Maillog No. 323522

ORDER NO. 91917

DRIVE Act Implementation	*	BEFORE THE
	*	PUBLIC SERVICE COMMISSION
	*	OF MARYLAND
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	*	CASE NO. 9761
	*	

ORDER ON DRIVE ACT IMPLEMENTATION PROPOSALS

Before: Frederick H. Hoover, Jr., Chair
Kumar P. Barve, Commissioner
Bonnie A. Suchman, Commissioner
Odogwu Obi Linton, Commissioner
Ryan C. McLean, Commissioner

Issue Date: October 21, 2025

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On July 11, 2024, the Maryland Public Service Commission issued Order No. 91218 for the purpose of implementing the 2024 Distribution Renewable Integrated and Vehicle Electrification ("DRIVE") Act, codified at § 7-1001 *et seq.* of the Public Utilities Article, *Annotated Code of Maryland* ("PUA"). In the Order, the Commission directed the State's investor-owned utilities to file with the Commission on or before July 1, 2025: (1) one or more "opt-in" time-of-use ("TOU") tariff offerings for appropriate customer classes; and (2) proposals for a pilot program or temporary tariff for electric distribution system support services ("EDSSS") as provided through virtual power plant ("VPP") and/or vehicle-to-grid ("V2G") programs. Subsequently, Baltimore Gas and Electric Company ("BGE"), Potomac Electric Power Company ("Pepco") and Delmarva Power & Light Company ("Delmarva") (together the "PHI Companies" or "PHI", and together with BGE the "Exelon Utilities"), and The Potomac Edison Company ("Potomac Edison") (collectively, the investor-owned electric companies are the "Utilities") each submitted EDSSS pilot program proposals and TOU rate offerings pursuant to the Order.[1]

After receiving stakeholder comments on the utility proposals, the Commission held an in-person legislative-style hearing on September 3, 2025, to consider the Utilities' proposals. The Exelon Utilities and Potomac Edison presented their proposals, and several other parties and interested stakeholders ("stakeholder parties") offered additional comments and recommendations.

[1] Maillog No. 320089, Baltimore Gas and Electric Company, Proposal for Virtual Power Plant Pilot Program and Certain Time-Of-Use Enhancements (July 1, 2025) ("BGE July 1 Filing"); Maillog No. 320092, Potomac Electric Power Company and Delmarva Power & Light Company, Proposed Distribution System Support Services Pilots and Time-of-Use Tariffs (July 1, 2025) ("PHI July 1 Filing"); Maillog No. 320115, The Potomac Edison Company, Application for an Electric Distribution System Support Services Pilot Program (July 1, 2025) ("PE July 1 EDSSS Filing"); Maillog No. 320116, The Potomac Edison Company, Residential Time of Use Rate Schedule Proposal (July 1, 2025) ("PE July 1 TOU Filing").

This Order addresses the Utilities' proposed TOU tariff offerings and EDSSS pilot programs. For the reasons explained below, the Commission will accept the Utilities' respective TOU offerings, as modified and discussed herein. The Commission denies the Utilities' EDSSS pilot proposals, as filed, to give the Utilities an opportunity to cure the defects highlighted in this Order and resubmit their pilot proposals within 90 days of this Order.

I. <u>BACKGROUND</u>

A. The DRIVE Act

In 2024, the Maryland General Assembly enacted, and Governor Wes Moore signed into law, the DRIVE Act,[2] which seeks to prepare Maryland's electric grid for the increase in demand from electric vehicles ("EVs") and other clean energy technologies. To that end, the DRIVE Act requires, among other things, that Maryland's investor-owned electric companies: (1) develop enhanced TOU electricity tariffs for appropriate customers, aimed at incentivizing EV charging and other electricity use during off-peak hours; and (2) propose for Commission approval an EDSSS pilot program or temporary tariff to compensate customers and aggregators for the use of distributed energy resources ("DERs") in providing distribution grid services such as reducing demand or injecting power into the grid. Further, the Act authorizes the Commission to approve or require an investor-owned electric company to offer upfront incentives or rebates, including enhanced incentives or rebates for low- or moderate-income ("LMI") customers, to enrollees of these pilots or tariffs to acquire and install renewable on-site generating systems.

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[2] 2024 Md. Laws, Ch. 475 (codifying Senate Bill 959/House Bill 1256 from 2024 legislative session).

For the TOU requirement, the DRIVE Act requires the investor-owned electric companies to make their TOU tariffs available on an opt-in basis; establish a sufficient price discount for electricity usage during off-peak hours compared to peak hours; propose reasonable TOU tariff enrollment targets to achieve by January 1, 2028; and work to achieve those enrollment targets through a combination of marketing, customer education, and other means to communicate the benefits and risks of TOU rates. For customers who already receive an incentive as part of an electric company's beneficial electrification program, the Commission can require the company to automatically enroll those customers in a TOU tariff, subject to a requisite opt-out provision.

For the EDSSS pilot/tariff requirement, the DRIVE Act enables customer owners and third-party aggregators of DERs to participate in VPP networks to provide distribution system support services. The DRIVE Act defines a "distributed energy resource" to mean "an energy resource located on a customer's premises that: (i) produces or stores electricity; or (ii) modifies the timing or amount of the customer's electricity consumption."[3] Electric distribution system support services[4] include: "(i) local or system peak demand reduction; (ii) demand response; (iii) the avoidance or deferral of a transmission or distribution upgrade or capacity expansion; and (iv) facilitating hosting capacity to accommodate additional distributed energy resources."[5] Where the General Assembly recognized that widespread beneficial electrification will increase demand on Maryland's electric

[3] PUA § 7-1001(d).
[4] As previously noted in Order No. 91218, under the DRIVE Act, "electric distribution support services mean[] the dispatch and control of a distributed energy resource to provide services that contribute to the efficient and reliable operation of the electric distribution system by an electric company, or an aggregator acting at the direction of an electric company." *In re Transforming Maryland's Electric Distribution Systems to Ensure that Electric Service is Customer-Centered, Affordable, Reliable and Environmentally Sustainable in Maryland*, PC 44, Order No. 91218 at 2 n. 3.
[5] PUA § 7-1001(e)(2).

distribution system, pairing the adoption of renewable on-site generating systems with beneficial electrification may facilitate load flexibility to mitigate distribution system impacts from electrification-driven load growth.[6] For purposes of the EDSSS pilot program, the Act prescribes a peak load reduction cap of up to two percent of each utility's highest coincident peak demand.[7]

B. Procedural Background

Upon initiating this proceeding in July 2024, the Commission received stakeholder comments from 11 parties in response to Order No. 91218, addressing: (1) the advisability of requiring an electric utility incentive or rebate for renewable on-site generating systems to supplement other available state and federal incentives; and (2) the licensing of distributed energy resource aggregators ("DERAs").[8] On October 25, 2024, the Commission issued Order No. 91391, authorizing the investor-owned electric companies to propose incentive programs for renewable on-site generating systems.[9] The Commission required that any utility proposal for a renewable on-site generating system incentive program should also include a component for LMI customers as well as components that first leverage existing Maryland Energy Administration ("MEA") and/or federal funds. The Commission further clarified this Order on January 31, 2025, addressing the allowable use of regulatory assets for DRIVE Act programs, excluding incentive programs; the applicable technologies within the statutory definition of "renewable on-site generating system"; and the consideration of different definitions of LMI as used in other state programs.

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[6] PUA § 7-1002(2)-(3).
[7] PUA § 7-1005(f).
[8] *See* Docket Item Nos. 2-12.
[9] *In re Transforming Maryland's Electric Distribution Systems to Ensure that Electric Service is Customer-Centered, Affordable, Reliable and Environmentally Sustainable in Maryland*, PC 44, Order No. 91391 at 3.

Also in January 2025, the Commission's Technical Staff ("Staff") filed its proposed Application for license to operate as a distributed energy resource aggregator ("DERA License to Operate"),[10] based on the Code of Maryland Regulations ("COMAR") 20.51.02.01 and 20.51.02.02 as applicable points of reference. The Commission issued Order No. 91597 on April 8, 2025, remanding the proposed DERA License to Operate application to Staff with additional guidance for stakeholder engagement and recommendations regarding the Code of Conduct. Staff revised and refiled its proposed DERA License to Operate on June 2, 2025, incorporating several elements of the Code of Conduct.

The Commission subsequently issued Order No. 91674 on June 6, 2025, accepting Staff's revised DERA License to Operate and further noting an open pathway for DERA aggregation best practices to emerge as the regulatory framework evolves.[11] The Commission expressed an intent to avoid "burdensome thresholds for entry for DERAs," particularly in the launch of initial DRIVE Act programs, and indicated that DERA licensing should be "part of the scope for lessons to be learned from [the] pilots."[12] The Commission explained that lessons learned from the initial DRIVE Act implementation would inform future updates to the DERA License to Operate application. Finally, Order No. 91674 established an effective date of July 1, 2025, for the DERA License to Operate, concomitant with the required filing date for the investor-owned electric companies' DRIVE Act pilot programs or temporary tariffs.

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[10] Maillog No. 314967, Office of Staff Counsel, Application for License to Operate as a Distributed Energy Resource in the State of Maryland, Case No. 9761 and PC 44.
[11] *See* Order No. 91674 at 3.
[12] *See id*.

On July 1, 2025, BGE, PHI, and Potomac Edison each filed their proposed TOU offerings and EDSSS pilot programs. The details of each company's proposals (TOU and EDSSS) are described in the corresponding sections below. On July 7, 2025, the Commission issued a Notice of Hearing and Request for Comments on the Utilities' proposals. Thereafter, the Commission received written comments from 21 interested stakeholder parties.[13] Their various positions—on specific aspects of the Utilities' proposals—are also described in the corresponding sections below.

II. <u>TIME-OF-USE PROPOSALS</u>

A. Utility Proposals

1. <u>BGE</u>

BGE proposes to adjust its existing residential TOU tariffs and employ various customer engagement strategies over the course of two years, for a total proposed budget of $369,000.[14] BGE will begin targeting residential customers in 2026 for TOU participation.[15]

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[13] Maillog No. 321868, Alliance for Transportation Electrification ("ATE Comments"); Maillog No. 321925, ChargeScape ("ChargeScape Comments"); Maillog No. 321929, Enerwise Global Technologies, LLC, d/b/a CPower ("CPower Comments"); Maillog No. 321887, Edison Electric Institute ("EEI Comments"); Maillog No. 321927, EnergyHub ("EnergyHub Comments"); Maillog No. 321942, ev.energy Corp. ("ev.energy BGE Comments"); Maillog No. 321943, ev.energy Corp. ("ev.energy PHI/PE Comments"); Maillog No. 321989, Delegate Fraser-Hidalgo and Chair Wilson ("Delegates Comments"); Maillog No. 321933, GoodLeap ("GoodLeap Comments"); Maillog No. 321947, Kaluza, LLC ("Kaluza Comments"); Maillog No. 321924, Maryland Energy Administration ("MEA Comments"); Maillog No. 321939, Mission:data Coalition ("Mission:data Comments"); Maillog No. 321938, Office of People's Counsel ("OPC Comments"); Maillog No. 321949, Office of Staff Counsel ("Staff Comments"); Maillog No. 321945, Resideo Grid Services ("Resideo Comments"); Maillog No. 321941, Solar Energy Industries Association, Advanced Energy United, and Chesapeake Solar and Storage Association ("SEIA/United/CHESSA Comments"); Maillog No. 321936, Solar United Neighbors ("SUN Comments"); Maillog No. 321930, Sunrun ("Sunrun Comments"); Maillog No. 321922, Tesla, Inc. ("Tesla Comments"); Maillog No. 321931, The Mobility House ("TMH Comments"); Maillog No. 321937, Vehicle-Grid Integration Council ("VGIC Comments"); Maillog No. 321889, Virtual Peaker ("Virtual Peaker Comments"); and Maillog No. 321934, WeaveGrid Inc. ("WeaveGrid Comments").
[14] BGE July 1 Filing at 25, Table 17.
[15] *Id*. at 35.

First, BGE proposes to modify Schedule RD[16] to reduce the on- to off-peak all-in rate ratio ("Ratio") under the schedule. On a total bill basis (including supply and distribution rates), BGE proposes to shift the Ratio from 3.2:1 to a new Ratio of 2.8:1.[17] According to BGE, the methodology behind this new Ratio was originally proposed by OPC,[18] and the proposed change is motivated by learnings from a survey conducted on BGE customers wherein the company found that the peak rate served as a barrier for many customers to take TOU service under Schedule RD.[19]

Next, BGE proposes to modify Schedule RL[20] by applying rate-shaping methodology from its existing Schedule EV. On a total bill basis, this modification represents a shift from a Ratio of 1.3:1 to a new Ratio of 1.9:1.[21] BGE notes that there has been "little to no difference" in usage patterns of customers on Schedule RL compared to those on BGE's flat rate, Schedule R, which is indicative of an insufficient price signal to shift electricity usage into off-peak periods. BGE indicates that this proposed change is intended to make Schedule RL more effective in incentivizing the shifting of load. BGE aims to minimize impacts to existing Schedule RL customers, in part, by retaining the existing intermediate peak period for Schedule RL. BGE also proposes to make this tariff change in a future Standard Offer Service ("SOS") filing to avoid creating an additional rate change for customers outside of the normal SOS schedule.[22]

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[16] BGE specifies that Schedule RD was initially developed in 2019 as part of the PC 44 TOU Pilot Program. At the time of its July 1 filing, BGE reported enrollment under this schedule at 1,200 customers. *See id*. at 28-30 (including Table 15, BGE TOU Periods by Schedule).
[17] BGE's Ratios are based on May 2025 rates. *Id*. at 33.
[18] *Id*.; *see also,* Maillog No. 240945 at 5, PC 44 Rate Design Work Group Leader's Report and Recommendations on Full-Scale Time of Use Rate Offerings, PC 44 ("2022 TOU Report").
[19] BGE July 1 Filing at 32.
[20] BGE specifies that Schedule RL was introduced in 1984, with over 50,000 customers enrolled at the time of filing. *Id*. at 28 and 32 (including Table 15, BGE TOU Periods by Schedule).
[21] *See* Staff Comments at 67 and BGE Response to Staff Data Request 1-4.
[22] BGE July 1 Filing at 32.

As a final modification to its existing selection of TOU tariffs, BGE highlights the company's EV Phase II filing in Case No. 9478 wherein the company proposes to eliminate Schedule EV[23] for new enrollments and maintain its Rider 6.[24, 25]

To complement its proposed residential TOU tariff adjustments, BGE proposes a customer engagement strategy that will leverage existing customer outreach and educational materials developed through the PC 44 TOU pilot program.[26] The marketing proposed in this filing is associated with an enrollment target of 3,200 additional customers by January 1, 2028, in Schedule RD or Schedule RL. BGE states that together with its existing EV TOU target, the marketing proposed in this filing targets a total of 11 percent of residential customers enrolled in a TOU rate by 2028 (compared to today's 5 percent enrollment).

For cost recovery, BGE proposes regulatory asset treatment, meaning the costs associated with implementing the proposed TOU adjustments, inclusive of marketing costs, would be recognized as an asset on the company's balance sheet and recovered through base rates in a future rate case. BGE requests the company's full Commission-authorized rate of return, with recovery to be reflected in base rates following a prudency review in a future rate case.

2. PHI Companies

Like BGE, the PHI Companies propose to adjust their existing residential TOU tariffs and employ various customer engagement strategies. Unlike BGE, however, PHI

[23] BGE specifies that Schedule EV was created in 2013, with 190 customers enrolled at the time of this filing.
[24] BGE specifies that Rider 6 was created in 2020, with 3,700 customers enrolled at the time of this filing.
[25] BGE July 1 Filing at 31.
[26] *Id*. at 34, Table 16.

proposes to implement its DRIVE Act TOU program for three years, with a total program budget of $1,912,500 for Pepco, and $922,500 for Delmarva.[27]

PHI's primary proposal is to modify each company's existing Schedule R-TOU-P[28] rate schedule to reduce the Ratio from about 4.5:1 to approximately 2.7:1.[29] Similar to BGE, PHI describes this modification as being motivated by the results of PHI customer feedback surveying, as well as by engagement with the PC 44 TOU Rate Design Work Group ("Rate Design Work Group"), and notes that the methodology behind this new Ratio was originally proposed by OPC.[30]

PHI proposes to maintain Delmarva's Schedule R-TOU-ND,[31] as-is and remaining open to new customers, and to also advertise and include it in customer education tools[32] alongside Schedule R-TOU-P (as modified).

PHI also proposes to maintain Pepco's Schedule R-TM,[33] as-is and remaining closed to new customers, but to advertise and include it in customer education tools alongside Schedule R-TOU-P (as modified). PHI indicates that if a significant number of customers migrate from Schedule R-TM to Schedule R (which is a potential outcome of modifying the rate design of Schedule R-TM), the company could experience revenue

[27] PHI July 1 Filing at 25.
[28] R-TOU-P means "Residential Time-of-Use Pilot." PHI specifies that Schedule R-TOU-P was initially developed in 2019 for both companies as part of the PC 44 TOU Pilot Program. At the time of its July 1 filing, PHI reported combined enrollment under this schedule at 1,610 customers across Pepco and Delmarva.
[29] PHI's Ratios as specified in their filing are based on the PHI Companies' June 2025 rates. PHI July 1 Filing at 18-19.
[30] *Id*. at 18. *See also,* 2022 TOU Report at 5.
[31] R-TOU-ND means "Residential Time-of-Use Non-Demand." Delmarva's Schedule R-TOU-ND was previously closed in 2022 but later reopened to new customers in 2023. At the time of its July 1 filing, PHI reported enrollment under this schedule at 16 customers.
[32] PHI specifies these tools as the companies' existing Rate Comparison, Rate Cost Simulator, and weekly Rate Coach tools (R-TOU-P is already available for viewing with these).
[33] R-TM means "Residential-Time Metered." Pepco's Schedule R-TM was introduced in 1984 and has been closed to new customers since July 1, 2000. At the time of its July 1 filing, PHI reported enrollment under this schedule at 52,646 customers.

erosion because of how PHI's Bill Stabilization Adjustment revenue targets are currently structured differently for each rate class.[34] PHI contends that changes to this schedule should therefore only be considered within the larger context of a rate case so that the Commission can holistically look at utility revenues when making decisions.

Similar to BGE, PHI notes the companies' EV Phase II filing in Case No. 9478, which proposes an EV TOU program.

Finally, while not proposing any associated changes at this time, PHI proposes to conduct an analysis to determine optimal changes to the companies' SOS TOU offerings for commercial classes and notes that discussion of this option was added to PHI's filing based on Staff raising the option during the Rate Design Work Group meetings.

PHI proposes to advertise the companies' residential TOU tariffs, as mentioned above, to all eligible[35] residential customers, the plan for which PHI indicates "will be developed and finalized following the approval of this filing."[36] PHI targets two percent TOU schedule enrollment by January 1, 2028, which includes existing TOU customers.

Similar to BGE, PHI proposes regulatory asset treatment for program costs and requests a return at the full Commission-authorized rate of return, with recovery to be reflected in base rates following a prudency review in a future rate case.[37]

3. <u>Potomac Edison</u>

Potomac Edison does not have an existing residential TOU rate beyond its EV Charger TOU Rider from its EV Phase I portfolio in Case No. 9478. Potomac Edison

[34] PHI July 1 Filing at 19.
[35] PHI considers eligible customers to be those with advanced metering infrastructure ("AMI") and who are not participating in aggregated net energy metering. *See id.* at 22.
[36] *Id.*
[37] *Id.* at 25-26.

proposes a new residential TOU tariff, R-TOU, with a difference between the on-peak and off-peak SOS supply rate of 6 cents/kWh, and a difference between the on-peak and off-peak distribution volumetric rate of 1 cent/kWh.[38] Schedule R-TOU will include a four-hour weekday on-peak window, which the company has defined to occur between 5:00 p.m. and 9:00 p.m. during the summer (Eastern Daylight Saving) and between 4:00 p.m. and 8:00 p.m. during the winter (Eastern Standard). According to Potomac Edison, this discrepancy between summer and winter on-peak hours is a result of the company's plan to install dual-register meters at participating residences due to the lack of Advanced Metering Infrastructure in Potomac Edison's service territory. Potomac Edison indicates that, once these dual-register meters are programmed and installed, the on-peak and off-peak periods cannot be altered without removing and reprogramming the meters at a Potomac Edison facility. These meters therefore cannot be adjusted when Daylight Saving time begins and ends unless they are physically removed. The shift in peak hours is intended to practically accommodate this technical constraint.

Potomac Edison proposes to undertake marketing and customer engagement as part of the roll-out of this new R-TOU tariff. The company's enrollment target is 1.2% of eligible residential customers.[39] Potomac Edison also describes a high-level plan to report on metrics. As the company does not have an existing residential TOU rate with established evaluation, measurement and verification ("EM&V") metrics, Potomac Edison proposes to work with the Rate Design Work Group to develop an EM&V methodology.[40]

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[38] PE July 1 TOU Filing at 6-7. These rate differentials amount to a Ratio of 1.8:1 based on June 1, 2025 rates. Staff Comments at 55.
[39] Potomac Edison considers eligible customers to be those that are eligible to receive Schedule R service, receive SOS generation service, and are not enrolled in Potomac Edison's EV Charger TOU Rider. PE July 1 TOU Filing at 3.
[40] Staff Comments at 173 and Potomac Edison Response to Staff Data Request 1-16.

Potomac Edison's proposed total budget to undertake this effort over the course of two years is $507,900,[41] and approximately half of this cost is associated with the proposed meter replacement.

Potomac Edison requests surcharge recovery for the costs of implementing this TOU proposal, to be collected solely from residential customers. The company proposes to combine this TOU surcharge with Potomac Edison's requested surcharges for both the EDSSS pilot program—as described below—and its energy storage filing in Case No. 9715. This combined surcharge would be called the "Grid Programs Surcharge."[42]

B. Interested Party and Stakeholder Positions

1. SolarEnergy Industries Association, Advanced Energy United, and the Chesapeake Solar and Storage Association Joint Comments

SEIA, United, and CHESSA jointly argue that the Utilities' TOU Ratios should remain high to limit what may lead to a "free rider problem"—namely, customers who can save money with no behavioral changes will have an incentive to enroll, and with a relatively lower Ratio, participating customers will have less incentive to shift their consumption.[43] They note that while the free rider issue would remain even when TOU Ratios are higher, such relatively higher Ratios would mitigate this concern as participating customers will have a greater relative incentive to lower peak demand.

[41] PE July 1 TOU Filing at 10, Table 3-1.
[42] *Id*. at 11.
[43] SEIA/United/CHESSA Comments at 13-14.

2. Maryland Energy Administration

MEA does not comment extensively on the TOU portion of the Utilities' filings but notes the possibility that TOU marketing dollars may be better spent on automated demand response.[44]

3. Office of People's Counsel

a. BGE

OPC recommends that the Commission approve BGE's proposed adjustment to Schedule RD.[45] OPC also supports BGE's proposal to modify Schedule RL, noting that the large customer base on this rate is an "untapped" resource, and the stronger price signal provided under BGE's proposal could result in substantial peak reductions at relatively low cost.[46]

Regarding costs, OPC contends that the Exelon Utilities' proposal to treat the administrative, marketing, and evaluation costs associated with their TOU proposal implementation as regulatory assets, earning a return at the full rate of equity, is inappropriate for implementation expenditures that comprise "short-term administrative and operational costs, undertaken for the purpose of testing new ideas…."[47] OPC recommends that these costs be tracked in a regulatory asset account but that the Commission defer any decision on rate of return to the Utilities' next base rate cases.[48]

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[44] MEA Comments at 3.
[45] Maillog No. 322378 at 3, Office of People's Counsel, Response to Bench Data Request No. 1 to OPC, Case No. 9761 ("OPC Bench DR Response") (referring to Schedule RD as "[BGE's] TOU [rate] developed through the PC 44 TOU pilot.").
[46] OPC Comments at 52.
[47] *Id*. at 63-64.
[48] *Id*. at 63-65.

b. PHI Companies

OPC recommends that the Commission approve PHI's proposed adjustment to Schedule R-TOU-P for both Delmarva and Pepco.[49]

Regarding Pepco's Schedule R-TM rate, OPC understands PHI's concerns related to revenue erosion,[50] and OPC recommends that the Commission require Pepco to include a proposal to strengthen Schedule R-TM in its next base rate case. OPC also recommends that Pepco be required to engage with the Rate Design Work Group to develop a new proposal.

OPC expresses concern with PHI's proposed budgets, stating that PHI's marketing budget is more than five times BGE's budget and has not been justified.[51] As a partial remedy for this concern, OPC first recommends that any costs associated with modifying Schedule R-TM should be removed from Pepco's budget. OPC indicates that, because Pepco is not proposing to modify R-TM now, ratepayers should not be asked to fund outreach for a program that remains unchanged.[52] OPC also recommends—based on its consultant's high-level analysis of PHI's approximate breakeven periods given the companies' proposed budgets and estimated benefit per customer—that PHI's marketing budget should be limited to a maximum of $150 per new TOU customer enrolled to improve the potential for the rates to be cost-effective. OPC notes that this modification may also require adjusting PHI's enrollment target such that enrollment can be achieved for no more than $150 per new customer.[53]

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[49] OPC Bench DR Response at 3 (referring to Schedule R-TOU-P as "[Delmarva's and Pepco's] TOU [rate] developed through the PC 44 TOU pilot.").
[50] Hr'g Tr. at 232.
[51] OPC Comments at 61.
[52] *Id*. at 54.
[53] *Id*. at 57-62.

As noted previously, OPC recommends that costs associated with implementation be tracked in a regulatory asset account, but that any decision on rate of return be deferred to the PHI Companies' next base rate case.

c. Potomac Edison

OPC indicates that Potomac Edison's proposal is generally a "cautious but reasonable starting point," and that the company's use of dual-register meters is a "pragmatic compromise."[54] However, OPC recommends one modification: that the proposed four-hour summer on-peak window be shifted from between 5:00 p.m. and 9:00 p.m. to between 4:00 p.m. and 8:00 p.m., based on when peak demand in PJM has historically occurred in the years 2018-2024. OPC observes that 46 percent of PJM's five coincident peak, or "5CP", hours—on which customer costs are ultimately based in significant part—occurred before 5:00 p.m., meaning that customers under Potomac Edison's proposal who shift usage could often not be contributing to system-wide savings. OPC notes that shifting the summer on-peak window to between 4:00 p.m. and 8:00 p.m. would result in 91 percent of PJM peak hours occurring during the on-peak period in the years 2018-2024.[55]

Regarding Potomac Edison's cost recovery proposal, OPC contends that a surcharge amounts to allowing cost recovery before analysis of effectiveness, and the Commission would be "reward[ing] [Potomac Edison] simply for filing a TOU proposal, not for delivering measurable benefits or useful lessons."[56] OPC recommends that the

[54] *Id*. at 57.
[55] *Id*. at 56.
[56] *Id*. at 64.

Commission require Potomac Edison to defer the recovery of DRIVE Act TOU implementation costs to its next base rate case, rather than recovering through a surcharge.

4. Commission Staff ("Staff")

a. BGE

Staff supports BGE's proposed adjustments to Schedule RD and Schedule RL.[57]

In response to a data request from Staff, BGE agreed to conduct an analysis on its existing non-residential TOU SOS rates. Staff recommends that the Commission require BGE to present to the Rate Design Work Group, within six months of an order, an analysis of the company's existing non-residential TOU SOS supply rates, including the results of a review of the company's supply ratios, use of intermediate periods, and peak periods.[58]

Staff indicates that it has no issue with BGE's proposed marketing and education budgets and that it supports BGE's plan to directly contact 800,000 residential customers. Staff additionally does not object to the Commission authorizing a regulatory asset for cost recovery, but Staff recommends deferring any decision on rate of return or any determination of the appropriate amortization period to BGE's next base rate case.[59]

b. PHI Companies

Staff supports Pepco and Delmarva's proposed adjustments to their respective R-TOU-P Schedules.

Staff expresses concern that Delmarva's existing Schedule R-TOU-ND provides an insufficient price signal to motivate customers to shift load off-peak, because the rate does not include an SOS TOU component. Staff therefore recommends that the Commission

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[57] Staff Comments at 37.
[58] *Id*. at 39.
[59] *Id*. at 38.

require Delmarva to present to the Rate Design Work Group, within six months of an order, an analysis of Schedule R-TOU-ND SOS TOU options and a preferred proposal to incorporate an SOS TOU component into Delmarva's Schedule R-TOU-ND.[60]

Staff notes potential complications associated with utility revenue reduction should the difference between on- and off-peak rates be made more pronounced under Pepco Schedule R-TM. Staff therefore recommends that the Commission require Pepco to include in its next base rate case an analysis of possible changes to Schedule R-TM (including the SOS and distribution components) along with a proposal to strengthen the price signal associated with R-TM.

As with BGE, Staff recommends that the Commission require PHI to present to the Rate Design Work Group, within six months of an order, an analysis of the companies' existing non-residential TOU SOS supply rates, including the results of a review of their supply ratios, use of intermediate periods, and peak periods.[61]

Staff supports PHI's proposal to conduct outreach regarding residential TOU tariffs to all eligible residential customers, and Staff recommends that the Commission require Pepco and Delmarva to consult with the Rate Design Work Group to finalize their marketing plans.

Regarding cost recovery, Staff notes that the PHI Companies' budgets exceed those submitted by BGE and Potomac Edison,[62] opining that PHI's proposed budgets may be "excessive."[63] Staff does not object to limiting the PHI budgets to two years.[64] Staff also

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[60] *Id*. at 50.
[61] *Id*. at 50-51.
[62] *Id*. at 48.
[63] *Id*. at 61.
[64] Hr'g Tr. at 272.

does not object to the Commission authorizing a regulatory asset but recommends deferral of any decision on rate of return or determination of the appropriate amortization period to the companies' next base rate case.[65]

c. Potomac Edison

Staff supports Potomac Edison's proposed implementation of Schedule R-TOU as well as the company's proposal to recover costs through a surcharge mechanism.

Potomac Edison stated in response to a Staff Data Request that the company will work with the Rate Design Work Group to develop EM&V metrics for Schedule R-TOU.[66] Potomac Edison specifically proposes to be the coordinator for meetings of a sub-group of interested parties that would focus on Potomac Edison's program, reporting capabilities, and development of reporting metrics. Staff supports Potomac Edison's proposal to engage the work group.[67]

Potomac Edison further responded to Staff that its Type I and Type II SOS bid blocks are bid as single price blocks, which the company then converts to declining block pricing. In the same data request response, Potomac Edison stated that in order to remove declining block rates for Type I and Type II SOS customers, the company would need to make a filing with the Commission for approval. Staff points out that declining block rates are inconsistent with Maryland's energy efficiency, net metering, and climate goals and policies. Staff therefore recommends that the Commission require Potomac Edison to file with the Commission, within six months of an order, a plan to remove its non-residential declining block rates and include customer education for affected rate classes. Staff

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[65] Staff Comments at 51.
[66] *Id*. at 173 and Potomac Edison Response to Staff Data Request 1-16.
[67] *Id*. at 59.

recommends that Potomac Edison consult with the Rate Design Work Group prior to making this filing.[68]

C. Commission Decision

The Commission has considered the Utilities' TOU proposals in their DRIVE Act filings along with the stakeholder comments filed in response thereto and presented at the September 3 hearing. As a preliminary matter, the Commission does not reach any decision in this docket with regard to modifying the Utilities' existing EV TOU rates. Those proposals were also filed in Case No. 9478, and the Commission will address them in that docket. The remainder of the TOU proposals are addressed here.

1. BGE

The Commission considers BGE's proposed TOU tariff modifications to be a reasonable step in encouraging customer participation in TOU rates and in shifting usage off-peak. Where BGE perceives that the Ratio of 3.2:1 for Schedule RD presents a high barrier for many BGE customers, the Commission finds that lowering this Ratio to 2.8:1 may encourage greater participation under this tariff. Similarly, for Schedule RL, the company states—and Staff and OPC agree—that the current Ratio of 1.3:1 is not a sufficient price signal to incent customers to shift their behavior. By applying new rate-shaping for Schedule RL, BGE expects to increase this ratio to 1.9:1, which may offer a "middle ground" for customers who feel the Schedule RD peak rates are too high.

The General Assembly indicated that well-designed TOU pricing can help mitigate the impacts of electrification on the electric distribution system and reduce greenhouse gas ("GHG") emissions during peak hours by incentivizing beneficial customer behavior

[68] *Id*. at 60.

through off-peak cost savings.[69] It is therefore imperative that TOU rates provide sufficient price signals to encourage customers to not only participate in these rates, but also shift their load to off-peak periods. The Commission finds that BGE's proposed modifications to Schedule RD and Schedule RL align with the intent of the DRIVE Act to better incentivize more customers to participate in TOU enrollment and facilitate meaningful changes in peak usage. Accordingly, the Commission directs that Schedule RD and Schedule RL be modified as proposed.

As noted by Staff and further discussed at the September 3 hearing, BGE has multiple non-residential SOS TOU rates already in effect. The DRIVE Act does not specifically limit TOU rate participation to residential customers. Indeed, the Act requires each investor-owned electric utility to "file with the Commission one or more time-of-use tariffs for appropriate customer classes, to be made available . . . on an opt-in basis."[70] To align with this broader legislative intent, the Commission finds that non-residential TOU rate enhancements should be explored. Therefore, the Commission directs BGE to bring to the Work Group an analysis of its existing *non-residential* TOU SOS supply rates within six months of the issuance of this Order. The analysis should include the results of a review of supply ratios, use of intermediate periods, and peak periods.

Lastly, none of the stakeholder parties—including Staff and OPC—object to BGE's proposed enrollment targets and budgets. While BGE aims to enroll an additional 3,200 customers in its revised Schedules RL and RD by January 2028, the company's estimated budget of $369,000 in incremental costs is moderate. Further, as Staff points out, these costs are related only to marketing and education; BGE does not have system programming

[69] PUA § 7-1002(1).
[70] PUA § 7-1003(a)(1).

costs associated with implementing these TOU offerings. The Commission will accept BGE's estimated budget for the two-year period specified in BGE's filing, i.e., over 2026 and 2027. For cost recovery, the Commission authorizes BGE to establish a regulatory asset for costs associated with its TOU proposal but defers all decisions on an appropriate rate of return and amortization period to a future base rate case after which costs have been incurred. The Commission will address the prudency of any TOU-related expenditures at that time. The company is directed to track its spending for purposes of reporting to the Commission on an annual basis.

2. PHI Companies

Similar to BGE's proposed modifications, the Commission considers PHI's proposed modifications to Delmarva's and Pepco's R-TOU-P Schedules to be a reasonable iteration on these existing residential TOU Schedules with a distribution and SOS TOU component. The enrollment data for these existing TOU rates underscores a need to reform. The PHI Companies, Staff, and OPC believe that moderating the current Ratio from 4.5:1 to approximately 2.7:1 may encourage greater customer participation. The Commission agrees. Furthermore, moderating the on-peak/off-peak price differential will serve to reallocate a significant portion of transmission and capacity costs across all hours, not just peak hours. This will better align the companies' R-TOU-P rates with cost causation principles as costs will be allocated in a manner that reflects the typical residential load factor. The Commission therefore directs that Pepco and Delmarva modify their Schedules R-TOU-P as proposed.

Pepco does not propose any changes to its Schedule R-TM, which is currently closed to new customers. Instead, Pepco indicates that changes to R-TM should be considered in a future base rate case. PHI and Staff raise the concern that a significant portion of Schedule R-TM customers may be unaware that they are on a TOU rate. Adjusting the schedule's design to more strongly incentivize these customers to shift load off-peak now could cause a migration away from Schedule R-TM to Schedule R. Because of the difference in revenue target treatment between the two rate classes, such a migration would result in a net drop in Pepco's base distribution revenue (i.e., revenue erosion). This could, in turn, increase the company's requested revenue requirement in its next base rate case. The Commission agrees that any potential changes to Schedule R-TM should be considered within the context of a base rate case. Accordingly, the Commission directs Pepco to provide an analysis of possible changes to strengthen price signals for Schedule R-TM in its next base rate case and include, as appropriate, a proposal for modification, a timeline for implementation, and a plan for customer education and outreach.

While PHI proposes no changes to Schedule R-TOU-ND at this time, the Commission shares Staff's concern that Delmarva's R-TOU-ND may not provide a sufficient price signal to shift customer load. The existing Ratio for this schedule is approximately 1.35:1. Staff argues that adding an SOS TOU component to R-TOU-ND will be beneficial. The Commission agrees. The Commission therefore directs Delmarva to present to the Rate Design Work Group, within six months of this Order, an analysis of R-TOU-ND SOS TOU options and a preferred proposal to incorporate an SOS TOU component into Schedule R-TOU-ND.

Additionally, as with BGE, the PHI Companies have existing non-residential SOS TOU rates. Accordingly, Pepco and Delmarva shall, within six months of this Order, present to the Rate Design Work Group an analysis of the companies' existing non-residential TOU SOS supply rates, use of intermediate periods, and peak periods.

The PHI Companies are dissimilar from BGE and Potomac Edison in the sizing of their DRIVE Act TOU implementation budgets. Pepco's proposed budget is approximately $1,912,500 and Delmarva's proposed budget is $922,500, for a combined budget exceeding $2.8 million over three years. These budgets exceed those of BGE and Potomac Edison in total and on a per-incremental-customer basis. As OPC observes, PHI proposes an estimated cost of $305 per new Delmarva customer enrolled under its new TOU program (inclusive of marketing and customer education), compared to BGE's $115 per incremental customer. Yet, PHI does not offer a clear explanation for why their proposed costs greatly exceed the other utilities' proposals, nor do the companies clearly demonstrate that the estimated benefits reasonably justify the costs. Two-thirds of PHI's proposed combined budget consists of marketing costs. PHI briefly describes these costs as including "general program/rate marketing (e.g., social media, website content, collateral), participant welcome kits, call center reference materials," and a customer survey to facilitate ongoing program feedback.[71]

The Commission finds the lack of sufficient detail around PHI's implementation costs troubling, especially where marketing represents the largest component of PHI's budgets. Additionally, per the DRIVE Act, enrollment targets should be achieved by January 1, 2028, so utilities will have two years to endeavor to reach these targets, not three. Therefore, the Commission directs that, within 45 days of this Order, PHI shall provide a modified budget proposal which, at minimum, is revised to cover two years'

[71] Staff Comments at 123 and PHI Response to Staff Data Request 1-15; *see also*, OPC Comments at 61-62.

worth of implementation efforts, instead of three. Alongside this modified proposal, PHI shall provide a more detailed breakdown of the anticipated costs included in the budget. This breakdown must split costs out per individual tariff modification, as applicable (i.e., costs shall be provided separately for modifications or marketing that are associated specifically with Schedule R-TOU-P and Schedule R-TOU-ND for Delmarva, and with Schedule R-TOU-P and Schedule R-TM for Pepco). PHI shall provide a more detailed marketing plan alongside this cost breakdown. In addition to a more detailed cost breakdown and marketing plan, PHI shall provide a rationale for the companies' budgets, including an estimated cost-benefit analysis which includes an enrollment target (or a range of enrollment target options), costs associated with this target (or these target options) per new TOU customer, years to breakeven, and a breakdown of the methodology and assumptions used such that calculations are understandable and replicable.[72]

3. Potomac Edison

Potomac Edison is situated differently from the Exelon Utilities in its DRIVE Act TOU rate offerings insofar as Potomac Edison does not have AMI in its Maryland service territory, thereby limiting its ability to offer TOU rates (with the exception of its EV Charger TOU Rider). Furthermore, the company does not have a timeline for implementing AMI. The Commission agrees with Staff that the absence of AMI need not delay the implementation of Potomac Edison's DRIVE Act TOU rates. The Commission also agrees with OPC that Potomac Edison's proposal to install dual-register meters, versus more expensive interval metering, to facilitate the company's first, residential (non-EV) TOU

[72] OPC provided its own version of this type of analysis in its comments and estimated a breakeven period of 10.3 years for Delmarva under PHI's current proposal. *See* OPC Comments at 57-62.

offering is a pragmatic approach. Therefore, the Commission directs Potomac Edison to begin the process to implement Schedule R-TOU, subject to the following modification: when finalizing its tariff, Potomac Edison shall modify its on-peak summer period (Eastern Daylight Saving) to occur between 4:00 p.m. and 8:00 p.m.—a shift from its proposed period between 5:00 p.m. and 9:00 p.m.—as recommended by OPC or, alternatively, provide a detailed justification for maintaining its originally proposed hours within 30 days of this Order. The Commission finds that shifting this period one hour earlier will better align the company's on-peak window with PJM's historical coincident peak hours, thereby enabling participating customers to contribute more substantially to Potomac Edison's system-wide savings when shifting their electricity usage to off-peak periods.[73] The Commission understands that this would result in an on-peak period in the winter (Eastern Standard) of 3:00 p.m. to 7:00 p.m. due to the nature of Potomac Edison's new dual-register meters.

Given no objection to Potomac Edison working with the Rate Design Work Group on developing an EM&V methodology to support its TOU implementation, the Commission directs Potomac Edison to engage the Rate Design Work Group on EM&V as soon as practicable to support ultimate implementation of Potomac Edison's overall proposal within six months from the date of this Order.[74]

Potomac Edison proposes to recover the cost of its TOU implementation through a surcharge mechanism. The Commission sees no reason to treat Potomac Edison's cost

[73] The capacity obligation of each zone in PJM is based in part upon the highest recorded coincident peak occurring in a previous year. This "weather-adjusted coincident summer peak" value, along with the times and dates upon which PJM's five highest coincident peaks (5CP) were recorded, is reported annually by PJM. *See* https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process; *see also*, PJM's Reliability Assurance Agreement, Schedule 8 https://agreements.pjm.com/raa/4176.
[74] Potomac Edison has requested up to six months to begin offering the new rate schedule. *See* PE July 1 TOU Filing at 11.

recovery mechanism differently from the Exelon Utilities. Where the DRIVE Act specifies that certain costs for the EDSSS component be recovered in the same calendar year in which the costs are incurred,[75] there is no such requirement for TOU implementation. Instead, the Act provides that utilities may "recover all reasonable and prudent costs" associated with the effort.[76] Therefore, the Commission directs Potomac Edison to track costs associated with this effort as a regulatory asset, but the Commission will defer all decisions on the appropriate rate of return or amortization period to a future base rate case after which costs have been incurred.[77]

Lastly, the Commission finds that Potomac Edison's legacy declining block rates run counter to the General Assembly's intention to incentivize lowering electricity consumption under the DRIVE Act. The Act states that implementing well-designed time-of-use pricing can "help mitigate the impacts of electrification on the electric distribution system" and "reduce greenhouse gas emissions during peak hours…."[78] Declining block rates are a pricing structure in which the price per unit of energy decreases as a customer's overall consumption increases, meaning higher energy usage results in a lower per-unit cost. This rate design effectively incentivizes higher energy consumption, which if it was appropriate in the past certainly is not appropriate now. Therefore, the Commission directs that Potomac Edison file with its next rate case or within two years, whichever is earlier, a proposal to cease the practice of implementing non-residential declining block rates. The

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[75] PUA § 7-1007(b).
[76] PUA § 7-1003(e).
[77] The Commission notes that Potomac Edison's proposed budget is based on an anticipated enrollment target and associated cost to replace this number of customer meters. If fewer customers enroll than the assumed enrollment target, it is presumed that implementation costs will scale accordingly.
[78] PUA § 7-1002(1).

Commission further directs Potomac Edison to consult with Staff and OPC prior to making this filing.[79]

III. DISTRIBUTION SYSTEM SUPPORT SERVICES PILOT PROGRAMS

A. Utility Proposals

The Commission received electric distribution system support services proposals for VPPs from Potomac Edison, BGE, and the PHI Companies as part of their respective July 1, 2025 DRIVE Act filings.

1. Potomac Edison

Potomac Edison proposes a two-year EDSSS pilot program focused on integrating residential battery electric storage systems ("BESS") and electric vehicles equipped with bidirectional charging capabilities into a cohesive VPP. This initiative aims to harness the collective potential of these residential assets to provide grid services.

The core of Potomac Edison's proposal is to leverage the energy storage and bidirectional charging functionalities of residential BESS and EVs.[80] By aggregating these devices, Potomac Edison intends to create a VPP that can actively participate in grid management, particularly during peak demand periods.

Potomac Edison targets an enrollment of up to 300 residential customers, operating under a "Bring Your Own Device" ("BYOD") model. This approach allows customers to use their existing, eligible equipment. Customer incentives will be based on device

[79] While declining block rates have been confirmed for Potomac Edison, it is unclear whether the Exelon Utilities also employ this practice. To the extent that the Exelon Utilities also have legacy declining block rates, they shall consult with Staff and OPC for the purpose of including a proposal to terminate this practice with their next rate case.
[80] BESS are stationary and expected to be consistently available, while EVs are mobile and their program success depends on their availability during event windows, rather than technology characteristics.

characteristics, estimated performance, and event participation. Incentives will have two off-bill components: (1) a connectivity incentive of $150 each year the device remains connected, paid annually after verification; and (2) a performance incentive of up to $300 per kilowatt per year, based on event participation. Upon enrollment, customers will receive the connectivity incentive after a successful test event. Subsequent connectivity incentives are annual and contingent on participation in the previous program year. Performance incentives are based on estimated device performance over a four-hour peak event period, with payments up to $300/kW-year of estimated performance. Due to data collection limitations, payments are based on the nominated nameplate discharge capacity. Customers participating in at least 75% of event hours will receive 100% of the performance incentive. Potomac Edison estimates the peak load reduction from its EDSSS pilot to be 1.186 MW over a two-year operational period.

To be eligible, customers must reside under Schedule R5, possess compatible equipment (BESS or EVs with bidirectional charging), and have successfully completed the necessary interconnection process with the company.

Beyond reducing system peaks, this program is designed to explore a broader range of potential grid services that can be provided by aggregated residential DERs. Potomac Edison commits to a minimum of three dispatch events per quarter, which will ensure regular engagement and data collection to assess the program's effectiveness and the capabilities of the VPP. Potomac Edison plans to partner with a third-party implementer that will be responsible for the technical aspects of dispatching customer DERs and for the overall management of the program. Potomac Edison did not propose to work with DERAs[81] in its pilot program proposal.

The total estimated cost for Potomac Edison's two-year EDSSS pilot program is $3,769,500. The company proposes to recover this cost through a dedicated "Grid Programs Surcharge," which would be applied to residential customers. Thus, for an average residential customer consuming 1,000 kWh per month, this surcharge is estimated to be approximately $0.55 per month, translating to $0.0006/kWh.

2. BGE

BGE proposes a two-year EDSSS pilot program that aims to build upon the company's existing knowledge and programs to significantly expand BGE's understanding of customer engagement, operational capabilities, resource potential, program design, and the overall grid benefits derived from DERs. BGE seeks to enhance and leverage insights from its current initiatives. This will allow the company to refine strategies for integrating DERs and specifically focus on how customer behavior, technological capabilities, and program structures can maximize grid advantages.

The program is designed with a multi-faceted set of goals. It seeks to enhance grid reliability and resilience by utilizing DERs for demand response and grid support. It also aims to support customer affordability by potentially deferring costly infrastructure upgrades, improving load forecasting accuracy, and providing direct compensation to participating customers. Furthermore, a significant objective is to promote sustainability

[81] A DERA combines multiple DERs into a single, coordinated VPP to participate in electricity markets, while a third-party implementer is the entity that executes a specific program for aggregation. A third-party implementer is the hands-on operator, while an aggregator is the market-facing entity that acts on behalf of the bundled DERs. In some cases, the same company may perform both functions.

through reductions in GHG emissions, fostering beneficial electrification, and contributing to broader decarbonization efforts.

BGE also adopts a BYOD approach, targeting existing residential Behind-the-Meter ("BTM") dispatchable DERs. This includes stationary energy storage systems and EVs with bidirectional capabilities, with a particular emphasis on those assets already paired with rooftop solar installations, which often have existing infrastructure for energy management. Forecasted participation includes 2,800 Vehicle-to-Home ("V2H")[82] make/models and 3,180 battery storage devices. BGE did not include any V2G[83] make/models in its proposed pilot program.

BGE also plans to partner with a third-party implementer. This third-party implementer will be responsible for the technical aspects of dispatching customer DERs and the overall management of the program. BGE did not propose to work with DERAs in its pilot program proposal.

Regarding customer incentives, participants in BGE's pilot will receive flat monthly payments. The amount of compensation, which can be up to $100, will vary based on several factors: the type of device enrolled, the forecasted load shed capability of the device, and actual device participation in dispatch events. This structure incentivizes both device availability and active contribution to grid services.

BGE's total estimated cost for its EDSSS pilot program is $1,545,955. This investment is projected to yield an estimated peak reduction of 7.621 MW, which

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[82] V2H means bidirectional-capable ability for electric vehicle supply equipment ("EVSE") connected to an EV to operate in parallel to the grid to feed power (discharge) from an EV's battery to the customer's home only, and not beyond the point of interconnection between a home and the grid.
[83] V2G means bidirectional-capable ability for EVSE connected to an EV to operate in parallel to the grid to feed power (discharge) from an EV's battery to the grid.

demonstrates a return on investment in terms of grid capacity management. BGE proposes regulatory asset treatment for these costs, meaning the incurred costs would be recognized as an asset on the company's balance sheet and recovered through base rates as determined in a future rate case. The projected monthly residential bill impacts range from \$0.07 to \$0.10.

3. PHI Companies

PHI proposes two distinct EDSSS pilots, each with a three-year duration that will be tailored for the respective Pepco and Delmarva customer bases. Both pilots aim to utilize BTM DERs, specifically BESS and EVs with bidirectional charging, to deliver measurable grid benefits. The primary focus for both Pepco's and Delmarva's pilot programs is to leverage the capabilities of BTM DERs, such as BESSs and EVs with bidirectional charging, to provide tangible and quantifiable benefits to the distribution grid. The overarching goal for PHI's EDSSS pilots is primarily system peak load shaving. By strategically dispatching DERs during periods of high demand, the PHI pilots aim to reduce the overall system peak, thereby alleviating strain on infrastructure and potentially deferring costly upgrades. Additionally, the pilot programs will explore the potential for voltage management and more localized peak reduction, addressing specific grid constraints.

PHI's VPP program will compensate customers through annual connectivity payments and performance payments for participating in Pepco or Delmarva power events. The connectivity payment covers equipment connection, Wi-Fi, and safe event operation, based on industry feedback and benchmarking. Event compensation will be performance-based, tied to customer participation and their system's ability to provide load relief for up to a four-hour peak capacity event. Participating customers will be compensated at up to $300/kW-year for peak shaving. Like BGE, PHI also plans to partner with a third-party implementer. This third-party implementer will be responsible for the technical aspects of dispatching customer DERs and the overall management of the program, including customer recruitment, engagement, and data collection. This partnership aims to leverage specialized expertise in DERA and management. PHI did not propose to work with DERAs in its pilot program proposal.

Once connected to the third-party implementer platform and verified for operational readiness, participants will then engage in dispatch events. They receive a connectivity payment upon their first successful event and performance-based payments throughout their participation, with full compensation for those participating in at least 80 percent of event hours (e.g., up to $900 annually for a 3 kW home load offset). Customers are encouraged to maintain system availability and receive ongoing engagement and payments. Altogether, the PHI Companies submit this proposal, which if approved, will have the following estimated impacts assuming 935 customer devices enrolled across both PHI Companies: 2.6 MW peak reduction by year three through customer BESSs and EVs, with approximately $2.7 million in performance payments to participating customers.

The proposed budgets for each PHI company's EDSSS pilot are: $6,258,500 for Pepco over a three-year period; and $1,998,000 for Delmarva over a three-year period. Similar to BGE, PHI proposes regulatory asset treatment for these program costs, with recovery anticipated through future base rates. The projected monthly residential bill impacts for PHI customers in Maryland are detailed as follows: for Pepco, customer impacts are estimated to range from $0.82 in Year 1 to $2.67 in Year 3, subsequently decreasing to $0.84 by Year 7, reflecting the amortization of costs over time; and for Delmarva, impacts are projected to range from $0.90 in Year 1 to $2.68 in Year 3, similarly decreasing to $0.82 by Year 7.

B. Commission Decision

The utility EDSSS filings generated significant feedback from several state agencies[84] and many non-utility stakeholders,[85] including Delegate David Fraser-Hidalgo and House Economic Matters Committee Chair CT Wilson ("Delegates").[86] With the exception of the Edison Electric Institute ("EEI") and WeaveGrid, both of whom fully support the investor-owned utility pilot program proposals, other non-utility parties support some aspects of the utility pilot program proposals and oppose other aspects. This non-utility feedback in opposition focused on several major topic areas. Accordingly, this Order will only address the following major topic areas focused on perceived gaps in the electric company filings—as highlighted by specific stakeholders—without attempting to identify each individual party's position due to the volume of filings and comments:

(1) Consistency with Legislative Intent;

(2) Scaling;

(3) Aggregator Role;

(4) Broader Participation;

(5) Importance of Grid Export and Bidirectional Electric Vehicle Programs;

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[84] *See generally*, MEA Comments, OPC Comments, and Staff Comments.

[85] *See generally*, EEI Comments, WeaveGrid Comments, ATE Comments, Virtual Peaker Comments, Tesla Comments, ChargeScape Comments, EnergyHub Comments, CPower Comments, Sunrun Comments, TMH Comments, GoodLeap Comments, SUN Comments, VGIC Comments, Mission:data Comments, SEIA/United/CHESSA Comments, ev.energy Comments, Resideo Comments, and Kaluza Comments.

[86] *See generally*, Delegates Comments.

(6) Clear Metrics and Requirements for Compensation;

(7) Pilot Duration;

(8) Data Exchange;

(9) Cost Recovery;

(10) Locational Value;

(11) Transparency, Metrics and Reporting;

(12) Transition to Permanent Programs;

(13) Equity; and

(14) Utility Ownership of BTM VPP Devices.

1. Consistency with Legislative Intent

a. Position of the Delegates

In their joint comments, Delegate Fraser-Hidalgo and Chair Wilson explain that the DRIVE Act was enacted in Maryland to tackle energy affordability and resource adequacy issues. They urge the Commission and utilities to be ambitious in this transformative effort and pursue all potential solutions with urgency given the electric system's cost and capacity pressures, stating that the DRIVE Act aims to activate the full market potential (up to two percent of utility peak demand), not just a minimum participation. The Delegates express concern that the proposed programs, as filed, only target about 0.06 percent of utility peak demand, falling significantly short of the two percent statutory limit. They state that the DRIVE Act envisions a robust, open-access pilot program and that the Utilities' proposed numbers should not be used as caps, as the law provides the relevant cap. They also express concern that the proposed pilots are narrow in scope and smaller than intended for a transformative model, stating that the intent of the General Assembly was to unlock customer-driven solutions for energy needs and enable rapid deployment of new and existing resources. They encourage the Utilities to seize this opportunity, as the DRIVE Act cannot be transformative if limited in scope.

b. ***Commission Determination***

The Commission finds that the Utilities need to be more ambitious in this transformative effort and that they need to cure weaknesses in their initial proposals by pursuing all potential solutions with urgency to better align with the General Assembly's legislative intent, given the electric system's affordability and resource adequacy pressures. The Commission agrees with the Delegates' explanation and looks to the statute itself as providing both guidepost and target for achieving the State's goals. More specific direction to cure these weaknesses is provided in the discussion of EDSSS pilot program major topic areas as described below.

2. <u>Scaling</u>

a. Positions of the Stakeholder Parties

There is also a strong and unified call, notably from GoodLeap, Sunrun, and Tesla, in addition to the Delegates, to scale the ambition of these pilots to align better with the DRIVE Act's cap of achieving two percent peak demand reduction through VPPs.

b. ***Commission Determination***

While the Commission will not prescribe specific targets, the Utilities are directed to provide pilot program solutions with greater scale than those currently proposed, particularly by targeting broader participation as described further below in Topic Area No. 3—Aggregator Role. Utilities should clearly define achievable program market participation goals for each year of the pilot, not minimum objectives, that are based on realistic and measurable targets for program engagement that are attainable given the projected market for these programs and the utility's organizational and technical capacity. If prerequisites such as Distributed Energy Resource Management System ("DERMS") implementation or other items, including but not limited to information technology ("IT") system enhancements that are described in the Commission's VPP implementation Order No. 91603,[87] are obstacles to achieving a greater scale, the utility should clearly describe how these limitations will limit scale. In addition, the Commission must balance achieving greater scale with affordability. The Delegates comment, "We hope that the electric utilities and the Commission will act on the DRIVE Act's potential, with the confidence that pay-for-performance will mitigate risks to ratepayers and help deliver the relief we intend these programs and accompanying time-of-use rates to provide."[88] The Commission agrees but also recognizes that the anticipated benefits that will eventually provide customer rate relief will likely lag the initial pilot program costs incurred. Therefore, to the extent that the Utilities can provide transparency on the rate impacts of different levels of scale, the Commission will use this information to aid our decision-making.

3. Aggregator Role

a. Positions of the Stakeholder Parties

CPower and Staff both emphasize the pivotal role that third-party aggregators play in the successful implementation of VPP programs. Aggregators are seen as crucial intermediaries for customer engagement, program enrollment, and the technical coordination of diverse DERs to form a cohesive VPP. In fact, the role of third-party

[87] *In re Interconnection Workgroup and the Implementation of FERC Order No. 2222 and Retail Grid Services in Maryland*, Case No. 9778, Order No. 91603.
[88] Delegates Comments at 3.

aggregators was discussed at length at the September 3, 2025 hearing.[89] Here, the Utilities favor a single third-party implementer model for perceived efficiency, while stakeholders like CPower stress the importance of aggregator participation for market development, scale, and leveraging existing assets. In addition, party stakeholders express concerns that the "third-party implementer" model proposed by the Utilities does not provide a clear pathway to transition to permanent programs. According to CPower at the September 3 hearing, Consolidated Edison ("ConEd") uses a single third-party implementer in New York, but 12 aggregators work through ConEd's third-party implementer, and all the aggregators bring actual assets into the ConEd programs.[90]

b. ***Commission Determination***

The Commission agrees with the non-utility parties' view that third-party aggregators have an important role to play in achieving the goals under the DRIVE Act. Aggregators can allow for broader DER participation while also simplifying utility management of the pilot programs since aggregators typically handle the dispatch, measurement and verification, and billing with individual customers.

The Commission is disappointed that the Utilities seemed to ignore the Commission's intent in pursuing aggregator licensing before July 1, 2025, which was timed to facilitate aggregator participation in DRIVE Act programs. The Commission clearly stated in Order No. 91597 that "establishing a licensing process now will avoid the need to license the aggregator participants in utility pilot programs in the future as these programs transition, or worse, remove pilot aggregators from transitioning programs due to the

[89] Hr'g Tr. at 39-44 (Suchman and Knight).
[90] *Id*. at 195-96 (Bergeron).

inability to obtain a license in the future."[91] Yet no electric company has proposed to use third-party aggregators in its pilot program. The Commission therefore directs the Utilities to revise their pilot programs to allow for aggregator participation either directly through the utility or through a third-party implementer.

Furthermore, the Commission recognizes that if third-party implementers are needed, this will likely involve multi-year contracts that may be needed past the pilot program duration as it may take time to transition from pilot programs to permanent programs. Therefore, the Commission directs the Utilities to plan for "least regrets," where risk mitigation strategies and multi-year contracts with exit clauses are encouraged in an effort to allow for the eventual elimination of third-party implementers if/when an electric company reaches the appropriate level of maturity with respect to VPP program implementation.

4. Broader Participation

a. Positions of the Stakeholder Parties

Multiple stakeholders advocate for a significant expansion of VPP participation beyond the current residential-centric proposals. For instance, OPC and CPower specifically champion the inclusion of commercial, industrial, and institutional customers ("C&I") and demand response in VPPs, recognizing their substantial load reduction potential and flexibility. Furthermore, SEIA/United/CHESSA, GoodLeap, and Solar United Neighbors emphasize the importance of ensuring eligibility for third-party-owned systems in VPPs, which represent a substantial and growing segment of the DER market.

[91] Order No. 91597 at 5 on Distributed Energy Resource Licensing in Maryland, Case No. 9761.

Sunrun and Solar United Neighbors opposed utility ownership of devices, advocating for third-party ownership and emphasizing the importance of enabling aggregators.

b. ***Commission Determination***

The Commission finds that the Utilities should provide program solutions that expand VPP participation beyond the current residential-centric and technology-limited proposals to include C&I and demand reduction participation. By broadening the pilot scopes to allow aggregator participation, the Utilities can likely achieve broader participation in addition to greater scale and greater program diversity, such as allowing for demand reduction in VPPs. These expanded VPP programs should include aggregator participation where aggregators bring C&I participation and demand reduction resources in addition to residential solar, storage and bidirectional EVs. Aggregators should also be licensed pursuant to Commission Order No. 91674.[92]

5. Importance of Grid Export and Bidirectional EV Programs

a. Positions of the Stakeholder Parties

Multiple stakeholders, including OPC, Kaluza, VGIC, SEIA/United/CHESSA, Tesla, GoodLeap, and Sunrun assert the necessity of allowing VPP participants to export surplus electricity back to the grid. This capability is seen as vital for maximizing the economic and grid-stabilizing benefits of VPPs and for accurately reflecting the full capabilities of DERs. Potomac Edison's proposal was cited as a positive model in this aspect, demonstrating a forward-thinking approach to grid integration. PHI proposed no grid injection—for either company—citing system challenges. Likewise, BGE does not

[92] *See generally* Order No. 91674 on Application Provisions for Distributed Energy Resource Aggregator License to Operate, Case No. 9761.

allow V2G. Kaluza, VGIC and TMH emphasize the importance of bidirectional vehicle (V2G and V2H) programs, and both VGIC and TMH commend Maryland's progress in adopting bidirectional vehicle regulations required by the DRIVE Act.

b. ***Commission Determination***

The Commission agrees with the above stakeholders on the importance and necessity of allowing VPP participants to export surplus electricity back to the grid, including V2G. The Utilities need to pilot methods that bring Maryland closer to standing up VPPs as fully capable non-wires solutions.

Regarding allowing grid injections, PHI expressed at the September 3 hearing the system challenges to allowing grid injections from batteries used in VPPs.[93] The Commission finds this assertion perplexing since all DERs with Level 1, 2, and 4 interconnections,[94] by definition, are exporting resources. Grid injections should be a standard requirement for all the electric companies and the Commission hereby directs all the Utilities to allow grid injections in their pilot programs.

Regarding V2G, on July 7, 2025, Maryland became the first state in the United States to adopt V2G regulations in accordance with DRIVE Act requirements. VPP pilot programs should align with the legislative intent of the DRIVE Act, which requires that these V2G regulations be adopted. However, the Commission also recognizes that V2G implementation is still in its nascent stages, and the Commission applauds BGE's and Sunrun's recent announcement on September 24, 2025, about the nation's ***first*** residential

[93] Hr'g Tr. at 79-81 (Moberg) and 98-103 (Suchman and Moberg).
[94] *See* COMAR 20.50.09.09 for Level 1 interconnection, COMAR 20.50.09.10 for Level 2 interconnection, and COMAR 20.50.09.12 for Level 4 interconnection.

V2G distributed power plant using Ford F-150 Lightning trucks.[95] Therefore, the Commission directs the Utilities to ensure that their pilot program proposals include a pathway for V2G demonstrations, while recognizing that V2G will likely not contribute largely to scale in the short-term.

6. Clear Metrics and Requirements for Compensation

a. Positions of the Stakeholder Parties

Several stakeholders emphasized the need for well-defined pilot program objectives, measurable performance metrics, and transparent performance-based compensation structures. OPC, Staff, Solar United Neighbors, Tesla, and Sunrun also underscore that compensation should be fair, easily understandable, and ideally disbursed in cash rather than bill credits to maximize participant engagement and value. This clarity is essential for both evaluating program success and ensuring participant satisfaction. Furthermore, the Delegates support the $300/kW pay-for-performance compensation design proposed by Potomac Edison and the PHI Companies as it clearly reflects the value of behind-the-meter resources to the grid. Implementing a similar pay-for-performance structure across all the Utilities could boost success, lower participation costs, and simplify the marketplace.[96] The Delegates also state that consistency in proportional compensation, device opt-out thresholds, and settlement at the inverter will facilitate rapid statewide deployment of EDSSS devices.[97] SEIA/United/CHESSA, Solar United Neighbors, Sunrun, TMH and EnergyHub also advocate for device-level metering.

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[95] *See* https://investors.sunrun.com/news-events/press-releases/detail/352/sunrun-and-bge-operate-nations-first-residential (last visited Oct. 6, 2025).
[96] Delegates Comments at 2.
[97] *Id*. at 2.

b. ***Commission Determination***

The Commission agrees with the above non-utility parties and finds the utility pilot proposals require more clarity to allow us to evaluate the success of their programs. Specifically, the Commission directs the Utilities to provide well-defined objectives, measurable performance metrics, and transparent, pay-for-performance-based compensation structures with device opt-out thresholds. Compensation should be fair, easily understandable, and disbursed in a manner that maximizes participant engagement. The Commission does not, however, prescribe how the compensation will be disbursed because the Utilities are also directed herein to include aggregators in their pilot programs where disbursements may not be direct from the electric company to customers. The Utilities should propose how the compensation will be disbursed to customers that directly participate in a VPP pilot program through the electric company and also to those customers that participate through an aggregator, once those details are known.

The as-filed VPP programs focus on peak load reductions and will compensate customers for performance in response to dispatch events, not in energy usage measured that typically requires billing quality utility meters. Therefore, customers should be allowed to use acceptable device-level metering such as inverters, electric vehicle supply equipment ("EVSE"), or battery management systems for settlement in the pilot programs that compensate for performance. Furthermore, the use of device-level metering should be a learning objective from the pilot programs that will inform future regulations. Therefore, the Commission finds the default position should be for the Utilities to accept these devices unless there is a specific concern with a particular device-level metering type. The Utilities should submit proposals to the Commission on their policies for device-level metering and settlement for both aggregators and for customers participating directly in their pilot programs through the utility or via a proposed third-party implementer.

7. Pilot Duration

a. Positions of the Stakeholder Parties

While BGE and Potomac Edison propose two-year pilot durations, PHI proposes a three-year pilot duration. A consensus among stakeholders in this proceeding, including Kaluza, The Mobility House, ChargeScape, Solar United Neighbors, and VGIC, supports a three-year duration for VPP components. This extended period is supposedly necessary to allow for sufficient data collection, robust market development, and comprehensive evaluation of the pilot programs, which was also the rationale for PHI's three-year pilot duration.

b. Commission Determination

While PHI's rationale for a three-year pilot program is understandable, customer enrollment in the pilots is not projected to begin until later in 2026, which would extend the pilots' duration to approximately 2030 under a three-year program. Consistent with the Commission's "call to action" in VPP Implementation Order No. 91603,[98] VPP programs are important to Maryland's energy future. Given that PJM's DER Aggregation Participation Model[99] effective date is February 1, 2028, for complying with FERC Order 2222 requirements, Maryland VPPs should ideally be situated to begin participating in PJM's markets sooner than 2030. Therefore, the Commission concludes that a three-year

[98] *See In re Interconnection Workgroup and the Implementation of FERC Order No. 2222 and Retail Grid Services in Maryland*, Case No. 9778, Order No. 91603 at 5-6.
[99] PJM's DER Aggregation Participation Model allows for DERs, like solar and storage, to be aggregated by a DERA and participate in PJM's wholesale energy, capacity, and ancillary services markets.

pilot program may not be in the public interest if it effectively delays implementation of permanent programs that can scale in a meaningful way to participate in PJM capacity markets to support resource adequacy needs and affordability. Therefore, the default pilot program duration shall be two years, but an electric company may petition the Commission at the end of the two-year pilot program duration for an extension for good cause.

The Commission also concludes that there needs to be a uniform approach to the start dates. Measuring pilot program implementation by calendar year is problematic as the timelines for enrolling customers and aggregators may vary. Therefore, the Commission directs that the Utilities propose two-year pilot programs, and the start of Year 1 of the pilot shall be defined as the start of the enrollment period for customers and aggregators. The Commission recognizes that the start of enrollment periods may be different for different electric companies. Consequently, a uniform Year 1 start date for all the Utilities is not prescribed.

In furtherance of this directive, the Commission rescinds its previous VPP pilot evaluation reporting direction in Order No. 91218, requiring an investor-owned electric company to assess its EDSSS pilot program on or before October 1, 2027. This will allow for clearer reporting deadlines aligned with the start of the two-year pilot programs. The former requirement is now superseded by a new reporting requirement as discussed below in Topic Area No. 11 – Transparency, Metrics and Reporting.

8. <u>Data Exchange</u>

a. Positions of the Stakeholder Parties

Some stakeholders stress the importance of establishing a formalized and streamlined data exchange framework. Effective VPP operations rely heavily on the timely and accurate exchange of data between utilities, aggregators, and participants. The imperative for transparent data exchange and robust measurement and verification protocols is a recurring theme.

b. ***Commission Determination***

The Commission agrees with the above non-utility stakeholders and finds that data exchange frameworks must be further defined considering that effective VPP operations rely heavily on the timely and accurate exchange of data between utilities, aggregators, and participants. Therefore, the Commission directs the Utilities to clarify in their revised pilot proposals how data will be collected, stored and shared between utilities, aggregators, and customers in addition to EM&V protocols.

9. Cost Recovery

a. Positions of the Stakeholder Parties

BGE and PHI advocate for a fair and reasonable return on regulatory assets, while some stakeholders such as OPC question this request for a two-year pilot, suggesting cost of debt might be more appropriate. Potomac Edison, by contrast, proposes a surcharge mechanism. Notably, MEA supported the Exelon Utilities' position at the September 3 hearing, particularly to incentivize non-wires solutions.[100] A general consensus also exists among other stakeholders, including Resideo, WeaveGrid, Sunrun, ChargeScape, and EnergyHub, in support of regulatory asset treatment for EDSSS pilot costs. These stakeholder parties view this approach as a way to encourage utility innovation and investment in emerging technologies. However, their support for regulatory asset treatment is contingent upon an electric company's demonstration of clear and measurable benefits,

[100] Hr'g Tr. at 212-17 (Lombardi).

coupled with proper cost allocation mechanisms to safeguard ratepayers from unwarranted expenses. OPC and Staff recommend that the Commission defer decisions on cost recovery and rate of return until future utility base rate cases.

b. ***Commission Determination***

The DRIVE Act requires

> (a) an investor-owned electric company may recover all reasonable costs incurred in:
>
> (1) participating in and administering a program under § 7-1005 of this subtitle; and
>
> (2) offering an upfront incentive or rebate under § 7-1006 of this subtitle.
>
> (b) To the extent feasible, the costs listed in subsection (a) of this section shall be recovered by the investor-owned electric company **within the calendar year in which those costs were incurred**.[101] (emphasis added).

Given the legislative intent to recover administrative and incentive costs within the calendar year in which those costs were incurred, the Commission does not conclude that a regulatory asset would be appropriate for these pilot programs as this mechanism defers cost recovery outside of the calendar year in which those costs are to be incurred. Rather, the Commission believes the legislative intent will be best accomplished through surcharges with annual reconciliations for the two-year EDSSS pilot programs. The Commission recognizes there are costs, such as programming and any costs related to potential utility ownership of DER assets, as discussed later in this order, which likely cannot be recovered in a single year. In this instance, the Commission is willing to consider either the use of a regulatory asset or further cost recovery in the surcharge over time. In the Commission's clarification of Order No. 91391, the Commission's proscription against

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[101] PUA § 7-1007(a)-(b).

the use of regulatory assets "applies to DRIVE Act incentive programs and not necessarily all DRIVE Act programs[]."[102] In this instance, the incentive costs shall not be subject to a regulatory asset. All costs, regardless of recovery through surcharge or by regulatory asset, shall be subject to a review for prudency of the electric company's expenditures.

Therefore, the Commission directs the Exelon Utilities to propose a surcharge mechanism for cost recovery for their EDSSS pilots similar in structure to Potomac Edison's pilot proposal. Moreover, the Utilities' surcharge cost recovery will be subject to annual reconciliations for the duration of the two-year pilot. At the annual reconciliation after Year 1, the Utilities shall provide an interim program evaluation and any proposed changes to pilot programs before the final program evaluation after Year 2. However, if an electric company deems pilot program changes are necessary anytime based on its experience running the pilot programs, it should not wait for a reconciliation to propose changes to the Commission. The Commission directs Staff to work with the Utilities and OPC to propose a uniform reconciliation process and reconciliation reporting requirements within 90 days of the issuance of this Order. Staff's recommendation should also include whether the Commission should address the reconciliation during an Administrative Meeting or whether it requires a separate, evidentiary hearing.

Finally, as these pilot programs potentially transition to permanent programs, a regulatory asset may be appropriate post-transition, provided that the costs are demonstrably unusual in nature, non-recurring, and extraordinary.[103] However, the

[102] Maillog No. 315287, Clarification of Order No. 91391 at 3.
[103] *See In re Application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan, Order on Application for a Multi-Year Rate Plan*, Case No. 9692, Order No. 90948 at 31 (applying specific requirements for establishing a regulatory asset in denying BGE's request for a regulatory asset for non-major outage event O&M costs).

Commission will defer any decisions on cost recovery and appropriate rate of return for these permanent programs—whether in a regulatory asset or other—until such permanent programs are proposed or addressed in future rate cases.[104]

10. Locational Value

a. Positions of the Stakeholder Parties

A number of participants emphasized the importance of identifying local needs for VPPs to be used as non-wires solutions and the associated locational targeting of VPP marketing efforts for this purpose. To that end, several stakeholders criticized certain electric company EDSSS proposals for focusing on system peak reduction and neglecting local peak reduction.

b. ***Commission Determination***

The Commission agrees with stakeholders on the importance of identifying local needs for VPPs and locational targeting of VPP marketing efforts. As stated at the outset of this Order, the DRIVE Act specifically defines EDSSS to include: (i) local or system peak demand reduction; (ii) demand response; (iii) the avoidance or deferral of a transmission or distribution upgrade or capacity expansion; and (iv) facilitating hosting capacity to accommodate additional distributed energy resources.[105] Therefore, the Commission directs the Utilities to develop strategies for identifying local needs as well as

[104] While not germane to this Order, the Commission believes that future rate recovery for any permanent VPP program—e.g., at a similar return on equity ("ROE") for electric distribution infrastructure—should require, at minimum, that the electric company clearly show these investments are providing grid benefits that are replacing the need for local electric system infrastructure, contributing to lower customer rates, and improving resource adequacy for the electric system.

[105] PUA § 7-1001(e)(2).

locational marketing targeting strategies to achieve the DRIVE Act goals for an EDSSS pilot.

11. Transparency, Metrics, and Reporting

a. Positions of the Stakeholder Parties

MEA, Staff, Solar United Neighbors, and Sunrun underscore that transparency is vital for evaluating EDSSS pilot program success, ensuring accountability, and fostering public trust. There is a strong call for clear metrics, transparent data streams, and robust evaluation plans for the pilots. Concerns have been raised about the lack of detail in the utility proposals and the need for approved evaluation plans before the Commission can approve program budgets. Parties also request more frequent and/or enhanced reporting.[106]

*b. **Commission Determination***

The Commission agrees with the above non-utility parties and finds the utility EDSSS proposals, as filed, lack sufficient detail to evaluate program success and secure public trust in their implementation under the DRIVE Act. Accordingly, the Commission directs the Utilities to propose clear metrics and robust evaluation plans for the pilot programs. Furthermore, the Commission has already established a systematic approach to developing and evaluating a pilot program as described in Order No. 88438[107] that, among other things, requires:

1. clear goal(s) established at the beginning of pilot program development;
2. evaluation metrics linked to those goal(s) that will

[106] *See e.g.*, Staff Comments at 14 and MEA Comments at 2.
[107] *See In the Matter of the Baltimore Gas and Electric Company Request for Approval of a Prepaid Pilot Program and Request for Waivers of COMAR and Commission Orders*, Case No. 9453, Order No. 88438 at 20 (describing necessary factors for successfully evaluating pilot programs).

inform whether the goal(s) are achieved;

3. an evaluation plan developed before final pilot approval;

4. an estimate of pilot program implementation costs [and projected benefits[108]];

5. public sharing of key pilot program data after pilot is complete, and at regular intervals during the pilot if appropriate;

6. public review of pilot results by the Commission;

7. a clear transition plan for current customers (including transitioning to permanent tariffs); and

8. a firm sunset date – any extension, amendment or permanent authorization must be affirmatively approved by the Commission.

The Utilities are directed to report pilot program evaluation metrics on a quarterly basis, within 30 days after the end of each quarter, upon the start of Year 1. These program evaluation metrics shall include customer device and aggregator enrollments as compared to targets, estimated cumulative system peak load reduction benefits as compared to targets, and actual expenditures as compared to budgeted expenditures, among other program evaluation metrics the electric company deems necessary for EDSSS program evaluation and status reporting. Each electric company shall also provide an interim pilot program evaluation report within three months after the conclusion of Year 1, and a final pilot program evaluation report three months after the conclusion of Year 2, including lessons learned from the pilot programs. The Utilities shall include in their final program evaluation

[108] Although Order No. 88438 did not specifically include an estimate of projected benefits, to the extent that quantitative benefits can be projected, an electric company should provide these estimates, including the assumptions made when performing the estimate. Since these programs are pilot programs that serve the public interest pursuant to the legislative intent of the DRIVE Act, the Commission shall consider other factors besides cost-effectiveness in approving these pilot programs as it did in Case No. 9619 for the energy storage pilot program, where several proposed pilot programs did not yield a positive benefit-cost analysis (BCA) above 1.0.

report their recommendations for transitioning the pilot programs to permanent programs, requesting an extension of the pilot program for good cause, or terminating a pilot program altogether.

12. Transition to Permanent Programs

a. Positions of the Stakeholder Parties

Several parties, including CPower and VGIC, emphasize the importance of establishing a clear and well-defined pathway for successful EDSSS pilot programs to transition seamlessly into permanent, scaled programs. They advocate that this is crucial for maintaining customer engagement, realizing long-term energy goals, and providing regulatory certainty. Several parties also call for standardized programs across the Utilities to facilitate scaling. They claim the pilots are a "bridge" to more robust, future VPP programs, with an emphasis on learning from the pilots and adapting programs accordingly to incorporate lessons learned.

*b. **Commission Determination***

The Commission agrees there must be a pathway for pilots to transition to permanent programs, as addressed above in Topic Item No. 3 – Aggregator Role. The Commission said if the Utilities retain a "third-party implementer" model, they are to also provide a clear pathway to transition to permanent programs. While several parties called for standardized pilot programs across the Utilities to facilitate scaling into permanent programs, the Commission does not agree that program standardization should be a guiding objective in the pilot phase, as diversity in the pilot programs should facilitate broader learning opportunities. The standardization of permanent programs may be a future objective that is informed by the learnings from the pilot programs in the event the pilot programs are made permanent.

13. Equity

a. Positions of the Stakeholder Parties

Staff, Solar United Neighbors, and SEIA/United/CHESSA collectively highlight the critical need for explicit strategies and targeted incentives to ensure equitable participation in VPP programs, particularly for LMI households. This focus aims to prevent VPP benefits from being concentrated among higher-income demographics and ensure that all Maryland residents can have the opportunity to participate in, and benefit from, the energy transition. The DRIVE Act prioritizes LMI households, but the as-filed utility proposals lack clear LMI initiatives or sufficient incentives. To shore up this gap, stakeholders suggest providing upfront incentives and exploring models from other states such as Connecticut.[109]

*b. **Commission Determination***

The Commission agrees that equity considerations must be designed into the EDSSS pilot programs given the DRIVE Act specifically states that "it is reasonable to provide additional incentives and protections to low- and moderate-income households [] to ensure access to the benefits of . . . on-site energy systems," among other things.[110]

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[109] In Connecticut, the equity adder is an increased incentive for income-eligible residents or those living in environmental justice communities. This equity adder is applied to the state's Energy Storage Solutions ("ESS") program, which supports the installation of residential energy storage systems that participate in VPPs. The equity incentive for the ESS program is not a simple multiplier, but rather a direct increase in the rebate amount based on specific eligibility criteria. *See generally*, Public Utilities Regulatory Authority, Energy Storage Solutions Program, https://https://portal.ct.gov/pura/electric/office-of-technical-and-regulatory-analysis/clean-energy-programs/energy-storage-solutions-program#:~:text=Program%20Overview,access%20to%20more%20reliable%20power (last visited Oct. 13, 2025).

[110] PUA § 7-1002(4).

Furthermore, the DRIVE Act states that in determining whether to require an investor-owned electric company to offer an incentive or rebate, "the Commission shall consider [] the benefit of reducing the operation of peak generating facilities in overburdened and underserved communities…."[111] Although the Drive Act does not define overburdened and underserved communities, it is clear that this refers to overburdened and underserved communities as defined in Section § 1–701 of the Environment Article. Where the legislative intent of the DRIVE Act includes the consideration of equity to ensure access to the benefits of on-site energy systems for LMI households, the Commission directs the Utilities to propose strategies that may include potential incentives[112] or other alternative creative strategies that promote equitable participation in VPP programs.

14. Utility Ownership of BTM VPP Devices

a. Positions of the Stakeholder Parties

As previously noted in the discussion of Topic Area No. 4 – Broader Participation, several stakeholders emphasize the importance of ensuring eligibility for third-party-owned systems in VPPs. Other stakeholders oppose utility ownership of devices, advocating for third-party ownership and emphasizing the importance of enabling aggregators.

[111] PUA § 7-1006(b)(1).

[112] In Order No. 91391 on DRIVE Act On-Site Generating System Incentives, the Commission specifically authorized utilities or other entities to propose incentive programs for renewable on-site generating systems (i.e., solar+storage) in the future. While not mandatory, the order requires that any utility proposing a renewable on-site generating system incentive program should include, *inter ali*a, a component for LMI customers in its proposal. The Commission further clarified this order in Maillog No. 315287. *See* Order No. 91391 at 3.

b. Commission Determination

In Order No. 91705, the Commission denied the Exelon Utilities' Utility-Owned Residential Customer Sited BTM BESS concept proposal[113] and further explained in subsequent Order No. 91812 that the Exelon Utilities' proposal may create a regulatory disincentive for third-party programs, among other concerns.[114] Order No. 91812 further stated that "the Commission is also concerned that the Exelon Utilities' proposal to replicate a similar program by Green Mountain Power ("GMP") may be a poor model for Maryland because the main driver for the GMP program was reliability, and Maryland reliability is generally 1st or 2nd quartile [with the Exelon Utilities' reliability being 1st quartile]."[115] The Commission further explained in the Order, however, that its decision on utility ownership of BTM energy storage "does not preclude future utility ownership of BTM energy storage" and used an EmPOWER use case as an example where utility ownership of BTM BESS may be appropriate.[116] Given the Commission's prior view, the Commission notes that other use cases may also be appropriate for utility ownership of BTM VPP devices.

As discussed in the above Topic Area No. 10 – Locational Value, the importance of identifying local needs for VPPs to be used as non-wires solutions and the associated locational targeting of VPP marketing efforts for this purpose was emphasized by several participants. To that end, the Commission will consider proposals for utility ownership of BTM VPP devices in the limited use case of non-wires solutions, provided that the third-party market does not provide acceptable solutions. Also as described herein in Topic Area

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[113] *See In re Maryland Energy Storage Program*, Case No. 9715, Order No. 91705 at 6.
[114] *See In re Maryland Energy Storage Program*, Case No. 9715, Order No. 91812 at 9.
[115] *Id*. at 13.
[116] *Id*. at 13-14.

No. 13–Equity, the Commission is directing the Utilities to propose strategies that may include potential incentives or other alternative creative strategies that promote equitable participation in VPP programs. For this purpose, the Commission may also consider utility ownership of BTM VPP devices for the use case of promoting equitable participation in VPP programs.

IV. CONCLUSION

The Commission recognizes that the General Assembly passed the DRIVE Act with the primary public benefit goals of accelerating the State's transition to clean energy resources while strengthening electric grid resiliency and reducing consumer energy costs. Both the General Assembly and the Commission have been challenged by a variety of factors in providing adequate and affordable energy while assuring environmental sustainability. By leveraging technology and policy to enhance the availability and effective management of energy resources, we can utilize the local distribution network as an important contributor to energy resource capabilities and system reliability. The Act stands on three strategic pillars, two of which involve the coordination of investor-owned electric companies to incentivize off-peak energy use and improve grid management through virtual power plants. In large part, the Commission considers the Utilities' TOU offerings to represent reasonable steps forward in promoting customer participation in TOU rates and in shifting electricity usage to off-peak periods. While the Commission generally agrees with the Utilities' proposed TOU modifications, specific concerns remain over the PHI Companies' outsized proposed budgets. For the reasons discussed herein, modifications to certain elements of the proposals are warranted.

Regarding the Utilities' EDSSS pilot proposals, the Commission has addressed a number of complex issues in this Order that reveal material gaps in the as-filed proposals that must be addressed to implement the DRIVE Act successfully. Accordingly, the Commission requires that the Utilities refile their EDSSS proposals to better align their programs with the legislative intent of the DRIVE Act, in accordance with the specific direction provided in this Order on several major topic areas. The Utilities are directed to re-file their EDSSS proposals within 90 days of this Order.

The Commission recognizes that it will take time for the Utilities to cure their EDSSS proposals and that all aspects of this Order may not be completed or clearly defined in the revised proposals within 90 days, with some aspects of their proposed program only able to be defined after a third-party implementer is secured through an RFP solicitation. However, the Commission is anxious to begin implementation of the pilot programs and views securing third-party implementers, if needed, through an RFP solicitation as the critical path approval needed by the Utilities to begin implementation. Therefore, the Utilities are directed to focus on presenting enough information in their revised proposals on the following items: a revised pilot program scale; pilot duration; the participation and role of the licensed aggregator vs. third-party implementer; and associated budgets—within 90 days of this Order to allow the Commission to consider and potentially approve the revised pilot programs. To the extent an electric company retains a third-party implementer model, this should allow for a timely Commission approval for the company to proceed with an RFP solicitation.

For all other aspects of the Utilities' refiled EDSSS proposals that are undefined within 90 days of the issuance of this Order, the companies are directed to clearly state in the filing when and what information they will provide to the Commission at a later date to facilitate full review and approval of their EDSSS pilot programs.

IT IS, **THEREFORE**, this 21st day of October, in the year Two Thousand Twenty-Five, by the Public Service Commission of Maryland, **ORDERED**:

(1) that the investor-owned electric companies shall file their revised time-of-use tariffs and/or new time-of-use tariffs in accordance with this Order;

(2) that Potomac Electric Power Company ("Pepco") shall provide an analysis of possible changes to its Schedule R-TM in the next base rate case, as described herein;

(3) that Baltimore Gas and Electric Company and The Potomac Edison Company shall implement their proposed time-of-use marketing and customer outreach plans in the timeframes specified in their proposals;

(4) that Pepco and Delmarva Power & Light Company shall provide, within 45 days of the issuance of this Order, a modified time-of-use budget that reflects a two-year implementation period, as well as an associated detailed cost-benefit analysis and marketing plan, consistent with this Order, as described herein;

(5) that Potomac Edison shall consult with the Technical Staff and the Office of People's Counsel regarding a proposal to cease its practice of implementing non-residential declining time-of-use block rates, to be filed with its next rate case or within two years, whichever is earlier;

(6) that the investor-owned electric companies shall file revised EDSSS proposals within 90 days of the issuance of this Order that address the Commission's direction as discussed herein;

(7) that Order item No. 9 in Commission Order No. 91218 that requires an investor-owned electric company assessment of EDSSS pilot programs on or before October 1, 2027, is hereby rescinded and replaced with the EDSSS reporting requirements in this Order as discussed herein: and

(8) that the Commission's Technical Staff shall work with the electric companies and OPC to propose a uniform reconciliation process within 90 days of the issuance of this Order as discussed herein.

/s/ Frederick H. Hoover, Jr.

/s/ Kumar P. Barve

/s/ Bonnie A. Suchman

/s/ Odogwu Obi Linton

/s/ Ryan C. McLean
Commissioners