts and plans, manages, and executes vegetation management work related to the electric distribution system, contributing to fewer service interruptions caused by trees and tree limbs. All of these efforts create costs related to maintaining distribution system assets' material condition and performance.

Central Engineering is also responsible for the overall management of reliability programs that support the distribution system meets reliability requirements for our customers. Activities and responsibilities in this area include inspecting underground and overhead electrical infrastructure, conducting reliability analysis and reporting, engineering activities, and implementing reliability programs. Central Engineering crews

will continue to inspect Pepco's underground and overhead electrical infrastructure and will conduct reliability analysis and reporting.

Q17. How will these initiatives impact O&M costs for Central Engineering in the MRP period?

A17. Generally, O&M related to Central Engineering activities will remain flat in the MRP period. The main drivers of O&M costs during this period will be vegetation management and distribution line preventive maintenance programs. The budgets for these areas are based on the actual inspection scope that is planned in each year, which is not expected to vary greatly from year-to-year during the MRP.

Pepco's Central Engineering department's initiatives have contributed to Pepco's top decile System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) performance in 2018. The department analyzes large outages affecting 1,000 customers or more in order to continually improve performance and proposed remediation plans. Central Engineering tracks Customers Experiencing Multiple Interruptions (CEMI) performance using linear and geospatial information to identify the neighborhoods to target for improved reliability - those neighborhoods that have seen multiple interruptions. All of these efforts have improved Pepco's customers' experiences.

2. Distribution Planning, Smart Grid, and Innovation Activities

Q18. What are the key initiatives and activities that will drive costs for the Distribution Planning, Smart Grid, and Innovation department during the MRP period?

A18. The initiatives that will be undertaken by this department are very fluid and arise from a range of areas and priorities shaped both by Exelon Utilities and Pepco as well as

in response to industry changes and adoption of emerging and new technologies. In general, the initiatives focus on the following key areas:

- Transportation Electrification; [4]
- Community Solar (Community Renewable Energy Facilities in the District);
- Distributed Energy Resources, including Battery Storage;
- Use cases for Advanced Metering Infrastructure; and
- Smart street lights.

Types of programs or initiatives that are undertaken may range from technology demonstrations, to full implementation of new products or services, developing new internal and external processes and controls, and developing new or enhancing existing systems and tools necessary to develop the modern grid platform necessary to advance the future of energy.

Q19. How will these initiatives impact O&M costs for the Distribution Planning, Smart Grid, and Innovation Department in the MRP period?

A19. The initiatives planned for this department are expected to cause O&M costs to rise as Pepco continues to grow as an organization to meet the demands for grid modernization. These efforts include developing engineering capabilities in advanced data analytics and new tools and software as well as developing new processes to coordinate and execute program work for grid modernization and to keep pace with advancing energy industry legislative actions.

[4] See Potomac Electric Power Company's Application for Reconsideration and Clarification of Order No. 19898, Formal Case No. 1130 and Formal Case No. 1155.

1 **3. Core Business Applications Activities**

2 **Q20. What are the key initiatives and activities that will drive costs for the Core Business**
3 **Applications department during the MRP period?**

4 A20. The Core Business Applications department performs tasks that are at the interface
5 between business functions and technology needs. The department participates in IT
6 projects on behalf of business users, administers systems, and promotes availability of
7 technological solutions for Pepco's workforce. Large IT projects that are planned will
8 impact Pepco's overall O&M spend. For example, the oneMDS project, which is replacing
9 Pepco's aged mobile dispatch solution, is an example of a large project that is scheduled
10 to come online from the end of 2020 through 2024. The oneMDS project provides a
11 platform that will allow for efficient dispatch of crews across our companies and the ability
12 to track asset data and work performed against those assets (e.g., poles and pipes).
13 Subsequently this information will be available for crews in the field. Smaller projects,
14 like updates to Pepco's smart meter system will also bring both benefits and some added
15 maintenance costs to the budget.

16 **Q21. How will these initiatives impact O&M costs for the Core Business Applications**
17 **department in the MRP period?**

18 A21. Overall, O&M related to the Core Business Application department activities will
19 remain flat in the MRP period. The main drivers of O&M costs during this period will be
20 primarily labor related. The department's plan does not anticipate increases unless the
21 planned programs require greater support than currently anticipated.

4. Business Planning and Support Activities

Q22. What are the key initiatives and activities that will drive costs for the Business Planning and Support department during the MRP period?

A22. Pepco's Business Planning and Support department provides organizational oversight for programs that are within the Technical Services responsibility area that contribute to the safe and reliable delivery of electricity to customers. The department is responsible for coordination among all Technical Services responsibility area departments to facilitate meeting budget and program goals. Business Planning and Support manages Technical Services O&M budget, develops and monitors Key Performance Indicators (KPIs), manages the corrective action program for continual improvement, and identifies and manages business initiatives.

Q23. How will these initiatives impact O&M costs for the Business Planning and Support Department in the MRP period?

A23. These are ongoing costs for the department and generally will remain flat. The Business Planning and Support department has O&M costs that are largely labor driven, including payroll, training, travel, and office expenses.

5. Investment Strategy Activities

Q24. What are the key initiatives and activities that will drive costs for the Investment Strategy department during the MRP period?

A24. The Pepco Investment Strategy department provides discipline and oversight for short-term and long-term planning activities related to strategic investments that contribute to the safe and reliable delivery of electricity to customers. The department will be implementing an improvement to the Project Authorization Process for the Company to

1 promote proper vetting and alternative analysis based on project complexity to support
2 appropriate investments are approved. The department will continue to facilitate monthly
3 forecast governance and oversight and provide transparency to variances between actual
4 spend and budget. The department is responsible for governance over the transactional
5 process for ledger changes within the responsibility area's various financial categories to
6 adjust funding within current year budgets. The department also is responsible for
7 maintaining the responsibility area's portfolio integrity and keeps an engineering calendar
8 and KPI performance metric for the Quarterly Work Plans for various lines of business
9 organizations within PHI.

10 **Q25. How will these initiatives impact O&M costs for the Investment Strategy Department**
11 **in the MRP period?**

12 A25. These are ongoing costs for the department and generally will remain flat. The
13 Investment Strategy department has O&M costs that are largely labor driven to include
14 payroll, training, travel, and office expenses.

15 **III. CONCLUSION**

16 **Q26. Does this conclude your Direct Testimony?**

17 A26. Yes, it does.

M.A. Ortega
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (N) – 1

2018-2022 Long Range Plan Documentation

VP Area: Technical Services

Vice President:

I – Approvals

This document has been checked for errors in calculations and content.

Prepared By: Date: 9/24/18

Approved By: Date: 2/22/19
Manager/Director

Approved By: Date: 2/22/19
Manager/Director

Approved By: Date: 2/22/19
Vice President

II – Major Business Functions

Pepco Holdings' Technical Services organization is responsible for the overall management of Pepco Holdings' system assets. The team oversees electric system performance, including distribution capacity planning, reliability and maintenance programs, smart grid and innovation, vegetation management and investment strategy for all regions, including the District of Columbia. The organization – composed of a diverse, talented workforce – is committed to powering a cleaner and brighter future for our customers and communities.

Pepco Holdings' Technical Services organization is responsible for:

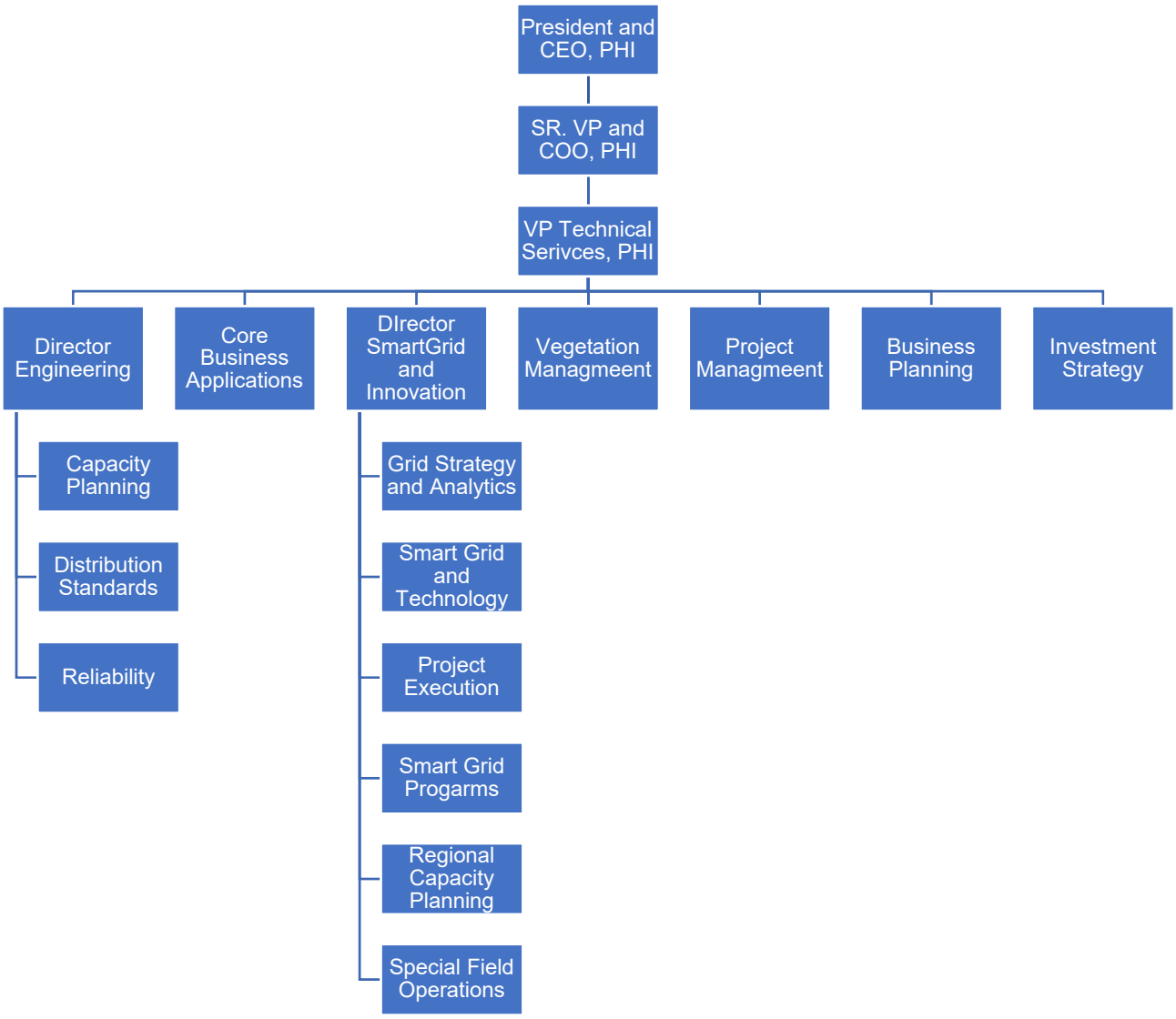
- Planning and executing distribution system capacity expansion projects and programs
- Planning, managing, and overseeing the execution of system reliability and maintenance activities in the District
- Developing and implementing smart grid and innovation programs and initiatives
- Planning and executing vegetation management in the District of Columbia
- Overseeing investment strategy

Pepco Technical Services organization is comprised of the following departments:

Pepco Technical Services	Responsibilities
Pepco Technical Services	Technical Services is responsible for the identification, design, engineering, initiation, and oversight of projects and programs on the PHI distribution system that promote the reliable delivery of energy to customers.
Pepco Business Planning	The Business Planning team is responsible for creating, managing, and tracking business initiatives and key performance indicators with a focus on safely providing reliable and affordable electricity to customers.
Pepco Central Engineering	The Central Engineering team is responsible for overall management of Pepco's electric system assets. The team oversees system performance, distribution capacity planning, reliability, maintenance programs, and distribution standards for Pepco's service area. The team provides engineering, system planning, and distribution system maintenance expertise and helps deliver safe, reliable, and affordable electricity to customers.
Pepco Core Business Applications	The Core Business Applications team builds and maintains critical applications and systems related to the operation, monitoring, and support of the electric system.
Pepco Investment Strategy	The Investment Strategy team provides financial rigor, discipline, and oversight for short-term and long-term planning activities related to strategic investments that contribute to the safe, reliable, and efficient delivery of electricity to customers.
Pepco Project Management	The Project Management team maximizes value for customers by optimizing resources to execute and control Pepco's project portfolio. The team uses proven project management processes and best practices that support safely achieving objectives on schedule and within the budget.
Pepco Smart Grid and Technology	The Smart Grid and Technology team focuses on smart grid, distributed energy resources, and deploys innovative technologies that are building a sustainable future. The Smart Grid organization is also responsible for the engineering analysis and customer services associated with renewable energy interconnection.
Pepco Vegetation Management	The Vegetation Management team is responsible for planning, managing, and executing vegetation management work related to the electric distribution system.

III – Home Center Hierarchy

The below chart depicts a high-level functional overview of the Technical Services department.



IV – Major Programs

The below table summarizes the major O&M programs and initiatives for Pepco Technical Services:

Pepco Technical Services	O&M Programs/Initiatives
Pepco Central Engineering	For operating and maintenance of the electric system, the group has scheduled inspection and equipment maintenance programs of electric system assets.
Pepco Core Business Applications	For operating and maintenance of the electric system the group is executing business intelligence data analytics initiatives and replacement of EGRET (Environmental Geospatial Resource and Engineering Tool) architecture and hosting services.
Pepco Vegetation Management	The team responds to emergency vegetation work during storm events and customer outage restoration events.

M.A. Ortega
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (N) – 2

2018-2022 Long Range Plan Documentation

VP Area: Technical Services

Vice President:

Technical Services

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	Approximately 34% work on engineering activities, 18% smart grid, the remaining 48% work on project management, vegetation management, core business applications, investment strategy, and business and office planning	7,477,747	5,936,406	6,104,466	6,219,454	6,354,259
2	Overtime	Emergent work requiring extended and additional shifts/hours	112,139	97,102	97,877	98,923	99,027
3	Incentive	Part of overall compensation package for employees at PHI to help hire, maintain, and attract top talent to the organization	1,410,147	710,025	736,469	750,063	771,278
4	Pension and OPEB	Part of overall compensation package for employees at PHI to help hire, maintain, and attract top talent to the organization	1,889,930	1,417,612	1,369,232	1,337,066	1,317,415
5	Fringe Benefits	Part of overall compensation package for employees at PHI to help hire, maintain, and attract top talent to the organization	1,377,412	939,233	979,232	1,019,015	1,062,671
6	Other Premium	Performance Based Awards, safety, years of service award, etc.	298,965	215,023	210,001	204,640	204,640
7	Stock Compensation	N/A	-	-	-	-	-
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	Driven by FTE's moved from Pepco to PHISCO indirect allocations - see base payroll)	566,216	506,899	520,833	530,624	542,149
10	Materials	Materials costs are present across the Tech Services organization for electrical system and office related materials such as overhead lines, underground lines, and line inspections	227,735	730,282	714,707	722,132	743,137
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	Storm restoration expenses	11,492,961	11,860,359	12,735,290	12,608,261	13,115,332
13	Contracting - Non-Ops	Contracting costs related to specialists utilized for a variety of management and project related activities	20,446,593	24,708,486	26,386,864	26,730,046	27,599,932
14	Contracting - Outsourced	Vegetation management-specific costs	-	-	-	-	-
15	Staff Augmentation	Staff contractors in project management, business applications and asset management	357,426	1,312,199	1,312,693	1,313,197	1,313,197
16	Insurance	N/A	-	-	-	-	-
17	Regulatory Fees/Permits	N/A	-	-	-	-	-
18	Licensing and Telecom	Software and Telecomm costs, including cell phones	107,317	119,612	120,425	121,232	121,712
19	BSC Services	N/A	-	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	Technical seminars and training programs	93,526	81,313	81,715	82,365	83,027
23	Travel & Entertainment	Business travel and meals	432,587	499,371	498,677	497,294	500,571
24	Memberships / Dues	Professional membership fees & licensing	466,274	520,795	535,422	550,477	565,965
25	Charity / Contributions	Charitable contributions		990	1,008	1,030	1,030
26	Lobbying	N/A	-	-	-	-	-
27	Office Expense	Misc. office supplies	29,358	40,240	40,414	40,591	40,719
28	Other Expenses	Misc. other costs	112,637	56,521	56,739	56,973	57,157
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	N/A	-	-	-	-	-
31	CIAC / CIAM	N/A	-	-	-	-	-
32	Facilities, Rentals, Utils	Driven by lower head count	1,320,215	1,282,092	1,291,060	1,301,529	1,303,191
33	Transportation / Fleet	Allocation of overhead fleet service costs	158,772	150,824	167,180	172,503	179,904
34	Depreciation & Amort	N/A	-	-	-	-	-
35	**Total Expense**		**$ 48,377,955**	**$ 51,185,386**	**$ 53,960,305**	**$ 54,357,412**	**$ 55,976,314**

Technical Services

VI - Headcount

Instructions:

List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt	232	217	217	217	217
Pepco Non-Exempt					
Pepco Union	8	9	9	9	9
Total Pepco	**240**	**226**	**226**	**226**	**226**
PHISCO Exempt					
PHISCO Non-Exempt					
PHISCO Union					
Total PHISCO	**-**	**-**	**-**	**-**	**-**

IN THE MATTER OF THE APPLICATION OF POTOMAC ELECTRIC POWER COMPANY FOR AUTHORITY TO IMPLEMENT A MULTIYEAR RATE PLAN FOR ELECTRIC DISTRIBUTION SERVICE IN THE DISTRICT OF COLUMBIA	**)**	**Formal Case No. 1156**

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA

VOLUME VII

DIRECT TESTIMONIES AND EXHIBITS OF

Ms. Sandra R. Fisher
Mr. Michael Maxwell
Mr. Michael S. Poncia
Mr. James L. Calabrese

S.R. Fisher
Direct Testimony
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (O)

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TRANSMISSION & SUBSTATION O&M SUMMARY

Table 1[1]

Historical	Bridge	Projection		
2018	**2019**	**2020**	**2021**	**2022**
$44,514,262	**$53,029,105**	**$52,685,454**	**$52,658,383**	**$53,593,700**

EXECUTIVE SUMMARY – SANDRA R. FISHER

This testimony discusses the cost projections, based on the Potomac Electric Power Company's (Pepco or the Company) Long Range Planning (LRP) process,[2] for Operation & Maintenance (O&M) costs for the Transmission and Substation responsibility area. The O&M cost levels discussed in this testimony are set forth in the Table 1. The expenses described in this testimony are intended to maintain the delivery of safe and reliable service to Pepco's electric distribution service customers in the District of Columbia. Pepco prioritizes its work to comply with applicable laws and regulations and to provide system integrity and reliability in accordance with our commitment to safety. Pepco's longstanding commitment to safety focuses on three primary areas – public safety, customer safety and employee safety. This safety-first culture is embedded in the manner in which we conduct our work and build our systems – from initial employee training to the installation, operation and maintenance of our utility infrastructure, and to our commitment to provide safe and reliable service to our customers.

In preparing its O&M cost projections, the Company analyzed historical levels, considered underlying cost drivers and developed an assessment of future requirements. In addition, this

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[1] Table 1 contains O&M costs for Pepco, including operations in the District of Columbia and Maryland. Please see the testimony of Company Witness Wolverton, which contains the allocation and direct billing of O&M costs between Pepco's District of Columbia and Maryland operations.

[2] The LRP process is described in the testimony of Company Witness Barnett.

testimony identifies requirements incremental to levels of historical spending and necessary to maintain the safe and reliable operations of the distribution system. Funding requirements for these new or more extensive elements are projected based on historical spending plus incremental expense requirements for new or more extensive elements.

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF SANDRA R. FISHER
FORMAL CASE NO. 1156

I. INTRODUCTION

A. Witness Qualifications and Purpose of Testimony

Q1. Please state your name and position.

A1. My name is Sandra R. Fisher. I currently serve as Vice President, Transmission and Substation, Pepco Holdings, LLC, formerly known as Pepco Holdings, Inc. (PHI). I am testifying on behalf of Pepco.

Q2. Please describe your education and other qualifications.

A2. I hold a Bachelor of Science in Electrical Engineering from Rutgers University's College of Engineering in Piscataway, NJ. The degree was awarded in 1987. I am also a Licensed Professional Engineer in State of New Jersey, and I have 29 years of experience in the electric utility industry.

Q3. What are your responsibilities as Vice President, Transmission and Substation?

A3. As Vice President of Transmission and Substation, I am responsible for the design, construction, operation, and maintenance of all substation and transmission assets for PHI's three electric utilities – Pepco, Delmarva Power & Light Company (Delmarva Power) and Atlantic City Electric Company (ACE). The departments I oversee employ approximately 700 employees and operate out of five locations in the PHI service territory.

Q4. Please describe your employment history with PHI.

A4. I began my utility career with ACE in 1990 as a design and field engineer in the Substation Engineering Department. I have held a variety of leadership positions at PHI

throughout my career, including Director, Project Management; Director, Substation and Transmission Engineering; and Manager, Distribution Engineering.

Q5. What is the purpose of your Direct Testimony in this proceeding?

A5. The purpose of my Direct Testimony is to support the O&M costs for the Transmission and Substation responsibility area, including O&M spending projected for the 2019-2022 time period. This testimony and accompanying exhibits were prepared by me or under my direct supervision and control. The sources for my testimony and exhibits are Company records and public documents. I also rely upon my personal knowledge and experience.

Q6. Are you sponsoring any exhibits in this proceeding?

A6. Yes. I am supporting PEPCO (O)-1 and (O)-2. These exhibits provide details regarding the O&M cost levels I am supporting in my testimony. PEPCO (O)-1 is a narrative description, including an organizational chart, of the Transmission and Substation responsibility area, and PEPCO (O)-2 is a spreadsheet containing LRP documentation.

Q7. Have you previously testified before the Public Service Commission of the District of Columbia (Commission)?

A7. No.

B. Description of Pepco's Transmission and Substation Responsibility Area

Q8. What are the responsibilities of the Transmission and Substation responsibility area?

A8. The Transmission and Substation responsibility area is responsible for safe and reliable, maintenance, construction, and operation of the Transmission and Substation-class assets for Pepco.

Transmission and Substation interacts with internal divisions and groups, such as the Operations Control Center, Regional Distribution Maintenance, Construction, and Engineering areas, Government Affairs, Regulatory, Customer Operations, Support Services, and Technical Services. In addition to internal stakeholders, Transmission and Substation collaborates with external entities, including adjoining utilities, PJM Interconnection, LLC, the North American Electric Reliability Corporation (NERC), the Federal Energy Regulatory Commission (FERC), local authorities, and governing agencies.

The Transmission and Substation responsibility area executes the safe and reliable duties on the Pepco (and other PHI utility) Transmission and Substation systems by planning capital installation and replacement of major assets to address system performance, capacity expansion, and some corrective maintenance projects. Transmission and Substation also performs operations and maintenance activities including corrective maintenance, preventive maintenance, and predictive maintenance to keep assets in service and achieve asset life expectancy. This includes planning and coordinating line clearances and resource scheduling, maintenance procedures, equipment repairs, inspections and testing, and engineering design and analysis.

Q9. Please describe your duties in more detail.

A9. I provide leadership of the design, construction, operations, and maintenance of all substation and transmission assets for Pepco and for all of PHI's electric utilities. Key areas of oversight include reliability performance, budget planning and management, project management of large capital projects, and development and execution of predictive, preventive and corrective maintenance programs.

Q10. Please describe the organizational structure of the Transmission and Substation responsibility area.

A10. I am responsible for the Transmission and Substation responsibility area. The responsibility area is further led by three directors: 1) PHI Engineering, 2) Pepco Operations, and 3) Delmarva Power/ACE Operations, all of whom work with a Manager of PHI Regulatory Strategy.

Within the PHI Engineering group there is a Manager of Transmission Reinforcement, a Manager of Substation Engineering, a Manager of Equipment, Standards, and Fire Protection, and a Manager of Protection and Control. Within the Engineering Manager groups the sub-managers, engineers, technicians, and drafters operate regionally between Pepco, ACE and Delmarva Power. The organization of the Transmission and Substation responsibility area is shown in PEPCO (O)-1.

Q11. Please explain how Transmission and Substation responsibilities benefit Pepco's electric distribution operations in the District of Columbia.

A11. The Transmission area Substation responsibility area provides benefit to Pepco DC's electric distribution operations regularly by collaborating on projects and maintenance where the electric system transitions between transmission and distribution functions. For example, the Transmission and Substation organization works with distribution operations to ensure appropriate switching and protection of distribution feeder switchgear circuit breakers, and the accurate analysis of distribution automated equipment settings and operations. Pepco's distribution operations and the Transmission and Substation responsibility area share the duties for the engineering, construction, and maintenance of the 69kV electric system. Transmission and Substation employees also

provide second role assistance to the distribution system during storm events, including damage assessment, wires-down spotters, and crew guides in support of the restoration of service.

Q12. How does the Transmission and Substations responsibility area work with other Pepco groups, such as Operations, Technical Services, Support Services, or Customer Operations?

A12. The Transmission and Substation responsibility area interacts with Operations to address emergent system alarms or abnormal system configurations, to prepare for extreme weather or loading events, and to coordinate and plan corrective, predictive, and preventive maintenance. Transmission and Substation works with Technical Services by reviewing extent of condition and operational comparisons for maintenance and operating practices. Transmission and Substation also coordinates with Support Services to manage facility, transportation, and logistic plans and issues and with Customer Operations to interact with our customers for planning, awareness and general communications including customers in the District of Columbia with bulk and/or critical loads.

Q13. What are the Transmission and Substation responsibility area's key goals and initiatives?

A13. In order to provide enhanced service quality and reliability, the Transmission and Substation responsibility area is undergoing a reorganization to increase efficiency and operational excellence. Transmission and Substation is implementing best practices to decrease safety events and substation interruptions and to alleviate corrective predictive, and preventative maintenance backlogs. These best practices include the Human

Performance Corrective Action program, Close Quarters Maneuvering driving courses, and Work Management software and practices.

II. TRANSMISSION AND SUBSTATION O&M ACTIVITIES

Q14. Describe the Transmission and Substation responsibility area's O&M activities.

A14. Transmission and Substation is responsible for the identification, design, engineering, initiation, and oversight of projects and programs on the PHI Transmission and Substation system to promote the safe and reliable delivery of power to PHI customers, including Pepco's customers in the District of Columbia. The Transmission and Substation area consists of engineers, drafters, electric mechanics, relay technicians, apprentices, office support personnel, supervisors and management. The primary job functions include: (1) respond to equipment alarms to troubleshoot and repair equipment and operational issues; (2) perform corrective and routine maintenance on Transmission and Substation assets; (3) analyze and assess Transmission and Substation asset health metrics to prioritize and initiate capital replacement projects; (4) conduct investigations of adverse situations to implement corrective actions and lessons learned; (5) train internal resources to meet regulatory compliance, job progression, certification, and technical needs; and (6) Participate in industry conferences and discussions to adopt and share industry leading practices and innovation.

Table 2 provides the Transmission and Substation actual and projected O&M costs.[3]

[3] Table 2 reflects costs for Pepco's operations in the District of Columbia and Maryland. Company Witness Wolverton addresses the direct billing and allocation of costs between the District of Columbia and Maryland.

Q15. What are the major cost drivers that contribute to the Transmission and Substation O&M projection?

A15. The major cost drivers affecting the Transmission and Substation responsibility area's costs are Base Payroll, Overtime, Contracting, Materials, and Facilities, Rentals, Utilities. Base Payroll incorporates employee time performing functions, including corrective maintenance, predictive, and preventive maintenance in addition to departmental, safety, and training sessions. Overtime incorporates work in excess of the standard work week to respond to emergent corrective maintenance and planned maintenance that cannot be performed within the normal work hours. Contracting includes external resources to provide consultation for corrective, predictive, and preventive maintenance related activities that are not handled by internal resources for availability or technical specialties. Materials includes replacement and repair of assets that are not considered major capital units of property required to correct deteriorated or depreciated assets as corrective maintenance. Facilities, Rentals, and Utilities includes leases and rental fees for Transmission and Substation property and utility expenses.

Table 2[4]

Historical	Bridge		Projection	
2018	**2019**	**2020**	**2021**	**2022**
$44,514,262	**$53,029,105**	**$52,685,454**	**$52,658,383**	**$53,593,700**

Q16. What are the major cost drivers that contribute to the Transmission and Substation Responsibility Area projections for 2018 to 2019?

A16. As shown in PEPCO (O)-2, costs associated with corrective, predictive, and preventative maintenance are the major element of the Transmission and Substation

[4] Further detail regarding the O&M projections for these responsibility areas are found in PEPCO (O)-2.

1 reliability area's $8.5 million in projected increases in O&M expenses from 2018 to 2019.
2 Overtime costs for maintenance activities reflect about $2.9 million of the projected
3 increase, and costs associated with contracting for maintenance activities reflect an
4 additional $1.5 million of the projected increase. Another significant cost increase (about
5 $0.6 million) relates to transportation and fleet services. The fleet performs many
6 functions, but a substantial portion of these costs are tied to the performance of corrective,
7 predictive, and preventative maintenance on Transmission and Substation assets and
8 facilities. Moreover, as discussed later in my testimony, Facilities, Rentals, Utilities costs
9 have increased to incorporate the Pepco I Street substation lease increase of about $1.3
10 million. Transmission and Substation is also increasing employee training and
11 certification, as described later in my testimony, resulting in an increase of nearly over $0.6
12 million in O&M costs from 2018 to 2019.

13 **Q17. Please describe the corrective and preventative maintenance costs in more detail.**

14 A17. As shown on PEPCO (O)-2, a substantial portion of the Transmission and
15 Substation responsibility area's O&M costs were related to Base Payroll. As described in
16 that line item, a majority of those costs are associated with employee time performing
17 corrective, predictive, and preventative maintenance, attending department and safety
18 meetings, and attending training sessions. Another major cost driver in the Transmission
19 and Substations responsibility area is overtime necessary to conduct maintenance.

20 The Transmission and Substation area executes corrective maintenance equipment
21 repairs, routine predictive and preventive maintenance programs, and analysis of
22 equipment health to justify capital replacement projects to maintain system health and
23 reliability. Corrective maintenance repairs include response to system alarms that trigger

first responder action to troubleshoot and diagnose system issues and make repairs to resolve equipment and configuration issues including field testing and relay interrogations followed by replacement of minor unit of property replacements and field adjustments. Preventive and predictive maintenance activities include routine inspections and tests of equipment to evaluate performance based on Institute of Electrical and Electronics Engineers (IEEE) and company standards to proactively address potential issues prior to serious deterioration or failure. Analysis of equipment health requires research into equipment maintenance history and trending test results to plan capital replacement of assets prior to their end of useable life. Additionally, Pepco maintains tools and vehicles required to perform these maintenance activities and respond timely to emergent events.

Q18. What other factors affect Transmission and Substation's maintenance costs?

A18. PEPCO (O)-2 demonstrates that an important component of maintenance costs is base pay and overtime for employees working on corrective, predictive, and preventive maintenance of facilities necessary to provide safe and reliable electric distribution service. Pepco works to ensure that these facilities meet or exceed their expected useful lives in order to provide reliable service at affordable rates.

Pepco's corrective, predictive, and preventive maintenance activities make efforts to perform work during the standard working shift hours; however, some events and workloads require overtime. In 2018, Pepco Transmission and Substation made efforts to reduce O&M overtime expenses through work management scheduling controls, capitalization of repairs by replacing deteriorated units of property, and scrutinizing planned overtime work. Overtime work is necessary to respond to emergent activities such

as storms in the utility operations of Transmission and Substation and 2018 did not see significant impact of storms in the Pepco region.

Q19. Please discuss in more detail the O&M costs related to Facilities, Rentals, Utilities for the Transmission and Substation responsibility area.

A19. The O&M costs for Facilities, Rentals, Utilities relates to the I Street Substation Lease costs. In 2018, the cost of the lease was $26,919 per month. The lease costs increased to $234,282 per month during the period covered by this MRP filing.

Q20. What are the major cost drivers that contribute to the Transmission and Substation responsibility area projections for 2018 to 2020?

A20. In addition to the factors described above in my testimony, Transmission and Substation is planning a training initiative for 2020. Transmission and Substation also plans a shift in external contracted resources to receive less corrective and preventative maintenance work and to focus on capital projects in 2020.

Q21. Please describe the training initiatives in more detail.

A21. Safety training and job preparation are essential to the operations of the Transmission and Substation responsibility area. Pepco's safety focus is not only on the difficult and skilled function of working on energized and de-energized electrical lines and equipment, but also focuses on employee driving skills and office personnel obligations. Employees are required to attend safety training classes specific to their role and to attend regular safety meetings to discuss safety issues and to receive information regarding the improvement of safety around the work place and at home.

NERC Cyber Infrastructure Protection upgrades are being conducted across the PHI territories to enhance the security of our infrastructure. Transmission and Substation

also complies with regulatory requirements to perform routine maintenance within required cycles in order to enable the Transmission and Substation organization to assess performance history and determine the corrective maintenance necessary to maintain system reliability. For example, Pepco conducts routine substation inspections, power transformer and circuit breaker electrical testing, dissolved gas oil analysis, protection relay trip testing, and infrared thermal scanning.

The Transmission and Substation responsibility area also promotes the progression of bargaining union lineman, mechanics, and technicians through apprenticeship program with classroom and on the job training provided by instructors and experienced lineman, mechanics, and technicians in their craft. Additionally, engineers attend conferences and seminars for exposure and lectures to develop knowledge of engineering design, technical equipment, and industry innovation.

Q22. What level of O&M costs are projected for the Transmission and Substation responsibility area projections from 2020 to 2022?

A22. Transmission and Substation O&M costs are projected to be fairly flat from 2020 to 2022.

III. CONCLUSION

Q23. Does this conclude your Direct Testimony?

A23. Yes, it does.

S.R. Fisher
Direct Exhibit
DC. P.S.C - - May, 2019

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An Exelon Company

2018-2022 Long Range Plan Documentation

VP Area: Transmission & Substation

Manager/Director:

I – Approvals

This document has been checked for errors in calculations and content.

Prepared By: Date: March 12, 2019

Approved By: Date: March 12, 2019
Manager/Director

Approved By: Date: March 12, 2019
Vice President/Sr. Vice President

II – Major Business Functions

The Transmission and Substation (T&S) organization is responsible for Safe, Reliable, and Financially responsible engineering, maintenance, construction and operation of the Transmission and Substation class assets in the Pepco Holdings footprint. The Pepco Holdings footprint incorporates Pepco (Washington DC and portions of Montgomery County and Prince Georges County, Maryland), Delmarva Power & Light (Northeast and Eastern Shore Maryland and Delaware), and Atlantic City Electric (Southern New Jersey). Detailed representation is included in the below Service Territory Maps.

T&S interacts with nearly all internal departments throughout the organization, including the following key departments:

- Operations Control Center
- Regional Distribution Maintenance, Construction, and Engineering areas
- Government Affairs
- Regulatory
- Customer Operations
- Support Services and Technical Services
- Capacity Expansion and the Transmission Planning group which resides in the Exelon Utilities Business Services Corporation (BSC)

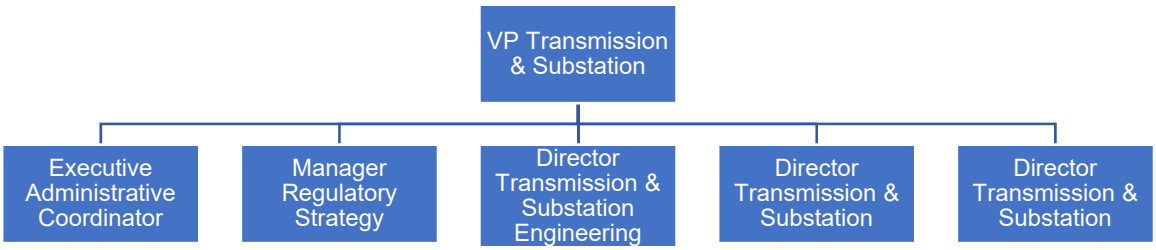
In addition to internal stakeholders, T&S collaborates with external stakeholders including:

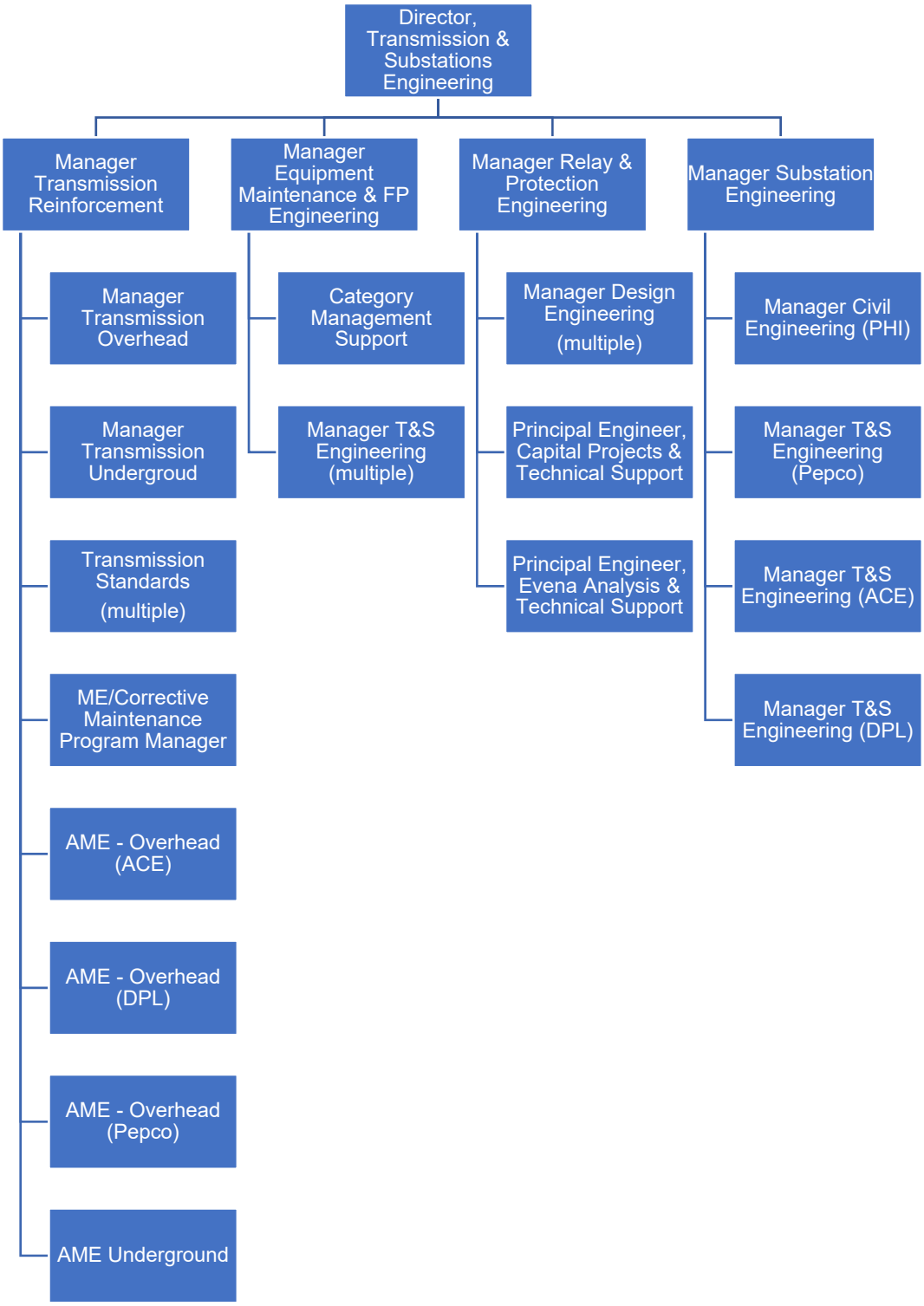
- Adjoining utilities (BGE, Dominion, PSEG, First Energy, etc.)
- Cooperatives within the footprint (e.g., Southern Maryland Electric Cooperative, Delaware Electric Cooperative, Choptank Electric Cooperative)
- Municipalities
- PJM, NERC and FERC
- Local Authorities and Governing Agencies

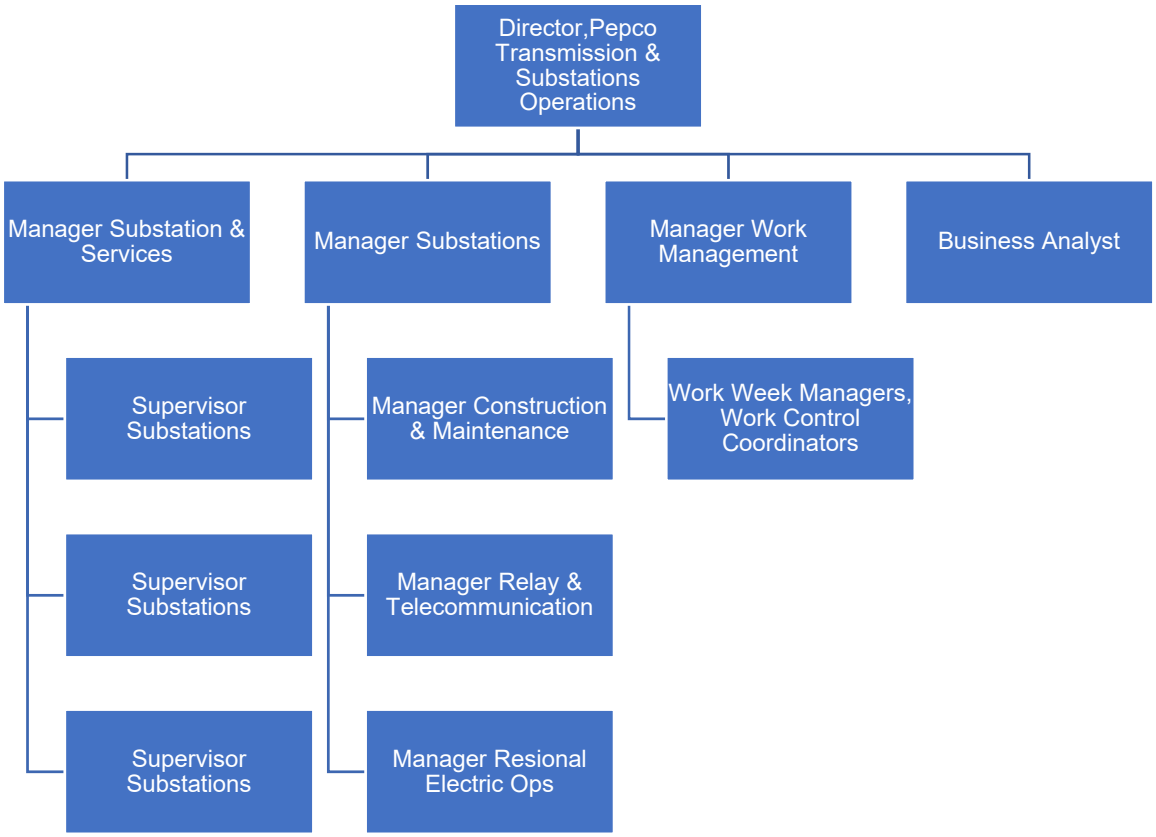
T&S executes the Safe, Reliable and Financially responsible duties on the Pepco Holdings Transmission and Substation systems by planning capital installation and replacement of major assets to address System Performance and some Corrective Maintenance projects. T&S performs the engineering activities for these types of projects as well as Capacity Expansion projects. T&S also performs Operations and Maintenance activities including Corrective Maintenance, Preventive Maintenance, and Predictive Maintenance to maintain the reliability of existing assets and achieve asset life expectancy. This includes planning and coordinating of line and substation equipment clearances and resource scheduling, maintenance procedures, minor repairs, inspections and testing, and engineering design and analysis.

III – Home Center Hierarchy

The below diagram illustrates a high-level overview of the Transmission and Substations department.




Director, Transmission & Substations Engineering
Manager Transmission Reinforcement
Manager Equipment Maintenance & FP Engineering
Manager Relay & Protection Engineering
Manager Substation Engineering
Manager Transmission Overhead
Manager Transmission Undergroud
Transmission Standards (multiple)
ME/Corrective Maintenance Program Manager
AME - Overhead (ACE)
AME - Overhead (DPL)
AME - Overhead (Pepco)
AME Underground
Category Management Support
Manager T&S Engineering (multiple)
Manager Design Engineering (multiple)
Principal Engineer, Capital Projects & Technical Support
Principal Engineer, Evena Analysis & Technical Support
Manager Civil Engineering (PHI)
Manager T&S Engineering (Pepco)
Manager T&S Engineering (ACE)
Manager T&S Engineering (DPL)


Director,Pepco Transmission & Substations Operations
Manager Substation & Services
Manager Substations
Manager Work Management
Business Analyst
Supervisor Substations
Supervisor Substations
Supervisor Substations
Manager Construction & Maintenance
Manager Relay & Telecommunication
Manager Resional Electric Ops
Work Week Managers, Work Control Coordinators

IV– Major Programs

The major O&M spending for T&S Programs is related to labor and materials for Corrective Maintenance, where less costly repair and replacement of minor parts will promote reliability and extend the life of Transmission and Substation assets. T&S Programs manage approximately $21 million of corrective maintenance annually across Distribution and Transmission classified assets. Corrective Maintenance is tracked through work management systems and is then prioritized and scheduled with bundling efficiencies in mind, to promote financial and reliability effectiveness. Prioritization of corrective maintenance work incorporates emergent activities responding to equipment failures, service interruptions, and safety issues. Planned corrective maintenance work is identified through routine inspections and equipment tests and planned through Work Management practices to incorporate efficiencies and keep assets and facilities performing at required operational and safe levels. Work backlogs are monitored and analyzed to work down priorities and address adverse equipment and system conditions. PHI T&S adopted Exelon Work Management practices in 2017 to better plan for the reactive response to system emergencies and plan proactive maintenance response to influence improved ability to control O&M budgeting.

Additionally, Preventive and Predictive Maintenance programs are in place to routinely inspect and test Transmission and Substation assets to prolong asset life and predict risks to reliability that can be proactively addressed. T&S Programs manage approximately $10 million of preventive maintenance annually across Distribution and Transmission classified assets. Preventive maintenance programs and cycles are primarily prescribed by asset class and managed in work management systems. Backlogs are monitored and maintained to keep maintenance within cycle. Results and findings are analyzed to provide short-term and long-term plans to maintain safety, reliability, and financial discipline. Main drivers to influence fluctuation are increased focus on how PHI T&S monitors assets, evaluating maintenance frequency cycles and prescribed maintenance practices to align with Exelon and Industry best practices and maintain regulatory compliance. Specific impacts include alignment of Power Transformer, Circuit Breakers, and Transmission Line and Structure inspection cycles, evaluation of enhanced Switchgear, High Voltage Disconnect Switch, and Tap Changer procedures, and incorporation of Field Equipment Groupings (FEGs) to take advantage of planned High Voltage line clearances to address all equipment within planned zone of protection.

Training and engagement in industry-related education and conferences promotes the technical competencies of our workforce for safe, reliable and efficient maintenance of our T&S Electric System. PHI has added a Training department to facilitate training programs to evaluate and enhance current training curriculums and deliver impactful training programs to Field and Engineering personnel, promoting technical growth and expertise in T&S. T&S invests approximately $5 million in training annually. T&S also participates in industry and Exelon conferences and seminars which requires additional travel and registration fees to keep at the forefront of the electric T&S industry.

Back Office charges for Safety and Departmental meetings, Employee PTO make up approximately $7 million and Operations Management is about $6 million of the T&S O&M Forecast. The new lease terms for the I Street Substation account for approximately the last $3 million.

S.R. Fisher
Direct Exhibit
DC. P.S.C - - May, 2019

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PEPCO _____ (O) – 2

2018-2022 Long Range Plan Documentation

VP Area: Transmission & Substation

Manager/Director:

Transmission & Substation

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	Employees time working on corrective and preventive maintenance, attending departmental and safety meetings, and training of employees	16,592,902	17,921,984	18,322,892	19,283,601	19,380,549
2	Overtime	Employee time supporting extended hours support for emergent corrective maintenance, extended preventive maintenance, and storm event response	5,549,974	8,445,636	8,578,503	7,565,830	7,950,474
3	Incentive	Overheads based on payroll	1,283,667	1,033,691	1,065,994	1,104,367	1,119,092
4	Pension and OPEB	Overheads based on payroll	1,275,262	3,736,712	3,491,713	3,356,114	3,036,864
5	Fringe Benefits	Overheads based on payroll	3,853,268	3,843,880	3,958,971	4,258,579	4,364,794
6	Other Premium	Stock compensation function of payroll	269,920	186,292	82,582	86,572	82,667
7	Stock Compensation	N/A	-	-	-	-	-
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	Overheads based on payroll	150,654	198,479	213,023	199,972	204,398
10	Materials	Materials purchased to support corrective maintenance repairs, perform preventive maintenance work, and procude spare replacement parts	2,650,501	1,620,104	1,670,572	1,705,410	1,733,312
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	Contracted T&S work to perform corrective and preventive maintenance and canceled capital work for contractors	2,330,595	1,157,878	1,492,008	794,306	1,171,259
13	Contracting - Non-Ops	Contracted T&S work to perform corrective and preventive maintenance	1,817,337	4,710,914	3,535,914	3,579,313	3,628,400
14	Contracting - Outsourced	Contracted T&S work to perform corrective and preventive maintenance	230,941	-	-	-	-
15	Staff Augmentation	Use of contracted resources to fill organizational needs during transition to new T&S organizational structure	688,558	640,631	646,941	661,172	671,633
16	Insurance	N/A	-	-	-	-	-
17	Regulatory Fees/Permits	Public space permit fees	502	-	-	-	-
18	Licensing and Telecom	License fees for equipment data software and employee professional license maintenance	390,504	602,488	605,101	620,831	626,981
19	BSC Services	N/A	-	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	Employee attendance and participation in industry seminars and training including registration fees	63,850	78,294	78,314	80,392	81,871
23	Travel & Entertainment	Emplyee travel mileage reimbursement, train tickets, plane tickets, and meal compensation for business travel	700,267	1,223,826	744,845	829,814	840,545
24	Memberships / Dues	Professional memberships to organizations such as IEEE	62,315	4,810	4,955	4,771	4,864
25	Charity / Contributions	N/A	-	-	-	-	-
26	Lobbying	N/A	-	-	-	-	-
27	Office Expense	Office supplies and office space management	88,520	106,536	108,327	111,506	113,276
28	Other Expenses	Canceled capital construction project expenses and default accounting for employee expenses	523,738	37,941	37,472	38,585	39,025
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	Intercompany costs and utility services	402,706	-	-	-	-
31	CIAC / CIAM	N/A	-	-	-	-	-
32	Facilities, Rentals, Utils	Facility lease and rental space	3,684,404	4,977,203	5,176,890	5,361,536	5,461,099
33	Transportation / Fleet	Company vehicles and space requirements	1,903,876	2,501,808	2,870,436	3,015,712	3,082,596
34	Depreciation & Amort	N/A	-	-	-	-	-
35	**Total Expense**		**$ 44,514,262**	**$ 53,029,105**	**$ 52,685,454**	**$ 52,658,383**	**$ 53,593,700**

Transmission & Substation

VI - Headcount

Instructions:
List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt	83	83	83	83	83
Pepco Non-Exempt					
Pepco Union	205	205	205	205	205
Total Pepco	**288**	**288**	**288**	**288**	**288**
PHISCO Exempt	131	131	131	131	131
PHISCO Non-Exempt					
PHISCO Union	3	3	3	3	3
Total PHISCO	**134**	**134**	**134**	**134**	**134**

M.W. Maxwell
Direct Testimony
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (P)

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EXECUTIVE SUMMARY – MICHAEL W. MAXWELL

Table 1[1]

	Historical	Bridge	Projections		
	2018	**2019**	**2020**	**2021**	**2022**
Expense[2]	**$19,222,156**	**$20,698, 688**	**$21,611,939**	**$22,096,884**	**$22,435,574**

This testimony discusses the cost projections, based on the Potomac Electric Power Company's (Pepco or the Company) Long Range Planning (LRP) process,[3] for Operation and Maintenance (O&M) costs for the Support Services responsibility area. The O&M cost levels discussed in this testimony are set forth in Table 1. The expenses described in this testimony are intended to maintain the delivery of safe and reliable service to our customers. Pepco prioritizes its work to comply with applicable laws and regulations and to provide system integrity and reliability in accordance with our commitment to safety. Pepco's longstanding commitment to safety focuses on three primary areas – public safety, customer safety and employee safety. This safety-first culture is embedded in the manner in which Pepco conducts its work and builds its systems – from initial employee training to the installation, operation and maintenance of Pepco's utility infrastructure, and to the commitment to provide safe and reliable service to customers.

This testimony addresses the projected costs associated with supporting and providing logistical support services to the operating organizations within Pepco performing electric distribution system in order to provide safe and reliable service to our customers. The Support

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1 Table 1 contains O&M costs for Pepco, including operations in the District of Columbia and Maryland. Please see the Direct Testimony of Company Witness Wolverton, which contains the allocation and direct billing of O&M costs between Pepco's District of Columbia and Maryland operations.

2 The O&M costs set forth in Table 1 for 2018 – 2022 are net of intercompany revenue.

3 The LRP process is described in the Direct Testimony of Company Witness Barnett.

Services costs are broken down into according to the nine departments in the Support Services responsibility area, three of which comprise the majority (53%) of the overall forecast. The major O&M programs and initiatives for Pepco Support Services stem from the Environmental Management department (22%), Claims & Damage Prevention department (16%), and Training and Methods department (15%). Each department is described in greater detail in this testimony.

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF MICHAEL W. MAXWELL
FORMAL CASE NO. 1156

I. INTRODUCTION

Q1. Please state your name and position.

A1. My name is Michael W. Maxwell, I currently serve as Vice President, Support Services of Pepco Holdings, LLC, formerly known as Pepco Holdings, Inc. (PHI). I have held this position from June 2017 to the present. I am testifying on behalf of Pepco.

Q2. Please describe your education and other qualifications.

A2. I am a 1987 graduate of the Virginia Military Institute where I earned a bachelor's degree in Electrical Engineering and a commission in the United States Army Reserves. I am currently a member of the Executive Committee of the Workforce Investment Council for the District of Columbia and a member of Leadership Greater Washington.

Q3. Please describe your employment history with PHI?

A3. I was most recently Vice President, Human Resources Operations, where I was responsible for overseeing the human resources merger and integration of PHI into the Exelon organization. Prior to leading Human Resources, I was Vice President, Asset Management, of PHI, where I was responsible for electric system planning, assuring the short- and long-term performance, reliability, and construction of the transmission and substation assets of PHI's regulated utilities. I have also held numerous positions within operations, engineering and maintenance and construction through my 31-year career at PHI.

Q4. What is the purpose of your Direct Testimony in this proceeding?

A4. I will support the cost levels of O&M costs reflected in the Company's LRP for the years 2019-2022 for the Support Services responsibility area. My testimony discusses how the Support Services area provides operational support to Pepco and provides overall benefits to customers. This testimony and any accompanying exhibits were prepared by me or under my direct supervision and control. The sources for my testimony and exhibits are Company records and public documents. I also rely upon my personal knowledge and experience.

Q5. Are you sponsoring any exhibits in this proceeding?

A5. Yes. I am sponsoring PEPCO (P)-1 and PEPCO (P)-2. These exhibits set forth the O&M costs supported by the Support Services responsibility area during the period covered by the MRP. PEPCO (P)-1 is a narrative description of the Support Services responsibility area and contains an organizational chart. PEPCO (P)-2 is a spreadsheet containing LRP documentation.

Q6. Have you testified previously before the Public Service Commission of the District of Columbia (Commission)?

A6. No, I have not.

Q7. What are your duties as Vice President of Support Services?

A7. I am responsible for support service functions including claims and damage prevention, training, human performance, safety, real estate, facilities, environmental management, corporate security, and fleet. My responsibilities include driving continuous improvements in employee safety, operational excellence and customer service for PHI utilities.

Q8. What are the responsibilities of the Support Services responsibility area?

A8. Support Services works across PHI, including Pepco, to support utility operations in claims and damage prevention, training, human performance, safety, real estate, facilities, environmental management, corporate security, and fleet for all of PHI. The duties and responsibilities of each department within Support Services will be described later in this testimony.

Q9. Does the Support Services responsibility area perform work for any companies other than Pepco within PHI?

A9. Yes. Support Services performs duties and provides support to Atlantic City Electric, Delmarva Power & Light Company, and Pepco Holdings Service Company (PHISCO). Support Services serves as the central organization in providing operational and logistical support, as well as governance and oversight, for all PHI companies. This ability to provide assistance to all PHI companies enhances efficiency and reduces costs for customers.

Q10. How does the Support Services responsibility area work with other Pepco responsibility areas, such as Operations, Technical Services, or Customer Operations?

A10. As I mentioned above, Support Services serves as the central support organization for activities conducted at each utility within PHI. As a result, Support Services works with all responsibility areas within Pepco and PHI.

Q11. Please describe the organizational structure of the Support Services responsibility area.

A11. Support Services has nine departments that support each of the utilities within Pepco Holdings including: 1) Utility Training and Methods, 2) Fleet Services, 3) Corporate Security, 4) Environmental Management, 5) Real Estate and Facilities, 6) Business Planning and Support, 7) Claims and Damage Prevention, 8) Safety and Human Performance, and 9) an Executive Administrative Coordinator. Each department is led by a manager, with the exception of the Executive Administrative Coordinator, with responsibilities for those functions within each region in the Company. PEPCO (P)-1 contains an organization chart of the Support Services responsibility area.

Q12. What are the key goals and initiatives of the Support Services responsibility area?

A12. Support Services is a true support organization with the primary responsibility of providing logistical support to the PHI utilities. As a result, Support Services' goals and initiatives often mirror those of the PHI operating organizations. Support Services also has discreet departments with varying areas of focus. I have listed some of the most critical goals of each department below.

<u>Utility Training and Methods</u> – Pepco is responsible for planning for an aging workforce. Over the last several years, Pepco has been committed to hiring a new workforce for craft positions. Being able to identify, recruit, hire and then train local talent for the types of positions Pepco has will continue to be an area of focus for this department within Support Services.

<u>Fleet Services</u> – This department provides the vehicles used by operational personnel. Fleet Services, like Pepco, has a strong commitment to environmental stewardship, which leads

the department to focus on fuel usage, vehicle idling and emissions, and fleet modernization. Fleet Services is constantly evaluating new options for alternate fuel, hybrid, and electric vehicles that can perform well and in a cost-efficient manner.

Corporate Security – This department is focused on the security of the Company's personnel and assets. Corporate Security is responsible for challenges arising from current threats that all utilities and society face. The department prepares the Company to respond to any eventuality.

Environmental Services – Pepco is committed to environmental stewardship and compliance, making Environmental Services one of the most critical departments within Support Services. Goals are to promote a corporate culture in which the Company is accountable to its communities with respect to environmental concerns and in which full compliance with environmental laws and regulations is the minimum level of acceptable performance.

Real Estate and Facilities – This department supports the management of corporate facilities, the acquisition of property and rights of way in support of our capital plans, and the disposal of property and other assets held by the company. Currently, the Real Estate and Facilities department is focused on the expansion of telecommunication infrastructure across the service territory using Company rights of way and assets. These efforts will leverage Company assets to better connect its communities.

Business Planning and Support – This department is responsible for addressing changing trends in workforce behavior, such as the declining need for centralized printing and mail distribution services. Business Planning and Support is also tasked with managing the cost

and expenses of the Company and making recommendations to better manage costs to ensure the most efficient and affordable operations.

Claims and Damage Prevention – Pepco owns and operates facilities and assets that may, despite the Company's best efforts, be involved in non-intentional events giving rise to potential claims. This department is responsible for educating the Company's contractors and the general public about the hazards associated with electric infrastructure in an effort to reduce events that may lead to claims

Safety and Human Performance – This department is tasked with carrying out Pepco's commitment dedicated to safety. To the best of its ability, the Company operates in a manner that protects the safety and health of our employees, contractors, customers and the general public. The Safety and Human Performance department works to continuously improve the Company's performance and to actively foster a safety culture.

II. SUPPORT SERVICES O&M ACTIVITIES

Q13. Describe the type of employees within the Support Services responsibility area.

A13. As described above, Support Services is responsible for many key areas necessary to support the provision of safe and reliable electric service in the District of Columbia. The Support Services department consists of facility engineers, fleet mechanics, claims managers, analysts, safety personnel, training specialists, security personnel, environmental scientists and engineers, supervisors, office support personnel, and management.

III. CLAIMS AND DAMAGE PREVENTION

Q14. Please describe the Support Services responsibility area's work with respect to Claims and Damage Prevention.

A14. The Claims and Damage Prevention group ensures that PHI develops and applies a consistent claims management approach that reduces exposure to claims and loss to the extent possible. When claims and losses occur, the Claims and Damage Prevention group investigates the claim, evaluates exposure to the claim, promotes compliance with all applicable laws and regulations related to the claim, and attempts to resolve the claim on a fair and equitable basis. The Claims and Damage Prevention group is responsible for all claims that may be made against PHI or against contractors working for PHI. In addition, this group investigates and assists in the recovery of major property damages to PHI companies. PHI Claims and Damage Prevention is also responsible for taking a proactive approach to training and education around the laws and safe digging practices. This is done by teaming up with other organizations to promote the message "811 Call Before You Dig." PHI Claims and Damage Prevention has also expanded its governance to increase the group's High-Risk Facility Standby responsibilities while also increasing the quality controls and quality audits performed on local supply vendors and contractors of choice.

IV. BUSINESS PLANNING AND SUPPORT

Q15. Please describe the Support Services responsibility area's work with respect to Business Planning and Support.

A15. The Business Planning and Support group performs the financial planning, business planning, management analytics, and similar efforts to assist the Support Services

organization in managing its operations. Business Planning and Support is also responsible for document and mail services.

V. CORPORATE SECURITY

Q16. Please describe the Support Services responsibility area's work with respect to Corporate Security.

A16. PHI Corporate Security is responsible for establishing security policies and security standards at the operating utilities that conform to Exelon Security Controls. Corporate Security promotes security education and awareness and provides security advice and services to the utility. In addition, they monitor compliance with the security policy and standards and investigate security incidents occurring on company property, impacting company infrastructure assets or personnel. Corporate Security conducts Site Vulnerability and Site Security Assessments at infrastructure sites and is responsible for security measures to mitigate and reduce identified risks to that infrastructure. The department develops specifications, requirements for contract uniformed security resources and oversees performance and conducts operational and personnel investigations when appropriate. Corporate Security also proactively acts as an active liaison with Federal, District, state and local law enforcement and Homeland Security agencies in all service areas. Corporate Security is recognized by the Federal Government as a subject matter expert in utility support of National Special Security Events.[4] The department also conducts Ethics Investigations as directed by the Exelon Office of Ethics.

[4] National Security Events are events of national or international significance deemed by the United States Department of Homeland Security to be potential targets for terrorism or other criminal activity.

VI. ENVIRONMENTAL MANAGEMENT

Q17. Please describe the Support Services responsibility area's work with respect to Environmental Management.

A17. The Environmental Management department manages environmental performance, plans and executes environmental permitting for all capital projects, manages environmental liabilities and oversees compliance obligations. The department interacts with local, state, and federal regulatory agencies to improve environmental performance and to reduce environmental risks associated with the company's operations. The Environmental Management department also manages the storage, transportation, and disposal of waste materials and oversees clean-up of hazardous waste spills, polychlorinated biphenyl clean-up, and Manufactured Gas Plant remediation. In these efforts, the Environmental Management department works with the Finance group to ensure that these efforts are undertaken in an efficient and cost-effective manner. The department also works with other Exelon departments to share and develop leading practices regarding environmental programs and efforts and participates in trade organizations with similar goals.

VII. FLEET SERVICES

Q18. Please describe the Support Service responsibility area's work with respect to Fleet Services?

A18. The Fleet Services department manages the fuel sites, procurement of vehicles, and equipment maintenance for vehicle related functions. These efforts include: (a) procurement and maximization of the asset value of on-road vehicles and off-road construction equipment, (b) maintaining safe, reliable and cost effective vehicles and

equipment that meet the needs of operational organizations, (c) providing fuel and fuel site management, to include the construction of replacement fuel sites, which comply with all federal, state and local regulations, and (d) evaluate alternative fuel vehicles and equipment and implement a strategy for procurement, maintenance and operation of same.

VIII. REAL ESTATE AND FACILITIES

Q19. Please describe the Support Services responsibility area's work with regard to Real Estate and Facilities?

A19. The Real Estate and Facilities department manages all real estate transactional and facilities maintenance and operations functions. These efforts include: (a) maximization of the asset value of real estate and facilities, appropriate reductions in operating costs and upgrades to the delivery of real estate and facilities services, (b) generation of revenues through real estate sales, land leasing and infrastructure leasing programs, (c) provision for the procurement of property rights necessary for the utility operations and (d) provision for the day-to-day management of land and project portfolio. The Real Estate and Facilities department manages and recommends all real estate transactions for the acquisition or disposition of land and infrastructure assets to senior management. Real Estate and Facilities also manages substation facilities in the Pepco region as well as the maintenance and security for office facilities, regional service centers and reporting centers and substations.

IX. SAFETY AND HUMAN PERFORMANCE

Q20. Please describe the Support Services responsibility area's work with regard to Safety and Human Performance.

A20. The Safety and Human Performance department is responsible for developing and fostering a safety culture within Pepco and the other PHI companies. The department works with employee groups to foster an understanding of work practices, expectations, and behaviors to enhance safety and supports Safety Action Committee meetings and safety discussion forums to increase the sharing of information regarding safety. The Safety and Human Performance department also establishes safety practices and rules and performs field observations to maintain compliance with those rules. The department has implemented programs to reduce injuries and motor vehicle accidents and works to identify the causes of injuries and accidents to reduce occurrences.

X. TRAINING AND METHODS

Q21. Please describe the Support Services responsibility area's work with respect to Training and Methods?

A21. The Training and Methods department provides the Utility Operations responsibility areas of Pepco and the other the PHI utilities with services to improve human performance using an industry-based systematic approach. The approach consists of several items, including: employee performance and quality evaluation; the development and facilitation of training and testing programs; and the development of construction, operating and maintenance work practices, including necessary tools and equipment. The department also supports training services, including apprenticeships, qualification training, emergency preparedness, and regulatory compliance training.

Q22. What O&M cost levels are projected for Support Services?

A22. The 2018 historical O&M costs and O&M projections for 2019-2022 are set forth in Table 3.[5]

Table 3

Description	Historical	Bridge	Projections		
	2018	2019	2020	2021	2022
Expense[6]	$19,222,156	$20,698, 688	$21,611,939	$22,096,884	$22,435,574

Q23. What are the major cost drivers that contribute to the Support Services responsibility area projections for 2018 to 2019?

A23. The major drivers resulting in O&M cost increases from 2018 to 2019 in the Support Services responsibility area are labor and overhead costs related to an organizational realignment. Environmental Permitting and Planning employees were moved to Support Services. Part of the cost increase resulting from this organizational realignment was offset by a reduction in contracting environmental services and legal charges.

Q24. What cost increases will contribute to the Support Services responsibility area projections for 2018 to 2020?

A24. In addition to the organizational realignment described above, the Support Services responsibility area is projected to experience annual merit increases and increased fuel and facility costs.

[5] Further detail regarding the O&M projections for these responsibility areas are found in PEPCO (P)-2.
[6] The O&M costs set forth in Table 3 for 2018 – 2022 are net of intercompany revenue.

Q25. What level of O&M costs is Support Services responsibility area projected to incur from 2020 to 2022?

A25. While O&M costs for Support Services responsibility area are projected to be fairly flat from 2020-2022, the responsibility area will experience annual merit increases and increased fuel and facility costs.

XI. CONCLUSION

Q26. Does this conclude your Direct Testimony?

A26. Yes, it does.

M.W. Maxwell
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (P) – 1

2018-2022 Long Range Plan Documentation

VP Area: Support Services

Vice President:

I – Approvals

This document has been checked for errors in calculations and content.

Prepared By: Date: 02/22/19

Approved By: Date: 02/22/19
Vice President

II – Major Business Functions

The major business functions of Support Services are claims and damage prevention, business planning and support, corporate security, environmental management, fleet services, real estate and facilities, safety and human performance, and training and methods. Each is outlined below.

Claims and Damage Prevention:

The Claims & Damage Prevention group ensures that PHI develops and applies a consistent claims management approach that reduces the company's exposure to claims and loss to the extent possible. When claims and losses occur, the Claims & Damage Prevention group investigates the claim, evaluates the company's exposure to the claim, ensures that the company complies with all applicable laws and regulations related to the claim, and attempts to resolve the claim on a fair and equitable basis. The Claims & Damage Prevention group is responsible for all claims that may be made against PHI or against contractors working for PHI. In addition, the group investigates and assists in the recovery of major property damages to PHI companies. PHI Claims & Damage Prevention is also responsible for taking a proactive approach to training and education around the laws and safe digging practices. It does so by teaming up with other organizations such as Miss Utility MD / DC, Columbia Gas, Washington Suburban Sanitary Commission, Verizon and other entities to promote the message "811 Call Before You Dig." PHI Claims & Damage Prevention has also expanded its governance to increase High-Risk Facility Standby responsibilities while also increasing the quality controls and quality audits performed on our locates supply vendors and our contractors of choice.

Business Planning and Support:

The Business Planning & Support group performs the financial planning, business planning, management analytics, and similar efforts to assist the Support Services organization in managing its operations. Business Planning & Support is also responsible for document and mail services.

Corporate Security:

PHI Corporate Security is responsible for establishing security policies and security standards at the operating utilities that conform to Exelon Security Controls at Pepco, ACE and DPL. Corporate Security promotes security education and awareness and provides security advice and services to the utility. In addition, they monitor compliance with the security policy and standards and investigate security incidents occurring on company property, impacting company infrastructure assets or personnel. Corporate Security conducts Site Vulnerability & Site Security Assessments at infrastructure sites and is the subject matter expert for security measures to mitigate and reduce identified risks to that infrastructure. The department develops specifications, requirements for contract uniformed security resources and oversees performance. The department conducts operational and personnel investigations when appropriate. The department also proactively acts as an active liaison with Federal, State and Local Law Enforcement and Homeland Security agencies in all service areas. Corporate Security is recognized by the Federal Government as a subject matter expert in utility support of National Special Security Events. The department also conducts Ethics Investigations as directed by the Exelon Office of Ethics.

Environmental Management:

The Environmental Management group manages PHI's environmental performance, plans and executes environmental permitting for all capital projects, manages environmental liabilities and oversees the company's compliance obligations. The group interacts with local, state, and federal regulatory agencies to improve PHI's environmental performance and to reduce

environmental risks associated with the company's operations. The Environmental Management group also manages the storage, transportation, and disposal of PHI's waste materials and oversees the cleanup of hazardous waste spills, polychlorinated biphenyl clean-up, and Manufactured Gas Plant remediation. In these efforts, the Environmental Management group works with the Finance department to ensure that these efforts are undertaken in an efficient and cost-effective manner. The group also works with other PHI and Exelon departments to share and develop best practices regarding environmental programs and efforts and participates in trade organizations with similar goals.

Fleet Services:

Fleet Services manages the fuel sites, procurement of vehicles, and equipment maintenance for vehicle related functions for PHI. These efforts include: (a) procurement and maximization of the asset value of PHI's on-road vehicles and off-road construction equipment, (b) maintaining safe, reliable and cost effective vehicles and equipment that meet the needs of PHI's operational organizations, (c) providing fuel and fuel site management, to include the construction of replacement fuel sites, which comply with all federal, state and local regulations, and (d) evaluating alternative fuel vehicles and equipment and implementing strategies for procurement, maintenance and operation of same at PHI.

Real Estate and Facilities

Real Estate and Facilities manages all real estate transactional and facilities maintenance and operations functions for PHI. These efforts include: (a) maximization of the asset value of the PHI's real estate and facilities, appropriate reductions in operating costs and upgrades to the delivery of real estate and facilities services, (b) generation of revenues through real estate sales, land leasing and infrastructure leasing programs, (c) provision for the procurement of property rights necessary for the utility operations and (d) provision for the day-to-day management of PHI's land and project portfolio. The Real Estate & Facilities group manages and recommends all real estate transactions for the acquisition or disposition of land and infrastructure assets to PHI's senior management. Real Estate & Facilities also manages substation facilities in the Pepco region as well as the maintenance and security for office facilities, regional service centers and reporting centers and substations.

Safety and Human Performance:

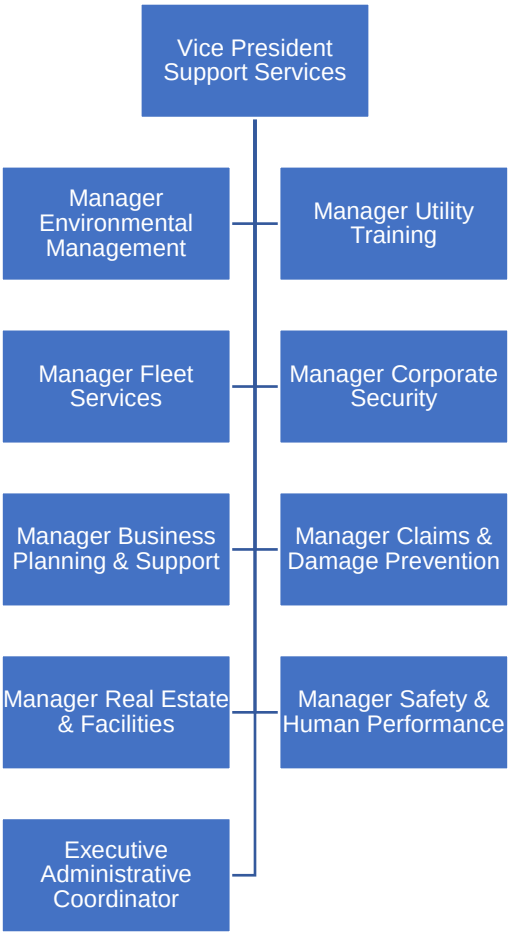
The Safety and Human Performance group is responsible for developing and fostering a safety culture within PHI companies. The group works with employee groups to foster an understanding of work practices, expectations, and behaviors to enhance safety. The group supports Safety Action Committee meetings and safety discussion forums to increase the sharing of information regarding safety. The Safety and Human Performance group also establishes best safety practices and rules and performs field observations to maintain compliance with those rules. The group has put programs in place to reduce injuries and motor vehicle accidents, and works to identify the causes of injuries and accidents to reduce occurrences.

Training and Methods:

The Training & Methods group provides the Utility Operations departments of the PHI utilities with services to improve human performance using an industry-based systematic approach. The approach consists of several items, including: employee performance and quality evaluation; the development and facilitation of training and testing programs; and the development of construction, operating and maintenance work practices, including necessary tools and equipment. The group also supports training services, including apprenticeships, qualification training, emergency preparedness, and regulatory compliance training.

III – Home Center Hierarchy

The below chart depicts a high-level overview of the Support Services department.



IV – Major Programs

Claims & Damage Prevention:

- Implement quarterly audits of Claims Case Managers field tool kits
- Implement quarterly audits of evidence lockers
- Creation of a certified Damage Prevention training on the learning management system for everyone performing excavation (internal and external)
- Crosstrain all Case Managers so they are interchangeable across the service territory
- Put online claims forms into production
- Standardize processes and procedures across the service territory
- Create position description for Damage Prevention resource and vet with Human Resources
    - Determine scope
    - Analyze workloads to assess resource need
    - Staff department accurately
- Align PHI Bodily Injury Medicare claims reporting process with other OpCo's
- Standardize claims entry points to gain consistency across PHI
- Align check processing with other OpCo's through Riskmaster
- Create strategic internal partnerships with other operational departments for collaboration and education
- Implement Riskmaster and Asset Suite 8
- Partner with Contract Management to create standards, thresholds, and consequence management for contractors-of-choice with outstanding invoices
- Partner with Governmental Affairs to improve the timely delivery of state and local documents needed to execute our mission
- Develop and implement metrics and scorecards to track performance against goals, evaluate compliance, and implement governance over the process
- Partner with Operations to create standards and metrics to track effectiveness and quality of invoices being produced to minimize rework due to inaccuracies
- Partner with PHI Safety and Governmental Affairs to promote Damage Prevention and Safety campaigns.

Business Planning and Support:

- Achieve target or greater on Duplicating and Mail Services metrics
- Maintain the Records Information Management and Audit Programs
- Leadership and guidance for Work, Planning and Tracking "WPT"
- Maintain Business Planning and Key Performance Indicator (KPI) Reporting Processes
- Maintain Contractor Management Process
- Implement employee engagement survey action plan
- Upskill the business analyst role across Support Services
- Maintain Support Services O&M and clearing expenditures within authorized targets to include any budget challenges
- Ensure effective execution of Support Services capital program in accordance with Leadership
- Support Efficiency Study
- Engage in audit processes and respond to the recommendations
- Support Exelon Utilities Electric Vehicle Strategy through the continued utilization of the Kia Soul Electric Vehicle used for mail movement
- Participate in the Distributed Energy Resource/ Solar Engagement Strategy

Corporate Security:

- Develop and execute 2019 PHI Corporate Security Safety Action Plan
- Maintain contractor safety performance through monthly reviews and quarterly forums
- Participate in Exelon Security Peer Group Activities
- Site vulnerability / security assessment format standardization
- Continued implementation of Facility Enhancement Program and expansion to facilities
- Develop plan for security system master service level agreement
- Cross OpCo security job shadow
- Conduct monthly PHI security team meetings, conduct quarterly skip meetings / contact
- Participate in ethics / legal investigation workshop training
- Represent Exelon on NATF Physical Security Peer Review
- Conduct two lunch and learns in each region (ACE, DPL, Pepco, Gas) on security topics (Workplace Violence, Active Shooter, Street Smarts, Suspicious Activity Reporting)
- Facilitate and encourage employee participation in Exelon Employee Resource Groups
- Maintain capital & O&M budget performance (+/- 2%)
- Identify opportunities for invoicing process improvement
- Peer review and benchmark security contractor resource requirement
- Provide security support / security presence for community outreach activities
- Participate in ASIS (industrial security society), Infraguard, Regional Fusion Center, and Department of Homeland Security Meetings, security training and workshops

Environmental Management:

Update and Enhance Training

- Enhanced safety training for environmental staff (Smith Driving for everyone, pre-job brief training / exercise)
- Update environmental training modules in learning management system and review environmental training matrices for operations / maintenance departments to ensure training is appropriate
- Development of avian Computer Based Training (CBT) module

Engage in Exelon Utilities charter initiatives to drive efficiencies, consistency and improvements

- PCB Work-Down Plans, Green House Gas Reduction Strategies, Pollinator Strategies, Contractor Environmental Performance
- Participate in the Exelon Utilities wide Spill and Waste bid

Centrally Managed Projects Support

- Training for Project and Construction Managers
- Work with Supply Chain on environmental terms and conditions in Construction Contracts
- Continue development of transmission nest removal strategy
- Influence distribution standards revisions – animal protection component
- Resume review of current permitting process and groups involved (Real Estate, Civil, etc.)

Environmental Management Team Reorganization

- Successfully integrate Planning and Services group
- Assess work load and reorganize the group based on bench strengths and business needs
- Address gaps by cross-training, backfilling vacancies, or hiring contractors
- Communicate new organization structure, roles and responsibilities to Stakeholders
- Develop and focus on strategies that establish processes to minimize interruptions from personnel/org changes; and offers consistency across PHI

Benning Redesign

- Support facilities in facility redesign such that environmental issues at Benning are understood and considered in site planning

ISO 14001 EMS Program

- Continue to work down all Environmental Management System corrective action plans around environmental training, root cause identification, effectiveness reviews, emergency response and evacuation plans and contractor awareness
- Set and achieve 2019 objectives and targets ('goals')
- Develop and implement new environmental compliance matrices for facilities Anacostia River Sediment Project

MD and DC Rate Cases

- Support MD and DC Rate Cases as environmental witness, prepare testimony, respond to information requests, etc.
- Develop relationships with regulators in Pepco region
- Explore blanket permitting with Montgomery County and Prince Georges County in Maryland
- Support the implementation of the Pepco Eco Club
- Manage liabilities at legacy sites such that financial burden on company and impact on environment and affected communities are minimized (manufactured gas plant sites, Buzzard Point, Anacostia River Sediment Project, etc.)
- Support DC Stewardship Strategy being led by Corporate Environmental

Fleet Services:

- Lead Safety Action Committee / Safety Programs to include the completion of the Smith driver training
- Support the development of and adopt Safety Best Practices
- Ensure that vehicles are ordered by 07/31/2019 and are received and placed into service within 10 working days after delivery
- Complete Capital Projects per agreed upon schedule
- Ensure that Preventative Maintenance is completed per schedule
- Manage Telogis units to ensure they are operational within the True (year-to-date) Non-Reporting Unit guidelines
- Manage Fleet Availability to ensure vehicles out of service are within established guidelines
- Increase Productive Hours per Technician by at least 5%
- Management & Supervision to attend at least 4 hours of internal (Exelon) or external professional or leadership development. Increase technical training by to 40 hours per Mechanic/Technician in 2018
- Implement employee engagement survey action plan
- Evaluate the development of a Fleet training/qualification program to ensure technical growth
- Maintain O&M and Capital expenditures within authorized targets
- Satisfy all Regulatory compliance requirements resulting in zero Notice of Violations (NOVs)
- Satisfy regulatory compliance requirements resulting in zero NOVs
- Implement the 2019 Fleet Electrification plan and develop a 5-year Fleet Electrification and Alternative Fuel plan
- Provide support to reduce "Geofenced" idling to reduce fuel costs and environmental impacts

Real Estate and Facilities

- Conduct quarterly table top safety job briefing exercises
- Edison Place restack and Benning redesign
- Zero critical mechanical failures at PHI critical facilities
- Achieve target or greater KPI compliance for all preventative or maintenance work orders
- Leverage Building Owner Program to collaborate and meet regional operations facility needs
- Complete integration of substation facilities maintenance program and substation condition study (Pepco)
- Support the utilization of building efficiency programs
- Comply with new Financial Accounting Standards Board (FASB) leasing standards

- Support multi-year rate case
- Maintain O&M/budget/efficiency initiatives
- Leverage transmission revenue opportunities
- Ensure effective execution of capital program in accordance with Leadership
- Evaluate third-party attachment process balancing customer needs and operational excellence

Safety and Human Performance (HP)

- Sponsor and coordinate a Safety Summit for PHI operational leaders featuring a motivational speaker
- Leverage and further exploit Telogis / Verizon Connect reporting technology for company monitored vehicles
- Develop an FLS Observation training program for new and current supervisors
- Continue the Executive, Key Manager and leadership field observations
- Safety Observations - Establish a minimum standard for safety professionals (10 per month)
- Support adopting Safety Best Practices
- Achieve 2019 Safety and Human Performance Targets
- Actively Participate in the Exelon Safety Summit (Washington DC)
- Enhance the Building Owner Program with Real Estate & Facilities (Automated External Defibrillator / First Aid / Evacuation Drills, Housekeeping, Audit Readiness, Signs)
- Evaluate the implementation of the Exelon vehicle driver authorization program
- Improve the Driver Qualification process with Kelmar
- Implement a Commercial Driver's License, backhoe, excavator and remedial driver training program utilizing the operator simulators
- Align Safety and HP personnel to optimize Governance, Oversight, Support, and Perform model to better incorporate out contractor employees
- Evaluate the DEKRA safety cultural assessments for applicability PHI
- Support Safety and HP Peer group activities
- Evaluate the effectiveness of the company Safety Action Committee / SWELL programs
- Improve leadership engagement, strengthen safety councils, enhance peer-to-peer programs, fatigue risk assessment / reporting / management
- Develop an appropriate incentive / reward & recognition program for behaviors that drive sustainable safety performance
- Attend at least four hours of internal (Exelon) or external professional development
- Conduct Quarterly Safety Steering Committee Meeting
- Introduce with Occupational Health and Safety the Exelon Safe Weight Program
- Conduct Silica Industrial Hygiene Assessment (Gas)
- Coordinate with the Environmental Group, the Safety Management System Audits at Asset Retirement Obligation and Pleasantville locations
- Maintain O&M and Capital expenditures within authorized targets
- Comply with local and regulatory compliance obligations
- Investigate a third-party outreach partner to minimize safety incidents to general public (schools/construction industry)
- Partner with PHI Claims and Governmental Affairs to promote Damage Prevention and Safety campaigns
- Support the DC Infrastructure Academy (Safety, Stretching, Safe Driving)
- Use the Gas and Electric Safety Trailers as an internal and external demonstration safety vehicle

Training and Methods

- Support DC Infrastructure Academy Utility Training Program
- Support implementation of Safety Best Practices

- Offer 8-hour Smith Driving Training
- Offer 4 hours Close Quarters Maneuvering
- 100% PHI completion of Ethics & Security Training
- Ensure training is offered and complete for 2nd Role assignments
- Provide focused Lockout-Tagout training to reduce violations and unplanned outages
- Implement Training Councils in each region
- Implement Regional tool committees facilitated by Methods leadership
- Improve training facilities across PHI
- Implement employee engagement survey action plan
- Include diversity / inclusion discussion in team meetings
- Maintain O&M expenditures within authorized targets
- Ensure compliance training status if communicated to operations leadership for appropriate action

M.W. Maxwell
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (P) – 2

2018-2022 Long Range Plan Documentation

VP Area: Support Services

Vice President:

Support Services

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	23% on training, 22% on environmental, 18% on claims, 12% on safety, 10% on real estate, 6% on security, 5% on facilities, and 2% each on business planning and vice president	5,514,811	6,646,712	6,838,840	6,975,786	7,130,310
2	Overtime	Administrative wages that exceed base payroll	190,917	173,599	173,360	173,101	175,142
3	Incentive	Formulaic based on key performance indicators in Annual Incentive Plans	865,318	757,519	784,787	800,852	823,617
4	Pension and OPEB	Function of payroll based on actuarial study	1,032,848	1,505,385	1,439,944	1,385,687	1,333,782
5	Fringe Benefits	Function of payroll based on headcount	1,092,370	1,202,145	1,251,843	1,302,855	1,359,054
6	Other Premium	Primarily long-term incentive plan for key managers and above; also includes other awards	197,966	180,247	222,703	165,813	165,813
7	Stock Compensation	N/A	-	-	-	-	-
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	Function of payroll: includes federal unemployment, federal social security, state unemployment	276,211	367,859	378,189	385,678	394,316
10	Materials	Used mainly for training materials such as harnesses and safety gear, environmental materials such as PPE/signs/containers, as well as materials to support business operations	143,152	117,001	120,157	123,290	126,290
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	Mainly environmental technical support and guidance with some external training contractors	922,590	989,005	1,103,367	1,129,846	1,158,245
13	Contracting - Non-Ops	Mainly safety contracting for on-site ergonomics and driver background checks, as well as limited professional services for environmental and facilities departments	1,154,571	557,002	520,122	537,471	549,896
14	Contracting - Outsourced	Contracting charges budgeted within Contracting - Ops Cost Type	45,294	-	-	-	-
15	Staff Augmentation	Used for contractors performing functions that are typically performed by Exelon employees and also includes dollars budgeted for interns	473,987	560,341	584,590	600,406	615,428
16	Insurance	Environmental and Real Estate Risk Management Insurance	13,438	-	-	-	-
17	Regulatory Fees/Permits	Environmental Permits	19,967	(86,904)	(90,434)	(90,434)	(90,434)
18	Licensing and Telecom	Cost of software maintenance fees, application licenses, as well as charges for cell phones, PDAs, and other personal telecommunication devices	187,159	208,734	214,319	219,890	225,242
19	BSC Services	N/A	-	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	Seminars and training for professional development and industry peer workshops and meetings	39,954	87,464	89,743	92,042	94,282
23	Travel & Entertainment	Includes business travel related expenses, such as mileage reimbursement, car rental, railways, taxi, travel booking fees, etc. This account also includes meal expenses, tuition reimbursement, and costs associated with employee relocation	263,076	296,131	281,453	289,476	295,807
24	Memberships / Dues	Cost of industry and professional memberships for employees and the company (e.g., Utilities Enterprise Membership)	49,268	34,528	45,239	46,416	47,536
25	Charity / Contributions	N/A	-	3,591	3,691	3,791	3,886
26	Lobbying	N/A	-	-	-	-	-
27	Office Expense	Supplies	37,267	137,085	140,077	143,108	146,172
28	Other Expenses	Other miscellaneous costs not specifically accounted for in other operating expense sub accounts	1,150,352	1,131,994	1,423,393	1,456,076	1,520,817
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	N/A	-	-	-	-	-
31	CIAC / CIAM	N/A	-	-	-	-	-
32	Facilities, Rentals, Utils	Facilities space used by Support Services organization, higher amount in 2018 is intercompany expense offset by intercompany revenue below	13,304,713	5,372,108	5,581,681	5,831,732	5,816,294
33	Transportation / Fleet	Fleet vehicles used by Support Services organization, higher amount in 2018 is intercompany expense offset by intercompany revenue below	1,164,920	457,143	504,876	524,000	544,082
34	Depreciation & Amort	N/A	-	-	-	-	-
35	**Total Expense**		**$ 28,140,147**	**$ 20,698,688**	**$ 21,611,939**	**$ 22,096,884**	**$ 22,435,574**
36	Intercompany Revenue	Intercompany revenue (offsets intercompany facility/fleet expense included in rows 32 and 33 above)	(8,917,991)	-	-	-	-
37	**Adjusted Expense**		**$ 19,222,156**	**$ 20,698,688**	**$ 21,611,939**	**$ 22,096,884**	**$ 22,435,574**

Support Services

VI - Headcount

Instructions:

List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt	19	25	25	25	25
Pepco Non-Exempt	4	4	4	4	4
Pepco Union	39	48	48	48	48
Total Pepco	**62**	**77**	**77**	**77**	**77**
PHISCO Exempt	73	89	89	89	89
PHISCO Non-Exempt	2	3	3	3	3
PHISCO Union	14	18	18	18	18
Total PHISCO	**89**	**110**	**110**	**110**	**110**

M.S. Poncia
Direct Testimony
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (Q)

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EXECUTIVE SUMMARY - MICHAEL S. PONCIA

Table 1[1][2]
Customer Operations O&M Summary

Historical	Bridge	Projections		
2018	2019	2020	2021	2022
$62,858,522	$76,510,905	$76,688,559	$77,462,872	$78,162,989

This testimony presents the projected Operations and Maintenance (O&M) costs associated with the Customer Operations responsibility area. The O&M cost levels discussed in this testimony are set forth in Table 1 and include the following areas: Meter Services and Meter Operations, Billing, Customer Contact Center, Revenue Management, Customer Experience and Program Implementation, and Energy Efficiency Programs.

In preparing its projections for the Multiyear Rate Plan (MRP) period 2020-2022, the Potomac Electric Power Company (Pepco or the Company) analyzed its actual 2018 spending levels, considered underlying cost drivers and developed an assessment of future requirements. The Company also projected costs for 2019 which is a bridge year between 2018 historical costs and the MRP period.

This testimony discusses current key initiatives of the Customer Operations responsibility areas as well as those planned for 2020-2022, which provide operational support to Pepco and benefits Pepco customers.

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1 O&M summary reflects the inclusion of Meter Field Operations in the Customer Operations organization in 2018 and the subsequent addition of a portion of the Applications Technology group in 2019 and beyond.

2 The O&M costs reflected are total Pepco costs, including the District of Columbia and Maryland. See the Direct Testimony of Company Witness Wolverton for the allocation of costs to the District of Columbia.

Finally, this testimony describes the Customer Operations Performance Incentive Mechanisms (PIMs) included in the Company's MRP for 2020-2022 and discusses the development of two service level PIMs: Service Level and Call Abandonment Rate. These PIMs will align the work of Customer Operations to achieve and maintain first quartile performance with respect to all facets of customer interactions in a safe and reliable manner. Customer Operations strives to provide the greatest value in customer engagements, and to promote continuous improvement as necessary, with an overall goal to achieve the highest levels of customer satisfaction in a cost-effective manner.

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF MICHAEL S. PONCIA
FORMAL CASE NO. 1156

I. INTRODUCTION

A. Witness Qualifications and Purpose of Testimony

Q1. Please state your name and position.

A1. My name is Michael S. Poncia and I am the Vice President of Customer Operations for Pepco Holdings, LLC, formerly Pepco Holdings, Inc. (PHI). I am testifying on behalf of Pepco or the Company.

Q2. What are your duties as Vice President of Customer Operations?

A2. I am responsible for customer operations functions including meter services and meter field operations, billing, credit and collections, customer contact centers, customer program technology implementation, and energy efficiency programs. My responsibilities include driving continuous improvements in employee safety, operational excellence, and customer service for PHI utilities.

Q3. Please describe your education and professional experience.

A3. I hold a Bachelor of Science degree and Master of Science degree in Civil Engineering from Drexel University. I have worked in the energy industry for more than 30 years and have held leadership positions in a variety of areas.

From 2002 through 2008, I served as Process Owner, Customer Relationship Management for PHI. My responsibilities included implementing outage response communication improvements and communicating customer satisfaction research findings throughout the company including internal consulting on various customer

satisfaction improvement initiatives. From 2008 through 2011, I served as the Director, Delmarva Power Gas Delivery responsible for managing all aspects of Delmarva's Gas Delivery business including engineering, construction, maintenance, leak response and financial reporting. From 2012 through 2015, I served as Program Director, Customer Information System Replacement Project for Pepco Holdings. This was a multi-year program which included the replacement of two legacy billing systems with a state-of-the-art commercial system. I was responsible for the design, development and deployment of the Customer Relationship Management and Billing System. Prior to joining Pepco Holdings, my professional experience also includes working in a variety of engineering, project management, construction, and account management roles for PECO.

Q4. What is the purpose of your Direct Testimony in this proceeding?

A4. The purpose of my Direct Testimony is to demonstrate how the Customer Operations responsibility area provides operational support to Pepco and benefits Pepco customers. My testimony will also support O&M costs reflected in the Company's Long Range Plan (LRP) for the years 2018-2022.[3] This testimony and accompanying exhibits were prepared by me or under my direct supervision and control. The sources for my testimony and exhibits are Company records and public documents. I also rely upon my personal knowledge and experience.

Q5. Are you sponsoring any exhibits in this proceeding?

A5. Yes. I am sponsoring PEPCO (Q)-1, which describes the Customer Operations organizational structure. PEPCO (Q)-2 provides details regarding the O&M costs

[3] See the Direct Testimony of Company Witness Barnett for details regarding the Company's LRP process.

supported by the Customer Operations responsibility area during the period covered by the MRP.

Q6. Have you previously submitted testimony to the Public Service Commission of the District of Columbia (Commission)?

A6. No.

B. Description of Customer Operations Responsibility Area

Q7. What are your duties as Vice President of Customer Operations?

A7. I am responsible for customer operations functions including: (1) meter services and field operations; (2) billing; (3) customer contact centers; (4) revenue management; (5) customer experience and program implementation; and (6) energy efficiency programs. My responsibilities include driving continuous improvements in employee safety, operational excellence and customer service for Pepco Holdings utilities.

Q8. Describe the six Customer Operations responsibility areas.

A8. Customer Operations is responsible for the integration of the following business groups in delivering quality services to our customers:

1. **Meter Services and Field Operations** – Responsible for ensuring timely and accurate meter readings, meter maintenance, periodic meter testing, and for theft prevention.
2. **Billing** – Responsible for ensuring timely and accurate invoicing for all classes of customers.
3. **Customer Contact/Customer Care Center** – Responsible for providing customer service to Pepco customers including key customer service metrics such as Telephone Service Level, Call Abandonment Rates and Call Center Satisfaction.

4. **Revenue Management** - Responsible for remittance processing and credit and collection activities.
5. **Customer Experience and Program Implementation** – Responsible for implementing and supporting customer facing systems such as website enhancements, mobile applications and the Interactive Voice Response (IVR) System. This group also provides project management resources for customer facing program implementations such as eBill and AutoPay programs.
6. **Energy Efficiency Programs** – Responsible for designing and implementing a portfolio of Energy Efficiency Programs for Pepco Holdings.

II. CUSTOMER OPERATIONS O&M ACTIVITIES

Q9. Please describe the Customer Operations responsibility area's O&M activities.

A9. Through its six business units, Customer Operations enables Pepco to support customers through the Meters to Cash process. The goal is to provide the highest level of service to customers throughout this process. The component activities to support this are meter system initiation and set-up, meter reading, billing for energy and non-energy customer requirements, the customer contact environment through live Customer Service Representatives, and our automated response systems (such as IVR, Web-based services such as MyAccount, ePay, AutoPay, Turn-On/ Turn-Off services), energy efficiency and demand reduction programs, credit management, revenue collection, and revenue protection. These areas are staffed by service representatives, analysts, engineers, office support personnel, supervision, and management. Table 2 provides the actual and projected Customer Operations O&M for the time periods indicated.

Table 2[4][5]
Customer Operations O&M Summary

Historical	Bridge	Projections		
2018	**2019**	**2020**	**2021**	**2022**
$62,858,522	**$76,510,905**	**$76,688,559**	**$77,462,872**	**$78,162,989**

To view the 2018 – 2022 Customer Operations O&M LRP costs in detail, please see PEPCO (Q)-2. As reflected in that exhibit, Customer Operations' costs are primarily labor, contracting, licensing and telecom, and facilities related. The variance between 2018 Historical O&M and the 2019 and beyond O&M costs, is in part due to the transition of Applications Technology staff (labor and contracting) from the Technical Services Organization to the Customer Operations organization, in order to better align their work in support of customer systems. Other contributing factors were overall corporate changes in pension and benefits, and staffing and contracting levels in Customer Operations.

Q10. How is Customer Operations organized?

A10. Please refer to PEPCO (Q)-1, which provides a description of Customer Operations in an organizational chart view. Please also refer to PEPCO (Q)-2, which provides a listing of the Pepco specific and shared departments that are reflected in the actual and budget dollars incorporated in my testimony.

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[4] O&M summary reflects the inclusion of Meter Field Operations in the Customer Operations organization in 2018 and the subsequent addition of a portion of the Applications Technology group in 2019 and beyond.

[5] The O&M costs reflected are total Pepco costs, including the District of Columbia and Maryland. See the Direct Testimony of Company Witness Wolverton for the allocation of costs to the District of Columbia.

Q11. How does the Customer Operations responsibility area work with other Pepco business areas, such as Operations, Technical Services, Support Services, or Customer Advocate?

A11. Customer Operations collaborates with each of the areas listed. Examples include working closely with Operations on timely and accurate outage response communication and outreach efforts, supporting various community events with the Customer Advocate team, and working with safety professionals to educate employees on injury prevention.

III. CUSTOMER OPERATIONS KEY INITIATIVES

A. Key Initiatives and Goals

Q12. What are the key initiatives of Customer Operations?

A12. Customer Operations has an overall goal to continuously improve Pepco's customers' experience with the company. As such, the multiple business groups focus on specific capabilities in their respective operational areas to contribute to this overall goal. Due to the many potential points of customer contact with the Company, we recognize the interdependencies required of our organization.

The Company makes the effort to provide as seamless an interaction process as possible for customers in the delivery of energy and services in a safe, timely, accurate, and reliable manner. Customer Operations strives to provide these services under the umbrella of employee safety, driving operational excellence in key customer service metrics, developing employees, and meeting financial targets.

Q13. Please provide the major cost components for ongoing operations and support functions included in the Customer Operations Baseline costs.

A13. Please refer to PEPCO (Q)-2, which describes the various cost components of Customer Operations. Labor- and contracting-related cost types comprise are the two largest components of costs for Customer Operations.

Q14. Please describe the key initiatives of the Meter Services and Field Operations business area.

A14. Meter Services and Customer Field Operations are making improvements to address customer service by focusing on the following:

- Timely and accurate meter reads;
- Daily Exception Management; and
- Leveraging AMI communication network in support of outage restoration.

Q15. Please describe the key initiatives of the Customer Care business area.

A15. Customer Care is making improvements in addressing customer service by focusing on the following:

- Continuing to achieve first quartile performance on Service Level, Agent Service Level and Abandonment Rate, as well as, exceed the target for Call Center Satisfaction.
- Property Management Web Portal – Implemented Q1 2019. This allows Landlords and Property Managers to manage their commercial rental space using the Portal to view their electric responsibility to all the buildings and units in their landlord agreement(s). They may also use the Portal to disconnect service on behalf of their tenants.

Q16. Please describe the key initiatives of the Billing business area.

A16. Billing is making improvements in addressing customer service by focusing on the following:

- Timely and accurate billing; and
- Daily Exception Management.

Q17. Please describe the key initiatives of the Revenue Management business area.

A17. Revenue Management is making improvements in addressing customer service by focusing on the following:

- Increasing efforts to refer low income customers to agency assistance; and
- Daily Payment Exception Management.

Q18. Please describe the key initiatives of the Energy Efficiency Programs business area.

A18. Energy Efficiency Programs is making improvements in addressing customer service by focusing on the following:

- Pepco has implemented a new and improved "My Account" experience. The new "My Account," which went live in March 2019, provides Pepco's customers with several new features designed to help customers manage and control their energy usage. The first new feature available is the ability to receive an alert when a customer's usage is trending higher than what a customer used last year or above a predetermined threshold that the customer can set. The "High Bill Alert" will be sent mid-bill cycle, giving customers time to modify their energy usage, reducing the magnitude of the high bill. A second new feature provided to District of Columbia customers is the option of receiving weekly AMI reports customized to a customer's actual usage. These

reports will show customers when their energy use is highest and customer specific energy use trends.

Q19. Please describe the key initiatives of the Customer Experience and Program Implementation business area.

A19. Customer Experience is making improvements in addressing customer service by focusing on the following:

- Improving website functionality, self-service, and energy management tools.
- Implementing a Customer Preference Center enabling customers to select from voice, email or text channels for proactive alerts related to Billing and Payment and to have efficient and effective communications in their interactions with Pepco.
- Outage Maps Improvements – Upgrading Pepco's outage maps to a more customer-focused tool with real-time configuration options to address customer communication needs

Q20. Discuss the variance between the O&M costs for 2018 and 2019.

A20. The variances between 2018 ($62.9 million) and 2019 ($76.5 million) are detailed in PEPCO (Q)-2. The variance between 2018 Actual O&M and the Projected 2019 O&M is due in large part to the transition of Applications Technology staff (labor and contracting) from the Technical Services Organization to the Customer Operations organization, in order to better align their work in support of customer systems. Other contributing factors were overall corporate changes in pension and benefits, and staffing and contracting levels in Customer Operations. The major components of the variance

between 2018 Actual O&M and 2019 O&M in both dollars and as a percent of the total increase are described in Table 3.

Table 3

O&M Variance from 2018 to 2019 (in Millions)		% of Total Increase
AT Transfer Total (Labor + Pension + Contractor)	**$5.12**	**37%**
Pepco Application Technology Labor:	$3.60	26%
Pepco Application Technology Pension Increase	$0.78	6%
Pepco Application Technology Contractor	$0.74	5%
Pension & OPEB Increase (net of Application Technology):	**$2.22**	**16%**
Vacancies:	**$3.00**	**22%**
Contractor:	**$2.97**	**22%**
Other:	**$0.35**	**3%**
Total:	**$13.65**	**100%**

Q21. Please explain any variances between Customer Operations O&M costs in 2018 and projected Customer Operations O&M costs during the period 2020-2022.

A21. The variance in Customer Operations between 2018 and the 2020 – 2022 time period represent the leveling off of the variances that took place between 2018 and 2019. As such, the 2020 to 2022 forecasted costs are relatively flat, with any slight changes due to the overall general wage growth at less than the current rate of inflation.

Q22. Why are you comparing the 2018 costs to the 2020 costs?

A22. The Company is comparing 2018 to 2020 because 2018 includes historical costs and 2020 is the first year in the MRP.

Q23. What are the major cost drivers of the Pepco O&M cost increases from 2020 through 2022?

A23. Costs from 2020 through 2022 remain relatively flat; they increase only 1.9% from about $76.7 million to $78.2 million, driven by direct labor and related costs.

1 **Q24. What are the Customer Operations Department's key initiatives for 2020-2022?**

2 A24. Customer Operations business areas align their efforts across their initiatives to
3 include driving continuous improvements in employee safety, operational excellence, and
4 customer service for Pepco Holdings utilities. Customer Operations will continue to focus
5 on improving the customer experience by engaging customers through technology and
6 achieving and/or maintaining first quartile operating performance throughout the Customer
7 Operations organization.

8 **IV. DISCUSSION OF CUSTOMER OPERATIONS PERFORMANCE INCENTIVE**
9 **MECHANISMS (PIMs)**

10 **Q25. Are you sponsoring any PIMs in your testimony?**

11 A25. Yes. I will address two operational PIMs focused on customer service: Service
12 Level and Abandonment Rate. Each is a measure of our ability to respond to Pepco
13 customers. Company Witness McGowan presents the PIMs proposal in his Direct
14 Testimony.

15 **Q26. Why is Pepco proposing customer service PIMs?**

16 A26. Pepco is proposing customer service PIMs to incentivize performance levels that
17 are in the first quartile relative to its peers in the industry. These metrics are measured, in
18 some cases daily, and are communicated throughout the respective business responsibility
19 areas. These metrics allow the Company to assess its performance in those specific areas
20 and, where necessary, provide input to changes that need to be made for improvement.
21 Additionally, certain performance metrics are incorporated in the employee Annual
22 Incentive Program (AIP), which is designed to incent high performance that aligns with

1 the goals of Pepco, PHI, and Exelon, for high levels of Customer Satisfaction and
2 Operational Performance. Please see Table 4 for a description of the proposed PIMs.

Table 4

Category	Goal	Metric	Target	Penalty/ Reward**
Operational	Customer Service	Service Level	90%	-2.5 bps / +2.5 bps
Operational	Customer Service	Abandonment Rate	1.5%	-2.5 bps / +2.5 bps

3 **Q27. What is Service Level?**

4 A27. Service Level is the actual number of calls answered within 30 seconds by all
5 methods divided by the total number of calls offered. For example, if 1,000 calls come into
6 the call center in a given period of time, and 920 of those calls were answered by either Call
7 Center Representatives or by the automated IVR system, in 30 seconds or less, then the
8 Service Level for that period of time would be 92% (920/1,000).

9 **Q28. What is the Company's current EQSS?**

10 A28. The current EQSS for Pepco for Service Level is 70% pursuant to District of
11 Columbia regulations.[6]

[6] District of Columbia Municipal Regulations Title 15, Chapter 36, Electricity Quality of Service Standards, (§3602.2).

1 **Q29. Please describe Pepco's current EQSS performance level as it relates to Service Level.**

2 A29. Under the EQSS, Pepco's current service level target is 70%. If Pepco fails to meet
3 this target, it is subject to potential penalties under District of Columbia regulations and
4 District law.

5 **Q30. Please describe Pepco's proposed PIM related to Service Level.**

6 A30. Pepco is proposing a Service Level PIM starting with 2020 performance, including
7 target performance of 90%, with a deadband of +/- 3 points around that performance level.
8 In this case the deadband represents a range of Service Level of 87% to 93%.

9 **Q31. How did the Company arrive at this deadband for the Service Level PIM?**

10 A31. The Company reviewed the last five years of performance and determined the
11 variance over that time period. Based on the variability of this metric getting smaller over
12 time, the Company developed conservative targets that account for the variation in
13 performance metrics experienced more recently.

14 **Q32. Why is Pepco's proposed Service Level target appropriate?**

15 A32. Pepco's proposed Service Level target of 90% represents first-quartile performance
16 based on the latest available three-year benchmarking average and represents a 20-point
17 improvement upon the EQSS performance level.

18 **Q33. What is Abandonment Rate?**

19 A33. The Abandonment Rate is the actual number of calls abandoned from queue divided
20 by the total number of calls offered, expressed as a percentage.

Q34. Please describe Pepco's current EQSS performance level as it relates to Abandonment Rate.

A34. Under the EQSS, Pepco's current abandonment rate target is 10%. If Pepco fails to meet this target, it is subject to potential penalties.

Q35. Please describe Pepco's proposed PIM related to Abandonment Rate.

A35. Pepco is proposing an Abandonment Rate PIM starting with 2020 performance, including target performance of 1.5%, with a deadband of +/- 1 point around that performance level.

Q36. How did the Company arrive at this deadband for the Abandonment Rate PIM?

A36. The Company reviewed the last five years of performance and determined the variance over that time period. Based on the variability of this metric getting smaller over time, the Company developed conservative targets that account for the variation in performance metrics experienced more recently. Company Witness McGowan's testimony discusses the development of the Company's PIMs proposal in greater detail.

Q37. Why is Pepco's proposed Abandonment Rate target appropriate?

A37. Pepco's proposed Abandonment Rate target of 1.5% represents first quartile performance and represents an 8.5 point improvement upon the EQSS performance level.

Q38. How did Pepco develop its proposed deadbands around both the service level and abandonment rate PIM?

A38. The proposed deadbands allow for some normal variation in performance and were developed based on the standard deviation of results in these metrics over the past five years.

Q39. What has been Pepco's historical Service Level and Abandonment Rate performance in the District?

A39. Table 5 illustrates the Pepco DC actual performance for Service Level and Abandonment Rate during the 2013 – 2018 time period.

Table 5

Year	Service Level	Abandonment Rate
2013	75%	3.9%
2014	60%	4.5%
2015	66%	8.2%
2016	86%	2.0%
2017	92%	0.7%
2018	92%	0.9%

Q40. How do these PIMs benefit customers?

A40. These PIMs incentivize Pepco to maintain or improve its performance in alignment with the District of Columbia's and Commission's goals to provide outstanding customer service. Under this PIM, Pepco will be penalized for performance worse than the deadband and rewarded for exemplary performance better than the deadband. If Pepco performs near the target level within the deadband, no reward or penalty will take place. Penalties and rewards under this PIM would be automatic, as opposed to penalties under the EQSS which are discretionary.[7]

[7] As noted by Witness McGowan, Pepco would ask the Commission to take any automatic PIM penalties under consideration when assessing potential EQSS penalties for non-compliant performance.

Q41. How will the Company report on its Service Level and Abandonment Rate performance in the context of its proposed PIMs?

A41. As discussed in the Direct Testimony of Company Witness McGowan and Company Witness Wolverton, Pepco will include a report on its performance against proposed PIM target levels in its Annual Reconciliation Filing, made around May of each year.

Q42. What does the Company propose happen to these PIMs at the conclusion of the MRP?

A42. The Company proposes that the PIMs be re-evaluated and re-established in its next MRP filing. That notwithstanding, PIMs could potentially be proposed outside of the MRP and included in the Annual Reconciliation Filing described above.

V. CONCLUSION

Q43. Does this complete your Direct Testimony?

A43. Yes, it does.

M.S. Poncia
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (Q) – 1

2019-2023 Long Range Plan Documentation

VP Area: Customer Operations

Vice President:

I – Approvals

This document has been checked for errors in calculations and content.

Prepared By: Date: September 21, 2018

Approved By: Date: March 2, 2019
Manager/Director

Approved By: Date: March 2, 2019
Vice President

II – Major Business Functions

Customer Operations strives to do the best work possible in the most safe, efficient, and cost-effective manner possible, while serving our customers at the highest level of customer satisfaction possible; within our budget constraints.

Customer Operations in Pepco consists of seven Business Areas or Departments with high-level responsibilities indicated in the table below:

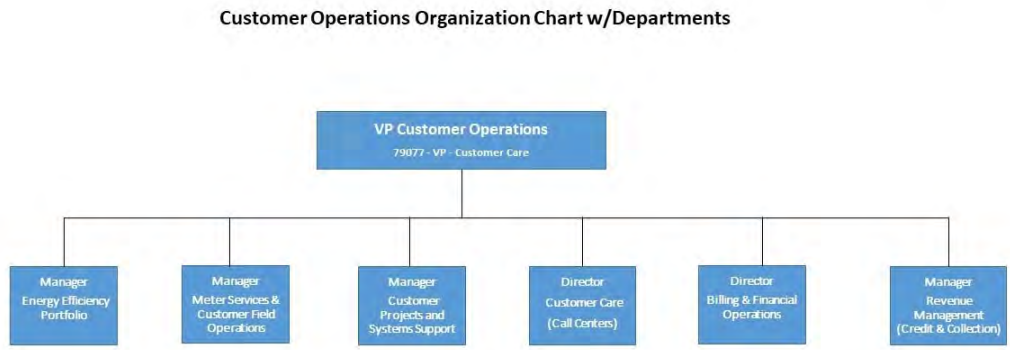
Business Area	Responsibilities
Customer Operations Management	Provides the overall management, strategy, integration, and improvement of the Customer Operations organization through the combined efforts of the leadership team. The primary areas of focus for the leadership team are: • Safety • Operational effectiveness and efficiency • Cost management
Credit/Remittance and Collection	Provides all areas of managing the inflow of payments from customers for the use of energy provided by Pepco: • Track all customer payment process activities • Identify various aspects of arrearage management • Determine and provide timely and accurate reporting of customer payment status, both timely and not, to determine customer payment quality and where necessary determine payment arrangements for customers in need of payment assistance, either through agencies or payment plans
Manage Customer Experience / Manage Revenue	This group consists mainly of program managers and a recently added Applications Technology (AT) group: • The AT group supports various technology driven portions of the Customer Operations' business • The program managers manage various initiatives that are in the development and implementation stages, so they can be handed off to the business once developed, tested, and successfully integrated into the normal day-to-day work • This group is also responsible for financial and operational analysis and reporting for Customer Operations
Customer Relations & Programs & DSM	This Department is responsible for all customer-facing activities in the Demand Side Management (DSM) arena. Areas they're involved in include: • Program design and evaluation • Managing Pepco's DSM activities with the participating commissions • Coordinating internal resources and contractors to implement the various DSM programs • Responding to customer requests for program information and energy efficiency options

Business Area	Responsibilities
Meters & Data Analysis	This group supports all meter deployment and meter data acquisition and analysis for Pepco: • Support the accurate and timely implementation of meters being deployed into the field as facilitated by internal and contract resources • Oversight of meter data acquisition systems for Advanced Metering Infrastructure (AMI) and non-AMI meters in the Pepco service territory to ensure proper functioning of all meters for data access and retrieval • Identify, prioritize and enable replacement of any meter determined to need repair, and / or testing as part of the overall meter testing requirements • Analysis of meter data for integrity, timeliness, and data validity so it can be provided to the billing system with the highest level of data quality • Provide all reporting measures regarding all aspects of Pepco's metering systems to measure and report system performance quality
Customer Care	Also referred to as the Call Center, this group at Pepco supports all call activities from Pepco customers: • Calls are tracked in fifteen high-level categories with the top three being Billing (51%), Moves / New Service (15%), and Outage (15%) calls. Through August, these three categories accounted for more than 80% of the time and calls handled by Customer Service Representatives (CSRs) • Pepco maintains two in-house call centers which are augmented by an off-site vendor (Convergent) with two locations (Atlanta, GA, and San Antonio, TX). All CSRs are connected to the same telephone routing system, so the in-house and vendor CSRs are transparent to the customers
Customer Financial Operations	Responsible for: • Reviewing the billing process by ensuring correct rate information is entered into the SAP billing system • Overseeing the correct application of rates to specific customer groups • Evaluating and providing corrections where necessary to those billing invoices that have been identified as having possible errors • Ensuring that all bills are produced and sent to customers within the required timeframes to help facilitate timely payment

Customer Operations is a customer-facing organization all the way through the meters-to-cash process. Our primary focus is towards our customers via the business areas indicated above. Customer Operations also works with other operational (Field Operations) and administrative (Finance, Regulatory, Corporate Communications, and Government Affairs) portions of the company inasmuch as it supports our customer-focused activities.

III – Home Center Hierarchy

The below chart represents the functions of Customer Operations:



The organization FTE count incorporates the recent addition of Applications Technology FTEs as a result of a re-organization. The positions of these FTEs are indicated in the respective Departments they were located in (Billing, Revenue Management, and Customer Relations/Customer Experience). Through 2018, the budget $ for these FTEs remains in the IT organization.

IV – Major Programs

Customer Operations has engaged in activities to help improve customer satisfaction based on the drivers that measure customer satisfaction as determined by our MSI customer satisfaction survey work. The key drivers tend to reliability, costs and management performance. We also focus on Call Center satisfaction to improve our customer interactions and provide the best experience possible for those customers who contact us. This is measured each month through post-call survey work.

Key Customer Operations initiatives include:

- Efficiency Study
- Customer Journey – Exelon Utilities (EU) level
- Business Intelligence and Data Analysis (BIDA), which consist of 27 customer-related initiative use cases that address overall improvements in customer facing activities (EU level, no OpCo O&M budget, all at IT levels)

As an ongoing part of Pepco Customer Operations' improvement efforts, it pursues first quartile performance in the below Key Performance Indicators. While these are not specific initiatives, they do constitute the major focus of the efforts the organization.

Performance Indicator Name
1029 - Service Level
1030 - Abandon Rate
1031 - Average Speed of Answer
1032 - Calls per Customer
1033 - Busy Out Rate
1034 - Response Time Agreement On-Time Delivery (OTD)
1035 - Percent of Meters Read
1036 - Customer Field Operations Year-to-Date Completed Work
1037 - Meter Corrective Maintenance Total Backlog Work down
1038 - All in Customer Operations Backlog
1039 - Percent of Delayed Bills
1058 - Customer Satisfaction Index
1065 - Uncollectible Expense as % of Revenue
1066 - Percent of Accounts Receivable > 60 Days
1067 - Past Due Days Sales Outstanding
1975 - Call Center Satisfaction
5065 - Agent Service Level
5090 - Total Accounts Receivable > 60 days ($)
5095 - Residential Customer Satisfaction Index
5096 - Small Business Customer Satisfaction Index
5118 - Residential Call Center Satisfaction
5125 - Agent Calls per Customer
5192 - Residential CSR Call Center Satisfaction

Other work / initiatives Customer Operations is engaged in are listed below:

- EU Digital Solar Toolkit
- EU Marketplace 2.0
- EU ePay
- AI, Automated Response and LiveChat
- Solar Concierge
- EU Digital Program - 2019 - 2020
- EU Prepaid Energy - DPL
- PHI CRMB Real Time Pricing Enhancements
- EU Outage Map Improvements (Kubra)
- CRMB Arrears Management Program (AMP) - D.C. Configuration

M.S. Poncia
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (Q) – 2

2018-2022 Long Range Plan Documentation

VP Area: Customer Operations

Vice President:

Customer Operations

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	Base Payroll	**Energy Efficiency Portfolio** **Meter Services & Customer Field Operations** **Cutomer Projects & Systems Support** **Customer Care (Call Centers)** **Billing & Financial Operations** **Revenue Management (Credit & Collection)**	25,762,503	30,412,826	31,140,205	31,743,326	32,335,566
2	Overtime	Administrative wages that exceed base payroll	1,318,971	2,199,940	2,216,729	2,233,574	2,247,469
3	Incentive	Formulaic based on key performance indicators in Annual Incentive Plans	2,608,518	2,759,337	2,847,609	2,908,169	2,983,828
4	Pension and OPEB	Function of payroll based on actuarial study	2,922,485	6,471,691	6,108,478	5,794,570	5,440,841
5	Fringe Benefits	Function of payroll based on headcount	5,713,297	5,923,733	6,128,600	6,368,572	6,617,824
6	Other Premium	Primarily long-term incentive plan for key managers and above	156,548	239,474	231,804	223,406	223,328
7	Stock Compensation	N/A	-	-	-	-	-
8	Severance	N/A	-	-	-	-	-
9	Payroll Taxes	Function of payroll: includes federal unemployment, federal social security, state unemployment	588,502	953,110	979,744	1,000,259	1,022,357
10	Materials	Computers, computer hardware, and desks	513,922	255,330	260,643	266,093	271,506
11	Taxes Other Than Inc	N/A	-	-	-	-	-
12	Contracting - Ops	Contracted services to support Customer Operations including Applications Technology, Collection Agency, final bill mailings and miscellaneous Customer Operations activities	4,108,629	2,018,096	1,201,634	1,179,962	1,165,102
13	Contracting - Non-Ops	Contracted services to support Customer Operations including Call Center, Field Collections, Billing, Remittance Processing, and miscellaneous Customer Operations activities	9,439,980	10,277,417	10,309,715	10,327,550	10,344,813
14	Contracting - Outsourced	Contracted services to support Customer Operations including Meter Services and Meter Field Operations, and Revenue Management	1,006,469	3,266,230	3,310,082	3,327,497	3,345,316
15	Staff Augmentation	Contractor staff - Expanding Customer Operations as required	88,744	62,494	62,902	63,328	63,328
16	Insurance	N/A	-	-	-	-	-
17	Regulatory Fees/Permits	N/A	-	-	-	-	-
18	Licensing and Telecom	Contracted services to support Customer Operations including Meter systems technology support, Call Center telephony, software maintenance fees, application license fees, and cell phone fees	1,107,912	3,658,710	3,739,412	3,741,271	3,743,170
19	BSC Services	Charges from EU on E Digital Strategy	47,113	-	-	-	-
20	BSC IT Services	N/A	-	-	-	-	-
21	BSC Non-Billed Adj	N/A	-	-	-	-	-
22	Seminars and Training	Seminars and training for professional development and industry peer workshops and meetings	33,528	89,419	89,443	89,476	89,505
23	Travel & Entertainment	Includes business travel related expenses, such as mileage reimbursement, car rental, railways, taxi, travel booking fees, etc. This account also includes meal expenses, tuition reimbursement, and costs associated with employee relocation	489,531	668,372	670,646	673,130	674,981
24	Memberships / Dues	Cost of industry and professional memberships for employees and the company (e.g., Utilities Enterprise Membership)	66,115	3,342	3,372	3,389	3,407
25	Charity / Contributions	N/A	-	-	-	-	-
26	Lobbying	N/A	-	-	-	-	-
27	Office Expense	Office supplies and postage for customer bills	3,754,189	3,558,305	3,567,245	3,603,501	3,644,551
28	Other Expenses	Other miscellaneous costs not specifically accounted for in other operating expense sub accounts	(224,943)	46,387	46,974	47,576	48,189
29	Accretion Expense	N/A	-	-	-	-	-
30	Allowances / Bad Debt	N/A	-	-	-	-	-
31	CIAC / CIAM	N/A	-	-	-	-	-
32	Facilities, Rentals, Utils	Allocated based on factors such as square footage and location	2,725,275	2,937,006	3,000,832	3,073,857	3,088,156
33	Transportation / Fleet	Costs related to vehicle charges, rental car costs, and allocation of overhead fleet service costs	631,234	709,687	772,490	794,365	809,752
34	Depreciation & Amort	N/A	-	-	-	-	-
35	**Total Expense**		**$ 62,858,522**	**$ 76,510,905**	**$ 76,688,559**	**$ 77,462,872**	**$ 78,162,989**

Customer Operations

VI - Headcount

Instructions:
List actual number of employees by category for 2018, and forecasted number of employees by category for 2019-2022.

Employees By Category	2018 Actual	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Pepco Exempt	43	49	49	49	49
Pepco Non-Exempt	208	220	220	220	220
Pepco Union					
Total Pepco	**251**	**269**	**269**	**269**	**269**
PHISCO Exempt	195	240	240	240	240
PHISCO Non-Exempt	242	257	257	257	257
PHISCO Union					
Total PHISCO	**437**	**497**	**497**	**497**	**497**

Direct and PHI Service Company Departments Included in Pepco Customer Operations

Department	Business Unit	Business Area
76036 - Remittance Processing-Pepco	17000 - Potomac Electric Power Co	Credit/Remittance and Collection
76037 - Credit & Collections-Pepco	17000 - Potomac Electric Power Co	Credit/Remittance and Collection
79076 - Customer Care Credit & Collect	19000 - PHI Service Company	Credit/Remittance and Collection
79081 - Cash Remittance Processing	19000 - PHI Service Company	Credit/Remittance and Collection
79131 - PHI Credit & Remittance	19000 - PHI Service Company	Credit/Remittance and Collection
76019 - Pepco Call Center	17000 - Potomac Electric Power Co	Customer Care
76033 - Pepco MD Energy Advisor (FERC	17000 - Potomac Electric Power Co	Customer Care
79072 - Salisbury Call Center & Outrea	19000 - PHI Service Company	Customer Care
79074 - Performance Consulting and Enh	19000 - PHI Service Company	Customer Care
79078 - Cust Ops, C&C, Remit Admin	19000 - PHI Service Company	Customer Care
79095 - Carney's Call Center	19000 - PHI Service Company	Customer Care
79102 - Resource Management Planning &	19000 - PHI Service Company	Customer Care
79114 - Quality Monitoring	19000 - PHI Service Company	Customer Care
79115 - Salisbury Outreach	19000 - PHI Service Company	Customer Care
76038 - Customer Care Billing-Pepco	17000 - Potomac Electric Power Co	Customer Financial Operations
76040 - Billing CRT	17000 - Potomac Electric Power Co	Customer Financial Operations
79075 - Customer Care Billing	19000 - PHI Service Company	Customer Financial Operations
79080 - Special Billing	19000 - PHI Service Company	Customer Financial Operations
79130 - PHI Billing	19000 - PHI Service Company	Customer Financial Operations
79044 - Customer Experience	19000 - PHI Service Company	Customer Operations Management
79048 - Manage Revenue Process	19000 - PHI Service Company	Customer Operations Management
79077 - VP - Customer Care	19000 - PHI Service Company	Customer Operations Management
76034 - Pepco MD Energy Engineers (FE	17000 - Potomac Electric Power Co	Customer Relations & Programs
79064 - PD- Customer Relations and Pro	19000 - PHI Service Company	Customer Relations & Programs
76080 - DSM - Pepco	17000 - Potomac Electric Power Co	DSM
79118 - DSM-Blueprint	19000 - PHI Service Company	DSM
79122 - Customer Programs	19000 - PHI Service Company	DSM
76086 - Customer Care Pepco	17000 - Potomac Electric Power Co	High Level Customer Operations
76050 - Meter Services	17000 - Potomac Electric Power Co	Meters & Data Analysis
79038 - Electric Maint Meter Shop-Shar	19000 - PHI Service Company	Meters & Data Analysis
79121 - Meter Data Analysis Services	19000 - PHI Service Company	Meters & Data Analysis

<== No FTEs in these departments

J. Calabrese
Direct Testimony
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (R)

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EXECUTIVE SUMMARY – JAMES L. CALABRESE

This testimony presents the operations that the Exelon Information Technology (IT) area of responsibility undertakes to support Potomac Electric Power Company (Pepco or the Company). The testimony discusses the Operations and Maintenance (O&M) costs that IT incurs in providing service to Pepco and provides projections of those costs for 2019 and over the 2020-2022 Multiyear Rate Plan (MRP) term. The testimony also details the capital expenses related to Pepco that IT is projected to undertake in 2019 and during the 2020-2022 MRP timeframe. This testimony supports the projected O&M and capital costs associated with providing IT support to Pepco.

In preparing the O&M cost projections for providing IT support to Pepco, historical O&M levels were analyzed and relevant IT cost drivers were considered. As summarized in Table 1, this testimony demonstrates that the IT O&M costs associated with supporting Pepco are projected to remain relatively flat through the term of the MRP.

Table 1 [1]
IT O&M Costs Attributable to Pepco
Summary

IT O&M Cost Type (Dollars in Millions)	2018	2019	2020	2021	2022
	Historical	Bridge	Projected		
Total	$48.57	$50.21	$51.32	$49.28	$47.83

The O&M and capital expenses described in this testimony are intended to facilitate safe and reliable service to Pepco's customers. The testimony explains how IT's operations are engineered to improve the Pepco customer experience. IT's work stretches across Pepco's operations and

[1] The O&M costs reflected are total Pepco costs, including the District of Columbia and Maryland. See the Direct Testimony of Company Witness Wolverton for the allocation of costs to the District of Columbia.

affects everything from utility reliability to app-based payment options. Despite the breadth of IT's work, IT remains committed to providing safe and reliable service to Pepco's customers.

POTOMAC ELECTRIC POWER COMPANY
BEFORE THE
PUBLIC SERVICE COMMISSION OF THE DISTRICT OF COLUMBIA
DIRECT TESTIMONY OF JAMES L. CALABRESE
FORMAL CASE NO. 1156

I. INTRODUCTION

A. Witness Qualifications and Purpose of Testimony

Q1. Please state your name and position.

A1. My name is James L. Calabrese, and I am Chief Information Officer (CIO) of Pepco Holdings LLC (PHI), and Information Technology (IT) Vice President, Work and Asset Management of Exelon Corporation (Exelon) Business Services Company (BSC). I am testifying on behalf of Pepco.

Q2. What are your responsibilities as CIO and IT Vice President, Work and Asset Management?

A2. I oversee all IT operations, services, and projects pertaining to PHI, which is comprised of Pepco, Atlantic City Electric Company, and Delmarva Power & Light Company. I also lead work management and asset management functions for all Exelon utilities including PHI, Baltimore Gas and Electric Company, Commonwealth Edison (ComEd), and PECO Energy Company (PECO). My responsibilities for Exelon utilities include IT services for enterprise asset management (EAM), mobile dispatch, support services platforms, and geographic information systems (GIS). My team provides IT compliance operations and oversight for North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) for all of Exelon.

Q3. Please state your educational background and professional experience.

A3. I graduated with a Bachelor of Science in Theoretical/Analytical Mathematics from Purdue University Calumet in May 1991. I have worked in IT in the electricity sector in various capacities, including management roles, since 1992.

I began working for ComEd in Chicago, Illinois in February 1992. I worked in several IT positions for ComEd until ComEd's parent company, Unicom Corporation, and PECO merged to form Exelon in 2000. Since the creation of Exelon, I have worked as Exelon's IT Senior Manager, Business Planning and Integration (November 2001-May 2003); IT Senior Manager, Exelon Way Program (June 2003-December 2004); IT Director, Center Operations (January 2005-December 2006); IT Director, Power Trading and Power Solutions (January 2007-April 2011); IT Director, Commercial and Power Merger Integration (April 2011-February 2012); IT Vice President, Constellation CIO (March 2012-May 2017); and PHI CIO and IT Vice President, Work and Asset Management of BSC (June 2017-current).

Q4. Have you previously submitted testimony to the Public Service Commission of the District of Columbia (Commission)?

A4. No.

Q5. What is the purpose of your Direct Testimony in this proceeding?

A5. The purpose of my Direct Testimony is to describe IT's responsibilities and structure as it relates to Pepco's operations in the District of Columbia. I will also discuss IT's key initiatives and goals during the term of the MRP and explain how these objectives advance Pepco's mission. Then I will break down IT's O&M activities and cost by type (*i.e.*, baseline, projects, and overheads) and explain how those costs are allocated to Pepco.

1 Finally, I will discuss the major capital programs and costs that fall within IT's purview
2 that impact Pepco.

3 **Q6. Are you sponsoring any exhibits in this proceeding?**

4 A6. Yes. I am sponsoring two exhibits: PEPCO (R)-1 and PEPCO (R)-2. This
5 testimony and the accompanying exhibits were prepared by me or under my direct
6 supervision and control. The sources for my testimony and exhibits are Company records
7 and public documents. I also rely upon my personal knowledge and experience.

8 **Q7. Please summarize each of the exhibits that you are sponsoring.**

9 A7. I am sponsoring the following exhibits:

10 - PEPCO (R)-1 contains the 2019 and 2020-2022 O&M cost projections for IT.
11 - PEPCO (R)-2 contains an organization chart that presents the structure of IT
12 and shows how PHI and Pepco fit within IT.

13 **B. Overview of IT**

14 **Q8. Please provide an overview of IT.**

15 A8. IT is a part of the BSC Corporate Operations organization that provides IT services
16 for all of Exelon's utilities, including Pepco. There are no IT full-time equivalents (FTEs)
17 dedicated solely to Pepco. Instead, IT has about 5,000 IT FTEs consisting of approximately
18 30% employees and 70% contractors. The major departments within IT include:

19 - Exelon Utilities;
20 - Exelon Generation;
21 - Commercial IT;
22 - the Chief Technology Officer (CTO); and
23 - the Office of the CIO.

All of the IT departments report to me. An IT organization chart has also been included in PEPCO (R)-2.

Q9. Please describe the IT Exelon Utilities department.

A9. Exelon Utilities manages all IT solutions supporting utility operations, including Pepco's operations. Each function listed below is led by an IT VP who also serves as the CIO for one of Exelon's utilities. I lead the Work & Asset Management functions listed below and serve as the PHI CIO:

- "Customer Solutions" manages core customer service, billing, and mobile platforms;
- "Digital Grid" manages private communication networks and business analytics IT platforms;
- "Real-Time Solutions" manages transmission and distribution real-time IT platforms that monitor, control, restore, and analyze power grid operations; and
- "Work & Asset Management" manages enterprise asset management, field worker mobile dispatch, work management platforms, geographic information system platforms, and NERC CIP IT platforms.

My role as PHI CIO includes overseeing IT solutions for Pepco.

Q10. Please describe the IT Exelon Generation department.

A10. Exelon Generation manages all IT systems that support Nuclear, Power, and Renewable operations.

Q11. Please describe the Commercial IT department.

A11. Commercial IT manages all IT solutions supporting competitive retail and wholesale energy trading operations.

Q12. Please explain the IT CTO's function.

A12. The CTO manages common IT platforms and functions across all of Exelon's businesses, including Pepco. The CTO optimizes common IT technology and solutions throughout Exelon, promoting cost effectiveness, reliable operations, and integrated platforms. The following responsibility areas report to the CTO:

- "Enterprise Wide Solution" manages IT solutions for HR, Finance, Supply, Legal, and Communication for all Exelon utilities, including Pepco;
- "Cloud & Infrastructure Engineering" designs and engineers hosting (servers, storage, network, and cloud) IT solutions for all Exelon utilities, including Pepco;
- "Cloud & Infrastructure Operations" operates all hosting (servers, storage, network, and cloud) platforms for IT solutions for all Exelon utilities, including Pepco. Cloud & Infrastructure Operations runs an IT Service Desk, centralized IT solution monitoring, client services, and problem and incident management;
- "Enterprise Architecture" designs technical IT hosting and integration environments for all Exelon utilities, including Pepco; and
- "Security Controls" ensures compliance with cybersecurity controls across IT services, operations, and projects.

Q13. Please describe the Office of the CIO in IT.

A13. The Office of the CIO governs and oversees the functions needed to operate a large IT organization, including finance and planning, project and portfolio management, strategic vendor management, compliance controls, and organization change management.

Q14. Please discuss the capital and O&M costs incurred by IT that are allocated to Pepco's customers.

A14. The capital and O&M costs incurred by IT that are allocated to Pepco are split into:

1. IT Baseline costs;
2. IT Pass-Through costs;
3. IT Business Unit (BU) Project costs;
4. IT Corporate (Corp) Project costs; and
5. NERC CIP Project costs.

Q15. Please describe IT Baseline costs.

A15. IT Baseline costs are the ongoing operating costs associated with delivering IT services to Pepco that are required for daily operations. These costs are incurred by IT and billed to Pepco according to the General Services Agreement (GSA) described in the Direct Testimony of Company Witness Giese. Application support, hosting, voice, network, and service desk are examples of IT Baseline costs. IT Baseline costs are primarily O&M and are organized into functional portfolios; however, a portion of costs supporting capital projects is capitalized. Pepco distributes IT costs associated with employees (for example, end-user network and device support costs) to Pepco departments containing those employees each month. As part of the monthly allocation process, these costs are allocated across O&M and capital projects in the same proportion as each department's labor.

Q16. Please describe IT Pass-Through costs.

A16. IT Pass-Through costs are IT components billed to Exelon and PHI by external companies that are directly associated with Pepco. BSC and PHI split the bill into the portion specific for Pepco and pass those costs directly to Pepco. These costs include

telecom circuits, printer services, mobile phone usage, and leased IT equipment phased out during 2019.

Q17. Please describe IT BU Project costs.

A17. IT BU Project costs are the costs related to the IT components of specific Exelon utility projects. Pepco is billed its portion of these costs as defined in the GSA, which is described in the Direct Testimony of Company Witness Giese. IT BU Project costs are incurred when Exelon utilities: (a) replace aging IT components through lifecycle refresh; (b) deliver new functionality to improve operational platforms, customer experience, grid interconnect, and outage restoration; and (c) meet regulatory requirements.

Q18. Please describe IT Corp Project costs.

A18. IT Corp Project costs cover the IT components of Exelon corporate projects that provide benefits to all Exelon utilities. Pepco is billed its portion of these costs as defined in the GSA, which is described in the Direct Testimony of Company Witness Giese. These corporate projects replace aging IT components through lifecycle refresh and improve operational IT platforms. They improve common corporate platforms for Finance, HR, Supply, Legal, and other BSC functions and ensure that Exelon utilities meet various regulatory requirements.

Q19. Please describe NERC CIP Project costs.

A19. NERC CIP Project costs are for IT components of NERC CIP projects that benefit Exelon. Pepco is billed its portion of these costs as defined in the GSA, which is described in the Direct Testimony of Company Witness Giese. NERC CIP projects implement regulatory requirements promulgated by NERC for cybersecurity information protection using common platforms, procedures, and approaches for all of Exelon. These costs are

mostly capital with the O&M portion varying from 15%-20% in any given year based on the specific mix of projects.

C. IT Key Goals and Initiatives

Q20. Please describe the key goals and initiatives for IT for 2019 and the 2020-2022 period.

A20. The key goals and initiatives for IT for 2019 and the 2020-2022 period focus on operational excellence, business and financial discipline, business partnership and collaboration, organizational engagement and effectiveness, and innovation.

Q21. How will IT's 2019 and 2020-2022 key goals and initiatives benefit Pepco's customers?

A21. IT's key goals and initiatives for 2019 and the 2020-2022 period will benefit Pepco's customers by maintaining critical existing IT systems and implementing new technologies that improve efficiency, reliability, and the overall customer experience.

Q22. Please describe how IT's key goals and initiatives for 2019 and the 2020-2022 period relate to Pepco's strategy to improve efficiency, reliable operations, and the overall customer experience.

A22. IT's 2019 and 2020-2022 key goals and initiatives focus on improving the reliability, resiliency, and security of the IT platforms serving Pepco. IT will continue to contribute to Pepco's strategy to improve efficiency, reliable operations, and the overall customer experience by maintaining operational excellence in all IT work associated with Pepco. IT will accomplish this by:

- Increasing the reliability and resiliency of IT Services (systems and applications);

- Facilitating efficient operations through common platforms and approaches with standardized and repeatable processes that effectively and efficiently deliver IT services;
- Implementing a consistent IT management framework for reliability, automation, and speed; and
- Cultivating an environment in which safety, security, and compliance are embedded in all that IT does.

Q23. Please describe how IT's 2019 and 2020-2022 key goals and initiatives relate to Pepco's financial management.

A23. IT's 2019 and 2020-2022 key goals and initiatives will also advance business and financial discipline in Pepco. IT will implement systems and strategies that continue to improve fiscal responsibility and budget management. IT will help Pepco efficiently deploy its resources to optimize the services it provides to Pepco's customers.

Q24. Please describe how IT's 2019 and 2020-2022 key goals and initiatives relate to Pepco's business partnership and collaboration.

A24. IT's 2019 and 2020-2022 key goals and initiatives will support Pepco's business partnership and collaboration by engaging with business partners to optimize outcomes for Exelon, Pepco, and Pepco's customers. Through the effective use of technology, IT will maximize the value Pepco provides to its business partners.

Q25. Does IT play a role in organizational engagement?

A25. Yes. IT strives to create an inclusive environment in which all IT employees can thrive and fully contribute. IT helps develop the talent necessary to provide leadership and

technical expertise to Pepco. IT fosters a culture of learning, feedback, and continuous improvement that ultimately results in better service for Pepco's customers.

Q26. How does IT cultivate an environment that produces innovative solutions and approaches?

A26. IT builds awareness and understanding of a common innovation definition that correlates with individual responsibilities and personal development. IT fosters an environment where feedback, whether positive or negative, enables us to integrate lessons, respond, and adapt. By encouraging innovation, IT develops and deploys improved programs and solutions for Pepco's customers.

Q27. How does IT project Pepco's IT costs?

A27. IT projects the IT costs attributable to Pepco using a five-year, long-range planning process, a process which is described in more detail in the Direct Testimony of Company Witness Barnett.

II. IT O&M ACTIVITIES

Q28. What are the actual Pepco O&M IT costs incurred by IT in 2018 and the projected Pepco O&M IT costs for 2019 and 2020-2022?

A28. The historical 2018, bridge 2019, and projected 2020-2022 O&M costs incurred by IT attributable to Pepco are contained in PEPCO (R)-1 and summarized in Table 2:

Table 2[2]
IT O&M Costs Attributable to Pepco

IT O&M Cost Type (Dollars in Millions)	2018	2019	2020	2021	2022
	Historical	Bridge	Projected		
Total	$48.57	$50.21	$51.32	$49.28	$47.83

[2] The O&M costs reflected are total Pepco costs, including the District of Columbia and Maryland. See the Direct Testimony of Company Witness Wolverton for the allocation of costs to the District of Columbia.

The IT O&M costs attributable to Pepco are comprised of IT Baseline, IT BU Projects, IT Pass-Through, NERC CIP Projects, and IT Corp Projects costs. These costs include items known at the time the LRP was developed and exclude emerging regulatory, legal, and operational requirements that may occur in the future.

Q29. How do the Pepco IT O&M costs benefit Pepco's customers?

A29. These IT costs help Pepco's customers by maintaining existing IT systems that serve Pepco operations while implementing new technologies intended to improve efficiency, reliable operations, and the overall customer experience. For example, IT operates secure platforms that allow Pepco's customers to view and pay their bills and manage their energy costs. Pepco's customers can view outage maps and monitor outage information through apps on their mobile devices and the Pepco website. Pepco's customers can use automated voice response options over the phone to manage their bills, get information about outages, and address other support needs. IT maintains internal communication networks and real-time systems to deliver reliable power to customers through secure power grid operations.

Q30. Please provide the major cost drivers for 2019 and 2020-2022 operations and support functions included in the IT Baseline costs

A30. The major Pepco IT O&M cost drivers for operations and support in years 2019 and 2020-2022 are the following:

- End User Services: covers services for internal employees and contracted staff connecting to IT systems, including network connection, service desk, and desktop/laptop software license costs;

- Billing and Payment Processing IT platform: bills customers and processes their payments. It also is the main platform used by customer care agents, mobile applications, and websites to support customer transactions;
- Workforce and Mobile Technology: the IT platform that manages maintenance and project work and mobile field work dispatch;
- Electric Real Time: enables real-time SCADA operating platforms; and
- Outage Management and Geospatial: provides information vital to managing power outage conditions and tracking the physical location of Pepco's assets.

Q31. Please explain any variances between Pepco O&M IT costs in 2018 and projected Pepco O&M costs in 2019.

A31. The major drivers for the 3.3% variance in cost from 2018 to 2019 shown in Table 2 are:

- The 2019 IT Baseline costs are higher due to new ongoing costs related to projects implemented in 2018; ongoing annual maintenance costs for telecom components that are required to receive software patches; higher ongoing NERC CIP support costs; and increased costs due to the shift from leases to purchases;
- IT Pass-Through cost reductions due to certain PHI IT lease costs ending in 2019;
- Costs related to IT BU Projects and NERC CIP v5 Projects decrease in 2019 due to project deferrals into 2020 based on project prioritization and resource availability. The project deferrals include Ratings Database, Land Mobile Radio replacement, and Next Gen Environmental, Health, & Safety system; and

- IT Corp Projects increase in 2019 over 2018 due to deferrals that shifted projects from 2018 to 2019. These IT Corp Projects were deferred because of other higher priorities in 2018.

Q32. Please explain any variances between Pepco O&M IT costs in 2018 and projected Pepco O&M costs during the period 2020-2022.

A32. Relative to 2018, the O&M costs in 2020 are 5.4% higher, 1.4% higher in 2021, and 1.5% lower by 2022. The major drivers for the variances between 2018 and the 2020-2022 period are:

- IT Baseline costs are 13.8% to 14.7% higher when compared to 2018 due to new ongoing costs related to projects implemented in 2018; ongoing annual maintenance costs for telecom components that are required to receive software patches; higher ongoing NERC CIP support costs; and increased costs due to the shift from leases to purchases;
- IT Pass-Through costs reduce by 50% due to certain PHI IT lease costs ending in 2019; and
- O&M costs related to IT BU Projects, NERC CIP v5 Projects, and IT Corp Projects change each year based on project timing and deferrals from earlier years.

III. IT CAPITAL PLAN

Q33. Please describe how IT's capital plan is developed as it relates to Pepco's IT requirements.

A33. As part of the five-year projected cost process, IT works with Pepco and other Exelon distribution utilities to develop a list of project investments over the next five years.

These costs include items known at the time the LRP was developed and exclude emerging regulatory, legal, and operational requirements that may occur in the future. The following factors drive IT project investments:

- Lifecycle/end-of-life replacement - replace aging equipment and software;
- Business Transformation - deliver projects that enable business strategies around business intelligence/data analytics, utility of the future, and common platforms across all Exelon utilities;
- Operational Improvements - security, storm restoration, financial reporting, and project management;
- Regulatory investments required to implement regulatory requirements; and
- Customer projects to improve customer experience through digital platforms.

Q34. Is the IT capital plan included in the Construction Report?

A34. Yes, the IT capital plan is included in the Construction Report that is discussed in the Direct Testimony of Company Witness Clark. However, IT capital projects are also discussed in this testimony because IT capital projects involve intangible software and hardware assets that are different than the physical assets created by many of the projects in the Construction Report.

Q35. Are the IT capital projects reflected in other testimony submitted in this proceeding? If so, pleases identify where these projects are discussed.

A35. Yes. The IT capital projects are listed in the Direct Testimony of Company Witness Clark.

Q36. What key IT capital projects are planned for Pepco in 2019 and 2020-2022?

A36. The key IT capital project investments for Pepco in 2019 and 2020-2022 are listed in Table 3.

Table 3
IT Capital Program Costs Attributable to Pepco

IT Capital Cost Type (Dollars in Millions)	2019	2020	2021	2022
	Bridge	Projected		
Lifecycle	$17.24	$18.84	$17.39	$16.64
Operational Platform	$10.68	$16.30	$13.50	$11.72
Customer Experience	$2.57	$3.25	$2.26	$2.15
Grid Interconnect	$2.19	$4.63	$4.63	$4.64
Outage Restoration	$1.22	$1.23	$1.31	$1.02
Regulatory	$0.61	$0.70	$0.55	$0.52
IT Capital Total* ***IT capital costs rounded to nearest 00.00.***	**$34.52**	**$44.95**	**$39.64**	**$36.67**

IT capital costs cover the following projects:

- Lifecycle projects replace or refresh aging components in smart grid infrastructure, communication networks, communication tower infrastructure, call center telephony, servers, storage, and personal computers/laptops.
- Operational platform projects integrate common Exelon platforms including Energy Management Systems, Advance Distribution Management Systems, Mobile Dispatch for Field Workers, Geographic Information Systems, and Data Alignment.
- Customer experience projects focus on improving customer satisfaction and ease-of-use with various interaction channels (phone, web, and mobile) and provide customers with data and analytics to manage their energy usage.

- Grid interconnect projects support grid interconnect for Distributed Energy Resources (DER) assets, operating distribution systems with a growing number of DER connected assets, net metering support, and customer solar toolkits.
- Outage restoration projects reduce outage times, improve communications during storm events, and leverage analytics to improve IT system performance during high-volume transactions events such as storms.
- Regulatory efforts support the implementation of mandatory programs, such as NERC CIP, Telephone Consumer Protection Act, and TOU Rate pilots.

Q37. Why are these IT capital projects necessary?

A37. These IT capital projects will improve the Pepco customer experience by providing Pepco's customers with tools to help manage their energy use. IT capital projects will also enable business transformation strategies, keep existing platforms operational and secured, and optimize efficiency with common platforms across Exelon.

Q38. How will IT's key capital projects planned for 2019 and 2020-2022 benefit Pepco's customers?

A38. IT's capital investments in 2019 and during the 2020-2022 period will benefit Pepco's customers by improving efficiency, reliable operations, and the overall customer experience. IT's investments will facilitate the reliable operation of Pepco's system as new DERs are added. IT's capital investments will also bolster grid cyber security, protect customer information, and enhance customer choice. Customers will experience fewer unplanned outages because new systems like the business intelligence data analytics

program will enhance Pepco's maintenance programs and restoration capabilities. IT's capital investments will also improve the way Pepco interacts with its customers. For example, IT's new mobile dispatch platform will allow Pepco to dispatch field crews more efficiently. Pepco's customers will also be able to monitor their service appointments thereby improving transparency and accountability. Additionally, IT's planned capital expenditures will allow Pepco to communicate critical outage information to its customers through the customers' preferred modes of communication.

Q39. Will Pepco's customers realize any other benefits from IT's capital project investments?

A39. Yes. IT's capital projects will improve Pepco services and streamline the performance of Pepco's online customer interface. For example, IT will improve the online customer payment experience by removing unnecessary steps and clicks. IT will also maintain Pepco's website according to industry-leading practices with the goal of improving customer satisfaction and the user experience.

IT's capital investments will also provide Pepco's customers with the information and tools they need to better understand and manage their electricity use. Pepco's customers will benefit from a variety of IT tools developed by IT, including web presentment, bill comparison, bill forecast, neighbor comparison, rate comparison, home analyzer, home energy reports, business energy reports, high bill alerts, portfolio manager, peak time rebates, and outage maps.

Q40. Do any of IT's capital project investments improve operational aspects of Pepco?

A40. Yes. Many of IT's capital projects drive operational improvements, reduce risk, and increase reliability. For example, IT capital projects:

- Enhance visibility into the distribution system through Smart Grid Implementation investment. Sources of data such as AMI, reclosers, and distribution sensors at different points along the grid network will increase visibility into the performance and health of the assets. IT uses analytics to improve efficiency and reliability while lowering system risk. IT's analytics focus on Meter Operations, Theft Detection, Consumption on Inactive Meters, AMI Network Operations, DER Interconnection, and improved grid operations. IT's capital projects will enable Exelon to leverage customer data to improve reliability, customer satisfaction, and efficiency;
- Help Pepco meet new operational compliance obligations and improve the online customer experience by enhancing Pepco's user interface and functionality; and
- Migrate Pepco's Customer Financial Reporting from its current data warehouse to Exelon's data analytics platform to improve financial insights and decrease operational cost.

Q41. When will these key IT capital projects be in use and of benefit to Pepco's customers?

A41. IT's key capital projects will be implemented throughout 2019 and the 2020-2022 period. Pepco will invest in lifecycle projects in 2019 and during the 2020-2022 period with specific components refreshed each year based on their useful life and operational risk.

IV. CONCLUSION

Q42. Does this conclude your Direct Testimony?

A42. Yes, it does.

J. Calabrese
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (R) – 1

2018-2022 Long Range Plan Documentation

VP Area: IT Budgeted Direct

PHI CIO & IT VP:

IT Budgeted Direct

V - Major Cost Drivers by Cost Type

Instructions:

List the O&M expenses for 2018 by cost type; provide a description of why each is required for the organization to achieve its objectives, and discuss the key drivers behind each. If a cost type does not apply to your organization, write "N/A" in the Description and Key Drivers column. Also list forecasted O&M expenses for 2019-2022.

Pepco IT O&M ($000,000)

#	Cost Type	Description and Key Drivers	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
1	IT Baseline[a]	Provides standard ongoing IT services to support Pepco. These IT services include End-User Support Services, IT Systems Operations Services, and IT Service Delivery. These IT services are provided by a combination of Application Delivery and Support Departments, Cloud and Infrastructure Services Department, and Office of the CIO, and relate to the ongoing maintenance of IT-supported systems.	32.16	37.74	37.69	37.48	37.33
2	IT BU Projects[b]	Deliverables for business-unit specific IT projects including planning, design, asset acquisition, and implementation of solutions. Additional IT BU Project costs for business labor dedicated to the Business Intelligence Data Analytics (BIDA) BU project costs directly mapped to PHI / Pepco. Additional IT BU Project costs for incremental PHI costs (*e.g*. backfill contractors) to support IT BU projects.	9.83	7.36	8.24	6.65	5.98
3	IT Pass-Through	Pass-Through costs include telecom circuits, managed print, and IT equipment lease.	3.95	2.83	2.63	2.57	2.56
4	NERC CIP Projects	Governance and oversight of NERC CIP compliance and policies	1.36	0.64	1.08	0.73	-
5	IT Corp Projects	Enterprise-wide IT software and infrastructure with a defined scope and durations	1.27	1.64	1.69	1.84	1.97
6	**Total Expense**		**$ 48.57**	**$ 50.21**	**$ 51.32**	**$ 49.28**	**$ 47.83**

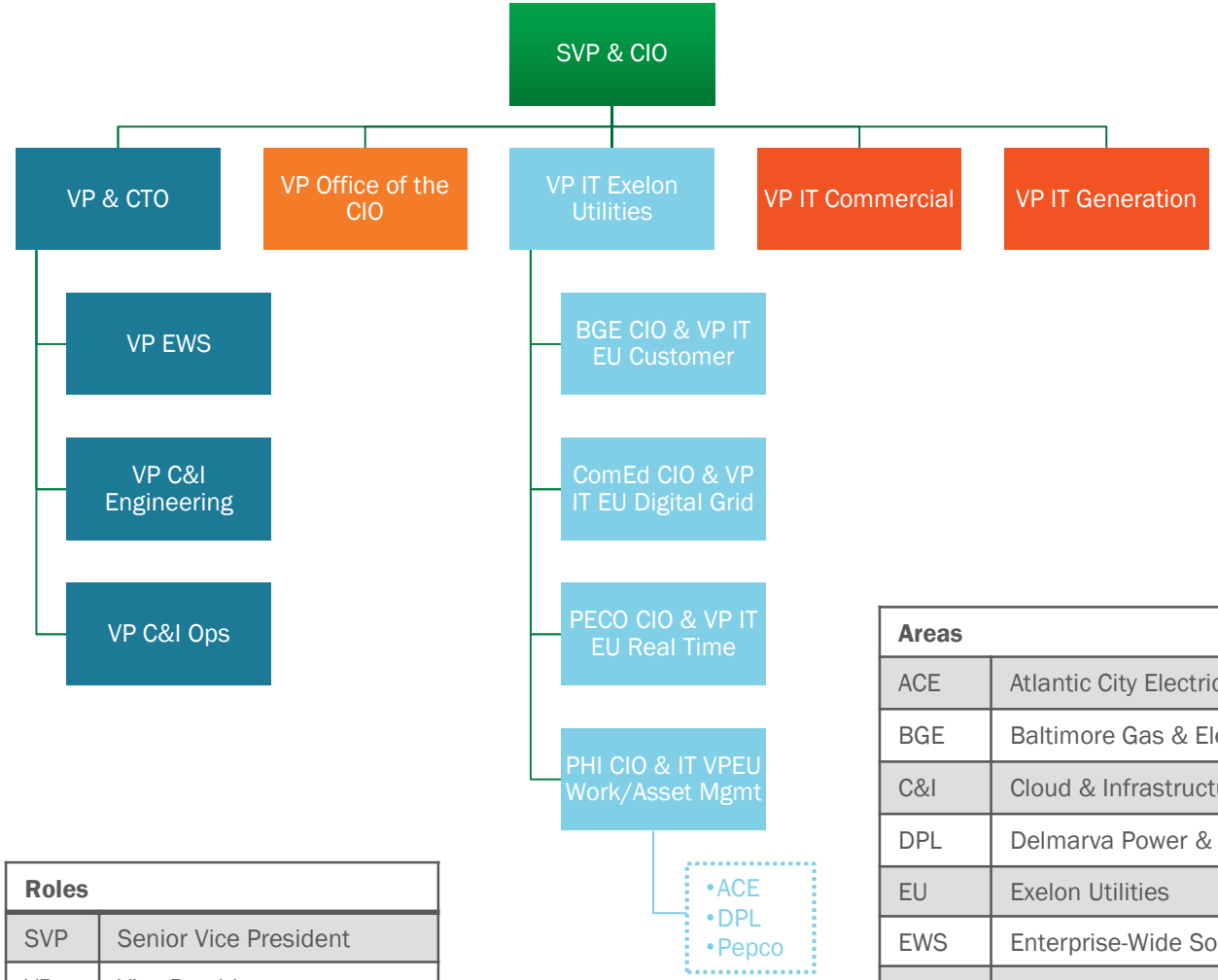
[a] IT Baseline includes reductions to O&M for capitalized overhead costs associated with end-user support and corporate applications.

[b] IT BU Projects includes labor costs incurred by PHI departments to support project work.

J. Calabrese
Direct Exhibit
DC. P.S.C - - May, 2019

Introduced as:
PEPCO _____ (R) – 2

Exelon's IT Organization



Roles	
SVP	Senior Vice President
VP	Vice President
CIO	Chief Information Officer
CTO	Chief Technology Officer

Areas	
ACE	Atlantic City Electric Corporation
BGE	Baltimore Gas & Electric
C&I	Cloud & Infrastructure
DPL	Delmarva Power & Light Company
EU	Exelon Utilities
EWS	Enterprise-Wide Solutions
PECO	Philadelphia Electric Company
Pepco	Potomac Electric Power Company
PHI	Pepco Holdings Incorporated

Exelon.

CERTIFICATE OF SERVICE

I hereby certify that a copy of Pepco's Application for Authority to Implement a Multiyear Rate Plan for Electric Distribution Service has been served this May 30, 2019 on:

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