PECO ENERGY COMPANY
STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PETITION OF PECO ENERGY COMPANY
FOR APPROVAL OF ITS
DEFAULT SERVICE PROGRAM
FOR THE PERIOD FROM
JUNE 1, 2021 THROUGH MAY 31, 2025

DOCKET NO. P-2020-________________

DIRECT TESTIMONY

WITNESS: JOSEPH A. BISTI

SUBJECTS: DEFAULT SERVICE RATE DESIGN,
TIME-OF-USE RATES, AND
TARIFF CHANGES

DATED: MARCH 13, 2020

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DIRECT TESTIMONY
OF
JOSEPH A. BISTI

I. INTRODUCTION AND PURPOSE

1. Q. Please state your full name and business address.

A. My name is Joseph A. Bisti. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

2. Q. By whom are you employed and in what capacity?

A. I am employed by PECO Energy Company ("PECO" or the "Company") as a Principal Regulatory and Rates Specialist. In that capacity, I am responsible for tariff administration, financial analysis, project management and regulatory affairs relating to PECO's electric and gas operations, including preparation of written testimony and other filings in proceedings before the Pennsylvania Public Utility Commission ("Commission" or "PUC").

3. Q. Please describe your educational background.

A. I earned a Bachelor of Science in Economics from The College of New Jersey in 2000, a Master of Science in Training and Organizational Development from Saint Joseph's University in 2009, and a Graduate Certificate in Utility Management from Willamette University in 2012. In 2015, I earned certification as a Project Management Institute Professional in Business Analysis (PMI-PBA).

4. Q. Please describe your work experience with PECO.

A. In February 2019, I was promoted to my current position within PECO's Regulatory Policy and Strategy department. Prior to that promotion, I was a

Senior Rate Administrator for over three years, during which I assumed oversight responsibilities for tariff administration as described above. In that position, my responsibilities also included analyzing and applying PECO's tariffs to retail customers, as well as coordinating and preparing PECO testimony and comments in several Commission proceedings.

For approximately nine years prior to my role as a Senior Rate Administrator, I was a Senior Analyst in PECO's Energy Acquisition department. The Energy Acquisition department is responsible for PECO's interaction with electric generation suppliers ("EGSs") and for fulfilling PECO's obligation as a default service provider to serve electric retail customers who need, or choose to obtain, default service.

5. Q. Have you previously testified before the Commission?

A. Yes. I have testified in the following proceedings before the Commission:

Docket Nos. C-2008-2058320 and C-2009-2089694 – *Rama Construction Inc. T/A Ramada Inn Int'l Airport v. PECO Energy Company*

Docket Nos. M-2018-3005860 et al. – *Office of Consumer Advocate v. PECO Energy Company*

6. Q. What is the purpose of your direct testimony?

A. The primary purpose of my direct testimony is to describe the rate design to take effect with the commencement of PECO's fifth default service program ("DSP V") on June 1, 2021. With one addition, PECO is adopting the same rate design employed in its fourth default service program ("DSP IV"), which the Commission previously approved as consistent with the Public Utility Code

("Code") and the Commission's default service regulations. The only change PECO is proposing in this filing is the introduction of Time-Of-Use ("TOU") default service rate options for eligible customers in PECO's Residential and Small Commercial procurement classes (the "TOU Rates") to comply with PECO's obligation under Act 129 of 2008 ("Act 129") to offer TOU and real-time rates to all default service customers with smart meters.[1]

In addition, I explain PECO's proposed tariff changes to facilitate shopping for electric generation supply by customers who participate in PECO's Customer Assistance Program ("CAP"). I also describe the Company's DSP V cost-recovery proposal for its plans to implement both optional TOU default service rates and its CAP Shopping Plan ("Plan"). Finally, I cover two topics that the Commission asked electric distribution companies ("EDCs") to address in upcoming default service program ("DSP") filings (adjustment of PECO's Price-to-Compare ("PTC") for default service and TOU rate design).[2]

7. Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring the following exhibits:

Exhibit JAB-1	System Peak Usage Analysis
Exhibit JAB-2	Pricing Analysis and TOU Pricing Multiplier Calculations
Exhibit JAB-3	TOU Period Allocator Calculations
Exhibit JAB-4	TOU Pricing Methodology – Illustrative Example

[1] 66 Pa.C.S. § 2807(f)(5). The hourly-priced default service rate for the Consolidated Large Commercial and Industrial ("C&I") Class already meets Act 129 requirements.

[2] *Investigation into Default Serv. and PJM Interconnection, LLC Settlement Reforms*, Docket No. M-2019-3007101 (Secretarial Letter issued Jan. 23, 2020) ("January 2020 Secretarial Letter").

Exhibit JAB-5	Net Metering, TOU Monthly Accounting and Cashout – Illustrative Example
Exhibit JAB-6	DSP V Estimated Filing and Program Costs
Exhibit JAB-7	Revised Electric Service Tariff (Relevant Pages)
Exhibit JAB-8	Revised Electric Service Tariff (Blackline)
Exhibit JAB-9	Responses to Questions in 52 Pa. Code § 53.52(a)
Exhibit JAB-10	Electric PTC History, GSA 1 (Residential) and GSA 2 (Small C&I – Rate GS General Service), January 2011 – Present

II. DEFAULT SERVICE RATE DESIGN

8. Q. Mr. Bisti, please provide an overview of PECO's current default service rate design and the costs those rates recover.

A. Under DSP IV, PECO conducts competitive procurements of default service supply for three different customer classes ("procurement classes"):

(i) Residential Class or "GSA 1" (Rate Schedules R and RH);

(ii) Small Commercial Class or "GSA 2" with up to and including 100 kW of annual peak demand (Rate Schedules GS, PD, and HT) and lighting customers (Rate Schedules AL, POL, SLE, SLS, SLC, and TLCL); and

(iii) Consolidated Large C&I Class or "GSA 3/4" whose annual peak demand is greater than 100 kW (Rate Schedules GS, PD, HT and EP).

Each default service rate consists of a generation and transmission component. The Generation Supply Adjustment ("GSA") currently recovers generation supply costs, Alternative Energy Portfolio Standards ("AEPS") compliance costs, and ancillary service costs. In addition, the GSA includes an administrative cost factor and a working capital factor. Administrative costs include the costs incurred by PECO to implement its Commission-approved programs designed to enhance the competitive retail market. PECO allocates administrative costs to the procurement classes based on default service supply sales unless a direct assignment is required. The working capital component is a fixed price per kWh that was established at 0.019¢ per kWh in the settlement of PECO's last electric distribution rate case at Docket No. R-2018-3000164.

PECO recovers Network Integration Transmission Service ("NITS") and Non-Firm Point-to-Point Transmission costs imposed by PJM Interconnection, L.L.C. ("PJM"), for transmission service that PECO acquires on behalf of default service customers through the Company's Transmission Service Charge ("TSC").

The Commission's Regulations (52 Pa. Code § 54.187(h)) provide that default service rates may be adjusted no more frequently than quarterly for customers with load requirements up to 25 kW. Those regulations (52 Pa. Code § 54.187(i)) also provide that default service rates shall be adjusted on a quarterly basis, or more frequently, for customers with load requirements between 25 kW and 500 kW. Finally, the Commission's regulations (52 Pa. Code § 54.187(j)) provide that default service rates shall be adjusted on a monthly basis, or more frequently for customers with load requirements equal to or greater than 500 kW.

9. Q. Please describe how the Company's default service rates are structured and adjusted for customers with annual peak demand up to and including 100 kW.

A. Under the current GSA approved by the Commission in DSP IV, PECO projects the cost of generation supply for each customer class with annual peak of up to and including 100 kW (i.e., residential and small commercial customers) on a quarterly basis. Those GSA projection periods are synchronized with PJM's planning year (June 1-May 31), corresponding to the quarters of June-August, September-November, December-February, and March-May. The projected cost of supply is a function of projected default service sales and projected procurement costs under PECO's generation supply contracts. This projection, combined with PECO's TSC, forms the basis of the PTC that customers may use to evaluate competitive generation service offerings by EGSs.

PECO files the GSA for each quarter 45 days before the start of that quarter. In accordance with its tariff, PECO compares its actual default service supply costs to the billed revenue it receives from customers under the GSA for default service. The GSA includes a charge or credit, known as the "E-Factor," for semi-annual reconciliation of any over/undercollection of actual revenues against actual costs for each procurement class. For example, PECO calculates the over/undercollection for the six-month period January 1 through June 30 by July 15 and includes that amount in the E-Factor during the six-month period beginning September 1. Interest on any overcollection and undercollection accrues from the month of such over/undercollection to the midpoint of the refund period in accordance with the Commission's default service regulations at 52 Pa. Code § 54.190.[3]

[3] Those regulations, adopted by the Commission in 2015, establish a symmetrical rate of interest applicable to both overcollections and undercollections resulting from the reconciliation of default service costs. Specifically, the applicable rate of interest for over/undercollections is the prime rate for commercial borrowing, not to exceed the legal rate of interest, in effect on the last day of the month the over/undercollection occurred,

10. Q. Please describe how the Company's default service rates are structured and adjusted for commercial and industrial customers receiving hourly-priced default service.

A. Under DSP IV, commercial and industrial customers with annual peak demand greater than 100 kW are supplied entirely by hourly priced products for generation. These include the day-ahead hourly price of energy as well as a demand charge based upon the reliability pricing model ("RPM") implemented by PJM. The individual customer's RPM charges are based upon the customer's Peak Load Contribution and RPM prices.

Additionally, the costs of acquiring ancillary services from the PJM market, AEPS compliance costs, an allocated portion of PECO's banked AECs, administrative costs and working capital are charged to these customers each month. The Company provides an estimate of these components of hourly priced default service rates, exclusive of energy and capacity costs, known as the "Hourly Pricing Adder," at least 45 days prior to the start of each quarter.

Under the current GSA, PECO reconciles any over/undercollection for customers receiving hourly-priced default service on a semi-annual basis through the E-Factor in the same manner as the Residential and Small Commercial Classes. Likewise, interest on any over/undercollection accrues in the same manner and at the same rate as for the Residential and Small Commercial Classes, as described above.

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as reported in *The Wall Street Journal*. *See generally Automatic Adjustment Clauses Related to Elec. Default Serv.*, Docket No. L-2014-2421001(Final Rulemaking Order entered June 11, 2015).

11. Q. Has PECO implemented any strategy to mitigate fluctuations in the PTC caused by over/under collections?

A. Yes. Over/undercollections are driven by two factors: (1) the difference between actual and projected supply costs and (2) billing cycle lag. Customer billing cycles (mostly non-calendar months) are not perfectly aligned with the actual incurrence of generation supply costs (mostly calendar months). Because customers are billed at different times throughout the month, the revenue from the month reflects sales from the subject month and the prior month that may have experienced higher or lower usage. This billing cycle lag results in a timing difference between revenue and expense that can produce significant fluctuations in the PTC that are not directly related to the underlying cost of default service supply. PECO uses a semi-annual, rather than quarterly, schedule for the reconciliation of over/undercollection amounts for the Residential and Small Commercial Classes to mitigate the potential volatility in default service rates for these customers.

Billing lag is also the primary driver of fluctuations in the Consolidated Large Commercial and Industrial Class PTC. Billing lag can cause a large overcollection for commercial and industrial customers receiving hourly priced default service in one month immediately followed by a large undercollection the next month. Accordingly, PECO currently reconciles the E-Factor of the GSA for those customers on a semi-annual, instead of a monthly, basis in the same manner as over/undercollections are handled for the Residential and Small Commercial Classes.

12. Q. Is PECO proposing to maintain its existing default service rate design in DSP V?

A. Yes, with the addition of the optional TOU Rates for the Residential and Small Commercial Classes. As discussed in detail in Section III below, under the Company's proposed TOU rate options, eligible default service customers will pay a discounted rate for off-peak usage and a higher rate for peak usage relative to PECO's standard non-time varying default service rate.

13. Q. Is PECO seeking a waiver of the Commission's regulations to continue semi-annual reconciliation of the over/undercollection component of the GSA?

A. Yes. As I explained previously, the Commission's Regulations (52 Pa. Code §§ 54.187(h)-(j)) require adjustment of default service rates on a quarterly basis, or more frequently, for customers with load requirements up to 500 kW and on a monthly basis, or more frequently, for customers with load requirements above 500 kW. However, the Commission has recognized that more extended periods for over/undercollection reconciliation may help keep default rates more market-reflective,[4] and the Commission granted PECO a waiver from these regulations in DSP IV to implement a semi-annual E-Factor reconciliation for the Residential, Small Commercial and Consolidated Large Commercial and Industrial Classes.[5] PECO again requests a waiver of these regulations, to the extent necessary, to maintain its current semi-annual reconciliation schedule for the Residential and

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[4] *See Investigation of Pennsylvania's Retail Elec. Mkt.: Recommendations Regarding Upcoming Default Serv. Plans*, Docket No. I-2011-2237952, at pp. 54-55 (Order entered Dec. 16, 2011).

[5] *Petition of PECO Energy Co. for Approval of its Default Serv. Program for the Period from June 1, 2017 through May 31, 2021*, Docket No. P-2016-2534980 (Opinion and Order entered Dec. 8, 2016) ("DSP IV Order"), p. 67.

Small Commercial procurement classes throughout DSP V to continue to mitigate potential default service rate volatility that may otherwise result from billing cycle lag.

14. Q. Is PECO seeking any other waiver of the Commission's Regulations to implement the proposed DSP V rate design?

A. Yes. In the DSP IV Order (p. 67), the Commission granted PECO a waiver of its Regulations (52 Pa. Code § 54.187(j)) to implement a quarterly, instead of monthly, filing schedule for Consolidated Large Commercial and Industrial Class default service rates in the same manner and at the same time as the Residential and Small Commercial Class default service rates. To the extent necessary, PECO again requests a waiver to continue to align the filing schedule for Consolidated Large Commercial and Industrial Class default service rates with PECO's other procurement classes and reduce administrative burden on both the Company and Commission Staff.

III. TIME-OF-USE RATE OPTIONS

15. Q. Does PECO currently offer TOU rate options to Residential or Small Commercial default service customers under DSP IV?

A. No. PECO previously offered a TOU generation rate through a PUC-approved, one-year pilot program known as the "PECO Smart Time Pricing Pilot" ("Pilot").[6] The primary objectives of the Pilot were to gauge customer interest in a TOU rate,

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[6] *Petition of PECO Energy Co. for Approval of its Initial Dynamic Pricing and Customer Acceptance Plan,* Docket No. M-2009-2123944 (Order entered Apr. 15, 2011) ("Dynamic Pricing Order").

assess the reasons why customers chose to enroll in or leave the program, and evaluate the impact of TOU rates on electricity consumption patterns.

The Pilot offered eligible customers a two-part TOU generation rate, a bill protection feature based upon PECO's default service rate at the time, and the option to leave the Pilot at any time without incurring cancellation fees or penalties. The two-part Pilot TOU rate structure offered a higher rate during non-holiday weekday afternoons from 2 p.m. to 6 p.m. and a reduced rate for all other hours of the year. The EGS selected through a competitive procurement process served as the TOU commodity supplier and implementation vendor for the pilot.[7]

The Pilot was offered to nearly 121,000 residential customers and over 3,500 small commercial customers from September 1, 2013 through November 1, 2013. In total, 4,779 residential customers and 23 small commercial customers enrolled, representing about 4% of the targeted population.

16. Q. Please summarize the key findings of the PECO Smart Time Pricing Pilot.

A. End-of-pilot survey and focus group results revealed that the main driver of customer interest and satisfaction with the Pilot was the opportunity to save money on their electric bills. Most residential customers who enrolled in the Pilot took action to shift consumption away from peak hours and saved money as a result, with monthly bill savings exceeding $5 for more than 2,350 customers. Only thirteen customers needed bill protection reimbursement from PECO, and

[7] *Petition of PECO Energy Co. for Expedited Approval of its Dynamic Pricing Plan Vendor Selection and Dynamic Pricing Plan Supplement*, Docket No. P-2012-2297304 (Opinion and Order entered Sept. 26, 2012) (approving modifications to the commodity supply, dynamic rate structure, size and term of the pilot approved in the Dynamic Pricing Order to enable an EGS to provide TOU supply in lieu of PECO).

the total amount refunded was very small (just over $100 in the total program, with individual amounts ranging from $1.01 to $19.23).

The Pilot delivered an average load reduction of 6% per customer during peak hours from June 2014 through August 2014, with load reductions in the 3%-4% range during September and spring months (March through May). The greatest load impact results came from customers who shifted large appliance and heating/cooling energy use outside of peak hours.

17. Q. Why is PECO proposing the new TOU Rates?

A. Since the Pilot, the scope of an EDC's obligation to offer TOU rates to default service customers was the subject of litigation before the Commission and Commonwealth Court.[8] Following this litigation, the Commission proposed a new TOU structure for PPL to satisfy Act 129 requirements.[9] The Commission noted that the proposed TOU design for PPL "may provide future guidance to all EDCs" for incorporation into their own TOU proposals in their individual default service proceedings.[10] At the same time, the PUC made clear that EDCs would have "the flexibility to propose other alternatives and/or modifications regarding their TOU operations" for PUC review and approval in future DSP filings.[11]

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[8] *See Petition of PPL Elec. Utils. Corp. for Approval of a New Pilot Time-of-Use Program*, Docket No. P-2013-2389572 (Order entered Sept. 11, 2014) (holding that Act 129 did not require PPL Electric Utilities Corp. ("PPL") to offer TOU rates directly to customer-generators); *Dauphin Cty. Indus. Dev. Auth. v. Pa. P.U.C.*, 123 A.3d 1124, 1136 (Pa. Cmwlth. 2015) ("*DCIDA*") (holding that Act 129 does not authorize default service providers to delegate the obligation to offer TOU rates to customers with smart meters to EGSs).

[9] *Petition of PPL Elec. Utils. Corp. for Approval of a New Pilot Time-of-Use Program*, Docket Nos. P-2013-2389572 and M-2016-2578051 (Secretarial Letter issued Apr. 6, 2017) ("April 2017 Secretarial Letter").

[10] *Id.*, p. 4.

[11] *Id.*

18. Q. What are the objectives underlying PECO's proposed TOU Rates?

A. In addition to the guidance provided in the April 2017 Secretarial Letter, PECO considered the following objectives in designing the Company's proposed TOU Rates to comply with Act 129 requirements and to implement lessons learned from the Pilot:

1. **Simplicity and value proposition for customer enrollment**. TOU rates can help customers reduce electricity bills by incentivizing customers to shift usage to lower-cost, off-peak hours. However, customers are more likely to enroll in and respond effectively to TOU rates if they understand the TOU rate structure and related potential for savings.

2. **Retail-to-wholesale market connection**. On February 26, 2019, the Commission entered an Order at Docket No. M-2019-3007101 to initiate an investigation of potential opportunities to better reflect wholesale cost causation in default service rates and incentivize customer behavior to lower peak demand. To that end, PECO considered cost-causation principles in developing its proposed TOU Rates to connect the product pricing structure to the PJM energy and capacity markets, as well as the generation component of PECO's default service rates, i.e., the GSA.

3. **Incentives for customer electric vehicle ("EV") adoption**. In the past five years, the number of known EV operators in PECO's service territory has grown significantly, with the number of EVs registered through PECO's Smart Driver Rebate program increasing from 3,000 customers to

over 11,000 customers. In the January 2020 Secretarial Letter (p. 6), the PUC observed that EV use will increase across the Commonwealth in the coming decades. Based on this observation, the Commission directed EDCs to explore TOU rates in the context of EV expansion and consider whether "the lack of TOU rate offerings for operators of EVs presents a barrier to EV adoption."[12] In order to address the Commission's guidance, PECO's proposed TOU Rates include a super off-peak pricing period to encourage EV charging during overnight low-priced energy hours and, in turn, lower the overall total cost of EV ownership.

19. Q. What are the key features of PECO's proposed TOU Rates?

A. As shown in the table below, PECO's proposed TOU Rates differentiate prices across three periods (peak, off-peak and super off-peak) that remain constant year-round based on price multipliers designed to motivate shifting of usage from the higher-cost peak period to lower-cost off-peak periods. The TOU pricing periods are identical for the Residential and Small Commercial Classes.

TOU Pricing Period	Year-Round Days/Hours Included
Peak	2 p.m. – 6 p.m. Monday Through Friday, excluding PJM holidays
Super Off-Peak	Midnight (12 a.m.) – 6 a.m. Every day
Off-Peak	All other hours

[12] January 2020 Secretarial Letter, p. 7.

The proposed TOU rate design is structured to establish a rate premium above PECO's standard, fixed-price default service rate for usage during the peak period and rate discounts from this baseline price for usage during two off-peak periods. The baseline price is the customer's applicable GSA rate, prior to application of the TOU price multipliers discussed later in my testimony.

20. Q. What customers are eligible for PECO's TOU Rates?

A. Consistent with the April 2017 Secretarial Letter, PECO's TOU Rate will be available, with limited exceptions, to default service customers with smart meters who are not receiving hourly priced default service (i.e., the Residential and Small Commercial Classes). As a prerequisite for enrollment, PECO must be able to configure the customer's smart meter to measure energy consumption in watt-hours. The customer must have a valid e-mail address to ensure that the Company is able to provide the enrolled TOU customers with timely and meaningful communications regarding their savings performance. Residential customers enrolled in PECO's CAP will not be eligible for the residential TOU Rate at this time.

21. Q. Please explain why CAP customers will not be offered the residential TOU Rate.

A. As explained by Ms. Reilly in PECO Statement No. 3, CAP customers receive a fixed bill credit each year for the utility service they receive based on their ability to pay regardless of the actual amount of their utility bill. The selection of the TOU Rate could adversely impact those benefits because CAP customers may not have the flexibility to shift usage outside of the higher-priced peak period. In addition, a CAP customer's evaluation of whether CAP benefits outweigh the potential bill savings under a TOU rate is dependent on PECO's current CAP design, which may change during the DSP V term.[13] Therefore, PECO is proposing to exclude CAP customers from the TOU Rate at this time to avoid the risk of higher generation charges on those customers' electric bills that could jeopardize affordability and impose an unreasonable cost burden on all residential customers that pay for the CAP.

22. Q. How did PECO determine the number and times of the price-differentiated usage periods?

A. PECO's proposed TOU pricing structure is designed to reasonably encompass the expected system peak usage times while addressing the need for simplicity to encourage customer enrollment. The Company examined PJM's PECO zonal load data and energy prices over a five-year historic period (2014-2018). As shown on Exhibit JAB-1, system peak usage generally occurred during weekdays over five months of the year (May-September). Over the 2014-2018 period, the hours between 2 p.m. and 6 p.m. from May through September tended to have the highest system loads. Similarly, between May and September each year, energy prices in general were higher during these four hours of the day.

Based on this data, PECO defined the peak period as 2 p.m. to 6 p.m. on non-holiday weekdays. PECO selected the same year-round peak period employed in its Pilot, in which, as I previously explained, participating customers successfully

[13] The Commission's Bureau of Consumer Services and Law Bureau have been directed to prepare a comprehensive universal service rulemaking order no later than the first quarter of 2020. *See Universal Serv. Rulemaking*, Docket No. L-2019-3012600 (Order entered Jan. 2, 2020).

responded to the TOU price signals to shift usage and achieve bill savings. The proposed peak period also allows for material price differentials that will be more likely to motivate customers to shift consumption to lower-priced (off-peak) hours.

Consistent with the January 2020 Secretarial Letter, PECO's proposed TOU Rates include a super off-peak pricing window to provide cost savings opportunities for EV operators. Based on PECO's system load patterns, the super off-peak period is defined as 12 a.m. to 6 a.m. every day to encourage EV charging within times of low energy prices.

23. Q. Why is PECO proposing year-round price-differentiated usage periods even though the April 2017 Secretarial Letter recommends seasonal variation?

A. PECO is proposing to apply the TOU Rates year round based on the results of the Pilot. This design is easier for customers to understand and reduces the number of variables for customers to consider in changing their consumption patterns. It also simplifies the development of TOU price ratios. PECO believes the year-round nature of its proposed TOU Rates strikes a balance reflective of periods that include the system peak while remaining more convenient and actionable for customers.

24. Q. How did PECO develop the price ratios that will used to set TOU rates for the peak, off-peak and super off-peak usage periods?

A. In the April 2017 Secretarial Letter, the Commission recommended that EDCs develop price multipliers to appropriately motivate shifting of consumption from on-peak to off-peak periods. To that end, PECO first examined five years of historical PJM Day-Ahead Spot Market Pricing data (2014-2018) for the PECO Zone to calculate the ratios of (1) the average annual peak price to the average annual super off-peak price, and (2) the average annual off-peak price to the average annual super off-peak price.

In addition to wholesale energy prices, the calculation of TOU rates depends on the cost of capacity, which varies by procurement class. PECO is proposing to allocate the cost of capacity to peak hours and off-peak hours only. This approach will send cost-based price signals and create larger peak/off-peak price differentials that are more likely to motivate customers to adjust the time of day they use electricity. PECO allocated capacity costs to peak hours using the percentage of the average daily PECO zonal capacity obligation under PJM's five coincident peak ("5CP") methodology[14] over the historic five-year period (2014-2018). PECO calculated these percentages (the "Capacity Cost Allocators") based on the average of the highest hourly demand (in MWh) during the proposed TOU peak pricing period (2-6 p.m.) on each of the PJM 5CP days. PECO added the remaining percentage of capacity costs to the respective off-peak pricing multiplier.

Based on the foregoing analyses, PECO is proposing to set the TOU price multipliers for each procurement class shown in the table below. These multipliers will remain constant throughout the DSP V term. The proposed

[14] The 5CPs are the five highest daily PJM peak loads for each summer (June 1 through September 30).

multipliers reflect the ratios calculated from average PJM PECO zone spot market prices as well as the cost of capacity during peak hours. Detailed calculations of the Company's proposed TOU pricing multipliers are provided in Exhibit JAB-2.

TOU Pricing Period	GSA-1 TOU Pricing Multipliers*	GSA-2 TOU Pricing Multipliers*
Peak	6.5	5.1
Super Off-Peak	1	1
Off-Peak	1.5	1.7

*Ratio to super off-peak TOU price

25. Q. Mr. Bisti, how will the TOU Rates be set for each procurement class using the Company's proposed pricing differentials?

A. As explained by Mr. McCawley in PECO Statement No. 1, PECO will source the residential and small commercial customers' standard and TOU default service from the same supply portfolio for each procurement class. PECO will continue to calculate the standard GSA on a quarterly basis based on the results of these procurements and use the standard GSA as the reference price for PECO's TOU rate calculations. The super off-peak price will be calculated to provide a discount from the standard GSA price in a way that offsets the higher peak and off-peak period prices and ensures revenue neutrality. The revenue neutral super off-peak price for each procurement class is derived from the portion of total system kWh usage attributable to each TOU pricing period. PECO determined these percentages (the "TOU Period Allocators") described in Exhibit JAB-3 based on PJM energy market settlements over the most recent historical five-year period (2014-2018).

The peak and off-peak TOU prices are a factor of multiplying the super off-peak price by the multiplier for the applicable procurement class and TOU pricing period. Exhibit JAB-4 provides an illustration of the TOU Rate for residential customers based on the proposed TOU pricing multipliers for DSP V and the GSA rate effective as of March 1, 2020.

26. Q. Please describe how default service rates will be adjusted for customers enrolled in the Company's TOU Rate.

A. The TOU Rates will be calculated on a quarterly basis, synchronized with the GSA adjustment periods for the Residential and Small Commercial class, using the Company's proposed pricing methodology. TOU customer kWh sales and costs will be included in the semi-annual reconciliation of the over/undercollection component of the GSA for the entire procurement class (i.e., Residential or Small Commercial). PECO's proposed reconciliation process using a single E-Factor for each procurement class will help mitigate potential large swings in GSA over/undercollections that could arise if customers switch between PECO's standard default service rate and TOU default service rate. In addition, the Commission has previously authorized other EDCs to recover TOU over/undercollection amounts from all default service customers based on its finding that the TOU rates mandated by Act 129 are a "form of default service."[15]

27. Q. Will customer-generators in the Residential and Small Commercial Classes who employ net metering be eligible for the TOU Rates?

A. Yes. Customer-generators who employ net metering will be eligible for the TOU Rate, consistent with the April 2017 Secretarial Letter. Customer-generators who employ virtual net metering will not be eligible due to the administrative complexity of offering TOU rates to those customers.

28. Q. Please explain the monthly accounting and annual cash out process for net metering TOU customers.

A. In each billing month, PECO will separately track net excess generation created by TOU net-metering customers within the TOU peak, off-peak and super off-peak periods. Any excess generation will be banked for use by the customer in subsequent billing periods. During any month when a TOU net metering customer consumes power in excess of the power generated by its facilities, the excess generation in the applicable TOU rate period will be used to reduce or offset the customer's bill at the full retail rate, including the current TOU prices for generation, in accordance with the Commission's guidance in the April 2017 Secretarial Letter.

At the end of the PJM planning period on May 31 of each year, a TOU net metering customer's accumulated excess generation will be cashed out based on

[15] *See Pa. P.U.C. v. PPL Elec. Utils. Corp.*, Docket No. R-2011-2264771 (Opinion and Order entered Aug. 30, 2012), pp. 22-23.

the applicable TOU rate and TSC in effect at the time that the excess electricity was generated. Exhibit JAB-5 provides a detailed example of how PECO will calculate the TOU net metering customer's total end-of-year compensation.

29. Q. How can customers enroll in PECO's TOU rate options?

A. Eligible default service customers may enroll in PECO's TOU Rates online or through the Company's Care Center. Customers will not be charged enrollment fees and may cancel TOU service at any time without a penalty or fee. Participating customers will remain on the TOU Rate until they affirmatively elect to return to PECO's standard default service rate, switch to an EGS, or otherwise become ineligible.

30. Q. Is PECO proposing any restrictions to reduce "free riders" who enroll in a TOU rate only for times of the year when they do not have to shift usage to save money?

A. Yes. TOU customers leaving the TOU Rate for any reason will be precluded from re-enrolling in the TOU Rate for twelve billing months after switching off the TOU Rate.

31. Q. Please describe PECO's communications plan to inform customers about the new TOU Rates and update enrolled TOU customers about the opportunity for bill savings.

A. PECO's communications plan will focus on introducing the educational tools and information to help customers make a rate choice that works best for them. In accordance with the Commission's guidance in the April 2017 Secretarial Letter, PECO will establish a web page dedicated to the Company's TOU Rate that will summarize the new TOU Rates, describe tips and ideas on how to shift electricity use, and provide information about how customers can determine the effect of the TOU Rates on their monthly electricity bills. PECO's communications plan will also include a one-time bill insert and targeted outreach to the customers who have registered EVs with PECO to introduce the new TOU Rates and instruct customers on how to obtain more information.

PECO will distribute progress letters via e-mail to enrolled TOU customers on a monthly basis that will update customers on their current savings on the TOU Rate and remind customers about the mechanics of the TOU Rates. In addition, PECO will provide quarterly updates on TOU generation prices on its website, concurrently with standard, fixed-price GSA updates, and in the Company's quarterly GSA filings with the Commission.

32. Q. Has PECO estimated the cost to implement its proposed TOU rate options?

A. Yes. As shown on Exhibit JAB-6, the Company anticipates that it will incur two categories of costs totaling approximately $3.8 million (based on preliminary costs estimates) to implement the TOU Rates. First, PECO will incur costs related to training and information technology ("IT") changes to the Company's billing and customer information systems to support TOU enrollment, billing, meter data management, customer self-service, Care Center scripting, and net metering excess generation tracking and compensation. The second category of expenditures is for customer communications, including care center scripting.

This cost estimate is based on PECO's proposed TOU rate design and PECO will recover the actual costs from customers through the administrative cost factor of the GSA as described in Section IV of my direct testimony.

33. Q. When will PECO's proposed TOU Rates be available to eligible customers?

A. PECO proposes to implement the TOU Rates at least twelve months following the Commission's final Order in this proceeding. This implementation timeline will allow sufficient time for the Company to develop customer education materials and complete IT programming necessary to implement the final TOU rate design approved by the PUC in this proceeding.

IV. RECOVERY OF DEFAULT SERVICE PROGRAM AND CUSTOMER ASSISTANCE PROGRAM SHOPPING PLAN IMPLEMENTATION COSTS

34. Q. Is PECO entitled to full and current recovery of all costs associated with DSP V?

A. Yes. In accordance with Section 2807(e)(3.9) of the Code, PECO is formally requesting that the Commission expressly affirm PECO's right to full and current recovery of all costs of DSP V.

35. Q. Is the Company seeking to continue to recover the cost of its default service proceedings through the GSA?

A. Yes. Consistent with the Commission's Policy Statement at 69 Pa. Code § 69.1808(a)(4) and the current GSA, the cost of this proceeding, including consultant fees, attorney fees, and costs related to IT changes, will be recovered through the GSA as an expense over the DSP V term. The estimated administrative cost, including the costs to implement the Company's proposed TOU Rates during the DSP V term, is delineated on Exhibit JAB-6.

36. Q. How does PECO propose to recover Standard Offer Program costs during DSP V?

A. Consistent with PECO's existing tariff and the DSP IV Order (p. 67), the Company proposes to continue to recover Standard Offer Program costs through an EGS participant fee not to exceed $30 per referred customer, with any remaining costs recovered in the following manner: (1) fifty percent from EGSs through a Purchase Of Receivables discount; and (2) fifty percent from Residential and Small Commercial default service customers via the GSA.

37. Q. Mr. Bisti, please describe PECO's proposed mechanism to recover the CAP Shopping Plan implementation costs described by Ms. Reilly in PECO Statement No. 3.

A. The Company is proposing to recover the costs associated with the customer-education initiatives included in the CAP Shopping Plan from residential customers in the current Consumer Education Charge approved by the Commission in Docket No. P-2011-2279773. The Company proposes to recover the remaining Plan implementation costs, which consist primarily of IT changes, from residential customers in a subsequent base rate case.

V. OTHER RETAIL TARIFF CHANGES

38. Q. Is PECO proposing any changes to its Electric Service Tariff to implement new TOU rate options for the Residential and Small Commercial Classes?

A. Yes. PECO is proposing the following tariff revisions to implement its TOU proposal:

- **TOU Prices and Terms and Conditions of Service**. The GSA for the Residential and Small Commercial Classes has been expanded to describe the new TOU Rates, including customer eligibility, pricing provisions, and switching rules. The pricing provisions include the current TOU Rates for each price-differentiated period and the formulas showing how PECO calculates the quarterly changes to the TOU Rates. In addition, PECO's CAP Rider has been revised to clarify that the TOU Rates are not available to CAP customers.
- **Reconciliation of TOU Rates**. PECO has revised the reconciliation provisions of the existing GSA to clarify that TOU and standard default service rate over/undercollections will be calculated in total for each procurement class.
- **TOU customer-generators**. The billing provisions for PECO's Rate RS-2 Net Metering have been revised to describe the accounting and cash-out process for TOU customer-generators.

These changes are shown in the clean and blacklined versions of PECO's electric service tariff attached to my testimony as Exhibit JAB-7 and Exhibit JAB-8, respectively.

39. Q. Does PECO's CAP Rider need to be revised to allow CAP customers to receive competitive generation supply?

A. Yes. PECO is proposing to eliminate the current restriction on availability of the CAP Rider to customers who obtain competitive energy supply. *See* Exhibit JAB-8.

40. Q. Has the Company submitted responses to the questions regarding changes to its tariff required by the Commission's Regulations?

A. Yes. Exhibit JAB-9 provides the Company's responses to the questions in 52 Pa. Code § 53.52(a).

VI. JANUARY 2020 SECRETARIAL LETTER TOPICS

41. Q. Did PECO consider the potential benefits of a semi-annual, instead of quarterly, adjustment schedule for default service rates based on the history of the Company's PTC as directed by the January 2020 Secretarial Letter?

A. Yes. PECO examined its electric PTC for the Residential Class and customers on Rate GS in the Small Commercial Class since PECO implemented its first DSP on January 1, 2011. Exhibit JAB-10 presents PECO's PTC history by quarter and procurement class. PECO assessed the benefits presented by both a six-month and three-month default supply price projection period in the context of the Company's PTC history. While a semi-annual schedule may offer several benefits, including less administrative complexity, quarterly changes to the PTC allow for more incremental adjustments consistent with the ratemaking principle of gradualism and to insulate customers from potential larger rate changes. Based on the Company's analysis, PECO is proposing to continue to adjust its default service rates each quarter, with semi-annual reconciliation of the E-Factor at this time. PECO believes its current approach appropriately balances the responsiveness of the PTC to current market conditions and fluctuations caused by billing lag.

42. Q. How is PECO proposing to make TOU rates available to EV operators during DSP V?

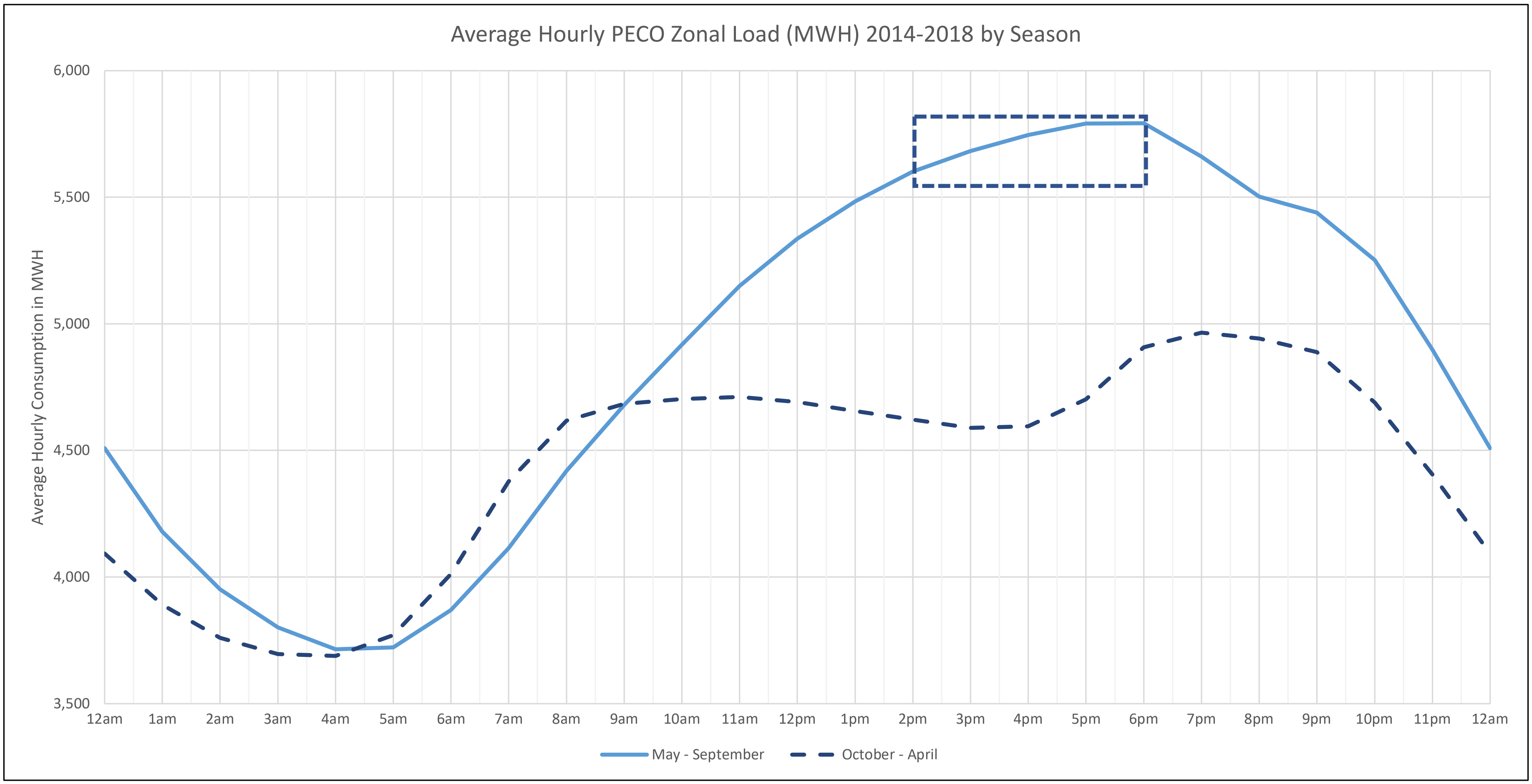
A. As explained in Section III above, PECO's proposed TOU rate design includes a super off-peak pricing time window that features discounted rates that would be attractive for EV charging during the designated hours.

VII. CONCLUSION

43. Q. Does this conclude your direct testimony?

A. Yes.

PECO System Peak Usage Analysis



Pricing Analysis and TOU Pricing Multiplier Calculations

Step 1: PJM PECO Day-Ahead Locational Marginal Pricing (LMP) Analysis

	PJM PECO Day-Ahead (DA) Average LMP Prices				LMP Price Ratios		
Year	**Peak (PP)**	**Off-Peak (OP)**	**Super Off-Peak (SOPP)**	**5-Year Average**	**PP-to-OP**	**PP-to-SOPP**	**OP-to-SOPP**
2014	$64.44	$55.67	$39.31	$52.59	1.16	1.64	1.42
2015	$43.03	$34.87	$24.17	$33.13	1.23	1.78	1.44
2016	$33.42	$25.06	$17.02	$24.01	1.33	1.96	1.47
2017	$34.41	$29.02	$20.95	$27.62	1.19	1.64	1.39
2018	$39.94	$35.38	$26.71	$33.74	1.13	1.49	1.32
5-Year Average	**$43.05**	**$35.99**	**$25.63**	**$34.21**	**1.20**	**1.68**	**1.40**

Pricing Analysis and TOU Pricing Multiplier Calculations

Step 2A: Allocate Capacity Costs to TOU Periods (GSA 1)

Determine highest hourly demand within the TOU Peak Period for each of the 25 PJM RTO CP days from 2014-2018.

PJM RTO 5CP Dates			PECO GSA 1 Demand in Proposed TOU Peak Period (Hour-Ending MWH)				
Year	Month	Day	15	16	17	18	MAX
2014	6	17	2,806	3,000	3,253	3,408	3,408
2014	6	18	3,048	3,254	3,494	3,638	3,638
2014	7	1	3,049	3,259	3,462	3,593	3,593
2014	7	22	2,543	2,728	2,923	3,119	3,119
2014	9	5	2,651	2,848	3,097	3,131	3,131
2015	7	20	3,491	3,636	3,795	3,945	3,945
2015	7	28	3,019	3,188	3,380	3,584	3,584
2015	7	29	3,260	3,428	3,625	3,740	3,740
2015	8	17	3,223	3,355	3,476	3,572	3,572
2015	9	3	3,004	3,201	3,390	3,517	3,517
2016	7	25	3,657	3,808	3,777	3,864	3,864
2016	7	27	3,212	3,382	3,583	3,762	3,762
2016	8	10	3,104	3,295	3,514	3,680	3,680
2016	8	11	3,541	3,726	3,875	3,949	3,949
2016	8	12	3,809	3,868	3,871	3,755	3,871
2017	6	12	2,999	3,197	3,427	3,635	3,635
2017	6	13	3,243	3,431	3,648	3,845	3,845
2017	7	19	3,311	3,491	3,682	3,878	3,878
2017	7	20	3,498	3,650	3,826	3,964	3,964
2017	7	21	3,355	3,497	3,674	3,836	3,836
2018	6	18	3,176	3,361	3,549	3,708	3,708
2018	8	27	3,027	3,218	3,433	3,615	3,615
2018	8	28	3,511	3,706	3,909	4,069	4,069
2018	9	4	3,366	3,567	3,774	3,960	3,960
2018	9	5	3,396	3,583	3,785	3,954	3,954
						5-Year Average:	**3,713**
						Total GSA 1 average daily capacity obligation, 2014-2018:	**4,238**

The ratio of these two averages represents the class's historical TOU peak period contribution to the class's overall capacity obligation for its class.

The resulting percentage is proposed as the capacity cost allocator to the TOU Peak Period price.
All remaining capacity costs are allocated to the TOU Off-Peak Period price.
No capacity cost is allocated to the TOU Super Off-Peak Price.

Resulting GSA 1 Capacity Cost Allocators	
Peak	87.6%
Off-Peak	12.4%
Super Off-Peak	0%

Pricing Analysis and TOU Pricing Multiplier Calculations

Step 2B: Allocate Capacity Costs to TOU Periods (GSA 2)

(A) Determine highest hourly demand within the TOU Peak Period for each of the 25 PJM RTO CP days from 2014-2018.

PJM RTO 5CP Dates			PECO GSA 2 Load in Proposed TOU Peak Period (Hour-Ending MWH)				
Year	Month	Day	15	16	17	18	MAX
2014	6	17	979	967	913	865	979
2014	6	18	1,014	999	930	888	1,014
2014	7	1	1,022	1,004	948	900	1,022
2014	7	22	975	958	939	863	975
2014	9	5	916	932	886	817	932
2015	7	20	1,062	1,053	1,003	928	1,062
2015	7	28	1,033	1,022	983	907	1,033
2015	7	29	1,061	1,052	1,011	931	1,061
2015	8	17	1,039	1,020	965	876	1,039
2015	9	3	1,052	1,043	1,001	917	1,052
2016	7	25	1,099	1,087	1,014	922	1,099
2016	7	27	1,060	1,051	1,017	941	1,060
2016	8	10	1,056	1,050	1,017	935	1,056
2016	8	11	1,112	1,105	1,062	969	1,112
2016	8	12	1,111	1,081	1,017	910	1,111
2017	6	12	1,024	1,018	982	908	1,024
2017	6	13	1,075	1,067	1,032	955	1,075
2017	7	19	1,093	1,087	1,049	975	1,093
2017	7	20	1,122	1,109	1,072	992	1,122
2017	7	21	1,072	1,057	1,020	947	1,072
2018	6	18	1,020	1,015	978	900	1,020
2018	8	27	1,013	1,006	972	891	1,013
2018	8	28	1,090	1,081	1,047	969	1,090
2018	9	4	1,082	1,073	1,032	955	1,082
2018	9	5	1,091	1,083	1,047	969	1,091
						5-Year Average:	**1,052**
						Total GSA 1 average daily capacity obligation, 2014-2018:	**1,424**

The ratio of these two averages represents the class's historical TOU peak period contribution to the class's overall capacity obligation for its class.

The resulting percentage is proposed as the capacity cost allocator to the TOU Peak Period price.
All remaining capacity costs are allocated to the TOU Off-Peak Period price.
No capacity cost is allocated to the TOU Super Off-Peak Price.

Resulting GSA 1 Capacity Cost Allocators	
Peak	73.9%
Off-Peak	26.1%
Super Off-Peak	0%

Pricing Analysis and TOU Pricing Multiplier Calculations

Step 3A: Calculate TOU Pricing Multipliers for GSA 1 (labeled below as "Factor vs. Super Off-Peak")

GSA 1 Capacity Cost Allocators	
Peak	87.6%
Off-Peak	12.4%
Super Off-Peak	0%

	Using Loads, Capacity Obligations, and LMPs from 2014			
Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	132,521,458	621,209,387	136,755,841	890,486,686
Load (MWH)	1,773,991	9,674,397	2,883,751	14,332,140
Energy Cost ($/MWH)	$74.70	$64.21	$47.42	$62.13
Capacity	*Total Capacity Cost:*		*279,090,272*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	244,541,725	34,548,546		279,090,272
Load (MWH)	1,773,991	9,674,397		14,332,140
Capacity Cost ($/MWH)	$137.85	$3.57		$19.47
Capacity + Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$212.55	$67.78	$47.42	$81.61
Rate Factors	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	2.60	0.83	0.58	1.00
Factor vs. Super Off-Peak	4.48	1.43	1.00	1.72

	Using Loads, Capacity Obligations, and LMPs from 2015			
Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	90,287,906	390,214,046	82,948,840	563,450,792
Load (MWH)	1,839,142	10,055,245	2,946,479	14,840,866
Energy Cost ($/MWH)	$49.09	$38.81	$28.15	$37.97
Capacity	*Total Capacity Cost:*		*229,390,294*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	200,994,101	28,396,193		229,390,294
Load (MWH)	1,839,142	10,055,245		14,840,866
Capacity Cost ($/MWH)	$109.29	$2.82		$15.46
Capacity + Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$158.38	$41.63	$28.15	$53.42
Rate Factors	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	2.96	0.78	0.53	1.00
Factor vs. Super Off-Peak	5.63	1.48	1.00	1.90

	Using Loads, Capacity Obligations, and LMPs from 2016			
Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	74,089,129	274,635,339	52,570,874	401,295,342
Load (MWH)	1,842,636	10,085,271	2,904,847	14,832,754
Energy Cost ($/MWH)	$40.21	$27.23	$18.10	$27.05
Capacity	*Total Capacity Cost:*		*249,024,823*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	218,198,074	30,826,749		249,024,823
Load (MWH)	1,842,636	10,085,271		14,832,754
Capacity Cost ($/MWH)	$118.42	$3.06		$16.79
Capacity + Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$158.62	$30.29	$18.10	$43.84
Rate Factors	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	3.62	0.69	0.41	1.00
Factor vs. Super Off-Peak	8.76	1.67	1.00	2.42

	Using Loads, Capacity Obligations, and LMPs from 2017			
Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	66,556,990	296,782,338	62,105,417	425,444,744
Load (MWH)	1,733,073	9,604,639	2,773,505	14,111,217
Energy Cost ($/MWH)	$38.40	$30.90	$22.39	$30.15
Capacity	*Total Capacity Cost:*		*249,287,196*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	218,427,968	30,859,228		249,287,196
Load (MWH)	1,733,073	9,604,639		14,111,217
Capacity Cost ($/MWH)	$126.04	$3.21		$17.67
Capacity + Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$164.44	$34.11	$22.39	$47.82
Rate Factors	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	3.44	0.71	0.47	1.00
Factor vs. Super Off-Peak	7.34	1.52	1.00	2.14

	Using Loads, Capacity Obligations, and LMPs from 2018			
Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	85,580,496	397,368,498	90,730,272	573,679,267
Load (MWH)	1,893,769	10,188,619	3,010,047	15,092,435
Energy Cost ($/MWH)	$45.19	$39.00	$30.14	$38.01
Capacity	*Total Capacity Cost:*		*313,461,043*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	274,657,744	38,803,299		313,461,043
Load (MWH)	1,893,769	10,188,619		15,092,435
Capacity Cost ($/MWH)	$145.03	$3.81		$20.77
Capacity + Energy	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$190.22	$42.81	$30.14	$58.78
Rate Factors	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	3.24	0.73	0.51	1.00
Factor vs. Super Off-Peak	6.31	1.42	1.00	1.95

	Resulting GSA 1 TOU Pricing Multipliers			
Factor vs. Total	3.17	0.75	0.50	1.00
Factor vs. Super Off-Peak	6.51	1.51	1.00	2.03

Pricing Analysis and TOU Pricing Multiplier Calculations

Step 3A: Calculate TOU Pricing Multipliers for GSA 2 (labeled below as "Factor vs. Super Off-Peak")

GSA 2 Capacity Cost Allocators	
Peak	73.9%
Off-Peak	26.1%
Super Off-Peak	0%

	Using Loads, Capacity Obligations, and LMPs from 2014			
Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	48,423,918	203,856,030	43,653,244	295,933,193
Load (MWH)	723,624	3,352,212	991,555	5,067,391
Energy Cost ($/MWH)	$66.92	$60.81	$44.03	$58.40
Capacity	*Total Capacity Cost:*		*105,175,582*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	77,683,235	27,492,347		105,175,582
Load (MWH)	723,624	3,352,212		5,067,391
Capacity Cost ($/MWH)	$107.36	$8.20		$20.76
Capacity + Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$174.28	$69.01	$44.03	$79.15
Rate Factors				
	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	2.20	0.87	0.56	1.00
Factor vs. Super Off-Peak	3.96	1.57	1.00	1.80

	Using Loads, Capacity Obligations, and LMPs from 2015			
Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	33,721,403	127,277,358	26,927,232	187,925,993
Load (MWH)	742,352	3,372,402	1,017,964	5,132,719
Energy Cost ($/MWH)	$45.43	$37.74	$26.45	$36.61
Capacity	*Total Capacity Cost:*		*88,274,240*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	65,199,816	23,074,425		88,274,240
Load (MWH)	742,352	3,372,402		5,132,719
Capacity Cost ($/MWH)	$87.83	$6.84		$17.20
Capacity + Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$133.26	$44.58	$26.45	$53.81
Rate Factors				
	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	2.48	0.83	0.49	1.00
Factor vs. Super Off-Peak	5.04	1.69	1.00	2.03

	Using Loads, Capacity Obligations, and LMPs from 2016			
Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	26,913,424	88,959,821	17,788,655	133,661,900
Load (MWH)	743,331	3,363,136	1,019,546	5,126,013
Energy Cost ($/MWH)	$36.21	$26.45	$17.45	$26.08
Capacity	*Total Capacity Cost:*		*85,722,031*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	63,314,741	22,407,291		85,722,031
Load (MWH)	743,331	3,363,136		5,126,013
Capacity Cost ($/MWH)	$85.18	$6.66		$16.72
Capacity + Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$121.39	$33.11	$17.45	$42.80
Rate Factors				
	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	2.84	0.77	0.41	1.00
Factor vs. Super Off-Peak	6.96	1.90	1.00	2.45

	Using Loads, Capacity Obligations, and LMPs from 2017			
Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	26,247,819	100,516,336	21,861,531	148,625,686
Load (MWH)	732,096	3,343,478	1,013,584	5,089,158
Energy Cost ($/MWH)	$35.85	$30.06	$21.57	$29.20
Capacity	*Total Capacity Cost:*		*73,408,862*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	54,220,170	19,188,693		73,408,862
Load (MWH)	732,096	3,343,478		5,089,158
Capacity Cost ($/MWH)	$74.07	$5.74		$14.42
Capacity + Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$109.92	$35.80	$21.57	$43.63
Rate Factors				
	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	2.52	0.82	0.49	1.00
Factor vs. Super Off-Peak	5.10	1.66	1.00	2.02

	Using Loads, Capacity Obligations, and LMPs from 2018			
Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy Cost ($)	31,074,197	126,583,486	29,535,744	187,193,427
Load (MWH)	744,190	3,395,633	1,036,277	5,176,101
Energy Cost ($/MWH)	$41.76	$37.28	$28.50	$36.16
Capacity	*Total Capacity Cost:*		*91,283,796*	
	Peak	Off-Peak	Super Off-Peak	Total
Allocated Capacity Cost ($)	67,422,689	23,861,107		91,283,796
Load (MWH)	744,190	3,395,633		5,176,101
Capacity Cost ($/MWH)	$90.60	$7.03		$17.64
Capacity + Energy				
	Peak	Off-Peak	Super Off-Peak	Total
Energy + Capacity Cost ($/MWH)	$132.36	$44.30	$28.50	$53.80
Rate Factors				
	Peak	Off-Peak	Super Off-Peak	Total
Factor vs. Total	2.46	0.82	0.53	1.00
Factor vs. Super Off-Peak	4.64	1.55	1.00	1.89

	Resulting GSA 2 TOU Pricing Multipliers			
Factor vs. Total	2.50	0.82	0.50	1.00
Factor vs. Super Off-Peak	5.14	1.67	1.00	2.04

TOU Period Allocator Calculations

		Residential (GSA 1)		Small Commercial (GSA 2)	
TOU Pricing Period	**Year Round Days/Hours Included**	**Total Zonal Load, 2014-2018 (kWh) (GSA 2)**	**TOU Period Allocator* (GSA 1)**	**Total Zonal Load, 2014-2018 (kWh) (GSA 2)**	**TOU Period Allocator* (GSA 2)**
Peak	2 p.m. - 6 p.m. Monday through Friday, excluding PJM Holidays	9,202,230,744	**12%**	3,733,091,154	**14%**
Super Off-Peak	Midnight (12 a.m.) - 6 a.m. Every day	14,698,764,508	**20%**	5,141,477,797	**20%**
Off-Peak	All other hours	50,228,717,200	**68%**	17,034,981,367	**66%**
		74,129,712,452	*100%*	*25,909,550,318*	*100%*

*The TOU Period Allocator represents the ratio of generation (kWh) attributable to each TOU pricing period based on PJM energy market settlements over the most recent historical five-year period (2014-2018).

Illustrative TOU Rate Calculation for Residential Class

The calculations in this exhibit provide an illustration of the Time-Of-Use ("TOU") Rate for residential default service customers based on PECO's proposed TOU pricing multipliers for DSP V (reproduced in Table 1) and the Residential Generation Supply Adjustment ("GSA-1") rate for the Residential Class effective as of March 1, 2020.

Table 1

TOU Pricing Period	Days/Hours Included	TOU Period Allocators PA-GSA(1)	TOU Pricing Multiplier, PM-GSA(1) (Ratio to Super Off-Peak)
Peak ("PP")	2 p.m. – 6 p.m. Monday through Friday, excluding PJM holidays	12%	6.5-to-1
Super Off-Peak ("SOPP")	Midnight(12 a.m.) – 6 a.m. Every day	20%	1-to-1
Off-Peak ("OPP")	All Other Hours	68%	1.5-to-1

There are three steps in developing the TOU Rate for the Residential Class each quarter.

First, PECO will calculate the ratio of the Standard GSA-1 rate to the SOPP price based on the portion of total system kWh usage attributable to each TOU pricing period calculated in PECO Exhibit JAB-3. This factor will remain constant throughout the DSP V term.

Super Off-Peak Price Factor ("SOPP-F")

= [TOU SOPP GSA(1) * 20%] + [TOU OPP GSA(1) * 68%] + [TOU PP GSA(1) * 12%]

= [TOU SOPP GSA(1) * 0.2] + [(1.5 * TOU SOPP GSA(1)) * 0.68] + [(6.5 * TOU SOPP GSA(1)) * 0.12]
= [0.2 * SOPP TOU GSA(1)] + [1.02 * TOU SOPP GSA(1)] + [0.78 * TOU SOPP GSA(1)]
= 2.0 * SOPP TOU GSA(1)

Second, PECO will solve the TOU SOPP price for revenue neutrality. The assumed existing rate used in this illustrative revenue neutrality calculation is the quarterly standard GSA-1 rate effective on March 1, 2020 – $0.05972/kWh. In this example, the revenue neutral TOU SOPP price for the Residential Class effective from March 1, 2020 through May 31, 2020 is as follows:

TOU SOPP GSA(1) = Standard GSA(1-R) *[(1 / SOPP-F GSA(1)]

TOU SOPP GSA(1) = $0.05972 * [1 / 2.0]
= $0.02986

Third, PECO will use this TOU SOPP price and the TOU pricing multipliers to create the peak and off-peak prices of the TOU Rate.

TOU Pricing Period	GSA 1 TOU Price, Rate R (Upcoming 2Q 2020)
Peak	$0.19409/kWh
Super Off-Peak	$0.02986/kWh
Off-Peak	$0.04479/kWh

Net Metering, TOU Monthly Accounting and Cashout – Illustrative Example

Generation and transmission charges used in the calculations below are for explanatory purposes only.

	Jun-Aug	Sep-Nov	Dec-Feb	Mar-May
Residential PTC (GSA 1):	$0.06595	$0.06680	$0.06668	$0.06640
Generation Charge:	$0.05972	$0.06057	$0.06012	$0.05984
Transmission Charge:	$0.00623	$0.00623	$0.00656	$0.00656

Illustrative TOU Prices, GSA 1	Jun-Aug	Sep-Nov	Dec-Feb	Mar-May
Peak ("PP"):	$0.19409	$0.19685	$0.19539	$0.19448
Off-Peak ("OPP"):	$0.04479	$0.04543	$0.04509	$0.04488
Super Off-Peak ("SOPP"):	$0.02986	$0.03029	$0.03006	$0.02992

TOU Pricing Multipliers, GSA 1		
PP-SOPP Ratio:	*(Exhibit JAB-2)*	6.5
OP-SOPP Ratio:	*(Exhibit JAB-2)*	1.5
SOPP Factor:	*(Exhibit JAB-4)*	2

Monthly Metering Data

Month and Year	TOU Period	Consumed kWh ("In")	Exported kWh ("Out")	Monthly Net kWh *(In)* or Out	Monthly Excess kWh for WAPTC$_e$	PTC$_e$ for TOU Period
Jun-20	Peak	300	350	50	50	$0.20032
	Off-Peak	200	100	*(100)*	0	$0.05102
	Super Off-Peak	25	0	*(25)*	0	$0.03609
Jul-20	Peak	400	550	150	150	$0.20032
	Off-Peak	250	300	50	50	$0.05102
	Super Off-Peak	50	0	*(50)*	0	$0.03609
Aug-20	Peak	350	500	150	150	$0.20032
	Off-Peak	125	175	50	50	$0.05102
	Super Off-Peak	75	0	*(75)*	0	$0.03609
Sep-20	Peak	300	150	*(150)*	0	$0.20308
	Off-Peak	100	25	*(75)*	0	$0.05166
	Super Off-Peak	20	0	*(20)*	0	$0.03652
Oct-20	Peak	200	250	50	50	$0.20308
	Off-Peak	75	150	75	75	$0.05166
	Super Off-Peak	25	0	*(25)*	0	$0.03652
Nov-20	Peak	175	200	25	25	$0.20308
	Off-Peak	150	75	*(75)*	0	$0.05166
	Super Off-Peak	10	0	*(10)*	0	$0.03652
Dec-20	Peak	200	150	*(50)*	0	$0.20195
	Off-Peak	150	50	*(100)*	0	$0.05165
	Super Off-Peak	10	0	*(10)*	0	$0.03662
Jan-21	Peak	250	150	*(100)*	0	$0.20195
	Off-Peak	200	50	*(150)*	0	$0.05165
	Super Off-Peak	10	0	*(10)*	0	$0.03662
Feb-21	Peak	200	225	25	25	$0.20195
	Off-Peak	100	25	*(75)*	0	$0.05165
	Super Off-Peak	25	0	*(25)*	0	$0.03662
Mar-21	Peak	300	150	*(150)*	0	$0.20104
	Off-Peak	100	25	*(75)*	0	$0.05144
	Super Off-Peak	20	0	*(20)*	0	$0.03648
Apr-21	Peak	200	250	50	50	$0.20104
	Off-Peak	100	125	25	25	$0.05144
	Super Off-Peak	50	0	*(50)*	0	$0.03648
May-21	Peak	200	400	200	200	$0.20104
	Off-Peak	125	300	175	175	$0.05144
	Super Off-Peak	50	0	*(50)*	0	$0.03648

12-Month Weighted Average TOU Price-To-Compare Equivalent (WAPTC$_e$) and May Annual Cash Out

TOU Period	Month and Year	Consumed kWh ("In")	Exported kWh ("Out")	Monthly Net kWh *(In)* or Out	Monthly Excess kWh for WAPTC$_e$	Net Excess Generation kWh	PTC$_e$ for TOU Period	Monthly Weight	12-month TOU WAPTC$_e$	Cash Out
Peak	Jun-20	300	350	50	50	50	$0.20032	10.02		
	Jul-20	400	550	150	150	200	$0.20032	30.05		
	Aug-20	350	500	150	150	350	$0.20032	30.05		
	Sep-20	300	150	*(150)*	0	200	$0.20308	0.00		
	Oct-20	200	250	50	50	250	$0.20308	10.15		
	Nov-20	175	200	25	25	275	$0.20308	5.08		
	Dec-20	200	150	*(50)*	0	225	$0.20195	0.00		
	Jan-21	250	150	*(100)*	0	125	$0.20195	0.00		
	Feb-21	200	225	25	25	150	$0.20195	5.05		
	Mar-21	300	150	*(150)*	0	0	$0.20104	0.00		
	Apr-21	200	250	50	50	50	$0.20104	10.05		
	May-21	200	400	200	200	250	$0.20104	40.21		
									$0.2009	$50.24
Off-Peak	Jun-20	200	100	*(100)*	0	0	$0.05102	0.00		
	Jul-20	250	300	50	50	50	$0.05102	2.55		
	Aug-20	125	175	50	50	100	$0.05102	2.55		
	Sep-20	100	25	*(75)*	0	25	$0.05166	0.00		
	Oct-20	75	150	75	75	100	$0.05166	3.87		
	Nov-20	150	75	*(75)*	0	25	$0.05166	0.00		
	Dec-20	150	50	*(100)*	0	0	$0.05165	0.00		
	Jan-21	200	50	*(150)*	0	0	$0.05165	0.00		
	Feb-21	100	25	*(75)*	0	0	$0.05165	0.00		
	Mar-21	100	25	*(75)*	0	0	$0.05144	0.00		
	Apr-21	100	125	25	25	25	$0.05144	1.29		
	May-21	125	300	175	175	200	$0.05144	9.00		
									$0.0514	$10.27
Super Off-Peak	Jun-20	25	0	*(25)*	0	0	$0.03609	0.00		
	Jul-20	50	0	*(50)*	0	0	$0.03609	0.00		
	Aug-20	75	0	*(75)*	0	0	$0.03609	0.00		
	Sep-20	20	0	*(20)*	0	0	$0.03652	0.00		
	Oct-20	25	0	*(25)*	0	0	$0.03652	0.00		
	Nov-20	10	0	*(10)*	0	0	$0.03652	0.00		
	Dec-20	10	0	*(10)*	0	0	$0.03662	0.00		
	Jan-21	10	0	*(10)*	0	0	$0.03662	0.00		
	Feb-21	25	0	*(25)*	0	0	$0.03662	0.00		
	Mar-21	20	0	*(20)*	0	0	$0.03648	0.00		
	Apr-21	50	0	*(50)*	0	0	$0.03648	0.00		
	May-21	50	0	*(50)*	0	0	$0.03648	0.00		
									$0.0000	$0.00
									Annual Cashout:	$60.51

PECO DSP V Estimated Filing and Program Costs

Item	Description	Estimated Cost ($Millions)[1]	Recovery Mechanism
1	Cost of DSP V Proceeding (a)	$1.0	GSA
2	Independent Evaluator	$1.2	GSA
3	GSA Forecasting	$0.8	GSA
4	Optional Residential / Small Commercial Time-Of-Use (b)	$3.8	GSA
5	CAP Shopping	$1.2	
	Implementation Costs (c)	$0.7	Base Rates
	Consumer Education	$0.5	Consumer Education Surcharge
6	Customer Referral Program - $30 per customer referred	$1.1	EGS receiving the referral
7	RFP Monitor for Procurement of Solar Alternative Energy Credits	$0.1	GSA

Notes:

1	Estimates subject to change based on final program design and implementation.	
(a)	Consultants	$0.5
	Legal Expense	$0.5
	Total	$1.0
(b)	Expense	$0.9
	Capital	$2.9
	Total	$3.8
(c)	Expense	$0.2
	Capital	$0.5
	Total	$0.7

PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 4.

Issued March 13, 2020 **Effective June 1, 2021**

ISSUED BY: M. A. Innocenzo – President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19103

NOTICE

LIST OF CHANGES MADE BY THIS SUPPLEMENT

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW – X REVISED PAGE NO. 34, X REVISED PAGE NO. 35, ORIGINAL PAGE NO. 35A,
Updated to reflect effective date of June 1, 2021 (DSP V). Expanded to describe new optional Time-Of-Use (TOU) Pricing Option, including customer eligibility requirements, pricing provisions, and switching rules. Labeled pre-existing non-TOU pricing as "Standard" GSA.

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 LOADS GREATER THAN 100KW REVISED PAGE NO. 36 - Updated to reflect effective date of June 1, 2021 (DSP V).

RECONCILIATION - X REVISED PAGE NO. 37 AND X REVISED PAGE NO. 38
Updated to reflect effective date of June 1, 2021 (DSP V). Modified "Applicability" section to clarify that Standard and TOU default service rate over/undercollections will be calculated in total for both Procurement Classes 1 and 2 (each "reconciled in one group"). Removed obsolete language on Procurement Class 3/4 transition.

RATE RS-2 NET METERING - X REVISED PAGE NO. 51, X REVISED PAGE NO. 52, X REVISED PAGE NO. 53
Updated "Metering Provisions" to exclude virtual net metering customers from default service TOU. Supplemented "Billing Provisions" with description of excess generation accounting and cashout processes for customer-generators enrolled in default service TOU. Pages 52 and 53 are repaginated.

CUSTOMER ASSISTANCE PROGRAM (CAP) RIDER – X REVISED PAGE NO. 77
Eliminated restriction of "Availability" to customers who obtain competitive energy supply. Also added restriction of "Availability" excluding CAP customers from selecting default service TOU.

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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW

Applicability: June 1, 2021 this adjustment shall apply to all customers taking default service from the Company with demands up to 100 kW. The rate contained herein shall be calculated to the nearest one thousandth of a cent. The GSA shall contain the cost of generation supply for each tariff rate. The Company will apply Standard Pricing unless customers voluntarily request and are eligible to participate in the Time-Of-Use Pricing Option as detailed below. **(C)** **(C)**

Standard Pricing: Standard Pricing provides default service to customers who have not selected or are not eligible for PECO's Time-Of-Use Pricing Option. The rates below shall include the cost of procuring power to serve the default service customers including the cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The standard pricing for default service will represent the estimate of the cost to serve the specific tariff rate for the next quarterly period beginning with the three months ended August 31, 2021. The rates in this tariff shall be updated quarterly on June 1, September 1, December 1 and March 1 commencing June 1, 2021 and are not prorated. If the balance of over/(under) recovery gets too large, the Company can file a reconciliation that will mitigate the subsequent impact. The standard generation service charge shall be calculated using the following formula: **(C)** **(C)** **(C)** **(C)** **(C)**

Standard GSA(n) = (C-E+A)/S*1/(1-T)* (1-ALL)/(1-LL) +AEPS/S*1/(1 - T) + WC where; **(C)**

C= The sum of the amounts paid to the full requirements suppliers providing the power for the quarterly period, the spot market purchases for the quarterly period, plus the cost of any other energy acquired for the quarterly period. Cost shall include energy, capacity and ancillary services, distribution line losses, cost of complying with the Alternative Energy Portfolio Standards, and any other load serving entity charges other than network transmission service and costs assigned under the Regional Transmission Expansion Plan. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as the load serving entity charges listed in the Supply Master Agreement Exhibit D as the responsibility of the supplier. This component shall include the proceeds and costs from the exercise of Auction Revenue Rights granted to PECO by PJM.

AEPS = The projected total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the C component above for the quarterly period for each procurement class. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

E = Experienced over or under-collection calculated under the reconciliation provision of the tariff to be effective semiannually with recovery during the periods March 1 through August 31 of the current year and September 1 of the current year through February 28 (29) of the following year.

A = Administrative Cost - This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement plan, legal fees incurred gaining approval of the plan and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or is approved in its Act 129 filing. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.

S = Estimated sales for the period the rate is in effect for the classes to which the rate is applicable. Six month sales are used for the E factor with effective periods March 1 through August 31 of the current year and September 1 of the current year through February 28 (29) of the following year.

T = The currently effective gross receipts tax rate.

n = The procurement class for which the GSA is being calculated.

ALL = Average line losses for the procurement class.

LL = Line losses for the specific rate class provided in the Company's Electric Generation Supplier Coordination Tariff rule 6.6.

WC = $0.00019/kWh to represent the cash working capital for power purchases.

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges. In general, the line loss adjustment is applicable to Procurement Class 2 only as those classes contain rate classes with three different line loss factors: Current Charges:

Standard Rate		Standard GSA Price
R	GSA (1)	$0.XXXXX
RH	GSA (1)	$0.XXXXX
GS	GSA (2)	$0.XXXXX

(C)

(C) Denotes Change

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW (CONTINUED)

(C)

PD	GSA (2)	$0.XXXXX
HT	GSA (2)	$0.XXXXX
POL*	GSA (2)	$0.XXXXX
SL-S*	GSA (2)	$0.XXXXX
TLCL	GSA (2)	$0.XXXXX
SL-E*	GSA (2)	$0.XXXXX
AL*	GSA (2)	$0.XXXXX
SL-C*, **	GSA (2)	$0.XXXXX

* Prices shall exclude capacity from the Procurement Class 2 RFP results.
** Rate SL-C was effective July 1, 2019 pursuant to the Order at Docket No. R-2018-3000164

Procedure: For Procurement Classes 1 and 2 the GSA shall be filed 45 days before the effective dates of June 1, September 1, December 1 and March 1 in conjunction with the Reconciliation Schedule.

Time-Of-Use (TOU) Pricing Option: The TOU Pricing Option provides eligible customers with an opportunity to shift energy usage away from peak periods, when wholesale electricity demand and prices are high, to off-peak periods, when demands and prices are lower. Customers may voluntarily request this option in lieu of Standard Pricing described above and must meet the TOU Eligibility Requirements below. TOU Pricing Option rates will be updated quarterly in concurrence with the Standard GSA on June 1, September 1, December 1 and March 1 commencing XXX and are not prorated. (C)

The year-round TOU Pricing Periods, TOU Period Allocators ["PA-GSA(n)"], and TOU Pricing Multipliers ["PM-GSA(n)"] as approved in the Company's most recent DSP proceeding at Docket No. XXX are as follows:

TOU Pricing Period	Days/Hours Included	TOU Period Allocator PA-GSA(1)	TOU Period Allocator PA-GSA(2)	TOU Pricing Multiplier PM-GSA(1) (Ratio to Super Off-Peak)	TOU Pricing Multiplier PM-GSA(2) (Ratio to Super Off-Peak)
Peak ("PP")	2:00 – 6:00 p.m. Monday through Friday, excluding PJM holidays	12%	14%	6.5-to-1	5.1-to-1
Super Off-Peak ("SOPP")	Midnight (12 a.m.) – 6 a.m. Every day	20%	20%	1-to-1	1-to-1
Off-Peak ("OPP")	All other hours	68%	66%	1.5-to-1	1.7-to-1

To calculate the quarterly TOU Pricing Option rates, the Company will first calculate the quarterly TOU Super Off-Peak Price ("SOPP") in accordance with the formula set forth below:

TOU SOPP GSA(n) = Standard GSA(n) * [1 / SOPP-F(n)] where;

Standard GSA(n) = Defined as above for Standard Pricing.

SOPP-F(n) = Super Off-Peak Price Factor representing the ratio of the Standard GSA(n) to the Super Off-Peak Price, calculated as follows:

TOU SOPP PA-GSA(n) + [(TOU OPP PM-GSA(n) * TOU OPP PA-GSA(n)] + [(TOU PP PM-GSA(n) * TOU PP PA-GSA(n)]

The Company will then calculate the quarterly TOU Peak ("PP") and Off-Peak ("OPP") prices as follows:

TOU PP GSA(n) = TOU SOPP GSA(n) * TOU PP PM-GSA and;

TOU OPP GSA(n) = TOU SOPP (GSA(n) * TOU OPP PM-GSA.

Current TOU Pricing Option Charges (Year-Round):

TOU Rate	Peak Hours (2-6 PM Monday-Friday, excluding holidays)	Super Off-Peak Hours (12-6 AM all days)	Off-Peak Hours (All other times)
R (GSA 1)	$0.XXXXX	$0.XXXXX	$0.XXXXX
RH (GSA 1)	$0.XXXXX	$0.XXXXX	$0.XXXXX
GS (GSA 2)	$0.XXXXX	$0.XXXXX	$0.XXXXX
PD (GSA 2)	$0.XXXXX	$0.XXXXX	$0.XXXXX
HT (GSA 2)	$0.XXXXX	$0.XXXXX	$0.XXXXX

(C)

(C) Denotes Change

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW (CONTINUED)

TOU Eligibility Requirements and Switching Rules: (C)

The TOU Pricing Option is available to new and existing Customers in Procurement Classes 1 or 2 with a smart meter configured to measure energy consumption in watt-hours. This includes Customers in the above referenced Procurement Classes taking default service from the Company and who also participate in the Company's RS-2 (Net Metering) tariff, except for virtual net metered Customers. Residential Customers enrolled in the Company's Customer Assistance Program (CAP) are not eligible for the TOU Pricing Option.

As a prerequisite for enrollment, the Customer must have a valid e-mail address to ensure the Company is able to provide the enrolled TOU Pricing Option Customer with timely and meaningful communications regarding their bill savings performance.

Participating Customers will remain on the TOU Pricing Option rate until they affirmatively elect to return to PECO's Standard GSA rate, switch to an EGS, or otherwise become ineligible.

Customers who select the TOU Pricing Option may leave at any time without incurring related penalties or fees. However, Customers who select and subsequently leave the TOU Pricing Option for any reason may not re-enroll on the TOU Pricing Option rate for twelve billing months after switching off the TOU Pricing Option rate.

(C) Denotes Change

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 LOADS GREATER THAN 100KW

Applicability: June 1, 2021 this adjustment shall apply to all customers taking default service from the Company with demands greater than 100 kw. **(C)**

Hourly Pricing Service
Pricing: The rates below shall include the cost of procuring power to serve the default service customers plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The rates for the GSA 3/4 Hourly Pricing Adder* shall be updated quarterly on June 1, September 1, December 1 and March 1 commencing June 1, 2021 and are not prorated. **(C)** If the balance of over/(under) recovery gets too large due to billing lag, the Company can file a reconciliation that will mitigate the subsequent impact. The cost for this hourly service rate shall be as follows:

Generation Supply Cost (GSC) = (C+R+AS+AC-E)/(1-T)+WCA where;

C = The PJM day ahead hourly price multiplied by the customers usage in the hour summed up for all hours in the month

ΣPJM_{DA} x usage / (1-LL)
PJM_{DA} – PJM on day ahead hourly price.
Usage - Electricity used by an end use customer.
R = The PJM reliability pricing model (RPM) charge for month for the customer. The RPM charge shall be the customers peak load contribution as established for PJM purposes multiplied by the current RPM monthly charge and the PJM established reserve margin adjustment.
PLC x (1+ RM) x P_{RPM} x Bill Days
PLC = Peak load contribution
RM = Reserve margin adjustment per PJM
P_{RPM} = Capacity price per MW-day
AC = Administrative Cost - This includes an allocation of the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the plan, and any other costs associated with designing and implementing a procurement plan divided by the total default service sales and then multiplied by the customers usage for the month. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.
A / S x Usage
A = Administrative cost
S = Default service sales
AS = The cost, on a $/MWH basis, of acquiring ancillary services from PJM and of complying with the Alternative Energy Portfolio Standard, multiplied by the customers usage for the month and divided by (1-LL). Congestion charges including the proceeds and costs from the exercise of
Auction Revenue Rights shall be included in this component. Ancillary services shall be those included in the Supply Master Agreement as being the responsibility of the supplier.

((PJM_{AS} x Usage*1/(1-LL) + AEPS/S_{AEPS} x Usage)

PJM_{AS} = $/MWH charged by PJM for ancillary services
AEPS = Cost of complying with the alternative energy portfolio standard
S_{AEPS} = Sales for which AEPS cost is incurred
If the supplier provides the ancillary services and AEPS cost then the customer shall be charged the supplier's rate for these services times usage and divided by (1-LL).

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges
LL = Line loss factor as provided in the Company's Electric Generation Supplier Coordination Tariff Rule 6.6 based upon the customers distribution rate class adjusted to remove losses included in the PJM LMP
T = The currently effective gross receipts tax rate
E = $\Sigma O/(U)/S_{3/4}$ x usage where
E (Purchased Generation Adj.) = Over/under recovery as calculated in the reconciliation
$S_{3/4}$ = Procurement class 3/4 sales
WC = $0.00019 kWh for working capital associated with power purchases
WCA = Individual customer sales x WC
Procedure: The "E" factor shall be updated semiannually in conjunction with the Reconciliation. The applicable above items are converted to the rates listed below.

Tariff Rate	GS	PD	HT	EP	
Hourly Pricing Adder* (dollars/kWh)	$0.XXXXX	$0.XXXXX	$0.XXXXX	$0.XXXXX	**(C)**

* Includes administrative cost (AC), ancillary service charge (AS), E factor (E) and working capital (WC).

(C) Denotes Change

RECONCILIATION

Applicability: June 1, 2021 this adjustment shall apply to all customers who received default service during the period the cost of which is being reconciled. Customers taking default service during the reconciliation period that leave default service prior to the assessment of the collection of the over/(under) adjustment shall still pay or receive credit for the over/(under) adjustment through the migration provision. The Company shall notify the Commission and parties to the Default Service Settlement 15 days in advance of the quarterly or monthly filing if the Migration Provision will be implemented in the filing. **(C)**

This adjustment shall be calculated on a semiannual basis for Procurement Classes 1, 2 and 3/4 Hourly. The reconciliation period will include the six month period beginning January 1 and July 1 commencing with the July 1, 2020 through December 31, 2020 reconciliation **(C)** period. The reconciliation shall be separate for each procurement class. Any resulting over or under recovery shall be assessed on an equal cents per kilowatt hour basis to all customers in the relevant procurement group. Any over/(under) recovery shall be collected after the Occurrence of two months from the end of the reconciliation period. Recovery shall be over a six month period commencing September 1 and March 1. The initial six month period is March 1, 2021 through August 31, 2021. For purposes of this rider the reconciliation shall be **(C)** calculated 45 days before the effective date of recovery. The over or under recovery shall be calculated using the formula below. The calculation of the over/(under) recovery shall be done separately for the following procurement classes – Class 1 – Residential Class 2 – Small C&I up to and including 100 kW, and Class 3/4 – Large C&I greater than 100 kW. For Procurement Classes 1 and 2, Standard **(C)** Pricing and TOU Pricing Option revenue and cost of supply will be included for the entire Procurement Class.

Reconciliation Formula

$E_N = \Sigma O/(U) + I$

Migration Provision $E_M = [\Sigma O/(U) + I]/S/(1\text{-GRT})*(1\text{-ALL})/(1\text{-LL})$

Where:

E = Experienced over or under collection plus associated interest
N = Procurement class
M = Migration Rider
O/(U) = The monthly difference between revenue billed to the procurement class and the cost of supply as described below in Cost, AEPS Cost and Administrative Cost.

Revenue = Amount billed to the tariff rates applicable to the procurement class including approved Real Time Price or other time sensitive rates for the period being reconciled through the GSA.

Cost = The sum of the amounts paid to all of the full requirements suppliers providing the power for the period being reconciled, the spot market purchases for the period being reconciled, plus the cost of any other energy acquired for the period being reconciled. Cost shall include energy, capacity and ancillary services as well as the proceeds and costs of auction revenue rights for Procurement Classes 1 and 2. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as those costs listed in the Supply Master Agreement as the responsibility of the seller.

AEPS = The total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the Cost component above for the reconciliation period for Procurement Classes 1 and 2 and not included in the ancillary services component for Procurement Class 3/4 Hourly Service. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

Administrative Cost = This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the strategy, and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or approved in its Act 129 filing. Administrative Costs also includes other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGS's or through another rate.

Full Requirements Supply = A product purchased by the Company that includes a fixed price for all energy consumed. The only cost added by the Company to the full requirements price is for gross receipts tax, distribution line losses, and administrative cost.

Ancillary Services = The following services in the PJM OATT- reactive support, frequency control, operating reserves, supplemental reserves, imbalance charges, PJM annual charges, any PJM assessment associated with non-payment by members, and any other load serving entity charges not listed here but contained in Exhibit D of the Supply Master Agreement. Also included shall be the proceeds and costs from the exercise of auction revenue rights for Procurement Class 3/4 Hourly Service.

(C) Denotes Change

RECONCILIATION
(CONTINUED)

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges.

Capacity = The amount charged to PECO by PJM for capacity for its default service load under the reliability pricing model (RPM).

I = interest on the over or under collection at the prime rate of interest for commercial banking, not to exceed the legal rate of interest, in effect on the last day of the month the over collection or under collection occurs, as reported in the Wall Street Journal in accordance with the Order at Docket No. L-2014-2421001.

S= Estimated default service retail sales in kWh for the period the cost of which is being reconciled.

ALL = The average line losses in a procurement class as a percent of generation.

LL = The average line losses for a particular rate (e.g. HT, PD, GS) as provided in the Electric Generation Supplier Coordination Tariff rule 6.6.

GRT = The current gross receipts tax rate.

Procurement Class - Set of customers for which the company has a common procurement plan.

Procedural Schedule
The Company shall file the calculation of the over/under collection for the period being reconciled and the proposed adjustment to the GSA 45 days before the effective date as described below. The over/under collection adjustment, shall be effective no earlier than the first day of the month such that the commencement of recovery shall lag by two months. The GSA will be effective June 1, September 1, December 1 and March 1 commencing June 1, 2021 with over/under collection recovery occurring over the six month period beginning September 1 and March 1. **(C)**
The data provided in the reconciliation shall be audited on an annual basis by the PaPUC Bureau of Audits.

(C) Denotes Change

RATE RS-2 NET METERING

PURPOSE.

This Rate sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system.

APPLICABILITY.

This Rate applies to renewable customer-generators served under Rates R, RH, CAP, GS, HT, PD and EP who install a device or devices which are, in the Company's judgment, subject to Commission review, a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system. This Rate is limited to installations where the renewable energy generating system is intended primarily to offset part or all of the customer-generator's requirements for electricity. A renewable customer-generator is a non-utility owner or operator of a net metered generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service (Rate R, RH, or CAP) or not larger than 3,000 kilowatts at other customer service locations (Rate GS, HT, PD and EP), except for Customers whose systems are above 3 megawatts and up to 5 megawatts who make their systems available to operate in parallel with the Company during grid emergencies as defined by the regional transmission organization or where a microgrid is in place for the purpose of maintaining critical infrastructure such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities provided that technical rules for operating generators interconnected with facilities of the Company have been promulgated by the Institute of Electrical and Electronic Engineers "IEEE" and the Commission.

Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. This Rate is not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

Service under this Rate is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

METERING PROVISIONS.

A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule R, RH, CAP, GS, HT, PD or EP.

1. A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. A dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

2. If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense.

   Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternative energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for their disposition.

3. Meter aggregation on properties owned or leased and operated by a customer-generator shall be allowed for purposes of net metering. Meter aggregation shall be limited to meters located on properties within two (2) miles of the boundaries of the customer-generator's property. Meter aggregation shall only be available for properties located within the Company's service territory. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis. Customer generators involved in virtual **(C)** metering programs are not eligible for the company's default service TOU Pricing Option.

(C) Denotes Change

RATE RS-2 NET METERING (continued)

BILLING PROVISIONS.

The following billing provisions apply to default service customer-generators in conjunction with service under applicable Rates R, RH, CAP, GS, HT, PD, EP. **(C)**

1. The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the full retail rate consistent with Commission regulations. If a customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the customer-generator for kilowatt-hours received from the customer-generator in excess of the kilowatt hours delivered by Company to the customer-generator during the preceding year at the "full retail value for all energy produced" consistent with Commission regulations. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

   For default service Time-Of-Use ("TOU") customer-generators only: The Company will record excess generation supplied by TOU Pricing Period, maintaining an active record of kilowatt hours produced and consumed at the customer-generator's premise. If, in a subsequent default service TOU billing period, a customer consumes more electricity than produced within a given TOU Pricing Period, The Company will pull kilowatt hours for the excess generation from the customer's banked kilowatt-hours for that TOU Pricing Period. Any excess kilowatt hours remaining in that TOU Pricing Period will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the TOU customer generator for accumulated excess generation at the full retail value based on the applicable TOU Pricing Option rate and TSC rate in effect at the time the excess electricity was generated. **(C)**

2. If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

3. For customer-generators involved in virtual meter aggregation programs, any excess credit shall be applied first to the account containing the meter through which the generating facility supplies electricity to the distribution system, also known as the "host account". If the host account's usage has been fully offset by this credit and additional excess credit still remains, PECO will divide that remaining credit into equal parts based on the number of additional virtually metered accounts under the customer-generator's name, also known as "satellite accounts", and apply one part to each satellite account in a "waterfall"-like fashion at each account's designated rate. This process continues as PECO bills each subsequent satellite account, with any additional excess credits from each divided equally among the remaining satellite accounts. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

4. Procurement Class 3/4 customer-generators will receive a generation credit, at the PJM Day Ahead hourly energy rate, for each kilowatt hour received by the Company during each hour of the billing period up to the total amount of electricity delivered to the customer during each hour of the billing period.

   If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator during any hour in the billing period, the excess kilowatt hours shall not be carried forward to a subsequent billing period but will be credited in the current month toward generation charges based on the PJM Day Ahead hourly rate. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year.

5 Procurement Class 3/4 customer-generators will also receive a variable distribution credit for each kilowatt hour received by the Company during the monthly billing period up to the total amount of electricity delivered to the Customer during the monthly billing period at the applicable distribution rate.

   If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator, the variable distribution charges will be reduced by the excess kilowatt hours, which will be carried forward and credited against the customer-generator's distribution kilowatt hours in subsequent billing periods until the end of the PJM planning period, ending May 31 of each year.

   Procurement Class 3/4 customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

   Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges.

(C) Denotes Change

RATE RS-2 NET METERING (continued)

NET METERING FOR SHOPPING CUSTOMERS

1. Customer-generators may take net metering services from EGSs that offer such services.

2. If a net-metering customer takes service from an EGS, the Company will credit the customer for distribution charges for each kilowatt hour produced by a Tier I or Tier II resource installed on the customer-generator's side of the electric revenue meter, up to the total amount of kilowatt hours delivered to the customer by the Company during the billing period. If a customer-generator supplies more electricity to the electric distribution system than the EDC delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the Company's distribution rates. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rates Schedule.

3. If the Company delivers more kilowatt hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the applicable rate schedule shall be applied to the net kilowatt hours of electricity that the Company delivered. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

4. Pursuant to Commission regulations, the credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs shall be stated in the service agreement between the customer-generator and the EGS.

5. If a customer-generator switches electricity suppliers, the Company shall treat the end of the service as if it were the end of the PJM planning period.

APPLICATION.
Customer-generators seeking to receive service under the provisions of this Rate must submit a written application to the Company demonstrating compliance with the Net Metering Rate provisions and quantifying the total rated generating capacity of the customer-generator facility. The installation cannot be directly connected to the Company's distribution system ("stand alone"). Instead, the installation must be connected to a facility (residence or business) that is connected to the Company's distribution system.

INTERCONNECTION EXPIRATION.
Interconnection applications will be reviewed and processed in accordance with the timeframes designated by PECO in Act 213 and Title 52 of the Pa Code Chapter 75. A customer-generator (or authorized designee) must submit a completed certificate of completion ("COC") for residential level 1 and 2 interconnection applications to PECO within 180 calendar days from the date that PECO approves the interconnection application. If a COC is not received within 180 calendar days from the date that PECO approves the interconnection application then the residential level 1 and level 2 interconnection applications shall expire. A customer-generator may request an extension of a residential level 1 or level 2 application expiration date for good cause shown (i.e., that significant progress in construction of the interconnection has been or will be made). Upon a showing of good cause, the application expiration date will be extended. The length of the extension may be extended up to but no more than 180 calendar days. A customer-generator must make such extension requests in writing or via e-mail no less than 30 calendar days prior to an application's original expiration date. PECO will provide notice to developers of distributed generation at least 45 calendar days ahead of the original expiration date.

MINIMUM CHARGE.
The Minimum Charges under Rate Schedule R, RH, CAP, GS, PD, HT and EP apply for installations under this Rate.

RIDERS.
Bills rendered by the Company under this Rate shall be subject to charges stated in any other applicable Rate.

CUSTOMER ASSISTANCE PROGRAM (CAP) RIDER

AVAILABILITY.
To payment-troubled customers who are currently served under or otherwise qualify for Rate R, or RH (excluding multiple dwelling unit buildings consisting of two to five dwelling units). Customers must apply for the rates contained in this rider and must demonstrate annual household gross income at or below 150% of the Federal Poverty guidelines. In addition, these customers are not eligible to select the Time-Of-Use default service pricing option. (C)

Based on the applicable level of income, number of household members, and their historical usage CAP customers will receive a Fixed Credit Option ("FCO") based upon that individual household's need. The details of the FCO calculation can be found in the PECO Universal Service and Energy Conservation Plan at Docket No. M-2015-2507139.

DISCOUNT LEVELS: The Company will modify the level of discounts every quarter to adjust for changes in Customer usage as well as any Rate changes which may have occurred.

CERTIFICATION/VERIFICATION Prior to enrollment in the CAP Rider, and then again every two years, customers must verify, to PECO's satisfaction, that their household income level meets the "Availability" standards set forth in this Rider. Customers being considered for the CAP Rider will be required to:

- Provide information sufficient to demonstrate to PECO their household income level.
- Waive certain privacy rights to enable PECO to effectively conduct the above certification process.
- Apply for and assign to PECO at least one energy assistance grant from the Commonwealth.
- Participate in various energy education and conservation programs facilitated by PECO.

PECO may, at its sole discretion, supplement this verification process by using data from Commonwealth or federal government programs which demonstrate the income eligibility of its customers. Such data may come from a customer's participation in, or receipt of benefits from, the Low Income Home Energy Assistance Program, Temporary Assistance for Needy Families, Food Stamps, Supplemental Security Income, and Medicaid. Information available from the Pennsylvania Department of Revenue may also be used where appropriate to expedite the process.

MINIMUM CHARGE. The minimum charge per month will be the $12 for Residential customers or $30 for Residential Heating customers.

ARREARAGE.
Customers who qualify and are enrolled in CAP will have their pre-program arrearage ("PPA") forgiven if the Customer pays his / her new, discounted CAP bill on time and in full each month. With every full and on-time monthly payment, one-twelfth of the PPA will be forgiven. If the customer develops any in-program arrearage while on the CAP Rate-- that is, if the customer does not pay the entire outstanding balance -- then preprogram arrearage forgiveness will not resume until the first month in which the full outstanding balance is paid.

(C) Denotes Change

Supplement No. X to
ELECTRIC PA P.U.C NO. 6

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PECO Energy Company

Electric Service Tariff

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 4.

Issued March 13, 2020 **Effective June 1, 2021**

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ISSUED BY: M. A. Innocenzo – President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19103

NOTICE

LIST OF CHANGES MADE BY THIS SUPPLEMENT

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW – X REVISED PAGE NO. 34, X REVISED PAGE NO. 35, ORIGINAL PAGE NO. 35A,
Updated to reflect effective date of June 1, 2021 (DSP V). Expanded to describe new optional Time-Of-Use (TOU) Pricing Option, including customer eligibility requirements, pricing provisions, and switching rules. Labeled pre-existing non-TOU pricing as "Standard" GSA.

GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 LOADS GREATER THAN 100KW REVISED PAGE NO. 36. Updated to reflect effective date of June 1, 2021 (DSP V).

RECONCILIATION - X REVISED PAGE NO. 37 AND X REVISED PAGE NO. 38
Updated to reflect effective date of June 1, 2021 (DSP V). Modified "Applicability" section to clarify that Standard and TOU default service rate over/undercollections will be calculated in total for both Procurement Classes 1 and 2 (each "reconciled in one group"). Removed obsolete language on Procurement Class 3/4 transition.

RATE RS-2 NET METERING - X REVISED PAGE NO. 51, X REVISED PAGE NO. 52, X REVISED PAGE NO. 53
Updated "Metering Provisions" to exclude virtual net metering customers from default service TOU. Supplemented "Billing Provisions" with description of excess generation accounting and cashout processes for customer-generators enrolled in default service TOU. Pages 52 and 53 are repaginated.

CUSTOMER ASSISTANCE PROGRAM (CAP) RIDER – X REVISED PAGE NO. 77
Eliminated restriction of "Availability" to customers who obtain competitive energy supply. Also added restriction of "Availability" excluding CAP customers from selecting default service TOU.

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Provision for the Recovery of Consumer Education Plan Costs – 2nd Revised Page No. 41¶
Reflects annual update to Consumer Education ¶
Rate R Residence Service – 9th Revised Page No. 49¶
Increased the Fixed Distribution Service Charge to reflect the Consumer Education Plan Costs ¶
Rate R-H Residential Heating Service – 9th Revised Page No. 50¶
Increased the Fixed Distribution Service Charge to reflect the Consumer Education Plan Costs ¶
Rate PD Primary Distribution Power –5th Revised Page No. 56¶
Increased the Fixed Distribution Service Charge to reflect the Consumer Education Plan Costs ¶
Rate HT High Tension Power –5th Revised Page No. 57¶
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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW

Applicability: June 1, 2021 this adjustment shall apply to all customers taking default service from the Company with demands up to 100 kW. The rate contained herein shall be calculated to the nearest one thousandth of a cent. The GSA shall contain the cost of generation supply for each tariff rate. The Company will apply Standard Pricing unless customers voluntarily request and are eligible to participate in the Time-Of-Use Pricing Option as detailed below. (C) (C)

Standard Pricing: Standard Pricing provides default service to customers who have not selected or are not eligible for PECO's Time-Of-Use Pricing Option. The rates below shall include the cost of procuring power to serve the default service customers including the cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The standard pricing for default service will represent the estimate of the cost to serve the specific tariff rate for the next quarterly period beginning with the three months ended August 31, 2021. The rates in this tariff shall be updated quarterly on June 1, September 1, December 1 and March 1 commencing June 1, 2021 and are not prorated. If the balance of over/(under) recovery gets too large, the Company can file a reconciliation that will mitigate the subsequent impact. The standard generation service charge shall be calculated using the following formula: (C) (C) (C) (C) (C)

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Standard GSA(n) = (C-E+A)/S*1/(1-T)* (1-ALL)/(1-LL) +AEPS/S*1/(1 - T) + WC where: (C)

C= The sum of the amounts paid to the full requirements suppliers providing the power for the quarterly period, the spot market purchases for the quarterly period, plus the cost of any other energy acquired for the quarterly period. Cost shall include energy, capacity and ancillary services, distribution line losses, cost of complying with the Alternative Energy Portfolio Standards, and any other load serving entity charges other than network transmission service and costs assigned under the Regional Transmission Expansion Plan. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as the load serving entity charges listed in the Supply Master Agreement Exhibit D as the responsibility of the supplier. This component shall include the proceeds and costs from the exercise of Auction Revenue Rights granted to PECO by PJM.

AEPS = The projected total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the C component above for the quarterly period for each procurement class. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

E = Experienced over or under-collection calculated under the reconciliation provision of the tariff to be effective semiannually with recovery during the periods March 1 through August 31 of the current year and September 1 of the current year through February 28 (29) of the following year.

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A = Administrative Cost - This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement plan, legal fees incurred gaining approval of the plan and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or is approved in its Act 129 filing. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.

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S = Estimated sales for the period the rate is in effect for the classes to which the rate is applicable. Six month sales are used for the E factor with effective periods March 1 through August 31 of the current year and September 1 of the current year through February 28 (29) of the following year.

T = The currently effective gross receipts tax rate.

n = The procurement class for which the GSA is being calculated.

ALL = Average line losses for the procurement class.

LL = Line losses for the specific rate class provided in the Company's Electric Generation Supplier Coordination Tariff rule 6.6.

WC = $0.00019/kWh to represent the cash working capital for power purchases.

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges. In general, the line loss adjustment is applicable to Procurement Class 2 only as those classes contain rate classes with three different line loss factors. Current Charges:

Standard Rate		Standard GSA Price
R	GSA (1)	$0.XXXXX
RH	GSA (1)	$0.XXXXX
GS	GSA (2)	$0.XXXXX

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Issued March 13, 2020 Effective June 1, 2021

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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2 LOADS UP TO 100KW (CONTINUED)

PD	GSA (2)	$0.XXXXX	(C)
HT	GSA (2)	$0.XXXXX	
POL*	GSA (2)	$0.XXXXX	
SL-S*	GSA (2)	$0.XXXXX	
TLCL	GSA (2)	$0.XXXXX	
SL-E*	GSA (2)	$0.XXXXX	
AL*	GSA (2)	$0.XXXXX	
SL-C* **	GSA (2)	$0.XXXXX	

* Prices shall exclude capacity from the Procurement Class 2 RFP results.
** Rate SL-C was effective July 1, 2019 pursuant to the Order at Docket No. R-2018-3000164

Procedure: For Procurement Classes 1 and 2 the GSA shall be filed 45 days before the effective dates of June 1, September 1, December 1 and March 1 in conjunction with the Reconciliation Schedule.

Time-Of-Use (TOU) Pricing Option: The TOU Pricing Option provides eligible customers with an opportunity to shift energy usage away from peak periods, when wholesale electricity demand and prices are high, to off-peak periods, when demands and prices are lower. Customers may voluntarily request this option in lieu of Standard Pricing described above and must meet the TOU Eligibility Requirements below. TOU Pricing Option rates will be updated quarterly in concurrence with the Standard GSA on June 1, September 1, December 1 and March 1 commencing XXX and are not prorated. (C)

The year-round TOU Pricing Periods, TOU Period Allocators ["PA-GSA(n)"], and TOU Pricing Multipliers ["PM-GSA(n)"] as approved in the Company's most recent DSP proceeding at Docket No. XXX are as follows:

TOU Pricing Period	Days/Hours Included	TOU Period Allocator PA-GSA(1)	TOU Period Allocator PA-GSA(2)	TOU Pricing Multiplier PM-GSA(1) (Ratio to Super Off-Peak)	TOU Pricing Multiplier PM-GSA(2) (Ratio to Super Off-Peak)
Peak ("PP")	2:00 – 6:00 p.m. Monday through Friday, excluding PJM holidays	12%	14%	6.5-to-1	5.1-to-1
Super Off-Peak ("SOPP")	Midnight (12 a.m.) – 6 a.m. Every day	20%	20%	1-to-1	1-to-1
Off-Peak ("OPP")	All other hours	68%	66%	1.5-to-1	1.7-to-1

To calculate the quarterly TOU Pricing Option rates, the Company will first calculate the quarterly TOU Super Off-Peak Price ("SOPP") in accordance with the formula set forth below:

TOU SOPP GSA(n) = Standard GSA(n) * [1 / SOPP-F(n)] where,

Standard GSA(n) = Defined as above for Standard Pricing

SOPP-F(n) = Super Off-Peak Price Factor representing the ratio of the Standard GSA(n) to the Super Off-Peak Price, calculated as follows:

TOU SOPP PA-GSA(n) + [(TOU OPP PM-GSA(n) * TOU OPP PA-GSA(n)] + [(TOU PP PM-GSA(n) * TOU PP PA-GSA(n)]

The Company will then calculate the quarterly TOU Peak ("PP") and Off-Peak ("OPP") prices as follows:

TOU PP GSA(n) = TOU SOPP GSA(n) * TOU PP PM-GSA and,

TOU OPP GSA(n) = TOU SOPP (GSA(n) * TOU OPP PM-GSA

Current TOU Pricing Option Charges (Year-Round):

TOU Rate	Peak Hours (2-6 PM Monday-Friday, excluding holidays)	Super Off-Peak Hours (12-6 AM all days)	Off-Peak Hours (All other times)
R (GSA 1)	$0.XXXXX	$0.XXXXX	$0.XXXXX
RH (GSA 1)	$0.XXXXX	$0.XXXXX	$0.XXXXX
GS (GSA 2)	$0.XXXXX	$0.XXXXX	$0.XXXXX
PD (GSA 2)	$0.XXXXX	$0.XXXXX	$0.XXXXX
HT (GSA 2)	$0.XXXXX	$0.XXXXX	$0.XXXXX

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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASSES 1 AND 2
LOADS UP TO 100KW (CONTINUED)

TOU Eligibility Requirements and Switching Rules: **(C)**

The TOU Pricing Option is available to new and existing Customers in Procurement Classes 1 or 2 with a smart meter configured to measure energy consumption in watt-hours. This includes Customers in the above referenced Procurement Classes taking default service from the Company and who also participate in the Company's RS-2 (Net Metering) tariff, except for virtual net metered Customers. Residential Customers enrolled in the Company's Customer Assistance Program (CAP) are not eligible for the TOU Pricing Option.

As a prerequisite for enrollment, the Customer must have a valid e-mail address to ensure the Company is able to provide the enrolled TOU Pricing Option Customer with timely and meaningful communications regarding their bill savings performance.

Participating Customers will remain on the TOU Pricing Option rate until they affirmatively elect to return to PECO's Standard GSA rate, switch to an EGS, or otherwise become ineligible.

Customers who select the TOU Pricing Option may leave at any time without incurring related penalties or fees. However, Customers who select and subsequently leave the TOU Pricing Option for any reason may not re-enroll on the TOU Pricing Option rate for twelve billing months after switching off the TOU Pricing Option rate.

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GENERATION SUPPLY ADJUSTMENT FOR PROCUREMENT CLASS 3/4 LOADS GREATER THAN 100KW

Applicability: June 1, 2021 this adjustment shall apply to all customers taking default service from the Company with demands greater than 100 kw. (C)

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Hourly Pricing Service

Pricing: The rates below shall include the cost of procuring power to serve the default service customers plus associated administrative expenses incurred in acquiring power and gaining regulatory approval of any procurement strategy and plan. The rates for the GSA 3/4 Hourly Pricing Adder* shall be updated quarterly on June 1, September 1, December 1 and March 1 commencing June 1, 2021 and are not prorated. (C) If the balance of over/(under) recovery gets too large due to billing lag, the Company can file a reconciliation that will mitigate the subsequent impact. The cost for this hourly service rate shall be as follows:

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Generation Supply Cost (GSC) = (C+R+AS+AC-E)/(1-T)+WCA where:

C = The PJM day ahead hourly price multiplied by the customers usage in the hour summed up for all hours in the month.

ΣPJM_{DA} x usage / (1-LL)

PJM_{DA} – PJM on day ahead hourly price

Usage - Electricity used by an end use customer.

R = The PJM reliability pricing model (RPM) charge for month for the customer. The RPM charge shall be the customers peak load contribution as established for PJM purposes multiplied by the current RPM monthly charge and the PJM established reserve margin adjustment.

PLC x (1+ RM) x P_{RPM} x Bill Days

PLC = Peak load contribution

RM = Reserve margin adjustment per PJM

P_{RPM} = Capacity price per MW-day

AC = Administrative Cost - This includes an allocation of the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the plan, and any other costs associated with designing and implementing a procurement plan divided by the total default service sales and then multiplied by the customers usage for the month. Administrative Costs also includes any other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGSs or through another rate.

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A / S x Usage

A = Administrative cost
S = Default service sales

AS = The cost, on a $/MWH basis, of acquiring ancillary services from PJM and of complying with the Alternative Energy Portfolio Standard, multiplied by the customers usage for the month and divided by (1-LL). Congestion charges including the proceeds and costs from the exercise of
Auction Revenue Rights shall be included in this component. Ancillary services shall be those included in the Supply Master Agreement as being the responsibility of the supplier.

((PJM_{AS} x Usage*1/(1-LL) + AEPS/S_{AEPS} x Usage)

PJM_{AS} = $/MWH charged by PJM for ancillary services
AEPS = Cost of complying with the alternative energy portfolio standard
S_{AEPS} = Sales for which AEPS cost is incurred

If the supplier provides the ancillary services and AEPS cost then the customer shall be charged the supplier's rate for these services times usage and divided by (1-LL).

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges.

LL = Line loss factor as provided in the Company's Electric Generation Supplier Coordination Tariff Rule 6.6 based upon the customers distribution rate class adjusted to remove losses included in the PJM LMP.

T = The currently effective gross receipts tax rate

E = $\Sigma O/(U)/S_{3/4}$ x usage where

E (Purchased Generation Adj.) = Over/under recovery as calculated in the reconciliation

$S_{3/4}$ = Procurement class 3/4 sales

WC = $0.00019 kWh for working capital associated with power purchases

WCA = Individual customer sales x WC

Procedure: The "E" factor shall be updated semiannually in conjunction with the Reconciliation. The applicable above items are converted to the rates listed below.

Tariff Rate	GS	PD	HT	EP
Hourly Pricing Adder* (dollars/kWh)	$0.XXXXX	$0.XXXXX	$0.XXXXX	$0.XXXXX

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* Includes administrative cost (AC), ancillary service charge (AS), E factor (E) and working capital (WC).

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RECONCILIATION

Applicability: June 1, 2021 this adjustment shall apply to all customers who received default service during the period the cost of which is being reconciled. Customers taking default service during the reconciliation period that leave default service prior to the assessment of the collection of the over/(under) adjustment shall still pay or receive credit for the over/(under) adjustment through the migration provision. The Company shall notify the Commission and parties to the Default Service Settlement 15 days in advance of the quarterly or monthly filing if the Migration Provision will be implemented in the filing. (C)

This adjustment shall be calculated on a semiannual basis for Procurement Classes 1, 2 and 3/4 Hourly. The reconciliation period will include the six month period beginning January 1 and July 1 commencing with the July 1, 2020 through December 31, 2020 reconciliation period. The reconciliation shall be separate for each procurement class. Any resulting over or under recovery shall be assessed on an equal cents per kilowatt hour basis to all customers in the relevant procurement group. Any over/(under) recovery shall be collected after the Occurrence of two months from the end of the reconciliation period. Recovery shall be over a six month period commencing September 1 and March 1. The initial six month period is March 1, 2021 through August 31, 2021. For purposes of this rider the reconciliation shall be calculated 45 days before the effective date of recovery. The over or under recovery shall be calculated using the formula below. The calculation of the over/(under) recovery shall be done separately for the following procurement classes – Class 1 – Residential, Class 2 – Small C&I up to and including 100 kW, and Class 3/4 – Large C&I greater than 100 kW. For Procurement Classes 1 and 2, Standard Pricing and TOU Pricing Option revenue and cost of supply will be included for the entire Procurement Class. (C) (C) (C)

Reconciliation Formula

$E_N = \Sigma O/(U) + I$

Migration Provision $E_M = [\Sigma O/(U) + I]/S/(1\text{-}GRT)*(1\text{-}ALL)/(1\text{-}LL)$

Where:

E = Experienced over or under collection plus associated interest
N = Procurement class
M = Migration Rider
O/(U) = The monthly difference between revenue billed to the procurement class and the cost of supply as described below in Cost, AEPS Cost and Administrative Cost.

Revenue = Amount billed to the tariff rates applicable to the procurement class including approved Real Time Price or other time sensitive rates for the period being reconciled through the GSA.

Cost = The sum of the amounts paid to all of the full requirements suppliers providing the power for the period being reconciled, the spot market purchases for the period being reconciled, plus the cost of any other energy acquired for the period being reconciled. Cost shall include energy, capacity and ancillary services as well as the proceeds and costs of auction revenue rights for Procurement Classes 1 and 2. Ancillary services shall include any allocation by PJM to PECO default service associated with the failure of a PJM member to pay its bill from PJM as well as those costs listed in the Supply Master Agreement as the responsibility of the seller.

AEPS = The total cost of complying with the Alternative Energy Portfolio Standards Act ("AEPS" or the "Act") not included in the Cost component above for the reconciliation period for Procurement Classes 1 and 2 and not included in the ancillary services component for Procurement Class 3/4 Hourly Service. Costs include the amount paid for Alternative Energy and/or Alternative Energy Credits ("AEC's") purchased for compliance with the Act, the cost of administering and conducting any procurement of Alternative Energy and/or AEC's, payments to the AEC program administrator for its costs of administering an alternative energy credits program, payments to a third party for its costs in operating an AEC registry, any charge levied by PECO's regional transmission operator to ensure that alternative energy sources are reliable, a credit for the sale of any AEC's sold during the calculation period, and the cost of Alternative Compliance Payments that are deemed recoverable by the Commission, plus any other direct or indirect cost of acquiring Alternative Energy and/or AEC's and complying with the AEPS statute.

Administrative Cost = This includes the cost of the Independent Evaluator, consultants providing guidance on the development of the procurement strategy, legal fees incurred gaining approval of the strategy, and any other costs associated with designing and implementing a procurement plan including the cost of the pricing forecast necessary for estimating cost recoverable under this tariff. Also included in this component shall be the cost to implement real time pricing or other time sensitive pricing such as dynamic pricing that is required of the Company or approved in its Act 129 filing. Administrative Costs also includes other costs incurred to implement retail market enhancements directed by the Commission in its Retail Market Investigation at Docket No. I-2011-2237952 or any other applicable docket that are not recovered from EGS's or through another rate.

Full Requirements Supply = A product purchased by the Company that includes a fixed price for all energy consumed. The only cost added by the Company to the full requirements price is for gross receipts tax, distribution line losses, and administrative cost.

Ancillary Services = The following services in the PJM OATT- reactive support, frequency control, operating reserves, supplemental reserves, imbalance charges, PJM annual charges, any PJM assessment associated with non-payment by members, and any other load serving entity charges not listed here but contained in Exhibit D of the Supply Master Agreement. Also included shall be the proceeds and costs from the exercise of auction revenue rights for Procurement Class 3/4 Hourly Service.

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RECONCILIATION
(CONTINUED)

Auction Revenue Rights (ARR) = Allocated annually by PJM to Firm transmission customers, the ARR's allow a Company to select rights to specific transmission paths in order to avoid congestion charges.

Capacity = The amount charged to PECO by PJM for capacity for its default service load under the reliability pricing model (RPM).

I = interest on the over or under collection at the prime rate of interest for commercial banking, not to exceed the legal rate of interest, in effect on the last day of the month the over collection or under collection occurs, as reported in the Wall Street Journal in accordance with the Order at Docket No. L-2014-2421001.

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S= Estimated default service retail sales in kWh for the period the cost of which is being reconciled.

ALL = The average line losses in a procurement class as a percent of generation.

LL = The average line losses for a particular rate (e.g., HT, PD, GS) as provided in the Electric Generation Supplier Coordination Tariff rule 6.6.

GRT = The current gross receipts tax rate.

Procurement Class - Set of customers for which the company has a common procurement plan.

Procedural Schedule
The Company shall file the calculation of the over/under collection for the period being reconciled and the proposed adjustment to the GSA 45 days before the effective date as described below. The over/under collection adjustment shall be effective no earlier than the first day of the month such that the commencement of recovery shall lag by two months. The GSA will be effective June 1, September 1, December 1 and March 1 commencing June 1, 2021 with over/under collection recovery occurring over the six month period beginning September 1 and March 1. The data provided in the reconciliation shall be audited on an annual basis by the PaPUC Bureau of Audits. (C)

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RATE RS-2 NET METERING

PURPOSE.

This Rate sets forth the eligibility, terms and conditions applicable to Customers with installed qualifying renewable customer-owned generation using a net metering system.

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APPLICABILITY.

This Rate applies to renewable customer-generators served under Rates R, RH, CAP, GS, HT, PD and EP who install a device or devices which are, in the Company's judgment, subject to Commission review, a bona fide technology for use in generating electricity from qualifying Tier I or Tier II alternative energy sources pursuant to Alternative Energy Portfolio Standards Act No. 2004-213 (Act 213) or Commission regulations and which will be operated in parallel with the Company's system. This Rate is limited to installations where the renewable energy generating system is intended primarily to offset part or all of the customer-generator's requirements for electricity. A renewable customer-generator is a non-utility owner or operator of a net metered generation system with a nameplate capacity of not greater than 50 kilowatts if installed at a residential service (Rate R, RH, or CAP) or not larger than 3,000 kilowatts at other customer service locations (Rate GS, HT, PD and EP), except for Customers whose systems are above 3 megawatts and up to 5 megawatts who make their systems available to operate in parallel with the Company during grid emergencies as defined by the regional transmission organization or where a microgrid is in place for the purpose of maintaining critical infrastructure such as homeland security assignments, emergency services facilities, hospitals, traffic signals, wastewater treatment plants or telecommunications facilities provided that technical rules for operating generators interconnected with facilities of the Company have been promulgated by the Institute of Electrical and Electronic Engineers "IEEE" and the Commission.

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Qualifying renewable energy installations are limited to Tier I and Tier II alternative energy sources as defined by Act 213 and Commission Regulations. The Customer's equipment must conform to the Commission's Interconnection Standards and Regulations pursuant to Act 213. This Rate is not applicable when the source of supply is service purchased from a neighboring electric utility under Borderline Service.

Service under this Rate is available upon request to renewable customer-generators on a first come, first served basis so long as the total rated generating capacity installed by renewable customer-generator facilities does not adversely impact service to other Customers and does not compromise the protection scheme(s) employed on the Company's electric distribution system.

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METERING PROVISIONS.

A Customer may select one of the following metering options in conjunction with service under applicable Rate Schedule R, RH, CAP, GS, HT, PD or EP.

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1. A customer-generator facility used for net metering shall be equipped with a single bi-directional meter that can measure and record the flow of electricity in both directions at the same rate. A dual meter arrangement may be substituted for a single bi-directional meter at the Company's expense.

2. If the customer-generator's existing electric metering equipment does not meet the requirements under option (1) above, the Company shall install new metering equipment for the customer-generator at the Company's expense. Any subsequent metering equipment change necessitated by the customer-generator shall be paid for by the customer-generator. The customer-generator has the option of utilizing a qualified meter service provider to install metering equipment for the measurement of generation at the customer-generator's expense.

   Additional metering equipment for the purpose of qualifying alternative energy credits owned by the customer-generator shall be paid for by the customer-generator. The Company shall take title to the alternative energy credits produced by a customer-generator where the customer-generator has expressly rejected title to the credits. In the event that the Company takes title to the alternative energy credits, the Company will pay for and install the necessary metering equipment to qualify the alternative energy credits. The Company shall, prior to taking title to any alternative energy credits, fully inform the customer-generator of the potential value of those credits and options available to the customer-generator for their disposition.

3. Meter aggregation on properties owned or leased and operated by a customer-generator shall be allowed for purposes of net metering. Meter aggregation shall be limited to meters located on properties within two (2) miles of the boundaries of the customer-generator's property. Meter aggregation shall only be available for properties located within the Company's service territory. Physical meter aggregation shall be at the customer-generator's expense. The Company shall provide the necessary equipment to complete physical aggregation. If the customer-generator requests virtual meter aggregation, it shall be provided by the Company at the customer-generator's expense. The customer-generator shall be responsible only for any incremental expense entailed in processing his account on a virtual meter aggregation basis. Customer generators involved in virtual metering programs are not eligible for the company's default service TOU Pricing Option. **(C)**

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RATE RS-2 NET METERING (continued)

BILLING PROVISIONS.

The following billing provisions apply to default service customer-generators in conjunction with service under applicable Rates R, RH, CAP, GS, HT, PD, EP. (C)

1. The customer-generator will receive a credit for each kilowatt-hour received by the Company up to the total amount of electricity delivered to the Customer during the billing period at the full retail rate consistent with Commission regulations. If a customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the full retail rate. Any excess kilowatt hours will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the customer-generator for kilowatt hours received from the customer-generator in excess of the kilowatt hours delivered by Company to the customer-generator during the preceding year at the "full retail value for all energy produced" consistent with Commission regulations. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

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For default service Time-Of-Use ("TOU") customer-generators only: The Company will record excess generation supplied by TOU Pricing Period, maintaining an active record of kilowatt hours produced and consumed at the customer-generator's premise. If, in a subsequent default service TOU billing period, a customer consumes more electricity than produced within a given TOU Pricing Period, The Company will pull kilowatt hours for the excess generation from the customer's banked kilowatt-hours for that TOU Pricing Period. Any excess kilowatt hours remaining in that TOU Pricing Period will continue to accumulate until the end of the PJM planning period ending May 31 of each year. On an annual basis, the Company will compensate the TOU customer generator for accumulated excess generation at the full retail value based on the applicable TOU Pricing Option rate and TSC rate in effect at the time the excess electricity was generated. (C)

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2. If the Company supplies more kilowatt-hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the appropriate rate schedule shall be applied to the net kilowatt-hours of electricity that the Company supplied. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

3. For customer-generators involved in virtual meter aggregation programs, any excess credit shall be applied first to the account containing the meter through which the generating facility supplies electricity to the distribution system, also known as the "host account". If the host account's usage has been fully offset by this credit and additional excess credit still remains, PECO will divide that remaining credit into equal parts based on the number of additional virtually metered accounts under the customer-generator's name, also known as "satellite accounts", and apply one part to each satellite account in a "waterfall"-like fashion at each account's designated rate. This process continues as PECO bills each subsequent satellite account, with any additional excess credits from each divided equally among the remaining satellite accounts. Virtual meter aggregation is the combination of readings and billing for all meters regardless of rate class on properties owned or leased and operated by a customer-generator by means of the Company's billing process, rather than through physical rewiring of the customer-generator's property for a physical, single point of contact. The customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

4. Procurement Class 3/4 customer-generators will receive a generation credit, at the PJM Day Ahead hourly energy rate, for each kilowatt hour received by the Company during each hour of the billing period up to the total amount of electricity delivered to the customer during each hour of the billing period.

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If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator during any hour in the billing period, the excess kilowatt hours shall not be carried forward to a subsequent billing period but will be credited in the current month toward generation charges based on the PJM Day Ahead hourly rate. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year.

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5. Procurement Class 3/4 customer-generators will also receive a variable distribution credit for each kilowatt hour received by the Company during the monthly billing period up to the total amount of electricity delivered to the Customer during the monthly billing period at the applicable distribution rate.

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If a Procurement Class 3/4 customer-generator supplies more electricity to the Company than the Company delivers to the customer-generator, the variable distribution charges will be reduced by the excess kilowatt hours, which will be carried forward and credited against the customer-generator's distribution kilowatt hours in subsequent billing periods until the end of the PJM planning period, ending May 31 of each year.

Procurement Class 3/4 customer-generators are responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.

Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges.

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RATE RS-2 NET METERING (continued)

NET METERING FOR SHOPPING CUSTOMERS

1. Customer-generators may take net metering services from EGSs that offer such services.
2. If a net-metering customer takes service from an EGS, the Company will credit the customer for distribution charges for each kilowatt hour produced by a Tier I or Tier II resource installed on the customer-generator's side of the electric revenue meter, up to the total amount of kilowatt hours delivered to the customer by the Company during the billing period. If a customer-generator supplies more electricity to the electric distribution system than the EDC delivers to the customer-generator in a given billing period, the excess kilowatt hours shall be carried forward and credited against the customer-generator's usage in subsequent billing periods at the Company's distribution rates. Any excess kilowatt hours at the end of the PJM planning period will not carry over to the next year and reduce distribution charges. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rates Schedule.
3. If the Company delivers more kilowatt hours of electricity than the customer-generator facility feeds back to the Company's system during the billing period, all charges of the applicable rate schedule shall be applied to the net kilowatt hours of electricity that the Company delivered. The customer-generator is responsible for the customer charge, demand charge and other applicable charges under the applicable Rate Schedule.
4. Pursuant to Commission regulations, the credit or compensation terms for excess electricity produced by customer-generators who are customers of EGSs shall be stated in the service agreement between the customer-generator and the EGS.
5. If a customer-generator switches electricity suppliers, the Company shall treat the end of the service as if it were the end of the PJM planning period.

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APPLICATION.

Customer-generators seeking to receive service under the provisions of this Rate must submit a written application to the Company demonstrating compliance with the Net Metering Rate provisions and quantifying the total rated generating capacity of the customer-generator facility. The installation cannot be directly connected to the Company's distribution system ("stand alone"). Instead, the installation must be connected to a facility (residence or business) that is connected to the Company's distribution system.

INTERCONNECTION EXPIRATION.

Interconnection applications will be reviewed and processed in accordance with the timeframes designated by PECO in Act 213 and Title 52 of the Pa Code Chapter 75. A customer-generator (or authorized designee) must submit a completed certificate of completion ("COC") for residential level 1 and 2 interconnection applications to PECO within 180 calendar days from the date that PECO approves the interconnection application. If a COC is not received within 180 calendar days from the date that PECO approves the interconnection application then the residential level 1 and level 2 interconnection applications shall expire. A customer-generator may request an extension of a residential level 1 or level 2 application expiration date for good cause shown (i.e., that significant progress in construction of the interconnection has been or will be made). Upon a showing of good cause, the application expiration date will be extended. The length of the extension may be extended up to but no more than 180 calendar days. A customer-generator must make such extension requests in writing or via e-mail no less than 30 calendar days prior to an application's original expiration date. PECO will provide notice to developers of distributed generation at least 45 calendar days ahead of the original expiration date.

MINIMUM CHARGE.

The Minimum Charges under Rate Schedule R, RH, CAP, GS, PD, HT and EP apply for installations under this Rate.

RIDERS.

Bills rendered by the Company under this Rate shall be subject to charges stated in any other applicable Rate.

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CUSTOMER ASSISTANCE PROGRAM (CAP) RIDER

AVAILABILITY.
To payment-troubled customers who are currently served under or otherwise qualify for Rate R, or RH (excluding multiple dwelling unit buildings consisting of two to five dwelling units). Customers must apply for the rates contained in this rider and must demonstrate annual household gross income at or below 150% of the Federal Poverty guidelines. In addition, these customers are not eligible to select the Time-Of-Use default service pricing option. (C)

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Based on the applicable level of income, number of household members, and their historical usage CAP customers will receive a Fixed Credit Option ("FCO") based upon that individual household's need. The details of the FCO calculation can be found in the PECO Universal Service and Energy Conservation Plan at Docket No. M-2015-2507139.

DISCOUNT LEVELS: The Company will modify the level of discounts every quarter to adjust for changes in Customer usage as well as any Rate changes which may have occurred.

CERTIFICATION/VERIFICATION Prior to enrollment in the CAP Rider, and then again every two years, customers must verify, to PECO's satisfaction, that their household income level meets the "Availability" standards set forth in this Rider. Customers being considered for the CAP Rider will be required to:

- Provide information sufficient to demonstrate to PECO their household income level.
- Waive certain privacy rights to enable PECO to effectively conduct the above certification process.
- Apply for and assign to PECO at least one energy assistance grant from the Commonwealth.
- Participate in various energy education and conservation programs facilitated by PECO.

PECO may, at its sole discretion, supplement this verification process by using data from Commonwealth or federal government programs which demonstrate the income eligibility of its customers. Such data may come from a customer's participation in, or receipt of benefits from, the Low Income Home Energy Assistance Program, Temporary Assistance for Needy Families, Food Stamps, Supplemental Security Income, and Medicaid. Information available from the Pennsylvania Department of Revenue may also be used where appropriate to expedite the process.

MINIMUM CHARGE. The minimum charge per month will be the $12 for Residential customers or $30 for Residential Heating customers.

ARREARAGE.
Customers who qualify and are enrolled in CAP will have their pre-program arrearage ("PPA") forgiven if the Customer pays his / her new, discounted CAP bill on time and in full each month. With every full and on-time monthly payment, one-twelfth of the PPA will be forgiven. If the customer develops any in-program arrearage while on the CAP Rate-- that is, if the customer does not pay the entire outstanding balance – then preprogram arrearage forgiveness will not resume until the first month in which the full outstanding balance is paid.

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Responses to Questions in 52 Pa. Code Section 53.52(a)

1. The specific reason for each change.

PECO Energy Company ("PECO" or the "Company") is proposing tariff changes to implement its fifth proposed default service program ("DSP V"), which includes the Company's proposed new time-of-use ("TOU") rate options and PECO's plan ("Plan") to allow customers enrolled in the Company's Customer Assistance Program ("CAP") to purchase competitive generation supply from an electric generation supplier ("EGS"). The Company's DSP V is being filed in compliance with the Commission's regulations at Title 52 Pa. Code Section 54.185.

2. The total number of customers served by the utility.

The total number of electric customers served by PECO was 1,661,605 as of December 31, 2019.

3. A calculation of the number of customers, by tariff subdivision, whose bills will be affected by the change.

Residential and small commercial customers are potentially affected due to proposed tariff changes to introduce TOU rate options under the Generation Supply Adjustment. Other limited changes are explained in PECO Statement No. 2, the direct testimony of Joseph A. Bisti.

4. The effect of the change on the utility's customers.

The primary effect of the proposed changes is to implement new time-of-use rate options for eligible residential and commercial default service customers, which will potentially reduce their electric bill. The tariff changes also will allow CAP customers to purchase competitive generation supply from an EGS. All of the proposed tariff changes and their potential effects are discussed in detail in PECO Statement No. 2.

5. The effect, whether direct or indirect, of the proposed change on the utility's revenue and expenses.

The effects of the proposed tariff changes on PECO's revenues and expenses cannot be determined at this time and will depend upon the implementation of PECO's procurement plan that is approved as part of this filing and the market prices in effect when generation supply service is procured. The effects of those tariff changes on PECO's revenues and expenses will also depend on the final Plan design and TOU rate design approved by the Commission.

6. The effect of the change on the service rendered by the utility.

PECO does not expect the proposed tariff changes to affect service.

7. A list of factors considered by the utility.

The changes are being made to comply with the Commission's Default Service Regulations and Policy Statement, the Commission's February 28, 2019 Proposed Policy Statement Order in Docket No. M-2018-3006578 – Electric Distribution Company Default Service Plans – Customer Assistance Program Shopping, the January 23, 2020 Letter of Rosemary A. Chiavetta in Docket No. M-2019-3007101 – Investigation into Default Service and PJM Interconnection, LLC Settlement Reforms, and the April 6, 2017 Letter of Rosemary A. Chiavetta in Docket No. P-2016-2526672 – Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program and Procurement Plan for the Period June 1, 2017 through May 31, 2017. PECO Statement No. 2, the direct testimony of Mr. Bisti, discusses the reasons for all of the proposed tariff changes.

8. Studies undertaken by the utility in order to draft its proposed change.

No specific studies were undertaken.

9. Customer polls taken and other documents, which indicate customer acceptance and desire for the proposed change.

No customer polls were taken.

10. Plans the utility has for introducing or implementing the changes with respect to its customers.

The Company's Petition requesting approval of its DSP V summarizes how the Company proposes to implement the changes and references specific testimony being filed with the Petition that provides further details about DSP V and how it will be implemented.

11. F.C.C., or FERC or Commission Orders or rulings applicable to the filings.

The following orders and PUC guidance are applicable to this filing:

Docket No. M-2018-3006578 – Electric Distribution Company Default Service Plans – Customer Assistance Program Shopping (Proposed Policy Statement Order entered Feb. 28, 2019)

Docket No. P-2016-2534980 - Petition of PECO Energy Company for Approval of Its Default Service Program for the Period June 1, 2017 to May 31, 2021 (Opinion and Order entered Dec. 8, 2016).

Docket No. I-2011-2237952 - Investigation of Pennsylvania's Retail Electricity Market: End State of Default Service (Order entered Feb. 15, 2013).

Docket No. M-2019-3007101 – Investigation into Default Service and PJM Interconnection, LLC Settlement Reforms (Secretarial Letter issued January 23, 2020)

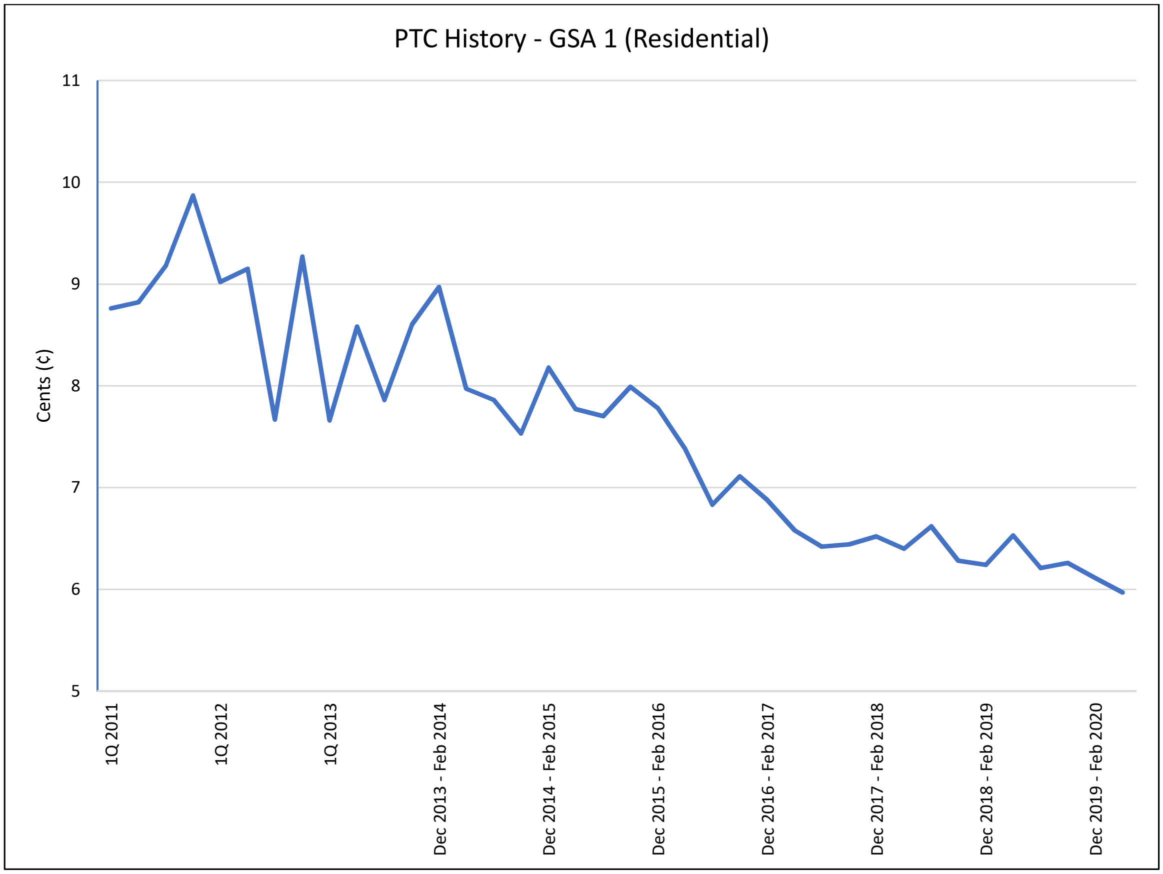
Docket No. P-2016-2526672 – Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program and Procurement Plan for the Period June 1, 2017 through May 31, 2017 (Secretarial Letter issued Apr. 6, 2017)

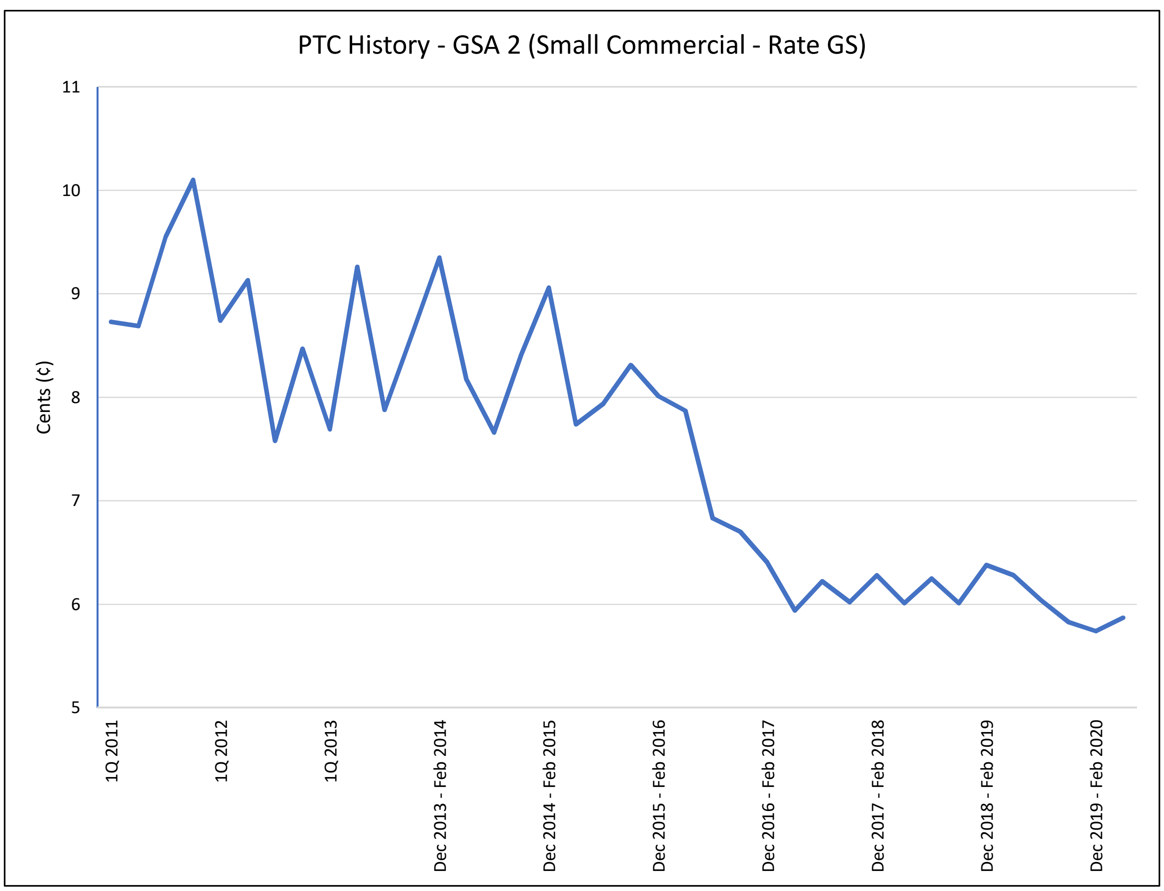
PECO Electric Price-To-Compare History
"GSA 1" (Residential) and "GSA 2 - Rate GS" (Small C&I General Service)
(January 2011 thru current)

	GSA 1 Residential		
	Price (¢)	Variance	% Change
1Q 2011	8.76		
2Q 2011	8.82	0.06	0.68%
3Q 2011	9.18	0.36	4.08%
4Q 2011	9.87	0.69	7.52%
1Q 2012	9.02	-0.85	-8.61%
2Q 2012	9.15	0.13	1.44%
3Q 2012	7.67	-1.48	-16.17%
4Q 2012	9.27	1.6	20.86%
1Q 2013	7.66	-1.61	-17.37%
Apr-May 2013	8.58	0.92	12.01%
June 2013 - Aug 2013	7.86	-0.72	-8.39%
Sep 2013 - Nov 2013	8.60	0.74	9.41%
Dec 2013 - Feb 2014	8.97	0.37	4.30%
Mar 2014 - May 2014	7.97	-1	-11.15%
June 2014 - Aug 2014	7.86	-0.11	-1.38%
Sep 2014 - Nov 2014	7.53	-0.33	-4.20%
Dec 2014 - Feb 2015	8.18	0.65	8.63%
Mar 2015 - May 2015	7.77	-0.41	-5.01%
June 2015 - Aug 2015	7.70	-0.07	-0.90%
Sep 2015 - Nov 2015	7.99	0.29	3.77%
Dec 2015 - Feb 2016	7.78	-0.21	-2.63%
Mar 2016 - May 2016	7.38	-0.4	-5.14%
June 2016 - Aug 2016	6.83	-0.55	-7.45%
Sep 2016 - Nov 2016	7.11	0.28	4.10%
Dec 2016 - Feb 2017	6.88	-0.23	-3.23%
Mar 2017 - May 2017	6.58	-0.3	-4.36%
June 2017 - Aug 2017	6.42	-0.16	-2.43%
Sep 2017 - Nov 2017	6.44	0.02	0.31%
Dec 2017 - Feb 2018	6.52	0.08	1.24%
Mar 2018 - May 2018	6.40	-0.12	-1.84%
June 2018 - Aug 2018	6.62	0.22	3.44%
Sep 2018 - Nov 2018	6.28	-0.34	-5.14%
Dec 2018 - Feb 2019	6.24	-0.04	-0.64%
Mar 2019 - May 2019	6.53	0.29	4.65%
June 2019 - Aug 2019	6.21	-0.32	-4.90%
Sep 2019 - Nov 2019	6.26	0.05	0.81%
Dec 2019 - Feb 2020	6.11	-0.15	-2.40%
Mar 2020 - May 2020	5.97	-0.14	-2.29%

	GSA 2 Small Commercial - Rate GS		
	Price (¢)	Variance	% Change
1Q 2011	8.73		
2Q 2011	8.69	-0.04	-0.46%
3Q 2011	9.55	0.86	9.90%
4Q 2011	10.1	0.55	5.76%
1Q 2012	8.74	-1.36	-13.47%
2Q 2012	9.13	0.39	4.46%
3Q 2012	7.58	-1.55	-16.98%
4Q 2012	8.47	0.89	11.74%
1Q 2013	7.69	-0.78	-9.21%
Apr-May 2013	9.26	1.57	20.42%
June 2013 - Aug 2013	7.88	-1.38	-14.90%
Sep 2013 - Nov 2013	8.61	0.73	9.26%
Dec 2013 - Feb 2014	9.35	0.74	8.59%
Mar 2014 - May 2014	8.17	-1.18	-12.62%
June 2014 - Aug 2014	7.66	-0.51	-6.24%
Sep 2014 - Nov 2014	8.41	0.75	9.79%
Dec 2014 - Feb 2015	9.06	0.65	7.73%
Mar 2015 - May 2015	7.74	-1.32	-14.57%
June 2015 - Aug 2015	7.94	0.20	2.58%
Sep 2015 - Nov 2015	8.31	0.37	4.66%
Dec 2015 - Feb 2016	8.01	-0.30	-3.61%
Mar 2016 - May 2016	7.87	-0.14	-1.75%
June 2016 - Aug 2016	6.83	-1.04	-13.21%
Sep 2016 - Nov 2016	6.70	-0.13	-1.90%
Dec 2016 - Feb 2017	6.40	-0.30	-4.48%
Mar 2017 - May 2017	5.94	-0.46	-7.19%
June 2017 - Aug 2017	6.22	0.28	4.71%
Sep 2017 - Nov 2017	6.02	-0.20	-3.22%
Dec 2017 - Feb 2018	6.28	0.26	4.32%
Mar 2018 - May 2018	6.01	-0.27	-4.30%
June 2018 - Aug 2018	6.25	0.24	3.99%
Sep 2018 - Nov 2018	6.01	-0.24	-3.84%
Dec 2018 - Feb 2019	6.38	0.37	6.16%
Mar 2019 - May 2019	6.28	-0.10	-1.57%
June 2019 - Aug 2019	6.04	-0.24	-3.82%
Sep 2019 - Nov 2019	5.83	-0.21	-3.48%
Dec 2019 - Feb 2020	5.74	-0.09	-1.54%
Mar 2020 - May 2020	5.87	0.13	2.26%

*PECO modified the three-month periods for the above rates in June of 2013 as part of DSP II.
See Docket No. P-2012-2283641, Order Issued September 27, 2012.


PTC History - GSA 1 (Residential)
Cents (¢)
11
10
9
8
7
6
5
1Q 2011
1Q 2012
1Q 2013
Dec 2013 - Feb 2014
Dec 2014 - Feb 2015
Dec 2015 - Feb 2016
Dec 2016 - Feb 2017
Dec 2017 - Feb 2018
Dec 2018 - Feb 2019
Dec 2019 - Feb 2020


PTC History - GSA 2 (Small Commercial - Rate GS)
Cents (¢)
11
10
9
8
7
6
5
1Q 2011
1Q 2012
1Q 2013
Dec 2013 - Feb 2014
Dec 2014 - Feb 2015
Dec 2015 - Feb 2016
Dec 2016 - Feb 2017
Dec 2017 - Feb 2018
Dec 2018 - Feb 2019
Dec 2019 - Feb 2020