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VIA eFILING

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: Alternative Ratemaking Methodologies
Docket No. M-2015-2518883

Dear Secretary Chiavetta:

Enclosed for filing in the above-referenced docket are the **Comments of PECO Energy Company on Alternative Ratemaking Methodologies**.

If you have any questions regarding this filing, please do not hesitate to contact me at 215.841.5974.

Very truly yours,

W. Craig Williams

Enclosures

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

ALTERNATIVE RATEMAKING METHODOLOGIES	: :	**DOCKET NO. M-2015-2518883**

COMMENTS OF PECO ENERGY COMPANY ON ALTERNATIVE RATEMAKING METHODOLOGIES

PECO Energy Company ("PECO" or the "Company") submits these Comments in response to the Pennsylvania Public Utility Commission's ("PUC" or the "Commission") March 2, 2017 Tentative Order inviting interested parties to submit written comments on the reasonableness and efficacy of employing certain alternative ratemaking methodologies. The Commission's consideration of these issues is timely as the landscape for utility service is changing due to the deployment of distributed generation technologies and implementation of energy efficiency programs resulting in significant energy and demand savings. Alternative ratemaking is being considered on a national scale by the National Association of Regulatory Utility Commissioners, among others, and the Commission has already been proactive by implementing a fully projected future test year and distribution system improvement charge. PECO appreciates the opportunity to share its perspective as the Commission continues to analyze ratemaking alternatives. In these Comments, the Company provides an overview of its position, responds to the questions in the Tentative Order directed to electric distribution companies ("EDCs") and natural gas distribution companies ("NGDCs"), describes PECO's preferred approach to electric and gas distribution rates, and responds to the gas and electric proposals put forth by Vice Chairman Place.

I. OVERVIEW OF POSITION

The Company believes that the fundamental challenge facing the Commonwealth is the need to ensure sustainable funding of a safe, secure, reliable and affordable grid while fairly allocating the costs of the grid. As the Commission considers the reasonableness and efficacy of alternative ratemaking methodologies, PECO urges the Commission to keep the following key considerations in mind:

Rates Should Reflect Cost Causation. Alternative ratemaking methodologies, properly structured, can provide the opportunity to better reflect cost causation and to send customers more appropriate price signals than current rate mechanisms. PECO notes that its commercial and industrial customers ("C&I") have shifted to demand-based rates which achieve this alignment. Moreover, to the extent practicable, fixed costs should be recovered through fixed charges. Fixed charges that fully recover fixed costs play an important part in assuring that all customers pay their fair share of grid costs, including distributed generation and net-metered customers.

Customer Impacts Should Be Minimized. Efforts should be made to minimize the impact of an alternative ratemaking methodology on any individual customer or class of customers. In the Tentative Order and Statement by Commissioner Sweet, special attention was given to potential impacts to low-income, income-challenged, and large C&I customers.[1] Impacts to all customers must be fully evaluated on a utility-specific basis as part of any transition to alternative ratemaking methodologies.

A Balanced Approach To Penalties And Incentives Should Be Taken. Under Act 129, EDCs are entitled to recover, on a full and current basis, "all reasonable and prudent costs

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[1] Tentative Order, pp. 15, 16, 18; Statement of Commissioner David W. Sweet, p. 1.

incurred in the provision or management" of their energy efficiency and conservation ("EE&C") plans, but EDCs may only recover lost revenues through a base rate proceeding. Moreover, EDCs can incur very substantial monetary penalties (i.e., up to $20 million) if they fail to achieve their required reductions in consumption or demand. 66 Pa.C.S. § 2806.1(k). At the same time, there are no positive incentives for utilities to exceed their EE&C targets. If the Commission wishes to encourage utilities to maximize the potential of their EE&C plans, it should support a more balanced approach where potential risks and rewards are aligned equitably. This will likely require a combination of statutory and regulatory changes to implement alternative rate designs that will encourage both continued energy efficiency gains and sustainable funding of the grid.

Utilities Should Be Given Flexibility. Assuming that the Commission proceeds with broader regulatory action, PECO urges the Commission to provide sufficient flexibility for individual companies to fashion innovative proposals that best meet the needs of their respective customers, provided those approaches are consistent with the overarching principles of sustainable funding and fair allocation of costs. The appropriate rate designs may vary from one utility to the next and from one utility group to another (e.g., electric as compared to water utilities).

Legislation Should Be Pursued Where Commission Authority Is Unclear. Over the past twenty years, the Commission has been proactive in devising and implementing new and innovative rate mechanisms. PECO believes the best path to adopting other alternative ratemaking methodologies (such as decoupling, lost revenue adjustment mechanisms, multi-year rate plans, and rates appropriate for emerging technologies such as electric vehicles and storage) would be through enabling legislation, which would remove uncertainty about the Commission's authority to approve such mechanisms.

II. RESPONSES TO THE TENTATIVE ORDER'S QUESTIONS FOR ELECTRIC DISTRIBUTION COMPANIES

A. PECO's Current Alternative Ratemaking Methodologies

The Company's discussion of alternative ratemaking methodologies in this section responds to question 1, page 15 of the Tentative Order, directed to EDCs. PECO currently uses several of the alternative ratemaking methodologies listed by the Commission in its Tentative Order: (1) a fully projected future test year; (2) cost trackers; (3) standby and backup charges; and (4) demand charges.

1. Fully Projected Future Test Year

In its most recent base rate filing on March 27, 2015, PECO used a fully projected future test year consisting of the 12 months ending December 31, 2016. Because the fully projected future test year better aligns incurred costs with cost recovery, use of this rate mechanism will reduce regulatory lag and may enable utilities to extend the period between base rate filings.

2. Cost Trackers

The Company currently uses the following ten cost trackers for ratemaking purposes. The revenue reflects 2016 levels.

- The Generation Supply Adjustment ("GSA") recovers the Company's cost of supplying default generation service to its customers. The Company recovers approximately $758 million per year through the GSA.

- The Transmission Service Charge ("TSC") recovers the cost of FERC-regulated network transmission service for the Company's default service customers. The Company recovers approximately $68 million per year with this cost tracker.

- The Non-Bypassable Transmission Charge ("NBT") recovers the cost charged to PECO by PJM for Regional Transmission Enhancement Plan costs and generation deactivation costs. The Company recovers approximately $89 million per year under this cost tracker.

- The Energy Efficiency and Conservation Program Cost Rider ("EE&CPR") recovers the cost of the Company's approved Act 129 EE&C plan. The Company recovers approximately $85 million per year through the EE&CPR.

- The Consumer Education Surcharge ("CES") recovers the cost of consumer education programs generally related to electric shopping for energy supply. Currently, the CES is collecting less than $1 million per year.

- The Tax Accounting Repair Credit ("TARC") credits to customers the benefits of a tax credit received by the Company following the implementation of a tax accounting change in the treatment of repairs to property. It was established as part of the Settlement in Docket R-2010-2161575 and is expected to terminate at the end of 2018. Approximately $21 million per year is being returned to customers through the TARC.

- The Universal Service Fund Charge ("USFC") refunds to or collects from customers the difference between the amount of universal service costs the Company incurs in a year and the amount that is included in base rates. The annual amount of revenue going through the USFC is currently an approximate $1.6 million credit. The USFC applies to residential customers only.

- The Nuclear Decommissioning Cost Adjustment ("NDCA") refunds to or collects from customers the difference between the current estimated annual nuclear decommissioning cost (calculated every five years) and the amount included in base rates ($29.2 million). It is currently refunding to customers approximately $7 million per year.

- The State Tax Adjustment Clause ("STAC") refunds to or collects from customers the costs or benefits associated with a change in certain state tax rates. It is currently refunding to customers less than $1 million per year.

- The Distribution System Improvement Charge ("DSIC") recovers from customers a return of and on the capital expenditures approved as part of the Company's Electric Long-Term Infrastructure Improvement Plan. Recovery under the DSIC occurs between base rate cases and is subject to an earnings test. The Company currently is not recovering any money under the DSIC.

The following table displays the revenues recovered under each cost tracker as a percentage of total electric revenue:

Electric Cost Trackers		Costs/Revenues (millions)	% Total Revenue
Generation Supply Adjustment (GSA)	$	758	29.9%
Transmission Service Charge (TSC)	$	68	2.7%
Non-Bypassable Transmission Charge (NBT)	$	89	3.5%
Energy Efficiency and Conservation Program Cost Rider (EE&CPR)	$	85	3.4%
Consumer Education Surcharge (CES)	$	0.2	0.0%
Tax Accounting Repair Credit (TARC)	$	(21)	-0.8%
Universal Service Fund Charge (USFC)	$	(1.6)	-0.1%
Nuclear Decommissioning Cost Adjustment (NDCA)	$	(7)	-0.3%
State Tax Adjustment Clause (STAC)	$	(0.2)	0.0%
Distribution System Improvement Charge (DSIC)	$	-	0.0%
Total Electric Revenue	**$**	**2,531**	38.3%

3. Standby and Backup Charges

While not specifically a standby or backup charge, PECO has a Pilot Capacity Reservation Rider ("CRR") for customers who operate generation in parallel to the Company distribution system and who need to reserve electric distribution system capacity to serve their load when the customer generator is offline. The CRR applies to customer generating facilities that have come online on or after January 1, 2016 and have a nameplate capacity of at least 100kW. Customers can negotiate the percentage of generation nameplate capacity that will be reserved (not lower than 40%) on the distribution system, and the CRR also provides default percentages based upon the size of the generation. The Company will report on the pilot in its next base rate filing and make a recommendation as to whether to modify the CRR and/or make it permanent.

4. Demand Charges

PECO uses demand charge pricing for transmission and distribution service for C&I customers. A customer's demand charge is based on its individual monthly peak demand, which encourages customers to manage their load and distribute usage throughout the day where possible. The Company recovers almost all of its non-customer charge C&I distribution costs through the demand charge. With a cost-based customer charge and a demand charge for distribution, cross-subsidization within the rate class has been minimized.

B. Discussion Of Alternative Ratemaking Methodologies

The Company's discussion of alternative ratemaking methodologies in this section is intended to respond to questions 2-4 for EDCs and 2-5 for NGDCs, as set forth on pages 15-17 of the Tentative Order. Regarding question 4 directed to NGDCs, PECO notes that it does not currently use a weather normalization adjustment.[2] PECO describes its preferred approach in Section II.C (electric) and Section III.C (gas).

1. Decoupling / Lost Revenue Adjustment Mechanism ("LRAM")

Revenue decoupling and LRAM each provide utilities with protection against revenue loss associated with load reduction due to energy efficiency, distributed energy resources, or weather. However, decoupling alone does not address the appropriate allocation of costs among customers, an issue that will become increasingly important with further deployment of distributed generation.

A decoupling mechanism or LRAM typically is designed to be revenue neutral on a customer class basis, although there may be bill impacts at the individual customer level. For example, if "revenue per customer" decoupling is implemented and the Company exceeds its revenue threshold (revenue per customer multiplied by the number of customers), the excess revenue would be refunded to all customers. Similarly, if the Company collects revenues below its threshold, the shortfall would be collected from all customers. Thus, the bill impacts of decoupling would be tied to both aggregate and individual customer usage. Decoupling could also accelerate cost shifting within a customer class, as revenue lost to energy efficiency or distributed generation is allocated to customers on a current basis instead of in a base rate

[2] The Company does believe, however, that a weather normalization adjustment can be an important tool and NGDCs should have the ability to propose such an adjustment. NGDCs, more than EDCs, are subject to wide revenue swings because of weather. In general, over 50% of gas sales are in the four-month period of December to March, such that a mild winter can significantly reduce sales and ultimately revenues.

proceeding. For example, revenues lost through residential customer net metering would be recovered from all other residential customers when a periodic decoupling adjustment is made. While this intra-class cost shifting would also occur during a base rate proceeding, under decoupling it would occur more frequently with each decoupling-mechanism adjustment.

PECO does not foresee significant impacts to low-income customers enrolled in the Company's Customer Assistance Program ("CAP"). A CAP customer has an established energy burden based on a number of factors, and the CAP fixed credit adjusts so the customer does not pay more than that appropriate energy burden. If distribution rates were decoupled, the energy burden for a particular CAP customer would be the same as under the current structure, and therefore, the bill paid by the CAP customer would adjust to the correct level on a quarterly basis. Income-challenged customers, who are not eligible to enroll in CAP, may be affected by a significant decoupling adjustment. Usage reduction by these customers could more than offset any decoupling adjustment.

Consistent with most decoupling programs, PECO believes it would be appropriate to exclude very large C&I customers from decoupling, because their diversity in size and usage would make it difficult to develop a reasonable "revenue per customer" baseline for decoupling. Street-lighting customers should also be excluded as the majority of their cost of service is already recovered in a fixed charge.

A decoupling mechanism or LRAM would likely not affect existing EE&C plans. While decoupling removes a lost revenue disincentive associated with energy efficiency and demand response, an EDC's mandatory targets and spending limitations would still be in place. Customers who participate in energy efficiency programs would continue to reduce their energy bills through reduced generation charges.

The Company also does not expect that decoupling or LRAM would have a significant effect on the frequency of base rate case filings as that frequency depends upon other cost drivers (e.g., capital investment, operating and maintenance expenses), but it would impact the magnitude of the increase.

As noted above, LRAM and decoupling remove a disincentive for utilities in offering energy efficiency programs. The Company also does not believe that decoupling would have a significant effect on customer adoption of energy efficiency programs. Rather, PECO believes the price of energy, be it electric generation or natural gas, is and would remain the key factor driving customer participation in energy efficiency programs.

As explained in Section V.3 *infra*, PECO believes the best path to decoupling or implementing a LRAM is through authorizing legislation, followed by an implementing base rate proceeding. A phase-in process should not be required, because the overall rate design for customers should not change significantly. Revenues from Section 1307 mechanisms should be excluded from the "revenue per customer" calculations to implement decoupling, because they are already reconcilable.

2. Straight Fixed Variable ("SFV") / Demand Charges / Backup Charges

Alternative rate designs such as SFV, demand charges and backup charges can provide utilities an opportunity to address existing intra-class cost subsidization issues and help prevent cost shifting moving forward. However, they would not provide the same revenue protection as decoupling or a LRAM. As described in Section II.A and III.A of these Comments, PECO has already integrated demand, standby and backup charges into its rate design for certain C&I customers.

While these alternative rate designs are intended to be revenue neutral on a customer class basis, they can have significant bill impacts for individual residential customers. For example, implementing SFV through higher fixed charges and lower usage-based charges will result in some customers seeing large reductions in their bills, while other customers see large increases. On the electric side, load factor would be a key determinant in the rate impact for an individual customer, while for gas customers, rate impact would be determined by volume. That said, SFV does not completely eliminate usage as a driver of the distribution bill, because truly variable costs are still billed on a usage basis. Implementing demand charges for residential customers could also have significant bill impacts if a customer's usage is concentrated during times of high system demand.

Due to the CAP credit structure, PECO does not foresee significant impacts to low-income customers enrolled in CAP. Income-challenged (non-CAP) customers who experience bill increases under these structures might mitigate bill impacts by shifting usage to times of lower demand (if a demand charge is implemented) or reducing overall usage (if SFV is implemented). In either case, significant customer education about managing demand would be required.

The integration of SFV, demand charges and/or backup charges could also impact the design of PECO's EE&C programs. For example, if a new rate design modifies the avoided costs associated with a measure, that measure may become more or less cost-effective. In response, the Company may change its preferred mix of measures within a program or the rebates for particular measures. As noted previously, PECO expects that customer participation in efficiency programs would continue to be driven by the commodity cost of electricity or natural gas – not distribution rate design.

SFV, demand charges and/or backup charges would be implemented in a distribution base rate proceeding. A phase-in process might be appropriate if the new rate design is significantly different than the existing rate design for a particular customer class. For example, if demand charges are implemented for residential customers, a phase-in period might be appropriate to educate customers about how their bills may change and what actions might moderate bill impacts. PECO does not expect rate design changes such as SFV, demand charges, and backup charges to have a significant impact on the magnitude and timing of base rate filings unless there is significant revenue erosion from energy efficiency or distributed generation. In the case of significant revenue erosion, the rate designs likely would reduce the magnitude of rate cases, but the rate designs likely would not change the timing of rate-case filings. The new rate design would, however, better assure that all customers are paying their fair share of distribution costs consistent with cost-causation principles.

3. Multi-Year Rate Plans

Multi-year rate plans can provide a more predictable revenue stream and greater certainty, particularly for utilities anticipating substantial capital investments. In addition, performance-based incentives can be incorporated into multi-year rate plans to encourage utilities to control costs. As noted in the Tentative Order (p. 10), the ability to accurately forecast several years into the future may be a challenge with multi-year plans. In particular, a large and unforeseen change in utility cost or revenue could create significant recovery risk for the utility unless the utility is permitted to make adjustments in the middle of a multi-year rate plan.

PECO does not foresee significant impacts to CAP customers from multi-year plans because of the CAP credit structure previously discussed. Income-challenged (non-CAP) customers would have more certainty concerning future rates.

Existing EE&C plans would probably not be affected by the use of a multi-year rate plan, because an EDC's mandatory consumption and demand reduction targets and spending limitations would remain in place. A multi-year rate plan could better address lost revenues resulting from efficiency and conservation programs by taking into account efficiency-related usage reductions several years into the future, which in turn would remove a disincentive for voluntary EDC or NGDC efficiency programs or exceeding mandatory Act 129 savings targets.

Depending upon the structure and term of a multi-year rate plan, the frequency of base rate filings may be decreased. A multi-year rate plan could establish rate certainty over a period of time. At the expiration of the plan period, the utility could either seek to implement another plan or leave the then-current rates in effect. A DSIC may not be as beneficial, since the multi-year projection would include expenditures under a utility's Long-Term Infrastructure Improvement Plan ("LTIIP"), but it could provide a mechanism to recover DSIC-eligible expenditures that were not foreseen at the time a multi-year rate plan was approved.[3] Multi-year rate plans, by themselves, while addressing revenue issues, would not address any existing misallocation of costs between or within customer classes.

PECO believes that legislation authorizing multi-year rate plans might be required prior to implementation. Following such legislation, the Commission could use either a rulemaking or adjudicatory process to establish the parameters of a multi-year rate plan.

4. Performance Incentives

Performance incentives can be used to further policy objectives (e.g., energy efficiency, operational efficiency). Incentives integrate shared savings such that benefits generated by the utility flow directly back to both customers and the utility, thereby further incenting a continuous loop of improvement. Similarly, if performance was lagging, the utility would bear some of the costs of underperformance. The use of performance incentives alone, however, would not address existing cost shifting concerns, including those generated by net metering.

[3] Another possibility for a multi-year plan would combine the fixed return on equity ("ROE") with a formula rate in the style of FERC transmission cases. A rate case would establish an ROE for a period of years with rates adjusted annually to reflect actual costs.

As the Commission notes in the Tentative Order (p. 13), it is unclear whether Act 129 permits performance incentives for EDCs implementing mandatory EE&C plans. Even if such incentives were statutorily permitted for "beyond compliance" savings, an EDC's ability to achieve such savings would be limited by the Act 129 plan spending cap. Moreover, the Company believes a balanced approach is necessary with respect to incentives and penalties. As discussed in Section I *supra*, EDCs may only seek recovery of lost revenues in a base rate case and face steep penalties for non-compliance with mandatory consumption and demand reduction targets. Incentives and penalties must be aligned in order to incentivize utilities to achieve savings beyond mandatory targets. In order for such incentives to be meaningful, however, lost revenues related to efficiency gains must be addressed.

Performance incentives could be implemented in a separate proceeding or base rate proceeding, depending upon the nature of the incentive. A properly designed incentive program will balance risks and rewards for the utility. Depending upon the magnitude and type of the incentives available to a utility, performance incentives could have an effect on the timing of future base rate filings. In no event should the incentives be used to reduce the magnitude of an otherwise justified rate increase. Without a specific performance incentive mechanism to consider, it is difficult to assess the potential impacts on different rate classes or the interplay with other surcharges.

C. PECO's Preferred Approach

As explained in Section I of the Company's Comments, the effectiveness of alternative ratemaking measures may vary from one utility to the next and from one utility group to another (for example from electric to water utilities). That said, PECO believes that the use of a combination of alternative ratemaking methodologies is appropriate given its existing customer base and rate design.

Under PECO's preferred approach, a "revenue per customer" decoupling model would be implemented for all customer classes excluding very large customers and possibly certain Street Lighting classes. Periodic true-up adjustments would be made to refund/recover the difference between the revenue collected and the Company's revenue threshold (revenue per customer multiplied by the number of customers). The magnitude of any true-up adjustment would be limited with the excess carried forward with interest. Traditional Section 1307 adjustment mechanisms would not be affected by decoupling as long as revenues from those mechanisms are excluded from the "revenue per customer" calculation. Decoupling would allow PECO to mitigate revenue losses from energy efficiency and distributed generation, but it would not address (and could even exacerbate) intra-class cost shifting, particularly in the residential class. As noted earlier, revenues lost through residential customer net metering would be recovered from all other residential customers on a more current basis if decoupling were implemented.

To address intra-class cost shifting and better assure that customers pay their fair share of grid costs, PECO would implement several changes to residential rates in addition to decoupling. First, PECO would continue to move its fixed charge (customer charge) to be fully cost based. Second, PECO would establish a separate class for net metered residential customers with a three-part rate structure (fixed, volumetric and demand components) to assure that such customers pay an appropriate portion of distribution costs.[4] Legislative changes would probably be required to authorize this separation. As an alternative to implementing a demand charge for net metered residential customers, PECO could offer a "buy all, sell all" rate, whereby a customer would pay the full retail rate for all its usage and receive payment for all output at the value of generation. If, after the first two changes had been implemented, revenues from the

[4] PECO suggests that a new rate structure should be phased in gradually to minimize customer impacts. Particularly, net-metering customers should have the benefit of their current arrangement for a reasonable period while new rates are rolled into effect.

residential customer class were still eroding due to significant energy efficiency or other reasons, PECO would continue to consider phasing in demand charges to provide a three-part rate structure while also considering other possible options to address revenue erosion. Any proposed solution developed by the Company would be implemented after a base rate proceeding.

III. RESPONSES TO THE TENTATIVE ORDER'S NATURAL GAS DISTRIBUTION COMPANY QUESTIONS

A. PECO's Current Alternative Ratemaking Methodologies

The Company's discussion of alternative ratemaking methodologies in this section is intended to respond to question 1, page 16 of the Tentative Order, directed to NGDCs. PECO currently uses or will use in the future several of the alternative ratemaking methodologies listed by the Commission in its Tentative Order: (1) the fully projected future test year; and (2) cost trackers.

1. Fully Projected Future Test Year

In its next gas base rate filing, PECO anticipates it will use a fully projected future test year.

2. Cost Trackers

The Company currently uses the following seven cost trackers for ratemaking purposes. The revenue reflects 2016 levels.

- The STAC refunds to or collects from customers the costs or benefits associated with changes in certain state tax rates. The STAC is currently refunding to customers approximately $2 million per year.
- The USFC refunds to or collects from customers the difference between the amount of universal service costs the Company incurs in a year and the amount that is included in base rates. The annual amount of revenue going through the USFC is currently an approximate $4 million credit. The USFC applies to residential customers only.

- The Sales Service Cost charge ("SSC") recovers the Company's cost of purchased gas from customers who purchase their gas supply from PECO as the supplier of last resort. The Company recovers approximately $127 million per year under this mechanism.

- The Balancing Service Cost charge ("BSC") recovers from customers, excluding large volume transportation customers, whether shopping for supply or not, the cost of balancing the system. The Company currently recovers approximately $22 million through the BSC per year.

- The CSC recovers the costs of education related materials generally associated with enhancing the competitive market. Currently the Company is not recovering any amounts with this charge.

- The TARC credits to customers the benefits of a tax credit received by the Company following the implementation of a tax accounting change in the treatment of certain property repairs. It was established as part of the Settlement in Docket R-2010- 2161592 and is expected to terminate at the end of 2019. Approximately $8 million per year is being refunded to customers under the TARC.

- The DSIC recovers from customers a return of and on the capital expenditures approved as part of the Company's Gas Long-Term Infrastructure Improvement Plan. Recovery under the DSIC occurs between base rate cases and is subject to an earnings test. The Company currently is not recovering any money under the DSIC.

The following table displays the revenues recovered under each cost tracker as a percentage of total gas revenue:

Gas Cost Trackers	Costs/Revenues (millions)		
State Tax Adjustment Clause (STAC)	$	(2)	-0.4%
Universal Service Fund Charge (USFC)	$	(4)	-0.9%
Sales Service Cost Charge (SSC)	$	127	27.4%
Balancing Service Cost Charge (BSC)	$	22	4.7%
Consumer Education Charge (CEC)	$	-	0%
Tax Accounting Repair Credit (TARC)	$	(8)	-2%
Distribution System Improvement Charge (DSIC)	$	-	0%
Total Gas Revenue	**$**	**463**	29.2%

3. Standby and Backup Charges

PECO does not have a specific standby or backup rate for gas distribution service. The firm large C&I rate as well as the firm transportation rates do, however, have a minimum bill equal to 15 days use of the Total Contract Quantity.

B. Discussion Of Alternative Ratemaking Methodologies

Please see PECO's discussion of alternative ratemaking methodologies in Section II.B *supra*.

C. PECO's Preferred Approach

PECO believes that a combination of alternative ratemaking methodologies is appropriate to achieve gas distribution rates that better reflect cost causation. First, similar to the Company's recommendation for electric distribution rates, a "revenue per customer" decoupling model would be implemented for the residential and small C&I customer classes. Periodic true-up adjustments would be made to refund/recover the difference between the revenue collected and the Company's revenue threshold (revenue per customer multiplied by the number of customers). The magnitude of any true-up adjustment would be limited with any excess carried forward with interest. Traditional Section 1307 adjustment mechanisms would be excluded from the "revenue per customer" calculation. Decoupling would allow PECO to mitigate revenue losses due to efficiency improvements in gas appliances and address the revenue uncertainty related to how usage changes with weather conditions. Decoupling would also remove any disincentive for PECO to implement gas efficiency programming for its customers. Second, PECO would phase in an increase in fixed charges for residential customers to a level that recovers all fixed costs that are not related the volume of gas used by a customer or the demand placed on the mains. The implementation of the Company's proposal, including the mechanics of the true-up adjustment, would be addressed in a base rate proceeding.

IV. RESPONSES TO VICE CHAIRMAN PLACE'S ELECTRIC DISTRIBUTION COMPANY RATE PROPOSALS

Vice Chairman Place's proposal for a three-part rate design for electric distribution customers consisting of a customer charge, a demand charge, and a volumetric charge would address many of the rate design issues discussed in these Comments, and the answers that follow are directed to that particular option. However, as described in Section II.C, PECO believes that the adoption of a "revenue per customer" model would be preferable for residential and small C&I customers, with the exception of net metered residential customers, for whom the Company does support a three-part rate design.

1. PECO agrees with Vice Chairman Place that a utility's cost of service should not change based upon the rate design used for cost recovery and that the phase-in of new rate designs would minimize significant impacts on customers consistent with the principle of gradualism. The Company believes that the phase-in schedule for a three-part rate design should be determined on a utility-specific basis based on the projected customer impacts. Regardless of schedule, meaningful customer education would be critically important. The Company does not believe that coincident peaks should be used for purposes of developing demand charges because distribution cost of service is typically allocated based on non-coincident peak ("NCP") demands.

2. Distribution demand charges should be based on a customer's NCP demand. As explained earlier, the cost of distribution service is typically allocated based on customer class non-coincident peaks. In addition, using a customer's NCP will provide it with more opportunity to respond to price signals than the use of class-wide NCP.

3. The demand billing determinant should be the customer's peak hourly demand for the month. Pricing the service on the peak provides the customer with an incentive to avoid spikes in its demand. Customers with AMI meters have the capability to review their hourly consumption data and can use that data to identify their peaks and take steps to reduce their demand during those times.

4. Peak demand measurement should be determined on a company by company basis. While PECO currently uses a 30-minute demand measurement for C&I customers, a 60-minute measurement may be more understandable for residential customers because, as noted above, they are currently able to review their historical hourly consumption data and the billing demand would simply be the highest hourly interval of usage.

5. While it may be possible to layer tiered demand rates (e.g., on peak/off peak) into a three-part rate structure, it would make rates more complex and likely add to customer confusion. PECO believes that any successful transition to a three-part rate by residential customers will require significant time and education. Once a demand charge is in place and understood by customers, the inclusion of tiered demand rates could be considered if it was determined by the EDC that it would be beneficial for the EDC and its customers. Given the complexity of moving to non-tiered demand charges, any move to tiered demand rates would be after a significant period of evaluation and review of trends nationally.

6. The demand charge should recover those costs that vary with demand. In a utility's cost of service study, this typically includes transformers, substations, and portions of the poles, conduit, and wires. To be consistent with cost of service principles, a demand charge would also be designed to recover associated operating expenses and an allocated portion of administrative cost. The costs of information systems, billing systems and customer service systems such as the call center should be recovered through a fixed customer charge along with other customer accounts expenses, customer related distribution costs, and associated administrative costs. Energy efficiency costs not otherwise recovered in the Company's EE&CPR should be recovered on a kWh basis. In general, an EDC's cost of service study should be used to determine which costs go into the demand charge, which go into the customer charge, and which go into the energy charge.

7. Residential customers could be divided into different classes based on load characteristics and there could be different phase-in periods for different residential classes. For example, it would be desirable to first phase in the three-part rate design for net metering customers to better ensure they pay their fair share of grid costs. The need for a three-part rate design for the remainder of residential customers could then be determined at a later date.

8. All of PECO's Section 1307 adjustment mechanisms are volumetric (kWh)-based and could be rolled into the volumetric component of the three-part rate structure. In the alternative, the nature of the costs recovered in the 1307 mechanism could be reviewed to see if they should be recovered on a customer or demand basis.

9. PECO's C&I customers have demand charges based on their non-coincident peak. As explained in the response to Vice Chairman Place's question number 1, this is appropriate and consistent with distribution cost of service. Furthermore, if the goal is to enable customers to react to their demand, use of a coincident peak ("CP") or customer-class NCP to bill the customer would provide no immediate feedback on the customer's actions because the CP and class NCP are not known until the end of the year. If a customer is billed on the basis of its maximum demand, it will see results on its bill as soon as it starts reducing its peak. Large customers already have a CP based charge in the case of generation charges under default service, where large customers pay for demand charges based on their PJM peak load contribution, which changes once per year in June. A customer who reduces demand after June sees no immediate benefit to reinforce their action. Having more charges on a CP basis would not provide any immediate feedback for a customer's actions.

10. While a three-part rate structure would be designed to be revenue neutral for residential customers as a whole, there will be some residential customers that experience bill increases and others bill decreases. Low-income customers who are not enrolled in CAP could

see either increases or decreases in their bill, the magnitude of which will depend upon the ultimate rate design. PECO does not foresee significant impacts to low-income customers enrolled in CAP as a result of these alternative rate designs because of the CAP credit structure described in Section II.B.1 *supra*. PECO's CAP program does have CAP credit maximums, so it is possible that a CAP customer's bill could increase if the unsubsidized bill was greater than the sum of the customer's energy burden and the maximum CAP credit. A potential transition to a three-part rate structure may change the overall costs of the CAP program for residential customers, depending upon whether CAP customers as whole require a greater or lesser amount of CAP credits.

11. Prior to the transition to a three-part rate structure, customers should be provided with educational material sufficient to allow them to understand the components of their new bill and how they can manage and control costs. For example, customers should have materials explaining what "demand" is and how it can be managed to reduce demand charges. Additionally, the Company could first pilot demand charges on a limited basis to gain a better understanding of the impact of the change on customers while also closely monitoring what is happening nationwide. This would provide PECO with a greater understanding of potential customer and Company impacts prior to making such a significant change.

12. Although not part of the numbered questions for EDCs, Vice Chairman Place also requested comments on reliability performance-based mechanisms. PECO is not opposed to such incentives, but believes that establishing reliability targets and determining how such a mechanism will operate would both be difficult tasks. If EDCs were given different reliability targets, EDCs with better baseline reliability could find it more difficult to get the performance incentives. PECO also notes that the Commission currently has the ability to consider reliability performance when setting the ROE in a base rate case.

V. RESPONSES TO VICE CHAIRMAN PLACE'S NATURAL GAS DISTRIBUTION COMPANY RATE PROPOSALS

1. PECO supports the "revenue per customer" decoupling proposal put forth by Vice Chairman Place. PECO further recommends that there be a periodic true-up adjustment for revenue with a cap and that the true-up period be designed to minimize swings in rates.

2. At present, approximately 18 states have implemented some form of gas decoupling.[5] Some jurisdictions, such as California and Connecticut, require decoupling by statute while others, such as Wisconsin, have implemented decoupling pilots approved at the public service commission level.

3. PECO understands that a number of stakeholders believe that authorizing legislation is necessary. PECO believes the best path to decoupling would be through authorizing legislation to remove any uncertainty regarding this issue.

4. The largest impact to bills would likely result from revenue volatility related to weather. For example, if weather leads to actual customer revenues that exceed authorized revenues, customers would be entitled to a refund of the difference. If the weather leads to actual customer revenues that fall short of authorized revenues, the shortfall would be collected from customers. Selecting a reasonable true-up period for under and over collections will be critical to minimizing bill impacts.

5. All NGDCs should have the option to implement decoupling because the decline in sales due to increasing efficiencies in gas appliances affects all NGDCs, not just those with conservation and efficiency programs. Decoupling would also eliminate any revenue

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[5] A decoupling map is available on the Center for Climate and Energy Solutions website at https://www.c2es.org/us-states-regions/policy-maps/decoupling.

disincentive for an NGDC to promote conservation and efficiency. NGDC efficiency and conservation programs should remain voluntary.

6. If an NGDC is seeking to recover the costs of efficiency and conservation programs in base distribution rates, the cost-effectiveness of such programs should be addressed in a base rate proceeding.

7. If this question refers to NGDC efficiency and conservation programs, a base rate proceeding would be the appropriate venue to review the program costs, benefits and outcomes. Similarly, if this question refers to decoupling, the design and administration of NGDC's decoupled rates should be reviewed in the context of a base rate proceeding.

8. The true-up mechanism under a decoupling model would address the difference between the actual revenues for a specific period of time and the authorized revenues based on an established "revenue per customer." As the Company has stated previously, there would be a periodic true-up adjustment with a cap on the true-up amount to mitigate swings in rates.

9. Decoupling should apply to residential and small C&I customers. Large C&I customers vary substantially in size such that a truly meaningful "revenue per customer" benchmark may be difficult to establish.

10. It would be appropriate to exclude Section 1307 automatic adjustment clause revenues because they are reconciled and are not subject to losses due to efficiency gains or declines in customer usage.

11. A usage per customer parameter is not necessary when using revenue per customer decoupling. Future rates would be adjusted based upon the then current sales levels. The revenue per customer adjustment would be spread across the current sales level. New and existing customers would not be treated differently.

12. As noted above, the frequency of the rate adjustment should be set to minimize the impact on customers and limit swings in rates and it should be determined on a company by company basis.

13. A cap on rate adjustments is reasonable and can help mitigate swings in rates if the excess is deferred, with interest, for recovery.

14. Adjustments should take effect with the rate effective period for new base rates. For example, if decoupling is implemented and a monthly decoupling adjustment is part of the plan, then the first adjustment would be applied the third month into the rate effective period, e.g., the adjustment for January would be applied in March.

15. Because the Commission already requires quarterly reporting of earnings, a separate review requirement is not necessary unless it is part of a multi-year rate plan.

16. The rate adjustments do not need to provide for carrying charges unless the recovery or refunding of costs is deferred due to a cap on the magnitude of the rate adjustment.

17. PECO does not foresee significant impacts to low-income customers enrolled in CAP as a result of these alternative rate designs because of the CAP credit structure described in Section II.B.1 and IV.10.

18. Customers should be provided with a high level description of what decoupling is and how it differs from the current rate design.

VI. CONCLUSION

PECO appreciates the opportunity the Commission has provided to offer these Comments on alternative ratemaking methodologies and looks forward to working with the Commission and interested stakeholders on this important initiative.

Respectfully submitted,

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