AN EXELON COMPANY

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April 7, 2025

VIA eFILING

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

Re: Energy Efficiency and Conservation Program
Docket No. M-2025-3052826

Dear Secretary Chiavetta:

Enclosed please find the **Comments of PECO Energy Company on the Commission's February 20, 2025 Tentative Implementation Order** ("the Comments") in the above-captioned proceeding.

As instructed in the Tentative Implementation Order, a Word formatted copy of these Comments will be sent via email to Joseph Sherrick at josherrick@pa.gov and Tiffany Tran at tiftran@pa.gov.

If you have any questions, please do not hesitate to contact me.

Very truly yours,

Caroline S. Choi

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Energy Efficiency and Conservation Program	:	**Docket No. M-2025-3052826**

PECO ENERGY COMPANY'S COMMENTS ON THE
COMMISSION'S FEBRUARY 20, 2025 TENTATIVE IMPLEMENTATION ORDER

Pursuant to the February 20, 2025 Tentative Implementation Order ("Tentative Order") entered by the Pennsylvania Public Utility Commission (the "Commission" or "PUC") in the above-referenced docket, PECO Energy Company ("PECO" or the "Company") hereby submits comments on the Commission's proposals for a fifth phase ("Phase V") of Act 129' s energy efficiency and conservation program ("EE&C Program"). The Company appreciates the significant efforts of the Commission and its staff to develop the Phase V proposal.

PECO agrees with the Commission that Phase V is an opportunity to increase focus on more comprehensive energy savings initiatives. To that end, PECO believes that the Phase V targets and carve-outs established for electric distribution companies ("EDCs") must permit a reasonable amount of flexibility in program design to achieve the Commission's goals while delivering savings to our customers. Furthermore, the targets must also permit EDCs a reasonable path to success given evolving program designs and market developments.

As explained below, with respect to specific Commission direction in the Tentative Order, PECO believes that the Company's proposed demand response ("DR") target set by the Commission is unreasonably high in light of the Tentative Order's program design and DR measurement restrictions. The Company is also concerned that EE&C implementation activities will be affected by macro-economic factors such as the establishment of federal tariffs and the removal of federal incentive funding and tax credits. To address these issues, the Company has recommended that the Commission provide for additional flexibility in DR programming and also establish a process whereby an EDC may propose revisions to its EE or DR targets during Phase V if external macro-economic factors will materially impair the EDC's ability to meet such targets.

I. BACKGROUND

Section 2806.1 of Act 129 of 2008 ("Act 129" or the "Act") required Pennsylvania's largest EDCs, including PECO, to adopt EE&C plans that would achieve consumption savings of at least 1% for their retail customers by May 31, 2011 and at least 3% by May 31, 2013. In addition, the Act required EDCs to achieve a peak demand savings over the 100 highest hours of demand of a minimum of 4.5% by May 31, 2013. Act 129 also required that the Commission evaluate the costs and benefits of the approved EE&C plans by November 30, 2013. If the benefits of the EE&C plans exceeded the costs, the Commission was to establish new, additional incremental consumption and peak demand reduction requirements.[1] In its August 2, 2012 Implementation Order for a second phase of Act 129, the Commission established additional consumption reduction, but not peak demand, targets for EDCs, to be achieved by May 31, 2016.[2] For the third phase of Act 129, the Commission prescribed both reductions in consumption and peak demand targets to be met by May 31, 2021.[3] For the fourth phase of Act 129, the Commission prescribed reductions in consumption and peak demand targets to be met by May 31, 2026.[4]

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1 *See* 66 Pa. C.S. §§ 2806.1(c) and (d).

2 *See Energy Efficiency and Conservation Program*, Implementation Order, Docket Nos. M-2012-2289411 and M-2008-2069887 (August 3, 2012) ("Phase II Implementation Order").

3 *See Energy Efficiency and Conservation Program*, Implementation Order, Docket No. M-2014-2424864 (June 19, 2015) ("Phase III Implementation Order").

4 *See Energy Efficiency and Conservation Program*, Implementation Order, Docket No. M-2020-3015228 (June 18, 2020) ("Phase IV Implementation Order").

PECO received approval of its Phase I EE&C plan on October 28, 2009 at Docket No. M-2009-2093215 (the "Phase I Plan"), its Phase II EE&C plan on February 28, 2013 at Docket No. M-2012-2333992 (as amended with Commission approval on May 9, 2013, the "Phase II Plan"), its Phase III EE&C plan, which the Commission approved on May 19, 2016 at Docket No. M-2015-2515691 (as amended with Commission approval on January 9, 2020, the "Phase III Plan"), and is currently administering its Phase IV EE&C Plan, which the Commission approved on March 25, 2021 at Docket No. M-2020-3020830 (as amended with Commission approval on May 23, 2024, the "Phase IV Plan").

In this Tentative Order, the Commission put forth several proposed targets and carve-outs for Phase V based on market potential studies ("MPS") performed by the Statewide Evaluator ("SWE"). Those proposed directives include (1) a 202.4 MW five-year peak demand reduction target for PECO; (2) a 1,174,520 MWh five-year consumption reduction target for PECO; and (3) a requirement that PECO obtain 74,456 MWh of savings (or 6.3% of its consumption reductions) from programs directed solely at low-income customers or from low-income-verified participants in multi-family programs. The Tentative Order also proposes several changes in plan design and administration, including the use of a daily load shifting design for DR programs and the use of seasonal averaging to calculate peak demand reductions. In the remainder of these comments, PECO provides its recommendations regarding several specific proposals in the Tentative Order for consideration by the Commission, including the DR program design proposals identified above and additional items in the Tentative Order.

II. COMMENTS ON SPECIFIC TENTATIVE ORDER PROPOSALS

A. PECO's Proposed DR Target Is Unreasonably High

The overall peak reduction target set for PECO in the Tentative Order is 202.4 MW. The Commission's analysis assumes that EE, solar PV, combined heat and power ("CHP") and daily load shifting resources will be used to achieve the peak reduction target.[5] While the Tentative Order provides an estimate of peak reduction contributions from daily load shifting, it provides flexibility for EDCs to meet the target through, for example, achieving greater peak reduction savings from EE measures and lower peak reduction savings through daily load shifting.

PECO agrees that a measure-agnostic approach is sensible to allow EDCs to utilize the most effective means possible to deliver peak reduction. However, the Company has significant concerns with the requirement for daily load shifting on all non-holiday weekdays in June, July, August, January and February (approximately 100 days in total),[6] the lack of a ramp-up period,[7] the apparent treatment of time-of-use ("TOU") customers,[8] the absence of specific measurement and verification ("M&V") guidance, and the exclusion of event-based DR. These concerns, and PECO's recommended changes to address them, are described below.

1. Daily load shifting is unproven and, therefore, is effectively being deployed as a large-scale, statewide pilot with stringent regulatory requirements

Daily load shifting programs are a new concept not just in Pennsylvania, but across the country, and there are limited examples of daily load shifting programs for EDCs to build upon. In order to deliver cost-effective savings at scale, EDCs will need to overcome significant barriers to quickly identify the right combinations of measures, customers, incentive levels, device control technologies, event dispatch strategies, marketing strategies, trade ally engagement approaches, and M&V methods. Because the Commission has proposed to measure compliance with the DR target by taking the average savings over the five-year period, resources

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5 *See* Tentative Order, p. 43, Table 13.

6 *See* Tentative Order, p. 39, Table 11.

7 *See* Tentative Order, p. 53.

8 *See* Tentative Order, p. 40.

early in Phase V have more representation than resources obtained later in the Phase (i.e., resources early in the Phase will be represented in more of the program years that are averaged than resources obtained in later years). This means EDCs will have very limited time to learn from failures while they face steep penalties under 66 Pa. C.S. 2806.1(f) if they fail to meet their DR target.

California is one example of a state that has taken steps to encourage daily load shifting.[9] However, rather than immediately enforcing significant daily load shifting requirements upon California utilities, the state has supported a series of activities to establish a foundation for daily load shifting to be viable. This includes the establishment of regulatory proceedings with broad stakeholder input, development of standards to facilitate communications with and control of end devices, as well as standards to facilitate M&V to measure demand savings and facilitate performance-based payments, reformation of markets and EDC tariffs to incentivize customer participation, and implementation of pilot programs to test, demonstrate, learn, and refine programmatic and technical approaches to facilitate daily load shifting.[10] California's efforts have been ongoing for years, and yet the California Energy Commission recommended that formal load shifting goals not be put into effect until 2030.[11] Pennsylvania, however, is asking EDCs to skip these steps and quickly deliver cost-effective savings from daily load shifting at significant scale or face possible large penalties.

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9 *See* California Energy Commission ("CEC"), https://www.energy.ca.gov/programs-and-topics/topics/load-flexibility/load-management-standards.

10 *See* California Public Utilities Commission Rulemaking 22-07-005, Advancing Demand Flexibility Through Rates, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-costs/demand-response-dr/demand-flexibility-rulemaking; CEC Load Management Standards, https://www.energy.ca.gov/programs-and-topics/topics/load-flexibility/load-management-standards; CEC Flexible Demand Appliance Standards, https://www.energy.ca.gov/proceedings/active-proceedings/flexible-demand-appliances

11 *See* CEC Senate Bill 846 Load-Shift Goal Report, https://www.energy.ca.gov/publications/2023/senate-bill-846-load-shift-goal-report, pp. 2, 18.

PECO notes that the potential benefits of daily load shifting may be best explored in Phase V on a limited basis through small scale pilots. Such pilots would permit EDCs to test, demonstrate, and refine various strategies, ensuring that any barriers can be addressed effectively before a daily load shifting framework is mandated.

2. The peak demand reduction target cannot realistically be achieved within the allotted budget without demand response programs

In the Tentative Order, the PUC states that "peak demand reduction targets may be satisfied with either coincident demand reductions from EE or verified demand reductions from load-shifting programs."[12] However, the peak demand reduction target cannot realistically be achieved with EE alone. As shown in the table below, if the PUC's acquisition costs for PECO are utilized for each component[13] and the 10% demand response budget[14] is reallocated proportionally to non-low-income EE, low-income EE, solar PV and CHP, PECO would only achieve 170.9 MW in peak demand reductions which is 15% short of PECO's mandatory DR target.

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12 Tentative Order, pp. 44-45.

13 Tentative Order, p. 16, Table 5.

14 Tentative Order, p. 20, Table 8.

	Non-Low Income EE	Low-Income EE	PV	CHP	Demand Response	Total	Source
PECO Acquisition Costs ($/MW) (I)	$2,995,930	$5,774,027	$1,278,518	$230,920	$879,000	**$2,111,590**	*Phase V Tentative Order*
Budget Allocation in TO (II)	67%	13%	9%	1%	10%[15]	**100%**	*Phase V Tentative Order*
Modeled Budget (III)	$286,348,506	$55,560,158	$38,464,725	$4,273,858	$42,738,583	**$427,385,830**	*- Total Budget from Phase V Tentative Order. - Component budget calculated as Row II x Total Budget*
Peak Demand Reduction Target (IV)	95.6	9.6	30.1	18.5	48.6	**202.4**	Calculated: Row III / Row I
Assumed Budget allocation without Demand Response (V)	74%	14%	10%	1%	0%	**100%**	*Calculated as Row II / (1 - Demand Response Allocation from Row II) ; or Row II / 90%*
Assumed Budget (VI)	$318,165,007	$61,733,509	$42,738,583	$4,748,731	$0	**$427,385,830**	*Calculated: Row V x Total Budget*
Peak Demand Reduction (Phase V Budget / Acquisition Costs x Budget Allocation) (VII)	106.2	10.7	33.4	20.6	0.0	**170.9**	*Calculated: Row VI / Row I*

3. Daily load shifting reduces the incentive to participate relative to event-based DR

The Tentative Order defines the peak period for DR reduction to be non-holiday weekdays in June, July, August, January and February, for a total of approximately 100 event days.[16] An event-based approach, by contrast, would typically have significantly fewer events per year. For example, each EDC ran a total of 18 events during Phase III from program year 9 through program year 12, for an average of 4.5 events per year.[17] By increasing the number of

15 Tentative Order, p. 20 Table 8 proposes a funding allocation for demand response of 10%. However, Tentative Order p. 42, Table 12 modeled an 8.5% funding allocation for PECO. For this analysis, PECO used the 10% funding allocation.

16 Tentative Order, p. 39, Table 11.

17 *See* SWE Annual Report Act 129 Phase III and Program Year 12; Published March 31, 2022; Table 84, Table 86, Table 88, Table 90, Table 92, and Table 94 on Pages 82 – 90 (https://www.puc.pa.gov/pcdocs/1746475.pdf).

event days and event hours relative to an event-based approach, there is less incentive to provide demand reduction. This can result in relatively low participation rates and relatively low savings per customer under a daily load shifting approach.

Daily load shifting programs would have a lesser peak demand savings value per event as compared to an event-based approach. The system value of peak demand reduction is relatively similar whether the load reduction occurs daily or only during coincident peak hours of the year. If the value were $100/kW-yr, for example, and it takes 20 event days with an average of 2.5 hours per event, the peak demand savings value is $5/kW per event day, or $2 per kWh dispatched. However, at 100 event days for 4 hours each day, the savings value is just $1/kW per event day and only $0.25 per kWh dispatched, which is similar to the average cost of electricity. If this lower value is reflected in a lower per-event customer incentive, customers may decide that program participation is not worth the inconvenience.

It is also worth noting that the PUC has proposed to average summer and winter peak period performance, which effectively gives more weight to each day of the winter period (due to three-month summer period vs. two-month winter period).[18] It is not clear if the Commission intended such an outcome, particularly when PJM is projecting that the mid-Atlantic region and the entire Regional Transmission Organization will be summer peaking through 2045.[19] Furthermore, PECO is a summer peaking utility and therefore grid capacity savings from demand response should be optimized for the summer to provide the most system benefits.

To address these concerns, PECO recommends that the Final Implementation Order allow for event-based DR resources to provide eligible demand reduction in addition to daily

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[18] Tentative Order, p. 47.

[19] *See* PJM Long-Term Load Forecast Report (January 24, 2025), pp. 6, 19 (https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf).

load shifting measures. Event-based DR is a proven approach that can reliably provide targeted, measurable demand reduction in the most valuable hours of the year. Similar to the Commission's approach in Phase III of the EE&C Program, the calculated savings should be based upon event days only (rather than the approximately 100 days for daily load shifting). In addition, instead of averaging summer and winter peak demand reduction savings, the Commission should apply an EDC-specific weighting based on the 2024 summer and winter peak to calculate progress towards target.

4. Daily load shifting will deliver lower savings from individual customers and measures than event-based DR would, particularly for the four-hour summer peak period

Each of the measures identified in the potential study is likely to deliver lower savings through daily load shifting than it would through event-based DR, especially during the four-hour summer peak period (weekdays from 2-6 pm in June through August). Targeted weather-based event forecasting can typically hit the peak hour over the course of a two to three hour event and therefore maximize grid benefits.[20] However, a less targeted daily load shifting requirement from 2-6 pm likely reduces the savings potential during critical peak times when DR is most valuable to the grid.

For thermostats, pre-cooling will likely be insufficient to fully ride through the four-hour event period, as the sun is still actively shining and warming up homes and buildings. With simple pre-cooling and set-point adjustment techniques, customers would likely require significant cooling loads well before the end of the event (6 pm). Alternatively, sophisticated

[20] For example, Liberty Utilities in New Hampshire ran an event-based battery storage pilot from December 2020 through August 2022 and ran 131 events that were two to three hours long. The monthly coincident system peak occurred during an event in each of the 21 months. Liberty Utilities Battery Storage Pilot Program Interim Evaluation Report, Section 3.1.2, p. 25 (https://www.puc.nh.gov/Regulatory/Docketbk/2017/17-189/LETTERS-MEMOS-TARIFFS/17-189_2022-11-29_GSEC_INTERIM-EVALUATION-REPORT.PDF).

control techniques may be used across a portfolio of customers to help levelize the load reduction over the 2-6 pm period, but this would result in lower savings per customer than would be realized for a shorter event.

Similarly for batteries, longer events result in less demand savings. Residential batteries often have a nominal duration of approximately two hours. Take, for example, a 20 kWh / 10 kW battery. If the battery is discharged at full power over two hours, it will deliver 10 kW of savings. However, if the battery is discharged over four hours, it will deliver average savings of just 5 kW.

For EV managed charging, load reduction may be relatively low between 2-5 pm, as many customers are likely to plug in when they return home from work.

For C&I customers, daily load shifting will limit the types of measures they can employ, as well as the degree to which shifting is feasible. For example, on an event day, a C&I customer may shift a certain business/production process to the day before or the day after in order to provide demand savings. However, when those events are "daily" (based on the approximately 100-day peak period proposed by the PUC), that shifting may not be possible. Furthermore, while C&I customers may be willing to endure some temporary disruption of business for occasional events with large per-event incentives, they are less likely to be willing to endure significant disruptions to their business on a daily basis for a relatively low per-event incentive. This logic is also true for residential thermostats, as customers are less likely to tolerate noticeable reductions in comfort on a daily basis than during a limited number of events.

5. The daily load shifting event period may inadvertently drive local capacity issues on certain circuits

The summer peak event period (2-6 pm) ends before the local circuit peak on some of PECO's circuits, particularly circuits that are highly residential. On these circuits, snapback effects from load shifting could increase the local circuit peak. In addition, circuits that currently peak between 5-6 pm could be adversely impacted if they have significant daily load shifting resources.

PECO analyzed data from its system coincident peak days from last year's summer peak season to investigate the alignment between system and local peaks. The coincident peak occurred on July 16, 2024 between 4-5 pm, but system load was still at 99.7% of peak between 5-6 pm. The most common peak hour for individual feeders and terminals[21] was between 5-6 pm, and some feeders and terminals peaked between 6-9 pm. Feeders that peaked between 5-7 pm had the highest portion of residential customers. On those circuits, the average load in the surrounding hours was 97% of load during the feeder peak hour. Thus, for customers on highly residential circuits that peak relatively late in the day, having significant daily load shifting resources on the circuit could inadvertently increase circuit peak load following an event.

To address the potential for adverse impacts to individual circuits, PECO recommends that the Final Implementation Order either adjust the summer peak period to later (e.g., until 7 pm), or allow for event periods to differ for certain customer types (e.g., residential or commercial) and/or certain circuits (e.g., constrained circuits with peaks near or after 6 pm in the summer).

6. Each load shifting measure presents significant uncertainties and barriers

The Phase V DR Potential Study focused on five measures – water heaters, batteries, thermostats, electric vehicle charging, and C&I customer load shifting. Each of these measures

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[21] A terminal is a group of transformers at a substation with the same secondary voltage where automatic operation of secondary voltage switches or circuit breakers transfers the load to the remaining transformers in the event of a transformer or supply line failure.

presents significant challenges for EDCs to effectively realize the target demand reductions from daily load shifting over the five-year Phase V period.

Water heaters and batteries can be excellent devices for daily load shifting given that such devices can be dispatched routinely with little to no observable impacts for customers. However, these two measures were both identified as not cost-effective in the DR Potential Study.[22]

For thermostats, the potential for customer fatigue regarding daily load reductions is high and therefore thermostats may not be a reliable measure for significant and persistent peak demand reduction. It is unclear how much demand reduction customers will be willing to support before dropping out of a load shifting program and it is also notable that the DR Potential Study made the assumption that customers would participate without being given a monetary incentive for their daily load shifting. While this assumption may be true for some customers, this is an unrealistic assumption at scale. Additionally, even if a customer remains in a load shifting program, there is the potential that customers adjust their behaviors to circumvent their discomfort by overriding the controls. For example, if a customer knows their thermostat set point will be increased by two degrees during event hours, they may program the set point two degrees lower so that it ends up at their desired target set point. Furthermore, the DR Potential Study states that smart thermostat DR potential is based on "Customers with Wi-Fi-connected thermostats [who] opt into an optimization feature where the EDC or its CSP (possibly the thermostat manufacturer) modifies the cooling or heating setpoint during peak hours".[23] However the savings potential for a daily load shifting program based on thermostat optimization

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22 *See* Demand Response Potential Study for Act 129 Phase V (January 29, 2025), pp. 45, 62.

23 EE/DR MPS Report (February 7, 2025), p. 70.

is uncertain, as optimization features are already part of the default factory settings of some of the largest smart thermostat manufacturers (NEST and Ecobee).[24]

For electric vehicles, there is some precedent for daily load shifting programs. However, there are nonetheless challenges in establishing programs that can cost-effectively deliver daily load shifting across a diverse portfolio of vehicles and chargers. Only a limited number of newer vehicles come with built-in communication and control capabilities for active managed charging. Control can take place via EV chargers, but only certain chargers offer the requisite capabilities for managed charging, and they tend to require a significant incremental cost. There are also passive managed charging approaches and devices that may be added at lower cost to facilitate managed charging, but the savings per customer may be lower.

Finally, the DR Potential Study suggests that C&I customer load shifting comprises over 70% of cost-effective daily load shifting potential across the Commonwealth,[25] but it is unclear how much savings any measure is expected to deliver, how much it will cost, or how significant the potential is across PECO's territory. PECO notes that during the Company's Phase III event-based DR program, C&I customers delivered more than 80% of the demand reduction, and 99% of the demand reduction from C&I customers came from large C&I customers. However, there are several significant barriers for large C&I customer participation in daily load shifting, including the following:

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[24] *See, e.g.*, NEST thermostats (https://store.google.com/ideas/articles/nest-thermostat-savings/); Ecobee thermostats (https://www.ecobee.com/en-ca/eco-plus/)

[25] Demand Response Potential Study for Act 129 Phase V (January 29, 2025), p. 19.

- Customer Fatigue: There is significant potential for customer fatigue due to a lack of tolerance for disruption to business activities. Various studies have found that opt-out rates range from 20 – 29%.[26]
- Complexity to Participate: Creating daily load shifting opportunities increases industrial control system complexity. Industrial customers are cost-conscious and may utilize continuous processes to increase their efficiency as compared to batch processes. The benefits of developing the new automation scripts for daily load shifting must outweigh the costs of lost production or decreases in efficiency from moving to batch operations. The costs of modifying or interrupting a process are typically not justified by a utility program incentive.
- Underestimation of Acquisition Costs: Acquisition costs for large C&I DR are highly variable given that large C&I customers have unique characteristics and load profiles. In order to capture large C&I DR savings, a DR program should customize the daily load shifting interventions for each individual customer, which is time consuming and expensive, especially if the customer needs to pause or change their operations.
- Demand Charges: For customers with demand charges, the ability to shift demand without increasing monthly demand, and therefore billing demand charges, may be limited.

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[26] *See* p. 19 of Filing of Entergy New Orleans, LLC's Energy Smart Program Year 12 Annual Program Report and Evaluation, Measurement and Verification Report for Demand Response Programs (https://cdn.entergy-neworleans.com/userfiles/content/energy_smart/Program_Year_12/Energy-Smart-PY12-Annual-Report-DR.pdf?utm_source=chatgpt.com)

7. The target does not account for necessary ramp-up time to deploy and grow an unprecedented new program

The Tentative Order states that demand reductions from load shifting should be computed as the average peak demand reduction across five years of Phase V.[27] This means that customers enrolled in the first year in Phase V have their load shifting represented in more of program years that are averaged than customers that are enrolled in later years. Assuming linear growth in enrolling customers to a DR program over the course of Phase V, PECO would need to add 13.9 MW of load shifting capacity each year in order to achieve an average capacity of 41.6 MW for Phase V, which corresponds to a cumulative total of 69.3 MW.

Notably, the DR Potential Study, on which the Tentative Order proposal is based, assumes somewhat logarithmic growth of daily load shifting capacity over the course of Phase V where initially the growth rate increases rapidly and then slows and levels off. However, as described above, daily load shifting would constitute a new program with significant challenges for EDCs to overcome. Therefore capacity growth may be more likely to resemble S-curve, rather than logarithmic growth, with limited demand reduction savings in the early years of Phase V, which would effectively require more than the 69.3 MW of cumulative capacity noted above. Furthermore, with Phase V starting in the summer on June 1, 2026, it is almost impossible to achieve any savings during the summer of 2026.

To address this issue, PECO recommends that the Final Implementation Order include a ramp-up period for daily load shifting resources. Specifically, PECO proposes a two-year ramp-up period such that the calculated savings from daily shifting resources is based upon the average from years three through five, rather than the full five-year period. Importantly, EDCs would still

[27] Tentative Order, p. 52.

be required to design their EE&C plans to achieve at least 15 percent of their peak demand reduction target in each program year.[28]

8. The Commission should permit TOU rates as an EE&C measure and should not exclude customers utilizing a TOU rate from participating in Act 129 load shifting programs

The Tentative Order states that "[attribution] of impacts between Act 129 programs and TOU rates would be challenging if homes or businesses enrolled in both an Act 129 DR program and a TOU rate."[29] This statement seems to suggest TOU customers should be discouraged from participating in daily load shifting programs. PECO urges the Commission to: (1) recognize TOU rates as a standalone EE&C measure; and (2) permit TOU customers to participate in Act 129 load shifting programs.

TOU rates are one of the most prevalent approaches nationwide to drive daily load shifting.[30] EDCs should have the flexibility to propose Phase V programs that incentivize enrollment on a TOU rate as a load shifting strategy. The incentive could include general customer education, targeted behavioral programming, or a monetary incentive – all of which are currently being deployed in Phase IV to generate energy savings. EDCs should also have the flexibility to include customers that are already enrolled on the TOU rate[31] in Act 129 load shifting programs (e.g., a managed EV charging program). PECO acknowledges that the Phase V Technical Reference Manual ("TRM") does not currently provide a detailed approach for measuring the load shift from a TOU rate and would welcome additional guidance from the

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28 Tentative Order, p. 48.

29 Tentative Order, p. 40.

30 *See* Demand Response and Time-Variable Pricing Programs | Department of Energy; (https://www.energy.gov/femp/demand-response-and-time-variable-pricing-programs)

31 PECO notes that it currently has approximately 3,000 customers enrolled on the Company's TOU rate.

SWE to facilitate the deployment of TOU as a standalone measure and the inclusion of TOU customers in Act 129 load shifting programs.

9. The TRM M&V requirements are not a good fit for daily load shifting programs and could impair program design

The TRM prescribes that evaluation methodologies for demand savings be prioritized in a specific order, which varies for residential[32] and commercial[33] customers. However, as explained below, these methodologies can be challenging to utilize for daily load shifting and/or can limit the ability to utilize performance-based incentives to help drive greater peak demand reduction.

a. The preferred methodology for residential customers may be challenging and impedes the ability to use performance-based incentives

The TRM requires that a randomized control trial ("RCT") be prioritized to evaluate residential demand response savings. Ensuring sufficient controls and sample sizes may be a challenge in some cases. Furthermore, this approach will only demonstrate savings across a group of daily load-shifting participants and does not identify savings at an individual level. Consequently, this impedes the ability to utilize tailored performance-based incentives to drive greater peak demand reduction from individual customers.

The next priority option is comparison group analysis, such as Nearest Neighbor Matched Controls. This approach can work well with large numbers of customers to determine overall impact for residential customers but does not work well for determining the impact of individual customers (to be able to use for tailored performance-based incentives).

32 Technical Reference Manual (Issued Sept. 2024), Volume 2: Residential Measures; pp. 231–233.

33 Technical Reference Manual (Issued Sept. 2024), Volume 3: Commercial & Industrial Measures; pp. 354–356.

The final option is a “within-subject analysis”, which uses the loads of participating customers on non-event days similarly hot or cold to the event day to estimate the reference load within a regression. This option typically works well for DR events, especially for determining the impact from individual customers. However, this relies on consumption data from surrounding days to determine customer behavior absent the event, which is not possible when events are occurring every single day.

b. Determining savings from many Large C&I customers may be very challenging

For C&I customers, the TRM requires that specific methodologies be used in the evaluation of C&I demand savings, and the methodology with the most rigor must be employed unless there is a compelling reason to not use it. The first of these methodologies is a comparison group analysis. As noted above, the method works well for determining overall impacts on customer groups with a large of numbers of similar customers to serve as controls, but does not work well for determining impacts for individual customers. Furthermore, the large C&I customers who contribute a significant share of C&I demand savings may not have peers with similar enough usage profiles to serve as valid controls.

The other evaluation methodologies described in the TRM are within-subject analysis, hybrid regression with matching, and custom baseline loads. A significant challenge for each of these methods with daily load shifting is the lack of suitable baseline data because every comparable day is an event day. It may be possible to mitigate these issues with some measures by calling “baseline” or “non-event” days. However, while this can work for certain residential measures that are directly controlled by PECO (e.g., thermostats, EV chargers), this can be challenging to execute for certain C&I measures (e.g., where a customer has already shifted their manufacturing processes in response to DR program to reduce load daily between 2-6 pm).

To address these issues, PECO recommends that the PUC provide specific guidance and standards for M&V specific to daily load shifting. At least one of the M&V protocols should allow for the measurement of impacts at the individual customer level to enable performance-based DR incentives, particularly for large C&I customers. EDCs should also be able to make program design and event dispatch choices to facilitate evaluation (i.e., calling baseline/non-events days, holding out customers as part of experimental design) without reducing calculated peak demand reduction.

10. The Commission could make several programmatic adjustments to improve the reasonableness of the proposed DR target

The proposed approach for daily load shifting would be challenging to execute and may compromise an EDC's ability to achieve its Phase V DR target. As discussed in more detail in the preceding sections, PECO recommends that the Final Implementation Order include the following:

- Continue to provide a single peak demand reduction target across all resources (including EE, CHP, solar PV, and DR) to allow EDCs the flexibility to deliver peak demand reduction as effectively as possible.
- Allow for event-based DR resources to provide eligible demand reduction in addition to daily load shifting measures. Event-based DR is a proven approach that can reliably provide targeted, measurable demand reduction in the most valuable hours of the year. Similar to the Commission's approach in Phase III of the EE&C Program, the calculated savings should be based upon event days only.
- The calculation of peak demand reduction savings delivered by daily load shifting resources for Phase V should include a ramp-up period. PECO recommends a two-year ramp-up period such that the calculated savings from daily shifting

resources is based upon the average from years three through five, rather than the full period.

- The Commission should recognize TOU rates as a standalone EE&C measure and also permit TOU customers to participate in other Act 129 load shifting programs.
- Instead of averaging summer and winter peak demand reduction savings, the Commission should apply an EDC-specific weighting based on the 2024 summer and winter peak to calculate progress towards target.
- The Commission should consider adjusting the summer peak period to later (e.g., until 7 pm), or at least allowing for event periods to differ for certain customer types and/or certain circuits, (e.g., constrained circuits with peaks near or after 6 pm in the summer).
- The Commission should provide specific guidance and standards for M&V specific to daily load shifting. At least one M&V protocol should allow for the measurement of impacts at the individual customer level to enable performance-based DR incentives, particularly for large C&I customers. EDCs should also be able to make program design and event dispatch choices to facilitate evaluation without reducing calculated peak demand reduction.

B. The Acquisition Costs Utilized To Determine Consumption Reduction Requirements Unreasonably Assume The Availability Of Federal Funding

The Commission utilized acquisition costs from the MPS for four portfolio components when determining proposed consumption reduction requirements: market rate traditional energy efficiency, low-income traditional energy efficiency, solar PV and CHP.[34] The MPS assumes

[34] Tentative Order, p. 19.

that federal incentives will be available to offset certain EE&C implementation costs. Specifically, in Section 4.1.3, the MPS states "Instead of modeling specific measures with differing acquisition costs, this analysis uses the eligible funding pool to lower the aggregate acquisition costs of valid measures." Furthermore, the study concludes that $13.9 million of Home Electrification and Appliance Rebate Program ("HEAR") funding and $42.5 million of Home Efficiency Rebate Program ("HER") funding is available to Act 129 programs and that in total, this funding increases the low-income savings potential by 42.7 GWh, and it decreases non-low-income savings by 5.6 GWh (see section 4.1.5 of MPS).

It is PECO's understanding that HER and HEAR funding has been awarded and vendors have been selected, but a recent federal Executive Order has frozen this funding and it is uncertain whether it will be available for Phase V.[35] Given the high level of uncertainty on whether this funding will become available again, PECO recommends excluding HER and HEAR funding from the acquisition cost calculations, and consequently, the EE target and low-income carve-out. PECO believes treating HER and HEAR funding this way is consistent with how the MPS treats funding for Reducing Industrial Sector Emissions in Pennsylvania ("RISE PA"): "Due to the inherent complexity of this [RISE PA] program and the uncertainty surrounding its implementation, the impacts of this program have been excluded from this analysis" (*see* section 4.1.1 of MPS). Regardless of whether the Commission accepts PECO's recommendation concerning federal funding, and as discussed in the next section, EDCs need the ability to petition for a revision of their targets if a change in circumstance (e.g., removal of federal funds) materially impacts their ability to meet mandatory targets.

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35 *See* January 20, 2025 Executive Order: Unleashing American Energy (https://www.whitehouse.gov/presidential-actions/2025/01/unleashing-american-energy/)

C. The Commission Should Establish A Process To Update An EDC's Targets If The EDC Can Demonstrate Material Impacts From Macro-Economic Factors

The Commission proposes to maintain the challenge process from previous phases for both the consumption and peak demand reduction requirements. Specifically, consumption and peak demand reduction requirements in the Phase V Final Implementation Order will become final for any EDC that does not petition the Commission for an evidentiary hearing within 15 days of the entry of the Final Implementation Order.[36]

While PECO does not oppose the challenge process laid out in the Tentative Order, the Company believes that an additional process should be established whereby, after plan approval, the Commission could revise targets when a change in macro-economic factors (e.g., inflation, federal tariffs, availability of federal incentives or tax credits) will have a material impact on an EDC's ability to meet existing targets. Taking inflation as an example, the SWE modeled a 2% inflation rate for each year of Phase V.[37] If actual inflation is significantly higher, it could drive up acquisition costs for energy and demand savings and make it difficult to achieve mandatory targets within the fixed Act 129 budget. Similarly, federal tariffs on commodities (e.g., steel, aluminum) and finished products (e.g., machinery, solar panels, lighting[38]) have the potential to drive up the cost of EE&C measures (e.g., high efficiency air conditioning units) beyond what has considered by the SWE in setting EE and DR targets.

Under the target revision process, an EDC would be permitted to file a petition with the Commission requesting an update to its existing targets and present evidence concerning how the

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[36] Tentative Order, p. 32.

[37] EE/DR MPS Report (February 7, 2025), p. 56.

[38] *See, e.g.*, "Manufacturers Are Raising Prices, With More on the Way", Inside Lighting (March 13, 2025) (https://inside.lighting/news/25-03/manufacturers-are-raising-prices-more-way)

change impairs the EDC's ability to meet its targets. If the Commission determines that the change will have a material impact on an EDC's ability to meet existing targets, the Commission would establish a revised target and require the EDC to file a revised plan reflecting the revised target. PECO believes establishing such a process is reasonable in light of the potential for change in market forces over the five-year Phase V period and the substantial penalties faced by EDCs if they fail to achieve their EE or DR target.

D. EDCs Should Continue To Have Flexibility On Non-Residential Lighting Measures

In the Tentative Order (pp. 28-29), the Commission urges EDCs to minimize the contribution of midstream delivery of non-residential lighting measures in their Phase V EE&C Plans and focus lighting program offerings on replacing the remaining inefficient lighting equipment stock (e.g., non-LED) in the Commonwealth.

PECO supports the Commission's overall goal of replacing inefficient lighting stock in the Commonwealth and notes that the Company's Phase IV Plan non-residential lighting strategy is designed to incentivize customers to purchase new lighting fixtures that have higher efficiency and longer lifetimes than replacement lamps. Midstream lighting programs have been, and will continue to be, the most cost-effective option for replacing the last of the Commonwealth's inefficient equipment stock.

PECO believes that it is appropriate for EDCs to continue to focus on both upgrading efficient lighting and replacing inefficient lighting through midstream programs. PECO's Phase IV midstream programs accounted for a significant portion (54%) of the Company's lighting energy savings in 2024, and therefore the Company continues to see strong potential for savings in future years. Importantly, midstream programs operate at a lower cost per kWh of energy saved as compared to other types of lighting programs and allow for more comprehensive, less cost-effective measures to be offered. Research has shown that when midstream incentives are removed, adoption of the most efficient LEDs (e.g., LED luminaires) slows and customers are more likely to utilize LED retrofit tubes instead of upgrading to integrated LED fixtures.[39] PECO urges the Commission to refrain from imposing new restrictions on how an EDC may design non-residential lighting measures.

E. EDCs Should Have The Flexibility To Determine When Coordination With Other State Conservation Programs Is Appropriate And Data Sharing Should Be Addressed In A Separate Proceeding

In the Tentative Order, the Commission highlights the potential for Act 129 programs to collaborate with other conservation programs and for customers to benefit by receiving multiple funding streams for conservation measures. The Commission further proposed that (1) EDCs track and report all outside funding by source, as well as the leverage ratio for each of their EE&C programs and the portfolio as a whole;[40] (2) EDCs consider co-funding the upfront completion of ASHRAE Level 2 audits for non-Act 129 programs;[41] (3) EDCs consider "joint marketing campaigns" with other conservation programs;[42] and (4) stakeholders provide specific suggestions regarding data sharing between EDCs and state agencies.[43]

Overall, PECO agrees that program coordination and multiple funding streams can bring benefits to customers, such as the Company's ongoing coordination of Act 129 activities with

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39 *See* Connecticut C2014 C&I Lighting Saturation and Remaining Potential – Phase One Results and Recommendations (June 28, 2021) (https://energizect.com/sites/default/files/2022-07/CT%20C2014_CI%20Lighting%20Saturation%20and%20Remaining%20Potential_Phase%201%20Memo_FINAL_20210628.docx); New Jersey Non-Residential Lighting Market Characterization (June 30, 2022) https://njcleanenergy.com/files/file/Library/FY23/NJ%20Non-Res%20Lighting%20Market%20Characterization%20FINAL%20Report%2020220630.pdf

40 Tentative Order, pp. 54-55.

41 Tentative Order, pp. 59-60.

42 Tentative Order, p. 60.

43 Tentative Order, p. 57.

PECO's Low-Income Usage Reduction Program. The Company believes, however, that requiring an EDC to track and report external funding sources and contribution ratios is unreasonable. The collection and reporting of such third-party information appears to be beyond the reasonable scope of plan implementation and also would be a time and resource intensive requirement for EDCs. PECO does not believe it would be appropriate to shift an EDC's limited Act 129 resources from actual energy efficiency measure implementation to the maintenance of third-party data. Similarly, PECO does not believe it would be reasonable to co-fund costly, upfront audits for other programs where there is no guarantee of Act 129 savings.

Regarding marketing, the Company intends to continue its current practice of providing links on the PECO website to other conservation funding opportunities. PECO is concerned that jointly developed marketing materials or campaigns would involve additional time, complexity and potentially new costs as compared to current marketing efforts. Further, joint marketing materials could easily become outdated or inaccurate if, for example, a government program is suspended due to lack of funding.

Finally, PECO views data sharing between EDCs and state agencies as a significant issue with implications well beyond Act 129 programs and should be considered in a separate, dedicated proceeding. Such a proceeding would permit the Commission,[44] EDCs, government agencies and other stakeholders to take the time necessary to address a range of key issues, including (1) what entities will share data and have access to shared data; (2) what types of data will be shared and how will that data be used; (3) where will the data be stored and what cybersecurity requirements should apply to data transmission and storage; (4) when will customer consent be required and what entity will obtain and maintain records of that consent;

[44] Commission participants could include, for example, the Office of Cybersecurity Compliance and Oversight.

and (5) who will bear the costs associated with the data transmission and storage. PECO urges the Commission to refrain from imposing any data sharing requirements on EDCs in the Final Implementation Order.

F. The PUC Should Establish A More Flexible Process For Plan Changes

In the Tentative Order (pp. 66-68), the Commission proposes to continue the existing two track framework for review of proposed EE&C plan changes. If a plan change fits into one of the established "minor change" categories,[45] it will be considered under an expedited review process.[46] If a plan change does not fit into a minor change category, a standard review process will be utilized.[47] In either case, EDCs will expend significant time and resources to prepare a plan change filing, including redlining their existing plan, and may be delayed in implementing changes that will improve plan performance.

PECO believes that additional flexibility should be integrated into the EE&C plan review process to reduce existing administrative burdens and permit EDCs to be nimbler and more cost-

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[45] Minor change categories include (1) The elimination of a measure that is underperforming; is no longer viable for reasons of cost-effectiveness, savings or market penetration; or has met its approved budgeted funding, participation level or amount of savings; (2) The transfer of funds from one measure or program to another measure or program within the same customer class; (3) Adding a measure or changing the conditions of a measure, such as is eligibility requirements, technical description, rebate structure or amount, projected savings, estimated incremental costs, projected number of participants or other conditions so long as the change does not increase the overall costs to that customer class; and (4) The elimination of programs that are not viable due to market conditions. *See* Tentative Order, pp. 67-68.

[46] Under the expedited process, the EDC would make a filing with the Commission to support the proposed minor plan changes and serve the filing on all parties to the EDC's EE&C plan proceeding. Comments from interested parties are due within 15 days after the EDC files the proposed minor plan changes and reply comments are due within 25 days after the EDC filing. Within 35 days of the EDC filing, PUC staff will issue a Secretarial Letter approving, denying, or transferring to the Office of Administrative Law Judge ("OALJ") for hearings some or all of the proposed minor plan changes. PUC staff has the discretion to extend the consideration period by an additional ten days. *See Energy Efficiency and Conservation Program*, Docket No. M-2008-2069887 (Order entered June 10, 2011) ("Minor Plan Change Order").

[47] Under the standard process, the EDC would file a petition with the Commission and serve the petition on all parties to the EDC's EE&C plan proceeding. The parties would have 30 days to file comments, an answer or both. All parties would then have 20 days to file replies, after which the Commission would determine whether to rule on the changes or refer the matter to the OALJ for hearings and a recommended decision. Minor Plan Change Order, p. 19; Tentative Order, pp. 66-67.

efficient in responding to market changes and in-phase implementation experience.[48] Specifically, the Company is proposing that EDCs be permitted to make plan changes through a notification process when (1) the cumulative value of the budget transfers across programs and/or rate classes resulting from all previously-approved changes and the proposed changes (the "Cumulative Change Value") does not exceed 10% of the EDC's total EE&C plan budget for the Phase; and (2) for any program year, the Cumulative Change Value does not exceed 5% of the EDC's total EE&C plan budget for the Phase.[49] The notification process would involve filing a document summarizing the planned changes by program or rate class (as appropriate), including the effective date of the changes, and serving that document on all parties to the EDC's Phase V EE&C plan proceeding. The notification process would permit EDCs to quickly and cost-efficiently implement relatively modest plan changes to improve the performance of particular programs.

Proposed plan changes that do not qualify for the notification process would proceed under the existing plan approval framework (e.g., plan changes that fit into the minor change category or standard change category, but do not qualify for the notification process, would proceed under the established review processes).

PECO believes that the inclusion of a limited notification process appropriately balances regulatory oversight with operational adaptability to ensure that utilities are efficiently managing

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[48] PECO notes that several EDCs (FirstEnergy Pennsylvania Electric Company, PPL Electric Utilities, and Duquesne Light Company) as well as the Energy Association of Pennsylvania ("EAP") are supportive of PECO's proposal and are including similar recommendations in their comments.

[49] In addition to budget transfers between programs and rate classes, plan changes qualifying for the notification process could include, but are not limited to, adding a measure, eliminating a measure, or changing the conditions of a measure in alignment and supported by the TRM, evaluation guidance, or Interim Measure Protocols.

EE&C programs.[50] The Company's proposal would permit EDCs to optimize customer-funded energy efficiency investments in real-time, enable rapid reallocation of monetary resources to the high-impact measures that reduce consumption and peak demand, and streamline a process that currently stifles program flexibility due to the amount of time it takes to navigate the plan change process. The Company notes that EDCs would remain subject to semi-annual and final annual reporting requirements (Tentative Order, pp. 70-72) as well as cost recovery reconciliation filing requirements (Tentative Order, pp. 96-98) so the PUC and interested parties would continue to have appropriate access to plan implementation and spending information.

G. The PUC Should Adjust The Plan Approval Timeline To Provide EDCs With Additional Time To Develop Plans

PECO fully supports the revised plan approval timeline set forth in the EAP comments. EDCs would benefit from the additional time to develop thoughtful plans that will provide customers with meaningful opportunities to save energy and reduce demand.

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[50] PECO notes that other states have permitted utilities to shift EE&C budgets among programs and customer sectors through a notification process where the shifts do not exceed established percentages of the utility's EE&C budget. *See, e.g., In re the Petition of Atlantic City Electric Company for Approval of a Portfolio of Energy Efficiency, Building Decarbonization and Demand Response Programs, A Cost Recovery Mechanism, and Other Related Relief*, BPU Docket No. QO23120871 (Order Adopting Stipulation dated October 30, 2024), pp. 11-12.

III. CONCLUSION

PECO appreciates the opportunity to comment on the Tentative Implementation Order and requests that the Commission consider and adopt the foregoing recommendations in developing the Final Implementation Order. PECO looks forward to continuing to work with the Commission and other stakeholders to move the EE&C Program forward.

Respectfully submitted,

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