Deferring Distribution System Upgrades

CONSIDERATIONS FOR EXPANDING NON-WIRES SOLUTIONS AND TIME-OF-USE RATES

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I. Introduction

The Distributed Renewable Integration and Vehicle Electrification (DRIVE) Act and Maryland Public Service Commission (Commission) Orders No. 91218 and 92422 require each investor-owned electric company to file a report providing an assessment of the potential to avoid or defer electric distribution system capital projects through various demand-side resources and programs, and the merits of transition to time-of-use (TOU) rates on an opt-out basis. This report is provided to meet these requirements on behalf of Potomac Electric Power Company (Pepco) and Delmarva Power & Light Company (Delmarva Power) (collectively, Pepco Holdings, Inc., PHI or The Companies).

The relevant section of the DRIVE Act, PUA § 7–1003, states:

> *On or before July 1, 2026, each investor-owned electric company shall submit a report to the Commission evaluating:*
>
> *(1) the potential to avoid or defer electric distribution system capital projects through the use of time-of-use rates, demand-response and demand-side programs, and renewable on-site generating systems; and*
>
> *(2) the merits and feasibility of transitioning all customers to a time-of-use tariff on an opt-out basis.*

The first section of the report, "Deferring Distribution System Capital Projects," addresses the initial requirement to assess the potential to defer capital projects through demand-side programs. For each currently forecasted system constraint, the report provides (a) projected peak load exceedance, (b) duration of forecasted overload, and (c) time-of-day distribution of overloads. The Companies did not identify non-wires solutions (NWS) for system constraints as part of their 2026 Annual Electric System Plan Updates, filed June 12, 2026, under Case No. 9665, and so peak load reduction potential of distribution programs per constraint and related benefit cost analyses are not included in this report. As directed by the Commission, this section also provides a screening for overall program potential, rather than a constraint-specific quantification of deferral potential. This section is intended to provide an understanding of the potential of each demand-side program/resource to contribute to avoidance or deferral of capital expenditures in the long term. For each program, this section includes the metrics (1) peak load reduction potential, (2) annual cost per kW of peak demand reductions, (3) the potential to direct load reductions to specific, localized, or defined geographic locations, (4) potential performance at different times of day, (5) other practical considerations, and (6) a description of distribution deferral screening capability, as directed by Order No. 92422.

The next section of the report, "Transitioning to Time-of-Use Rates on an Opt-Out Basis," addresses the second requirement to assess the merits and feasibility of transitioning to a TOU tariff on an opt-out basis for all customers. This section describes the Companies' existing residential TOU offerings in Maryland, compares opt-in and opt-out deployment approaches, and evaluates the potential peak-demand impacts of broader TOU adoption. It also discusses implementation considerations associated with an opt-out TOU transition, including customer communications, marketing, digital tools, program management, customer protections, decoupling, metering, information technology (IT) systems, and transition costs.

The Companies are in the process of continuing to understand the associated time and cost considerations for the following requests included in Order No. 92422:

> *To extent information is available provide:…(b) where there is a high level of uncertainty regarding the potential per-participant load reductions or enrollment levels associated with a program or rate offering, the IOUs should present expected peak load reduction potential and corresponding cost estimates across at least three scenarios—conservative, expected, and high-achievement cases—to bound potential outcomes. The IOUs should explain how these scenarios were derived; (c) for existing programs, the IOUs should assess whether design modifications could improve performance and quantify the impacts of such modifications. The IOUs should document what modifications would be required to enhance the programs and what the potential impacts of such modifications would be, (d) where complete data is not available for all programs, provide reasonable estimates with description of underlying assumptions, (e) Identify key measurement choices and assumptions in analyses including peak period evaluated and relevant time window for load reductions and report if value reported is actual observed performance, modeled potential, optimized deployment or come combination.*

The Companies detailed in their "Proposed Distribution System Support Services Pilots Plans," filed January 20, 2026, under Case No. 9761, as well as in their filing "Demand Side Management Program Inventory" in Accordance with Case No. 9761 and Notice of Hearing & Initiating PC 77, proposed improvements to existing load management programs. As additional programs mature, the Companies will be able to collect lessons learned and design program improvements for filing each cycle.

II. Deferring Distribution System Capital Projects

This section presents PHI's evaluation of the potential to avoid or defer electric distribution system capital projects through the use of TOU rates, demand response, demand-side programs, and renewable on-site generating systems.

The first subsection provides the procedural background for this report, including links to key parallel proceedings such as the 2026 Annual Electric System Plan Updates filed June 12, 2026, under Case No. 9665, which contains more detailed, constraint-specific analyses of the need and potential for deferral of planned distribution projects.

The second subsection provides information regarding currently forecasted distribution constraints, as directed by the Commission in Order No. 92422:

> *First, the IOUs report, as described by the JEUs, for each currently forecasted system constraint, (a) projected peak load exceedance, (b) duration of forecasted overload, (c) time-of-day distribution of overloads, and (d) peak load reduction potential of, at minimum, the distribution programs an IOU has assessed as possible non-wires solutions for that constraint as part of ESP.*

The third subsection evaluates demand-side programs and distributed energy resources (DERs) based on six program metrics, as directed by the Commission in Order No. 92422:

> *Second, the Commission adopts all six of the metrics recommended by Staff and the corresponding detailed descriptions, and directs that the utilities include these metrics in their July Reports.*

A. Procedural Background

This report builds on several active Maryland regulatory proceedings that collectively define how PHI plans for distribution needs, evaluates NWS, and develops and evaluates flexible load and DER programs. Together, the Electric System Planning, Distributed Renewable Integration and Vehicle Electrification (DRIVE) Act, Virtual Power Plant Program, Maryland Energy Storage Program, Electric Vehicle Smart Programs, EmPOWER Maryland load management, and Universal Benefit-Cost Analysis (UBCA) proceedings provide the planning framework, program data, and evaluation metrics used to assess whether these resources may avoid or defer future distribution capital projects.

Electric System Planning and Non-Wires Solutions: Maryland's Electric System Planning (ESP) process, including Case No. 9665, is the primary distribution-planning venue through which utilities identify system constraints, forecast load growth, evaluate DER impacts, and plan potential capital investments. The ESP is the relevant venue for evaluating whether a resource can be considered in PHI's NWS evaluation process and provide the grid services needed to mitigate a specific identified distribution grid constraint. Therefore, this report instead provides a screening for overall program potential of the characteristics of each existing and proposed demand-side program and outlines the important considerations for their inclusion in the NWS framework.

DRIVE Act/Distribution System Support Services Program/Virtual Power Plant Program: In Case No. 9761, PHI proposed Distribution System Support Services (DSSS) pilots as part of the DRIVE Act implementation process. PHI's revised proposal includes a portfolio of customer-side and aggregator-enabled resources, including behind-the-meter (BTM) batteries and electric vehicle (EV) resources, commercial and industrial (C&I)/aggregator curtailment, and heating, ventilation, and air conditioning (HVAC) load management resources. This portfolio as a whole comprises PHI's proposed virtual power plant (VPP) framework, which can provide system peak reduction, locational grid services, and potentially defer distribution investments (if needed) where sufficient resources are available in the relevant location time window, with demonstrated ability to perform.

Existing Load Management, Demand Response, and EV Programs: Several of the resources evaluated in this report are existing or proposed expansions of PHI programs already operating under other Maryland dockets, including EmPOWER Maryland (Case No. 9705), and related demand response/load management programs, and EVSmart electric vehicle portfolio of programs (Case No. 9478). These include Smart Charge Management, bring your own device (BYOD) thermostats, direct load control (DLC) devices, and other flexible load resources. The DRIVE/DSSS proposal contemplates transitioning certain load management resources into a coordinated VPP framework to expand their role in reducing peak demand and supporting grid flexibility.

Maryland Energy Storage Program: The Maryland Energy Storage Program (MESP) and the Next Generation Energy Act require utilities to procure distribution-connected front-of-the-meter battery energy storage systems (BESS). PHI's initial Proposed Distribution Connected Energy Storage Procurement Plan for Front-of-the-Meter Energy Storage Devices, filed in accordance with Case No. 9715, focuses on third-party-owned BESS resources used primarily for system peak reduction, with the potential to provide additional distribution grid services where projects are sited, contracted, and dispatched to address specific local system needs. Although the initial procurement is not tied to a specific identified NWS constraint, future procurement rounds may allow front-of-the-meter (FTM) storage to be more directly integrated into NWS screening and distribution planning.

Distributed Energy Resources Management Systems (DERMS), Aggregation, and Operational Visibility: The ability of DERs and flexible load resources to support capital deferral depends on more than installed capacity or system peak reduction capability. It also depends on telemetry, communications, dispatchability, cybersecurity, aggregator coordination, customer participation, and utility operational visibility. PHI's DRIVE, ESP, and DERMS-related filings identify Utility DERMS, Grid-Edge DERMS, DER Gateway functionality, and data exchange as important enabling capabilities for future locational dispatch and planning reliance. Completion of PHI's utility DERMS and DER Gateway initiatives will further improve the ability to dispatch load management resources based on feeder-, substation-, or other location-specific system needs. The immediate use cases for the utility DERMS include monitor and control of utility owned and operated DERs, flexible interconnection, and DER Aggregator (DERA) orchestration. PHI aims to finalize a utility DERMS in 2027 and corresponding communications and cybersecurity protocols by end of 2028.

Universal Benefit-Cost Analysis: The UBCA framework is Maryland's framework for evaluating the costs and benefits of DERs, utility-led programs, and grid investments. Development of this framework is currently in progress. The UBCA can help structure comparisons between traditional wires solutions and NWS such as storage, managed charging, demand response, load management, and on-site generation. Because UBCA methods continue to evolve, this report does not attempt to report a full program-wide BCA for each resource. Instead, it reports the Commission-ordered program metrics and discusses BCA results where they are available from existing proceedings.

B. Forecasted System Constraints

This subsection reports the forecasted system constraints identified in Pepco's and Delmarva Power's June 2026 Annual Electric System Plan Updates[1] and provides the constraint-specific information requested by the Commission: projected peak load exceedance, duration of forecasted overload, and the time-of-day distribution of overloads.

PHI's latest ten-year forecast identifies a limited number of distribution system constraints. Delmarva Power's system is not forecasted to have any feeder or substation constraints in its latest ten-year forecast. Pepco's system has six forecasted constraints: four feeder overloads in 2026, one feeder overload in 2027, and one substation overload in 2030. Table 1 provides the Commission-requested metrics for each of Pepco's identified constraints.

TABLE 1. CONSTRAINT-SPECIFIC METRICS FOR CURRENTLY FORECASTED SYSTEM CONSTRAINTS

Constrained Asset	Forecasted constraint year	Projected peak load exceedance above asset rating	Duration of forecasted overload	Time-of-day distribution of overloads
Feeder 14288	2026	0.1 MW	1 hour	Summer 8pm to 9pm
Feeder 15282	2026	0.7 MW	2 hours	Summer 1pm to 3pm
Feeder 15855	2026	1.0 MW	6 hours	Summer 1pm to 7pm
Feeder 14246	2026	0.7 MW	3 hours	Winter 7am to 10am
Feeder 14163	2027	0.2 MW	2 hours	Summer 5pm to 7pm
Kingswood Substation	2030	1.7 MW	4 hours	Summer 4pm to 8pm

Evaluation of NWS as a potential remediation for identified constraints is a standard part of PHI's distribution system planning process. The NWS evaluation process is described in the June 2026 Annual Electric System Plan Update.[2] PHI conducts two steps as part of the NWS evaluation:

1. **Timeline:** The distribution project identified as a remediation for the constraint has an in-service date at least 36 months after the project approval date. This allows for sufficient time for NWS scoping, procurement, and implementation.

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1 Pepco 2026 Annual Electric System Plan Update and Delmarva Power 2026 Annual Electric System Plan Update, Case 9665

2 Pepco's Annual Electric System Plan Update, pp. 11–12.

2. **Cost:** The distribution project identified as a remediation for the constraint has a cost exceeding $500,000. This ensures that the planning and implementation efforts associated with NWS procurement are directed to high value opportunities and makes it more likely that NWS portfolios identified will be cost-effective.

None of the forecasted constraints passed both criteria for NWS evaluation, as summarized in Table 2. Pepco plans to remediate all constraints through load transfers, as adjacent feeders have availability to receive transferred load. Load transfers are also the most cost-effective and efficient solution, as they are not expected to exceed the $500,000 cost threshold and will be resolved within a three-year period. Therefore, Pepco has not identified NWS as the appropriate solution for any of the currently forecasted constraints.

TABLE 2. NWS SCREENING RESULTS FOR EACH FORECASTED CONSTRAINT

Constrained Asset	Planned Remediation Measure	Is remediation project cost > $500,000?	Is remediation project in-service date > 36 months away?
Feeder 14288	Load Transfer	No	No
Feeder 15282	Load Transfer	No	No
Feeder 15855	Load Transfer	No	No
Feeder 14246	Load Transfer	No	No
Feeder 14163	Load Transfer	No	No
Kingswood Substation	Load Transfer	No	Yes

C. Demand-Side Program Metrics

To facilitate a consistent and comparable assessment of the potential for demand-side resources to avoid or defer electric distribution system capital projects, this report applies the common program evaluation and criteria framework proposed by Staff[3] and adopted by the Commission.[4] The Order directed the investor-owned electric utilities to report six program-level metrics for each TOU rate, demand response program, demand-side management program, and renewable on-site generation resources evaluated in this report. The six metrics

[3] Staff comments Maillog No. 328627

[4] In Order No. 92422

are focused on the ability of demand-side resources to reduce peak demand because it is often the primary driver of distribution grid constraints. The six metrics reported for each program in this report are:

1. **Peak Load Reduction Potential**: The estimated magnitude of peak demand reduction that a program can provide. Where available, the report provides both existing and forecasted load reduction capability.
2. **Annual Cost per kW of Peak Demand Reduction**: The estimated annual program cost associated with each kilowatt of peak demand reduction, with utility administrative costs and participant incentives reported separately where possible.
3. **Potential to Direct Load Reductions to Specific Locations**: The ability of the program to produce load reductions in defined geographic areas. Incremental location-specific load reductions can be achieved through two strategies: (i) by scaling program enrollment in specific locations or (ii) by modifying program operation to optimize for location-specific grid needs. Scaling location-specific enrollment could involve additional location-based incentives and targeted marketing. Location-based optimization of program operating would involve planning and operational visibility into local grid needs and interfacing between utility-side systems and aggregator/customer-side DER management systems to dispatch DERs based on the load shape and needs of a specific location on the distribution grid. The report discusses both strategies as part of this metric for each program.
4. **Potential Performance at Different Times of Day**: The ability of the program to reduce load during specific hours or operating windows, including the duration and repeatability of those reductions.
5. **Other Practical Considerations**: Operational, customer, program management, and implementation considerations that may affect program performance, including dispatchability, customer participation requirements, and reliance on behavioral response.
6. **Distribution Deferral Screening Capability**: The ability of the program to contribute to the avoidance or deferral of distribution capital investments, including the types of constraints for which the resource may be applicable, the expected magnitude and duration of load reductions, deployment timelines, and the extent to which the resource is reliable and dispatchable enough to be incorporated into planning assumptions.

As staff noted,[5] these metrics are intended to support a screening-level evaluation of distribution system value rather than a definitive quantification of specific avoided capital expenditures. Further, peak demand reduction alone is not sufficient to demonstrate the ability to avoid or defer a distribution capital project. For a resource to provide distribution planning value, its load reductions must be *locationally coincident* with constrained portions of the system*, temporally coincident* with the relevant peak or overload condition, *sufficient in magnitude* to affect the timing or need for an investment, and *sufficiently reliable* to be incorporated into planning assumptions. Accordingly, the program metrics presented in this section should not be interpreted as estimates of avoided capital expenditures or as evidence that a specific distribution project can be deferred. When program capability is to be evaluated to facilitate deferral of a specific constraint as part of a non-wires solution, each of these metrics must be further studied and quantified in the context of the specific location and constraint. However, the metrics discussed in this report provide a consistent basis for comparing the characteristics and capabilities of different resources and evaluating their potential suitability for future application through PHI's distribution planning and NWS evaluation processes.

The following sections provide the six metrics for the following PHI DER programs: (1) Maryland Energy Storage Program, (2) Smart Charge Management Program, (3) DRIVE/DSSS Battery VPP Program, (4) Load Management Programs, (5) C&I/Aggregator Program, (6) Behind-the-Meter Solar Generation, and (7) EmPOWER Energy Efficiency Program.

1. Maryland Energy Storage Program

The Maryland Energy Storage Program (MESP) is being developed pursuant to the Next Generation Energy Act. The program is designed to allow for the electric owned utilities to develop utility-owned and operated or third-party owned and operated based on utility direction FTM, distribution-connected BESS that can provide system peak reduction, wholesale market services, and distribution grid services. PHI's initial proposal[6] focuses on third-party owned batteries directed to target system peak reductions to reduce PJM capacity obligations. When not being used to target peak shaving, the batteries are expected to serve multiple use cases and "value stack" including participation in wholesale markets.

[5] Staff comments Maillog No. 328627

[6] Proposed Distribution Connected Energy Storage Procurement Plan for Front-of-the-Meter Energy Storage Devices, filed November 3, 2025 in Case 9715.

Table 3 provides the six Commission-adopted metrics for the planned FTM storage procurements through the MESP.

TABLE 3. MARYLAND ENERGY STORAGE PROGRAM METRICS

Metric 1: Peak load reduction potential
Existing capacity: 0 MW **Procurement targets:** • MESP 1: 10.5 MW/42 MWh for Pepco and 4 MW/16 MWh for Delmarva Power • MESP 2: 21MW/84MWh for Pepco and 8MW/32MWh for Delmarva Power **Potential peak load reduction capability:** The procured resources are expected to be four-hour batteries. PJM accredits 4-hour batteries with an effective load carrying capability (ELCC) of 58%,[7] which suggests that each MW of procured storage can reduce load and offset the need for 0.58 MW of alternative capacity resources. PHI is investigating the opportunity for greater credited load reduction as a load modifier through a PJM Peak Shaving Adjustment Plan.
Metric 2: Annual cost per kW of capacity
Contract costs: Contract costs are confidential. **Administrative cost:** PHI's proposed non-contract program costs include utility administration, IT, outside services, and EM&V, totaling $336,867/year for Pepco and $182,133 for Delmarva Power on average over 15 years of the program. **Estimated annual cost per kW of peak demand reduction:** The cost-per-kW will depend on executed contract pricing.
Metric 3: Potential to direct load reductions to specific, localized, or defined geographic locations
Potential to direct procurement to defined locations: PHI's procurement process evaluates project location, interconnection feasibility, timeline, and system value. FTM storage provides a high degree of locational flexibility because projects can be intentionally sited at specific locations on the distribution system. **Potential to direct operation based on location specific needs:** Storage resources can be dispatched to provide location-specific distribution grid services where dispatch rights have been secured through the MESP contract. PHI's Utility DERMS deployment will improve the ability to utilize storage resources for location-specific applications. As part of PHI's second MESP filing (due November 1, 2026), PHI is investigating the opportunity for future capital project deferrals via local load reduction using BESS. These projects would have a direct impact on the local load on the feeder / substation and defer the point when their thermal limit during peaks would become constraints.

7 ELCC Class Ratings for the 2027/2028 Base Residual Auction

Metric 4: Potential performance at different times of day
Storage resources can be scheduled regardless of time of day, subject to state-of-charge constraints. Battery degradation and warranties may limit battery operation to one cycle per day. This is likely to be sufficient for some of the distribution constraints that PHI may face but is an important consideration to assess when planning for a specific constraint.
Metric 5: Other practical considerations
Availability: Performance depends on battery state of charge and potentially conflicting needs from different use cases. Battery operators may be required to prioritize between wholesale and distribution related services depending on their timing and economic value. To the extent a battery is critical for distribution grid reliability, it may need to be contracted and compensated such that it prioritizes distribution grid needs over other parts of the value stack. **Control and dispatchability:** FTM storage is the most dispatchable resource evaluated in this report. With implementation of a Utility DERMS and integration with the battery control system, assets are expected to be capable of being dispatched on a near real-time basis. **Reliability:** FTM Storage resources provide measurable and verifiable performance and can be monitored directly through utility systems and DERMS platforms. **Other considerations:** Developer readiness, community engagement, vendor experience, cybersecurity compliance, and permitting are important procurement considerations.
Metric 6: Description of distribution deferral screening capability
Types of constraints applicable: FTM batteries can address several types of distribution constraints including voltage, power factor, and thermal constraints at feeders and substation transformers. **Magnitude and duration of load reduction relative to constraints:** Battery load reductions depend on the duration of procured batteries. If sufficient capacity is procured in the required location, or if it is supplemented by a portfolio of other DERs, the portfolio can be scheduled in a coordinated manner to achieve the required magnitude and duration of load reduction to mitigate a constraint. **Ability to deploy resources in targeted areas within required planning timelines:** PHI's NWS process allows for evaluation of NWS solutions for projects with in-service dates at least 36 months from the date of constraint identification. This timeline is expected to be sufficient for procurement, interconnection, and energization of distribution-connected FTM batteries. **Incorporation into planning assumptions:** PHI plans to integrate FTM storage into NWS evaluations and distribution planning in future MESP procurements, starting with the Phase II procurement in Q4 2026. Once batteries are installed, their operation is sufficiently reliable and dispatchable to allow for incorporation into planning assumptions.

2. Smart Charge Management Program

PHI's Smart Charge Management (SCM) Program is designed as an active managed charging program (direct, real-time control of EV changing sessions via vehicle telematics or networked

Level 2 chargers) to optimize EV charging in a manner that supports customer charging needs while reducing system upgrade costs by shifting load to off-peak hours and timing charging sessions to avoid overloading the distribution system. This is in contrast to passive managed charging approaches like TOU rates that encourage customers to shift charging to off-peak periods but the utility or software provider cannot intervene or adjust charging directly. PHI gained approval from the Commission in January 2026 to expand SCM from a pilot into a full program that will operate through 2030. PHI launched the full SCM in May 2026. All data included in this document reflects program performance as of December 31, 2025.

Table 4 provides the six Commission-adopted metrics for the SCM program.

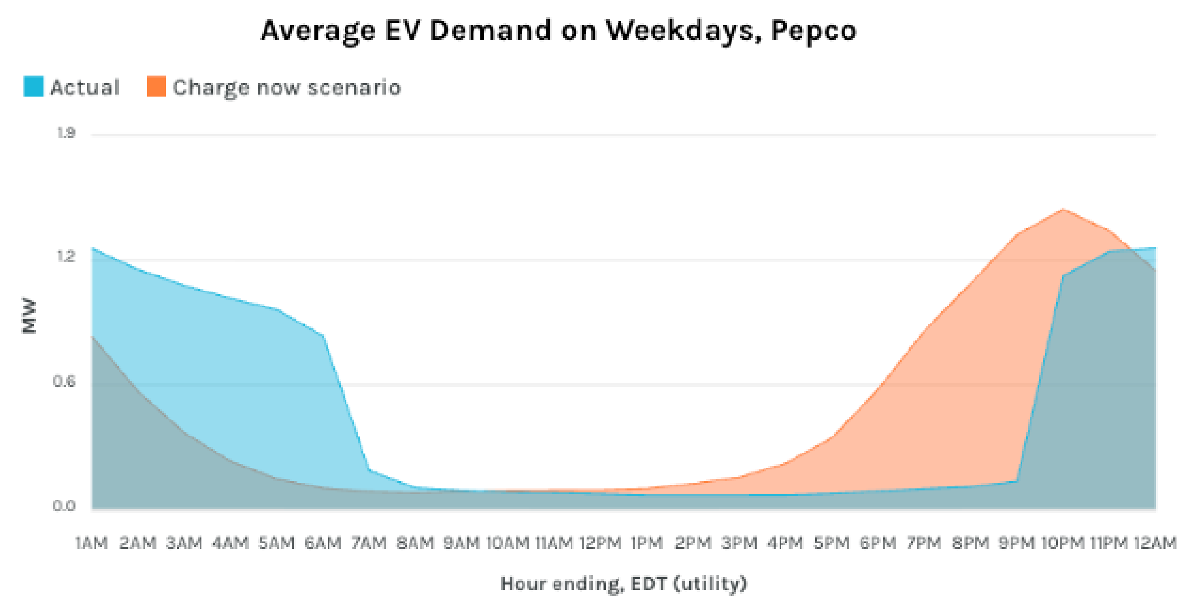
TABLE 4. SCM PROGRAM METRICS

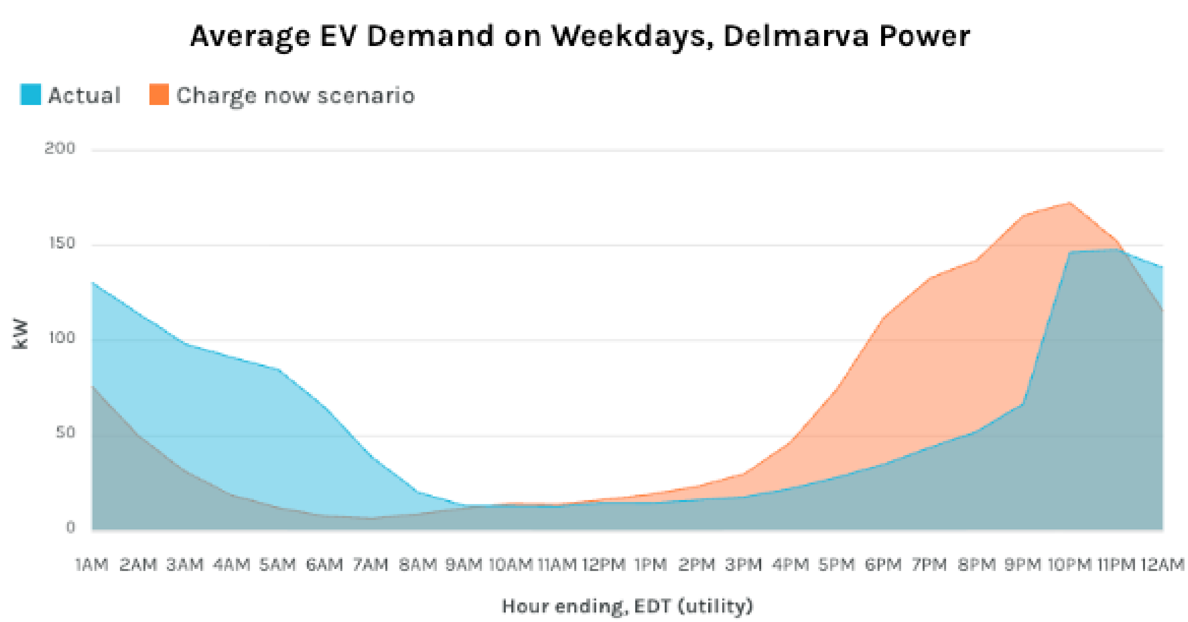
Metric 1: Peak load reduction potential
Existing enrollment[8]: • 1,825 Pepco customers with 2,148 enrolled devices • 156 Delmarva Power customers with 183 enrolled devices
Existing flexible capacity: Aggregate enrolled EV charger capacity of 19.7 MW Pepco and 1.5 MW Delmarva Power
Estimated existing peak load reduction capability: 2.81 MW Pepco and 0.21 MW Delmarva Power, estimated based on the assumption that one out of seven (14%) of enrolled EVs are charging during the peak.
Potential future peak load reduction capability: PHI forecasts that EV adoption in Maryland will grow 230% by 2030. If program enrollment scales to the goals submitted to the Commission (37,500 Pepco and 3,500 Delmarva Power chargers enrolled), peak load reduction capability could reach 49 MW for Pepco and 4 MW for Delmarva Power by end of year 2030.
Metric 2: Annual cost per kW of peak demand reduction
Customer incentives: Customers can receive $10/month per enrolled vehicle with a Level 2 charger and $5/month per enrolled vehicle with a Level 1 charger.
Administrative cost: For the 5-year program period, PHI estimated average annual administrative costs of $3,228,300 for Pepco and $533,100 for Delmarva Power.[9]

8 End of Year 2025 Smart Charge Management Program Report, MD PSC Case No. 9478, ML 326705 (filed on 1/30/26)

9 Based on SCM program admin, utility admin, and marketing costs filing in Case No. 9478 – Filing in Compliance with Order No. 92166, May 12, 2026.

Estimated Annual Cost per kW of Peak Reduction: \$157/kW-yr for Pepco and \$233/kW-yr for Delmarva Power. This estimate is based on the forecasted peak load reduction capability, administration costs, and a \$10/month incentive for each enrolled EV.
Metric 3: Potential to direct load reductions to specific, localized, or defined geographic locations
Potential to direct enrollment to defined locations: The program does not currently use geographically targeted enrollment strategies but could do so in the future as location-specific needs arise. **Potential to direct operation based on location specific needs:** The program is currently designed based on the system-wide average distribution system peak and off-peak periods. PHI is also currently implementing feeder-specific load balancing and is exploring more dynamic optimization strategies that would incorporate forecasted non-EV load on specific distribution assets like feeders. This approach would enable charging schedules designed based on forecasted demand on each feeder. Optimization for more granular assets such as transformers could also be explored in the future.
Metric 4: Potential performance at different times of day
The load reduction capability of EV managed charging programs is dependent on the number of enrolled EVs charging at a given time. Data from enrolled EVs shows that aggregate charging load typically peaks between 5pm to 11pm, making this the time of day when the program's demand reduction capability is highest. Charging load is typically low from 3am to 3pm, so charging can be shifted into this window without creating a new peak. The SCM program shifts load every day to off-peak hours and balances load across the off-peak period in order to prevent secondary peaks from stressing distribution assets. The figure below shows, based on program operation data, how actual EV load enrolled in the program now occurs primarily overnight. If the EVs instead began charging as soon as they plugged in ("charge now scenario"), their load would have occurred primarily between 5pm to 11pm (orange shaded area of the chart, courtesy of WeaveGrid).





Metric 5: Other practical considerations

Availability: Availability of program capacity is subject to customers' charging behavior. As noted under Metric 3, program capacity varies throughout the day and is highest at the times when more customers are charging.

Control and dispatchability: The SCM program is an active managed charging program, with PHI's program partner, WeaveGrid, scheduling EV charging every day during optimal times for customer charging preferences, along with PJM capacity and distribution system needs. The customer is not required to take any action beyond enrolling for the program.

Reliability: The program is designed to provide a reasonable level of reliability through a performance-based incentive structure. Customers must charge at home at least once per month and complete at least 60% of their charging during the specific time periods selected by WeaveGrid to receive their incentive. Customers receive a Smart Charging score, which represents the extent to which a driver follows WeaveGrid's optimized charge schedules. It describes the percentage of total charging energy delivered that occurs during specific time frames from an optimized schedule for that customer on a given day. The average Smart Charging score for the second half of 2025 was 91%, demonstrating high compliance with managed charging schedules.

Metric 6: Description of distribution deferral screening capability

Types of constraints applicable: The SCM program is capable of contributing to avoidance or deferral of thermal capacity constraints at substations, feeders, and service transformers.

Magnitude and duration of load reduction relative to constraints: The program is well-suited to contribute to remediation of thermal constraints that are either driven by EV charging or are coincident with typical unmanaged EV charging peaks. The magnitude and duration of load reduction from this program can be optimized based on location-specific distribution needs, subject to availability of EV capacity.

Ability to deploy resources in targeted areas within required planning timelines: The program does not currently pursue geographically targeted enrollment strategies but could do so in the future. The ability to scale enrollment in a specific location is dependent on the number of EVs in the location. If sufficient EVs are available, the program can pursue geographically targeted enrollment strategies such as marketing and incentive adders to achieve higher enrollment. PHI's NWS screening process allows for consideration of NWS solutions for projects with in-service dates at least 36 months from the date of constraint identification. This timeline is intended to serve as a buffer to allow for scaling enrollment in a location, with time to revert to a traditional grid solution if enrollment fails to reach the levels required to mitigate the identified constraint. In cases where enrollment in a location is already sufficient, but program operation must be optimized to mitigate a specific constraint, the program is more likely to be a timely solution. The program allows for dynamic optimization based on distribution grid needs without negatively affecting the customer experience and therefore, it can be modified on relatively short timelines to meet emerging grid constraints.

Incorporation into planning assumptions: The program can be incorporated into planning through two avenues: (i) through modifications to distribution load forecasts, and (ii) through the NWS process.

PHI does not yet modify its distribution component load forecasts to reflect the impacts of managed charging. However, PHI's implementation of LoadSEER as the load forecasting tool may allow for future modifications to hourly load forecasts to reflect load shape changes from DERs such as managed charging. As the program scales, PHI plans to account for the daily load shape changes from managed charging in load forecasts.

PHI considers managed charging as one of the demand-side solutions in its NWS process. The program is reliable and dispatchable enough to be incorporated into the distribution planning process and PHI expects that it will be part of NWS identified in the future. PHI's implementation of Utility

DERMS and the DER Gateway will allow for an even more sophisticated locationally targeted operation of this program to mitigate distribution constraints.

3. DRIVE/DSSS Battery VPP Program

As part of its revised proposal for a DRIVE VPP pilot program,[10] PHI proposed the DRIVE/DSSS program to enable a coordinated set of core programs to allow customers to manage their energy use while providing enhanced grid services including flexible, dispatchable load reductions. This section focuses on the proposed BTM battery program for residential and commercial customers. The proposed BTM battery program would coordinate customer-sited and aggregated BTM batteries to provide dispatchable load reductions and other grid services. The program is proposed as a two-year pilot that would test DER aggregation, grid export, locational deployment, and performance measurement capabilities.

Gathering learnings of vehicle-to-grid (V2G) technology and integration will be a focus of the DRIVE VPP pilot program scope with the Companies prioritizing efforts to demonstrate successful vehicle-to-everything (V2X) connections. As the Companies develop additional VPP capabilities and gain learnings from these pilots, the Companies will explore a path to including V2G as a resource within the VPP.

Table 5 provides the six Commission-adopted metrics for the DSSS battery program.

TABLE 5. DSSS BATTERY PROGRAM METRICS

Metric 1: Peak load reduction potential
Existing enrollment and peak load reduction capability: None. The program is expected be operational in 2027. **Forecast enrollment and peak load reduction capability:** By Program Year 2, PHI forecasts 418 Pepco battery participants providing 3.28 MW of peak reduction and 124 Delmarva Power participants providing 0.93 MW of peak reduction.
Metric 2: Annual cost per kW of peak demand reduction
Customer incentives: Participants will receive annual connectivity payments and performance-based compensation tied to participation in utility-called distribution system events. The performance-based payment will be up to $300/kW-year based on measured and validated performance. At the forecasted participation rates, PHI projects a total incentive cost of $1.05 million for Pepco and $0.30 million for Delmarva Power in Program Year 2.

10 Proposed Distribution System Support Services Pilots, filed January 20th, 2026, in Case No. 9761

Administrative cost: PHI's January 2026 proposal requested an annual utility administration budget of \$11.96 million for Pepco and \$2.3 million for Delmarva Power, to be shared across the VPP portfolio components. Allocating a third of this budget each to batteries, the C&I program, and load management programs implies battery DSSS program administration costs of \$565,524 for Pepco and \$235,729 for Delmarva Power. [11] **Estimated annual cost per kW of peak demand reduction:** Based on the combined incentive costs and administration costs allocated to the battery program, the total cost per unit of peak demand reduction is \$491/kW-yr for Pepco and \$572/kW-yr for Delmarva Power.
Metric 3: Potential to direct load reductions to specific, localized, or defined geographic locations
Battery resources provide a high degree of locational flexibility because they are dispatchable and can be deployed in targeted geographic areas. **Potential to direct enrollment to defined locations:** PHI does not currently plan to vary the availability of the program or the connectivity incentive by location. However, for participating customers, PHI may vary the participation incentive based on the locational value of load reductions, with higher payments in locations with distribution grid needs. In the future, this program has the potential to be more geographically targeted through locational enrollment goals and connectivity incentive adders, in addition to varying participation payments. **Potential to direct operation based on location specific needs:** Battery resources can be dispatched in response to location-specific distribution needs through coordination between PHI systems and the selected Grid-Edge DERMS platform. PHI outlined several ways it plans to test and verify the value of locational events during the pilot in its January 2026 proposal. Completion of PHI's Utility DERMS and DER Gateway initiatives will further improve the ability to dispatch battery resources based on feeder-, substation-, or other location-specific system needs.
Metric 4: Potential performance at different times of day
Battery resources can provide load reductions during any utility-defined operating windows, including periods of system peak demand or location-specific distribution constraints. Unlike behavioral or load management programs, battery systems can be dispatched whenever sufficient state of charge is available and they are not being utilized by owners for other purposes. Peak shaving can be most effective when the battery is charged during off-peak hours (e.g., overnight) and discharged during midday or evening peaks. The pilot assumes batteries can provide load relief for up to a two-hour peak capacity event after application of appropriate derating factors.
Metric 5: Other practical considerations
Availability: Performance depends on battery state of charge. Assuming customers are unlikely to be discharging their batteries for other purposes, the enrolled batteries are expected to be largely available for program purposes. Targeted dispatch events will not be called more than 4 times per

[11] This figure removes the portion of utility admin costs that is for installation for DLC switches.

month. PHI plans for each event to last for 3 hours and to be scheduled on a weekday between 11am and 7pm, with no events called on holidays or weekends. **Control and dispatchability:** Battery resources are highly dispatchable and represent one of the most controllable demand-side resources available to the utility. The DSSS battery program is planned to operate through direct control of customer batteries or through an aggregator, with 24-48 hours of notice before events. **Reliability:** Customers will be allowed to opt out of events as needed. PHI proposes device-level monitoring, telemetry, and event verification to validate performance. One objective of the pilot is to determine the reliability and planning value of customer-owned battery resources.
Metric 6: Description of distribution deferral screening capability
Types of constraints applicable: The DSSS battery program can address several types of distribution constraints including voltage, power factor, and thermal constraints at feeders and substation transformers. **Magnitude and duration of load reduction relative to constraints:** Battery load reductions will depend on the duration of participating batteries. Residential batteries are typically 2-hour batteries, and commercial batteries can vary widely in their specifications. If sufficient capacity is enrolled in the required location, the portfolio of enrolled batteries can be scheduled in a coordinated manner to achieve the required magnitude and duration of load reduction to mitigate a constraint. **Ability to deploy resources in targeted areas within required planning timelines:** PHI's NWS screening process allows for consideration of NWS solutions for projects with in-service dates at least 36 months from the date of constraint identification. This timeline is intended to serve as a buffer to allow for scaling enrollment in a location, with time to revert to a traditional grid solution if enrollment fails to reach the levels required to mitigate the identified constraint. In cases where enrollment in a location is already sufficient, but program operation must be optimized to mitigate a specific constraint, the program is more likely to be a timely solution. The program allows for location-specific variations in event calls to meet emerging grid constraints. **Incorporation into planning assumptions:** The pilot is intended to establish the operational performance data necessary to support future incorporation into load forecasting, NWS screening, and distribution planning processes. As enrollment scales, PHI expects that DSSS program batteries will be an important component of future NWS portfolios.

4. Load Management Program

PHI's load management programs include the Bring-Your-Own-Device (BYOD) thermostat program and the Direct Load Control (DLC) program for AC cycling via switches, known as EnergyWise Rewards under the EmPOWER Maryland program. The load management programs reduce peak load by adjusting thermostat operation or cycling heating and cooling equipment during utility-called events. Table 6 provides the six Commission-adopted metrics for the load management programs.

TABLE 6. LOAD MANAGEMENT PROGRAM METRICS

Metric 1: Peak load reduction potential

Existing enrollment and peak load reduction capability: PHI operates the BYOD thermostat and DLC resources under EmPOWER. Program enrollment and capabilities as of December 31, 2025[12] are:

- Pepco: 213,853 residential and 3,509 commercial customers with total coincident peak demand reduction capability of 247 MW
- Delmarva Power: 35,188 residential and 1,995 commercial customers with total coincident peak demand reduction capability of 37 MW

Metric 2: Annual cost per kW of peak demand reduction

Customer incentives: The 2025 Customer Incentives budget for EmPOWER's EnergyWise Rewards DLC and BYOD programs was $12,383,814 for Pepco and $2,321,917 for Delmarva Power.[13, 14]

Administrative cost: The 2025 non-incentive program budget including utility administration, operations and maintenance, capital costs, marketing, and evaluation for EnergyWise Rewards were $14,967,081 for Pepco and $4,365,903 for Delmarva Power.[15, 16]

Estimated annual cost per kW of peak demand reduction: Based on the combined incentive costs and allocated administration costs, the total cost per unit of peak demand reduction is approximately $111/kW-year for Pepco and $180/kW-year for Delmarva Power.

Metric 3: Potential to direct load reductions to specific, localized, or defined geographic locations

Potential to direct enrollment to defined locations: PHI can target enrollment and customer outreach to locations where distribution grid needs have been identified. The BYOD thermostat component can be promoted through geographically targeted customer marketing, while DLC enrollment and device replacement can be prioritized in areas with local distribution value. The ability to achieve incremental load reduction in a targeted area will depend on the number of eligible customers, customer willingness to enroll, and the density of controllable heating and cooling load on the constrained feeder or substation.

Potential to direct operation based on location specific needs: Existing BYOD and DLC resources have historically supported system-wide peak reduction and PJM capacity participation. The EmPOWER Locational Demand Response (LDR) Pilot demonstrations allow PHI to explore different deployment strategies and customer approaches to demand response that provide grid services at specific points on the distribution system and during a different season. PHI is pursuing both strategies through the LDR Pilot Program. This program is expected to have 2,849 Pepco customers[17] and 672 Delmarva

[12] Source: EmPOWER Maryland Energy Efficiency Act Report of 2026 With Data for Compliance Year 2025.

[13] Table ES-3B of Pepco Pepco 2025-2026 EmPOWER MD Program Filing, Case No. 9705

[14] Table ES-3B Delmarva Power2025-2026 EmPOWER MD Program Filing, Case No. 9705

[15] Table ES-3B of Pepco Pepco 2025-2026 EmPOWER MD Program Filing, Case No. 9705

[16] Table ES-3B Delmarva Power2025-2026 EmPOWER MD Program Filing, Case No. 9705

[17] Table 5 of Pepco 2025-2026 EmPOWER MD Program Filing, Case No. 9705

Power customers[18] by the end of 2026. Completion of PHI's Utility DERMS and DER Gateway initiatives will further improve the ability to dispatch load management resources based on feeder-, substation-, or other location-specific system needs.
Metric 4: Potential performance at different times of day
Heating and cooling load management performance is tied to the underlying HVAC load shape. The programs are most effective during weather-driven summer and winter peak periods when air-conditioning or electric heating equipment is operating. The programs are less effective during shoulder-season periods or hours when enrolled HVAC equipment may not be actively contributing to load. Cooling load typically peaks in the afternoon through evenings of the hottest summer days. Heating load tends to be flatter and peaks during cold winter mornings and evenings.
Metric 5: Other practical considerations
Availability: Availability depends on weather conditions, and the extent to which HVAC equipment is operating during the event window. Because the underlying end use is weather-sensitive, available capacity will vary by season, type of day, and hour. **Control and dispatchability:** Both DLC and BYOD thermostats are utility-controlled and dispatchable. DLC involves utility ownership of the control switch that provides direct control of HVAC load and customers cannot opt-out during an event. PHI sends signals for participation for customer-owned thermostats and that signal is dependent on the customer's Wi-Fi network and is subject to the interface between the thermostat and the HVAV equipment. Both are mature and proven dispatchable technologies. Dispatch strategies may need to account for potential snapback peaks after events and/or the need to pre-condition before events. **Reliability:** Heating and cooling load control can provide repeated reductions across multiple events, but sustained performance is limited by customer comfort and the need to avoid excessive temperature deviations. This makes the programs most useful for recurring, weather-driven thermal peaks that occur over limited event windows rather than long-duration or non-HVAC-driven constraints. The DLC platform consistently delivers near 100% participation during load-shedding events, providing a highly reliable and predictable resource. BYOD thermostat resources are also dispatchable, but depend on customer-owned devices, customer Wi-Fi or communications systems, and are subject to potential customer overrides.
Metric 6: Description of distribution deferral screening capability
Types of constraints applicable: Heating and cooling load management programs are best suited to address thermal capacity constraints at feeders and substation transformers. **Magnitude and duration of load reduction relative to constraints:** At the portfolio level, the load management programs represent PHI's largest source of dispatchable customer-side capacity. For a specific distribution constraint, however, the relevant magnitude is the amount of enrolled and available HVAC load located on the constrained facility and operating during the relevant constrained hours. The programs can provide meaningful reductions for short-duration, weather-driven peaks,

[18] Table 5 of Delmarva Power2025-2026 EmPOWER MD Program Filing, Case No. 9705

but are subject to customer overrides, device availability, and the coincidence of HVAC load with the local constraint. **Ability to deploy resources in targeted areas within required planning timelines:** PHI's load management programs offer an ideal resource to explore targeting dispatch because there are many devices already deployed. These resources can be evaluated more quickly than newly developed DER resources where enrolled load already exists in a constrained area. Expansion of these devices could likely be achieved within the NWS timeframe of at least 36 months, assuming the type of device can address the identified constraint. **Incorporation into planning assumptions:** The maturity of the load management programs, historical event performance, and PJM capacity participation provide a stronger empirical basis for planning assumptions than is available for many newer DER-based resources. As these resources are integrated with DERMS functionality, PHI expects to incorporate heating and cooling load management into NWS screening and distribution planning analyses. With appropriately derated capability assumptions informed by empirical data, the programs are sufficiently reliable and predictable to be incorporated into distribution system planning.

5. C&I/Aggregator Program

As part of its revised proposal for a DRIVE VPP pilot program, PHI proposed a C&I/Aggregator program that would enroll commercial and industrial customers through PJM-registered Curtailment Service Providers (CSPs) that are also licensed DERAs in Maryland. The program is designed to leverage large customer load curtailment as a dispatchable distribution system support service. Participants would reduce electricity usage during utility-called events, and compensation would be paid on a performance basis using measured curtailment against an established baseline. The program is designed as a secondary program to existing PJM programs, so that utility-called events do not conflict with customers' PJM commitments, which can carry high penalties.

Table 7 provides the six program-wide metrics adopted by the Commission.

TABLE 7. C&I/AGGREGATOR PROGRAM METRICS

Metric 1: Peak load reduction potential
Existing enrollment and peak load reduction capability: None. The program is not yet operational as a DRIVE VPP offering. **Forecasted peak load reduction capability:** PHI forecasts 47.36 MW of Pepco commercial curtailment capability and 12.73 MW of Delmarva Power commercial curtailment capability by Program Year 2 in the Recommended Portfolio scenario and 23.68 MW of Pepco commercial curtailment capability and

6.37 MW of Delmarva Power commercial curtailment capability by Program Year 2, at the Alternative Portfolio scenario.[19]
Metric 2: Annual cost per kW of peak demand reduction
Customer incentives: The program provides pay-for-performance compensation based on average kW curtailed during dispatch events relative to a baseline. PHI proposes incentives of up to $75/kW-year in Pepco and up to $40/kW-year in Delmarva Power. At the forecasted curtailment levels, PHI projects annual incentive costs of $3.55 million for Pepco and $0.51 million for Delmarva Power. These budgets were original proposal estimates and will need to be recalculated due to Order No. 92488 in Case No. 9761.[20] **Administrative cost:** PHI's January 2026 proposal requested an annual utility administration budget of $11.96 million for Pepco and $2.3 million for Delmarva Power, to be shared across the VPP portfolio components. Allocating a third of this budget each to batteries, the C&I program, and load management programs implies C&I DSSS program administration costs of $565,524 for Pepco and $235,729 for Delmarva Power.[21] These budgets were original proposal estimates and will need to be recalculated due to Order No. 92488 in Case No. 9761.[22] **Estimated annual cost per kW of peak demand reduction:** Based on the combined incentive costs and allocated non-incentive costs, the estimated annual cost per unit of peak demand reduction is $224/kW-year for Pepco and $234/kW-year for Delmarva Power. This estimate is based on a proportional allocation of shared VPP administrative costs and were original proposal estimates. They will need to be recalculated due to Order No. 92488 in Case No. 9761.[23]
Metric 3: Potential to direct load reductions to specific, localized, or defined geographic locations
C&I curtailment resources can provide location-specific value where participating customers are located on or near constrained feeders, substations, or other distribution facilities. **Potential to direct enrollment to defined locations:** The program can target enrollment through CSPs and DERAs serving customers in specific geographic areas. However, location-specific enrollment depends on the presence of sufficiently large C&I load in the constrained area and the willingness of customers and aggregators to participate. PHI has not proposed locational variation in incentives in the initial VPP proposal but may introduce this in the future as a geographical targeting strategy. **Potential to direct operation based on location specific needs:** Where enrolled C&I load is located in a constrained area, PHI can call targeted events and coordinate event orchestration through the Grid-Edge DERMS vendor and participating aggregators. Event calls must take into consideration aggregator and customer commitments to PJM programs, which may limit the ability to modify operation for location-specific purposes if wholesale and distribution needs are conflicting or adjacent

[19] Pepco Holdings Proposed Distribution System Support Services Pilots Plans, filed January 20, 2026, under Case No. 9761

[20] Maillog No. 331573

[21] This figure removes the portion of utility admin costs that is for installation for DLC switches.

[22] Maillog No. 331573

[23] Maillog No. 331573

rather than coincident. As PHI develops Utility DERMS and DER Gateway capabilities, planners and operators will have improved visibility into enrolled resources and better ability to align C&I curtailment dispatch with local distribution system needs.
Metric 4: Potential performance at different times of day
Event window: Targeted dispatch events are expected to occur on weekdays between 11 AM and 7 PM, with no events scheduled on holidays or weekends. PHI proposes that targeted dispatch events will not be called more than four times per month, and each event will last for three hours. The program is best suited to constraints occurring during weekday daytime or early evening operating windows, when C&I customers are operating and have load available to curtail. It is less suitable for constraints that occur overnight, on weekends, on holidays, or during periods when participating customer load is not operating.
Metric 5: Other practical considerations
Availability: Availability depends on participating customer operations, baseline load levels, aggregator performance, and the ability to schedule utility-called events without conflicting with PJM commitments. **Control and dispatchability:** The program is aggregator-controlled and utility-directed. PHI would provide the DERA or CSP with 24 to 48 hours of advance notice of an event request, and the DERA would then provide participating customers with approximately 21 to 24 hours of advance notice. Customers or their aggregators would confirm that the requested event does not conflict with their PJM commitments. This framework means customer load is not directly controlled by the utility in the same manner as a battery or the load management programs. However, on an aggregate program basis, the load reduction capability can still be considered to be dispatchable, subject to reasonable derates based on observed program-wide performance. **Measurement and verification:** Performance will be measured by defining baseline load, measuring actual load during events using participant meter data or telemetry, adjusting for weather and operational factors, aggregating reductions across participating assets, and validating actual performance against nominated or forecasted peak MW reduction. **Performance risk:** Because the program depends on third-party aggregators and customer operational decisions, PHI plans to include agreements with enrollment goals, incentive values, data-sharing requirements, pay-for-performance timelines, reporting requirements, and exit clauses if aggregators do not meet enrollment or curtailment expectations.
Metric 6: Description of distribution deferral screening capability
Types of constraints applicable: The C&I/Aggregator program is best suited to thermal capacity constraints at feeders, substations, and transformers that occur during weekday daytime and early evening periods when participating C&I loads are operating. **Magnitude and duration of load reduction relative to constraints:** The forecasted portfolio includes significant curtailment capability, but distribution deferral value depends on how much of that system-wide capability is located at a constrained section of the grid. Individual events are expected to last three hours and to be limited to no more than four targeted dispatch events per month.

Ability to deploy resources in targeted areas within required planning timelines: The program may be deployable more quickly than programs that require installation of new physical assets where an aggregator already serves eligible customers in the constrained area. However, if a constrained area lacks sufficient participating C&I load, targeted recruitment may require a longer planning timeline. PHI's NWS screening process allows for consideration of NWS solutions for projects with in-service dates at least 36 months from the date of constraint identification, providing time to evaluate customer availability, aggregator participation, and performance risk. This timeline is likely to be sufficient to scale C&I enrollment in this program as needed for an NWS portfolio. **Incorporation into planning assumptions:** The pilot is intended to provide the performance data necessary to evaluate whether C&I curtailment can be incorporated into future NWS screening and distribution planning assumptions. Because the program is pay-for-performance and depends on customer and aggregator action, planning treatment will require sufficient confidence in baseline accuracy, event participation, repeatability, and the ability to target reductions at the relevant location and time.

6. Behind-the-Meter Solar Generation

BTM solar reduces load by generating electricity at the customer site. BTM solar is non-dispatchable and intermittent, with output determined by solar irradiance, weather, panel orientation, shading, and system design. In general, BTM solar can provide distribution value where solar production is locationally and temporally coincident with distribution constraints, particularly constraints occurring during daylight hours. To reliably defer or avoid a specific distribution grid constraint, BTM solar would need to be supplemented with dispatchable resources such as batteries.

Table 8 provides the six program-wide metrics adopted by the Commission.

TABLE 8. METRICS FOR BEHIND-THE-METER SOLAR GENERATION

Metric 1: Peak load reduction potential
Existing enrollment and peak load reduction capability[24]: • Pepco: 67 MW estimated peak load reduction from 41,103 customers with 418 MW of installed capacity as of April 2026 • Delmarva Power: 12 MW estimated peak load reduction from 7,549 customers with 106 MW of installed capacity as of April 2026

[24] Peak load reduction capability is estimated based on a peak coincidence factor of 16% for Pepco and 11.3% for Delmarva Power, developed based on average observed generation coincidence with distribution system peaks. Installed capacity is based on April 2026 figures from EIA Form 861.

Metric 2: Annual cost per kW of peak demand reduction
Customer incentives: Customers are compensated for solar generation through net metering, which credits them for the kWh generated on a one-for-one basis against consumption. Therefore, every kWh generated is essentially compensated at the full retail rate. In 2025, residential solar net metering customers received credits worth an estimated $64 million for Pepco and $14 million for Delmarva Power.[25] **Estimated annual cost per kW of peak demand reduction:** Based on the residential installed capacity and residential net metering credits paid in 2025, the estimated annual cost per unit of peak demand reduction achieved through residential solar is $1,303/kW-year for Pepco and $1,932/kW-year for Delmarva Power.[26]
Metric 3: Potential to direct load reductions to specific, localized, or defined geographic locations
Potential to direct enrollment to defined locations: If future changes to BTM solar compensation include components that reflect differences in locational value, these components may drive incremental solar adoption in beneficial locations. For example, New York's "Value Stack" tariff[27] includes a "Locational System Relief Value" component of compensation, which reflects additional distribution system value of solar in specific locations. **Potential to direct operation based on location specific needs:** As solar is a non-dispatchable resource, there is no potential to change its operation based on location-specific needs. Operation can be curtailed for location-specific needs, but this is unlikely to contribute to deferral of load-driven distribution constraints.
Metric 4: Potential performance at different times of day
Solar reduces load during the daytime, with generation typically peaking between 12-2pm. Generation is higher for longer durations in the summer than in the winter. Performance can be affected by changing weather such as cloud cover and other weather conditions.
Metric 5: Other practical considerations
Availability: Availability depends on customer adoption of solar in a specific location. The potential for adoption depends on various factors including roof orientation, premise ownership status, and DER hosting capacity on the distribution grid. **Control and dispatchability:** Solar availability depends on weather, season, time of day, system orientation, shading, and equipment performance. Output cannot be scheduled and cannot contribute to the avoidance of a constraint that is outside of solar production hours.

[25] These payments are estimated based on the number of credits in 2025 (297,620,312 kWh Pepco and 67,277,141 Delmarva Power) multiplied by the average residential net metering rate in 2025 ($0.21478/kWh Pepco and $0.20967 Delmarva Power).

[26] Estimated based on peak coincidence factors of 16% Pepco and 11.3% Delmarva Power, and mid-year 2025 residential solar installed capacity of 307 MW Pepco and 65 MW Delmarva Power.

[27] Value Stack - Value of Distributed Energy Resources | NYSERDA

Reliability: Because solar generation is non-dispatchable and intermittent, it would require augmentation with other dispatchable resources to be part of an NWS. Solar can contribute to reducing load that happens to be coincident with its operating profile but cannot resolve distribution constraints on a standalone basis.
Metric 6: Description of distribution deferral screening capability
Types of constraints applicable: BTM solar can contribute to mitigation of thermal capacity constraints occurring during times of day with high solar generation at feeders and substations, if adequately supplemented by other dispatchable resources. **Magnitude and duration of load reduction relative to constraints:** Solar contribution depends on installed capacity at the relevant location, expected hourly production, weather variability, and coincidence with the projected overload period. Planning assumptions will consider the coincident solar output at system peak, instead of installed nameplate capacity, for purposes of potential load reduction. **Ability to deploy resources in targeted areas within required planning timelines:** BTM solar deployment depends on customer adoption and interconnection timelines. In areas with strong customer interest and available hosting capacity, additional solar may be deployed within an NWS planning horizon. In areas with limited customer adoption, roof suitability constraints, or hosting capacity limitations, solar may be difficult to scale for a specific deferral need. **Incorporation into planning assumptions:** As a non-dispatchable resource, BTM solar should be incorporated into planning primarily through the load forecasting process. A secondary approach could be to include incremental solar deployment as an option in NWS evaluation, but it would need to be part of a broader portfolio containing dispatchable resources, and new compensation mechanisms are needed to incentivize locationally targeted adoption.

7. EmPOWER Energy Efficiency Program

Energy efficiency (EE) reduces customer load by improving the efficiency of equipment, building systems, lighting, appliances, controls, and building shells and therefore reducing energy usage and load. Unlike dispatchable resources such as batteries, managed charging, or load management programs, EE does not provide load reductions in response to a utility-called event. Instead, EE produces persistent load reductions based on the operating profile of the installed measure.

Table 9 provides the six program-wide metrics adopted by the Commission.

TABLE 9. METRICS FOR EMPOWER ENERGY EFFICIENCY PROGRAM

Metric 1: Peak load reduction potential
Existing deployment and peak load reduction capability: • Pepco: 63.8 MW reported peak load reduction from the EmPOWER portfolio in 2025 • Delmarva Power: 89.6 MW reported peak load reduction from the EmPOWER portfolio in 2025 This does not include the contributions of the load management programs, which are part of the EmPOWER portfolio but are discussed separately in Section II.C.4 of this report. **Forecasted incremental peak load reduction:** • Pepco: 139.11 MW forecasted peak load reduction from the EmPOWER energy efficiency and conservation portfolio by the end of the 2024-2026 cycle[28] • Delmarva Power: 57.31 MW forecasted peak load reduction from the EmPOWER energy efficiency and conservation portfolio by the end of the 2024-2026 program cycle[29]
Metric 2: Annual cost per kW of peak demand reduction
Customer incentives: PHI estimates total incentive costs of $247.12 million for Pepco and $71.3 million for Delmarva Power over the 2024-2026 program cycle. **Administrative cost:** PHI estimates total non-incentive costs of $97.29 million for Pepco and $38.18 million for Delmarva Power over the 2024-2026 program cycle. **Estimated annual cost per kW of peak demand reduction:** Based on the combined incentive costs and non-incentive costs, the estimated annual cost per unit of peak demand reduction is $2,476/kW-year for Pepco and $1,627/kW-year for Delmarva Power.
Metric 3: Potential to direct load reductions to specific, localized, or defined geographic locations
Potential to direct enrollment to defined locations: EE measures can be deployed in specific locations through targeted marketing and additional incentives. This type of targeting is not currently part of the EmPOWER program's design. **Potential to direct operation based on location specific needs:** Once installed, EE measures reduce load according to customer usage patterns and measure load shapes rather than utility dispatch instructions. However, it is possible to select and prioritize deployment of measures whose expected load reductions align with the timing and seasonal profile of a specific distribution constraint. For example, cooling-related energy efficiency measures are likely to be useful to mitigate summer peak loads driven primarily by high cooling loads. This type of measure-level optimization is not currently part of the EmPOWER program's design.
Metric 4: Potential performance at different times of day

[28] Table ES-2 of Pepco 2025-2026 EmPOWER MD Program Filing, Case No. 9705

[29] Table ES-2 of Delmarva Power2025-2026 EmPOWER MD Program Filing, Case No. 9705

EE performance profiles vary by measure and follow the profile of the underlying end use. Once a measure is installed, its duration of load reduction generally matches the duration of the load profile of the underlying end use.
Metric 5: Other practical considerations
Availability: EE savings are generally persistent over the measure life and do not require dispatch, customer response, or aggregator action after installation. Availability depends on measure persistence, equipment performance, and continued customer use of the technology/device. **Control and dispatchability:** EE is non-dispatchable. PHI cannot call an event to increase or decrease EE output in real time. The planning value of EE must therefore be estimated through deemed savings, EM&V, AMI-based analysis, and modeled measure-level load shapes. **Reliability:** The aggregate load reducing impact of an EE portfolio is generally observable and predictable. Operational reliability is not a consideration with EE because it is not a resource to be operated in the same manner as the other programs discussed in this report.
Metric 6: Description of distribution deferral screening capability
Types of constraints applicable: EE is best suited to contribute to deferral of thermal capacity constraints at feeders and substations caused by load that can be reduced through targeted measures. **Magnitude and duration of load reduction relative to constraints:** EE can provide durable reductions across many hours, but the magnitude depends on measure adoption and measure load shape. Because EE is not dispatchable, planning assumptions should include appropriate derates for realization rates, persistence, and uncertainty in hourly impacts. **Ability to deploy resources in targeted areas within required planning timelines:** Targeted EE can be deployed within NWS planning timelines if the constrained area has sufficient eligible customers, appropriate measures, and adequate lead time for outreach and installation. Where the constraint is imminent or the eligible customer base is small, EE may be better suited as part of a broader NWS portfolio rather than as a standalone solution. **Incorporation into planning assumptions:** As a non-dispatchable resource, EE should be incorporated into planning primarily through the load forecasting process. A secondary approach could be to include incremental EE deployment as an option in NWS evaluation, but it may need to be part of a broader portfolio containing dispatchable resources. New program designs would be needed to incentivize locationally targeted adoption of a mix of measures that are optimized for a specific constraint.

III. Transitioning to Time-of-Use Rates on an Opt-Out Basis

A. Procedural Background

DRIVE Act and Order No. 91218 directed Maryland investor-owned utilities to file opt-in TOU tariffs, enrollment targets achievable by January 1, 2028. These directives reflect the interest in expanding customer participation in time-varying rates and leveraging advanced metering infrastructure to improve system efficiency and customer engagement.

The Commission's PC44 Rate Design Work Group had initiated the R-TOU-P rate structures, currently available to residential customers in the Pepco and Delmarva Power service territories. These rates represent opt-in TOU offerings that apply to both distribution and supply charges.

Subsequent Commission orders further expanded the scope of the TOU discussion. In Order No. 91917, issued in connection with the DRIVE Act implementation proceeding, the Commission accepted PHI's proposed modifications to the R-TOU-P schedules while directing the Companies to submit a revised implementation budget, marketing plan, supporting rationale, and cost-benefit analysis. The Commission also directed PHI to conduct additional analysis of Delmarva Power's R-TOU-ND Standard Offer Service (SOS) TOU options, non-residential SOS TOU rates for Pepco and Delmarva Power, and potential changes to Pepco's Schedule R-TM through future base rate case proceedings or the PC44 Rate Design Work Group process. The Companies presented their analysis for R-TOU-ND SOS TOU options and current non-residential SOS TOU rates in an April 21, 2026, work group meeting.

More recently, Order No. 92422 directed PHI to provide an analysis of key implementation, operational, and customer bill-impact considerations associated with a potential transition to opt-out TOU rates. **This report responds to that directive by evaluating the considerations relevant to a transition from the current opt-in TOU rates to residential opt-out TOU rates.**

B. Residential TOU Rates Offered by PHI in Maryland

Table 10 shows the enrollment in different rates for residential customers of Delmarva Power and Pepco in Maryland. PHI offers various opt-in TOU rates for residential customers besides the default residential rate, R. PHI also offers TOU rates for **residential customers with electric vehicle charging**, namely R-PIV and PIV. **Technology-neutral TOU rates** include R-TOU-ND and R-TOU-P for Delmarva Power, and R-TM and R-TOU-P for Pepco. While Pepco's Schedule R-TM has a significant number of customers, it is closed to new customers at this time.

R-TOU-P was developed as part of the PC44 Rate Design Work Group in both Pepco and Delmarva Power service territories. These rates represent opt-in TOU offerings that apply time-varying pricing to both distribution and SOS supply charges if receiving energy from PHI and are also available to existing residential customers regardless of energy supplier. Rate levels and pricing periods vary based on the season – summer is defined as June through September, while the rest of the year is defined as winter. In the summer, peak hours are between 2:00 pm and 7:00 pm, excluding weekends and holidays. In the winter, peak hours are between 6:00 am and 9:00 am and 5:00 pm and 9:00pm. The all-in summer peak to off-peak price ratio is currently approximately 2.8:1 for both Pepco and Delmarva Power in the summer. [30]

R-TOU-ND is an opt-in TOU rate offered by Delmarva Power and currently includes a time-varying price only for its distribution charges. The rate is available to existing residential customers regardless of energy supplier. Standard Offer Service remains a flat charge, although it differs between summer and winter, and the Company will propose to incorporate a time-varying charge. The all-in peak to off-peak price ratio is approximately 1.3:1. Currently 34 Delmarva Power customers are enrolled in this rate.

TABLE 10: ENROLLMENT IN RESIDENTIAL RATES OFFERED BY PHI IN MARYLAND (AS OF MAY 2026)

Residential Rates	Rate Description	Customers
Delmarva Power		**188,573**
R	Default flat rate	187,941
R-TOU-P	TOU rate (all-in)	497
R-TOU-ND	TOU rate (distribution only)	34
PIV	Electric vehicle charging TOU rate, whole house	12
R-PIV	Electric vehicle charging TOU rate, EV load only	89
Pepco		**560,873**
R	Default flat rate	506,885
R-TOU-P	TOU rate (all-in)	1,268
R-TM	TOU rate (supply only)	51,563
PIV	Electric vehicle charging TOU rate, whole house	144
R-PIV	Electric vehicle charging TOU rate, EV load only	1,013

[30] Previously, the ratio was 4.5:1, but this ratio was reduced based on discussions and recommendations from the PC44 TOU Rate Design Work Group and its members.

C. Approaches to TOU Deployment

Residential TOU rates can be deployed through either on an opt-in basis, in which customers voluntarily enroll in the rate, or on an opt-out basis, in which customers are automatically enrolled but retain the ability to select an alternative rate. Both approaches can produce customer and system benefits, but they differ significantly in terms of participation levels, customer responsiveness, implementation requirements, implementation costs and overall value to the electric system. As a result, the choice between opt-in and opt-out deployment involves balancing customer engagement, administrative complexity, investment requirements and the scale of expected benefits.

Opt-In TOU Deployment

Under an opt-in deployment, customers voluntarily enroll in the TOU rate. While participation levels tend to be relatively low, participants are generally more engaged and often exhibit stronger responses to TOU price signals, resulting in a greater peak demand reduction on a per-participant basis than under default enrollment.

Opt-in deployment also involves fewer implementation requirements because participation grows gradually over time. Customer outreach can be more sequenced and targeted, operational risks are lower due to the smaller scale of customer participation in TOU rates, and customers are less likely to react negatively because enrollment is voluntary. As a result, many utilities introduce TOU rates through pilots or voluntary offerings before considering broader deployment.

The primary drawback of an opt-in approach is that low participation and time it takes to reach to meaningful participation levels limit the overall system benefits that can be achieved. While there are several jurisdictions with material opt-in participation levels (i.e., APS and Salt River Project in Arizona), they reached these levels over multiple decades. Although enrolled customers may respond strongly to price signals, the utility captures only a portion of the potential value that would have been available from widespread customer participation and load shifting.

Opt-Out TOU Deployment

Under an opt-out deployment, customers adopt the TOU rate unless they decide to opt-out and choose an alternative rate option. Because most customers remain on the existing rate (due to tendency to stick with status quo), participation levels are substantially higher than under opt-in programs, allowing TOU pricing to influence a much larger share of residential load. Utilities that have adopted default TOU rates frequently view these higher participation levels (upwards of 80% of the customers remaining on the rate) as essential to achieving meaningful reductions in system peak demand and improving overall system efficiency.

While the average peak impact reduction on a per customer basis tend to be less than that of opt-in deployments, the much higher participation rates often result in greater total peak demand reductions. The average response from an opt-out participant may be approximately 70 percent of the response observed from an opt-in participant under the same rate design.[31] However, the larger number of participating customers generally produces greater aggregate system benefits.

The larger scale of opt-out deployment allows utilities to capture broader benefits associated with load shifting, including reductions in peak demand, generation, transmission, and distribution system costs, improved utilization of existing infrastructure and improved integration of intermittent resources. For this reason, opt-out TOU deployment is often viewed as the approach that is more likely to maximize long-term system value when implemented successfully.

Implementation and Investment Trade-Offs

The greater potential system value associated with opt-out TOU deployment comes with correspondingly greater implementation requirements. Utilities that have successfully transitioned customers to opt-out TOU rates typically invest heavily in customer education and outreach, digital customer tools, billing system upgrades, employee training, customer service preparedness, and ongoing program management. Many utilities also implement customer protections such as bill protection, phased deployment strategies, and targeted communications to reduce customer concerns during the transition. These activities require dedicated staffing and ongoing operational support that exceed the requirements of a traditional opt-in program.

By comparison, opt-in programs require lower upfront investment because customer volumes are smaller and participation is self-selected. Customer education efforts can be more targeted, implementation can proceed more gradually, and operational risks are lower because the smaller number of participating customers limits the scale of billing, customer service, and

[31] S. Sergici, A. Faruqui, and Z. Tang, "Do Customers Respond to Time-Varying Rates: A Preview of Arcturus 3.0." Brattle Working Paper, January 2023.

system implementation challenges. An opt-in strategy may therefore represent a lower-risk and lower-cost approach, while an opt-out strategy may require greater investment but provide substantially larger opportunities for long-term system value creation. However, it is important to note that participation rates may not increase steadily under an opt-in deployment approach, even with active marketing efforts. As a result, marketing costs could accumulate over time, if those efforts are prolonged while participation remains low.

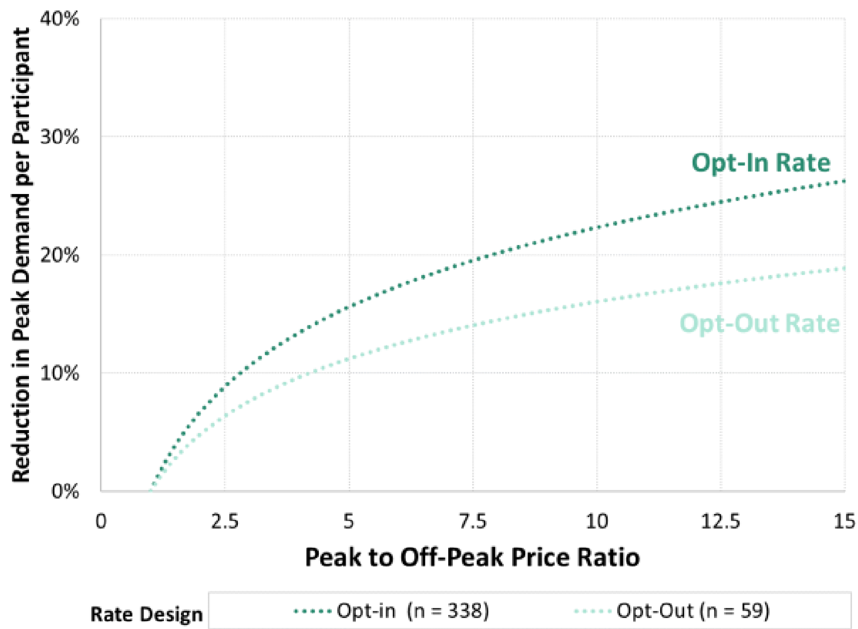
D. Potential Peak Impacts of Opt-Out TOU Rates

Utilities, working closely with stakeholder groups under the guidance of appropriate regulatory bodies, have carried out numerous implementations of time-varying rates (TVRs) around the globe. The empirical evidence from these tests reveals that a large percentage of customers respond to TVRs by lowering demand in peak periods and shifting it to off-peak periods, although the shift is lower for opt-out rates compared to opt-in rates on a per-participant basis (Figure 1).[32] The evidence also indicates that the response increases with the ratio of peak to off-peak (P/OP) prices, but at a decreasing rate. Notably, the PC44 TOU pilot administered by three Maryland utilities found that low-to-medium income customers were as equally responsive to price signals as the high-income group.[33]

[32] S. Sergici, A. Faruqui, and Z. Tang, "Do Customers Respond to Time-Varying Rates: A Preview of Arcturus 3.0." Brattle Working Paper, January 2023.

[33] S. Sergici, A. Faruqui, N. Powers, S. Shetty, and Z. Tang, "PC44 time of use pilots: End-of-pilot evaluation," Maryland Public Service Commission, Baltimore, MD, USA, Oct. 2021. https://www.brattle.com/wp-content/uploads/2021/12/PC44-Time-of-Use-Pilots-End-of-Pilot-Evaluation.pdf

FIGURE 1: PRICE RESPONSIVENESS TO TIME-VARYING RATES BY METHOD OF ENROLLMENT



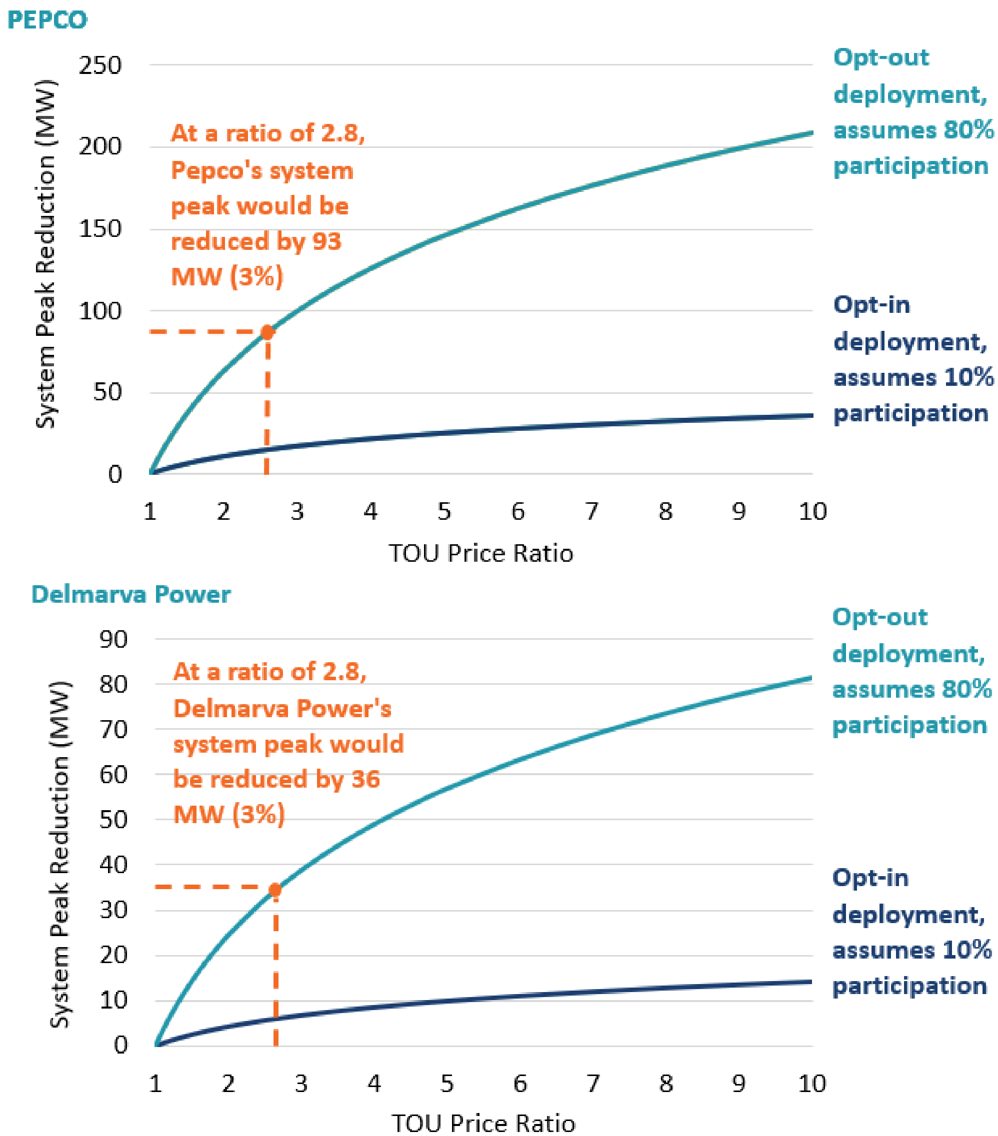
Notes: This model does not differentiate between treatments that are price only or paired with technology.

Source: S. Sergici, A. Faruqui, and Z. Tang, "Do Customers Respond to Time-Varying Rates: A Preview of Arcturus 3.0." Brattle Working Paper, January 2023.

To estimate the system peak reduction impacts of a TOU rate design, both the strength of the P/OP price ratio and the expected participation level should be considered. A stronger P/OP ratio can increase customer response, but the overall system impact ultimately depends on the combination of customer participation and per-customer peak reduction.

In Figure 2, we simulate the potential impacts of opt-out TOU rate deployments in the Pepco MD and Delmarva Power service territories. As a conservative assumption, we assume 80% of customers may remain enrolled in an opt-out TOU offering. The simulation indicates that for a P/OP ratio of 2.8, the system peak reduction would be 3%, or approximately 93 MW in Pepco MD and 36 MW for Delmarva Power, at the current system peak levels. However, the absolute peak reduction will increase as system peak grows over time. In contrast, achieving a 10% participation in an opt-in with the same P/OP ratio would result in 0.5% system peak reduction. Another consideration is the time it would take to reach a participation level such as 10% under an opt-in deployment. It may take years to reach that level of participation, and a steady focus on marketing efforts.

FIGURE 2: POTENTIAL PEAK REDUCTION FOR A RANGE OF TOU PRICE RATIOS



E. Successful Practices for Transitioning to Opt-Out TOU Rates

Several utilities have transitioned residential customers to opt-out or mandatory TOU rates, while others have achieved high participation levels through voluntary enrollment programs.[34] While there is not yet an established industry best practice for transitioning customers to opt-

[34] Examples of utilities offering default TOU rates include Ameren, California investor-owned utilities (SCE, PG&E SDG&E), SMUD, DTE, LIPA, Xcel Energy Colorado. Consumers Energy and Fort Collins Utilities offer mandatory TOU rates. Arizona Public Service and Salt River Project have high participation in their opt-in TOU rates.

out TOU rates, several common themes have emerged based on the experiences of these utilities. These past experiences provide useful insights for PHI as it considers future opt-out TOU deployment strategies.

1. Transition Strategy

> A successful transition to opt-out TOU rates requires careful planning and coordination across multiple utility functions. Utilities that have implemented opt-out TOU consistently emphasize the importance of establishing a clear implementation strategy that addresses customer readiness, operational preparedness, and regulatory considerations well before customers are transitioned. PHI has prior TOU implementation experience that could inform the planning and execution of a future opt-out transition and would develop a detailed transition strategy.

a. Timeline

Utilities generally begin customer education and implementation planning well in advance of TOU transitions. Most utilities devote about a year or more to customer outreach and education before transitioning customers to opt-out TOU rates. Some utilities conduct pilots before a full-scale transition. For example, some California utilities conducted pilot programs, allowing them to test customer communications, evaluate bill impacts, and refine implementation processes. This preparation period supports the development of customer-facing materials, employee training, system upgrades, and market research. PHI participated in the PC44 opt-in TOU pilots and will be in a position to leverage the learnings from that process.

Many utilities introduce TOU rates through pilots or opt-in offerings before making it the opt-out option. This “soft launch” approach allows utilities to gain operational experience, identify technical issues, and build customer familiarity with managing their bills under TOU rates. An overwhelming majority of utilities that ultimately adopt opt-out TOU rates have prior experience with opt-in TOU rates or pilot programs. Utilities also commonly transition customers to the opt-out TOU rates in waves rather than all at once, allowing customer service, billing, and operational teams to manage the increased workload associated with the rollout.

To enable a smooth transition to an opt-out TOU rate, PHI would develop a transition strategy, including a list of activities and timelines for each work stream in the planning and implementation of the rates. This plan would encompass customer communication and education plans, program management, evaluation and development of performance metrics, and cost recovery. PHI has previously submitted TOU implementation plans detailing budget needs, customer engagement, and program administration as part of the DRIVE Act filings, and the opt-out TOU plan would incorporate similar topics albeit for a larger scale program.

b. Timing of Implementation Steps

Opt-out TOU implementation often occurs as part of broader rate modernization initiatives and is frequently coordinated with major regulatory proceedings. Rate design, customer protections, education plans, and system investments are commonly developed together rather than in isolation. Because TOU implementation frequently requires investments in billing systems, customer tools, workforce training, and communications, aligning deployment with broader regulatory planning efforts helps ensure that all supporting elements are in place before customers are transitioned.

Seasonality also plays an important role in implementation timing. Utilities frequently avoid transitioning customers during periods when bill impacts are likely to be highest and instead begin customer transitions during shoulder or non-summer months. This approach allows customers to become familiar with the rate before entering high-usage seasons and reduces the likelihood that customers associate seasonal bill increases with the TOU transition itself.

Phased deployment strategies are common among utilities implementing opt-out TOU. Rather than transitioning all customers simultaneously, utilities often deploy customers in manageable waves. Some utilities also target customers who are expected to benefit immediately from TOU rates during early deployment waves to generate positive customer experiences and favorable word-of-mouth.

PHI's existing TOU implementation experience suggests that customer education, system preparation, and operational readiness would need to occur before any transition to opt-out TOU rates. Current implementation efforts have focused on modifying and promoting existing opt-in TOU offerings, expanding customer engagement tools, and evaluating future TOU options through the PC44 Rate Design Work Group process. Implementation of an opt-out TOU rate would likely proceed through coordinated billing-cycle transitions rather than a single system-wide conversion date, with sufficient lead time for customer notification, employee training, and system testing. PHI has an SAP system that has the functionality to bill customers on a TOU rate.

2. Customer Communication

> Customer communication plays a central role in helping customers understand TOU rates and preparing them for a transition. Utilities consistently reported that effective communication strategies reduced confusion, improved customer satisfaction, and increased the likelihood that customers responded to TOU price signals. PHI expects customer education to remain a key component of any transition strategy and would build on and enhance its existing customer engagement capabilities.

Customer education is a central component of successful TOU transitions. Most utilities provide multiple customer notifications before implementation, often at 90-day, 60-day, and 30-day intervals. These communications explain the upcoming rate change, outline available options, and provide customers with opportunities to opt out before being transitioned to the opt-out TOU rate. Repeated communications improve customer awareness and reduce confusion.

Educational efforts typically simplify TOU concepts and focus on customer benefits. Customers generally respond more positively when communications emphasize the lower off-peak prices available during most hours of the year rather than highlighting higher peak-period prices. Educational materials frequently include explanations of how customers can shift energy use, examples of common household activities that can be moved to off-peak hours, and personalized information showing how customers may benefit from participation.

Utilities found that routing TOU-related inquiries to dedicated customer service representatives trained on TOU rates helped address detailed customer questions and provide guidance tailored to individual circumstances. Although these calls were often lengthy, they proved effective in educating customers and supporting the transition to TOU rates. Offering multiple TOU rate options increased the complexity of these conversations, as representatives needed to explain the differences among rates and help customers identify the option best suited to their usage patterns.

Affordability is often a central theme in TOU communications and customer outreach. Utilities generally find that customers are more receptive to TOU rates when communications focus on opportunities to save money and maintain control over energy costs. Rather than focusing on higher peak-period prices, utilities highlight opportunities to save money through lower off-peak prices and changes in usage behavior. Messaging centered on savings opportunities, customer control, and financial benefits generally resonates more strongly than technical discussions of rate design or system operations. However, it is important to manage customer expectations about potential bill savings, and to be clear that the savings are not guaranteed.

PHI expects customer communication to be one of the most important elements of any opt-out TOU transition. PHI's key communication channels include email campaigns, bill messages, website updates, social media content, My Account notifications, and call-center support. PHI also anticipates the need for ongoing customer education after implementation, potentially extending for a year or longer, to help customers understand TOU pricing and manage bills under the new rate structure. Existing experience with TOU implementation indicates that customers will require clear explanations of how TOU rates work, how they can opt out, and how behavioral changes may affect bill outcomes. PHI also expects increased call-center activity following implementation and would need to develop customer-service training materials and talking points to support customer inquiries.

3. Marketing

> Marketing efforts complement customer education by building awareness and reinforcing key messages about TOU rates. Utilities often use a variety of communication channels and messaging approaches to reach customers with different preferences and levels of engagement. PHI's approach is aligned with these practices and would focus on helping customers understand the rate change and clarifying what it means for customer-specific circumstances.

Utilities generally rely on broad, multi-channel marketing campaigns to build awareness and support customer education efforts. Common communication channels include direct mail, email, websites, social media, television and radio advertising, community events, bill inserts, billboards, and outbound call campaigns. Many utilities also develop dedicated TOU websites, online educational resources, and community outreach programs targeted at specific customer segments.

Market research often helps identify messages that resonate with customers. Depending on the jurisdiction, successful messaging focuses on bill savings, environmental benefits, grid reliability, customer empowerment, or customer choice. Utilities frequently develop slogans or branding campaigns to make TOU concepts easier to understand and remember. Examples include messages such as “Shift and Save,” “Wait Till Eight,” and other simple reminders that reinforce the value proposition of TOU participation.

PHI's current marketing philosophy emphasizes helping customers understand that TOU outcomes depend on customer behavior. PHI's recent customer research similarly found that customers are most interested in understanding how TOU rates would affect their own bills and usage patterns. PHI can evaluate marketing effectiveness through customer retention, bill outcomes, participation levels, and annual PC44 reporting metrics. Low- and moderate-income (LMI) customers would require clear communication that any existing discounts, bill assistance programs, or other affordability protections will continue following a transition to TOU rates. The PC44 TOU pilots found that LMI customers responded to TOU price signals at least as strongly as other customer groups, suggesting they can successfully participate in TOU rates when provided with appropriate education and support. However, another option is to make TOU rates opt-in for LMI customers, at least initially. This was the approach utilized by the California IOUs.

4. Utility Program Management

> Implementing opt-out TOU requires coordination across many parts of the organization. Program management and internal governance are critical factors in ensuring that customer-facing, operational, and technical activities remain aligned throughout the transition process. PHI has existing structures for managing TOU-related activities but would likely need to expand program oversight and coordination for a large-scale deployment.

Successful TOU deployment relies on cross-functional coordination among rates, regulatory affairs, customer service, information technology, billing, communications, and operations personnel. Implementation typically requires significant planning and ongoing coordination, particularly during the customer transition period.

A phased deployment approach reduces operational risk, allows lessons learned from early phases to be incorporated into later phases, and prevents customer service and billing organizations from becoming overwhelmed.

Effective program management often requires dedicated staff to coordinate implementation activities and maintain accountability throughout the transition. Utilities frequently assign dedicated personnel to oversee customer outreach, operational readiness, regulatory reporting, vendor coordination, and program performance. As TOU deployment expands, dedicated resources help ensure consistent execution across departments and provide a clear point of responsibility for managing the program.

5. Digital Tools

> Digital tools increasingly serve as an important bridge between TOU rate design and customer understanding. Utilities use these tools to provide customers with personalized information, improve transparency, and help customers identify opportunities to save under TOU pricing. PHI already has customer-facing TOU tools in place that could serve as a foundation for supporting customers under an opt-out TOU framework and will consider enhancements.

Digital tools are a common component of modern TOU programs. Most utilities offer online bill comparison tools or bill calculators that allow customers to estimate how their bills would change under TOU pricing. Some tools rely on representative customer usage patterns, while others use each customer's own historical usage data to provide personalized estimates. These tools help customers understand potential bill impacts and increase confidence in the transition process. Utilities also found that walking customers through these online tools during support calls improved customer understanding and confidence. Many customers continued using the tools independently to monitor usage, compare rates, and better understand their bills.

Many utilities supplement these tools with additional digital resources, including appliance-specific savings calculators, usage dashboards, online account tools, and personalized energy reports. Some utilities also provide customers with information showing how changes in appliance usage could affect bills under TOU pricing. These tools help customers identify practical opportunities to shift load and maximize savings.

PHI already has several digital tools available to support TOU participation. These include the Opower Rate Comparison tool, which provides customers with information about eligible rate options and estimated costs; the Rate Cost Simulator, which allows customers to compare rate options based on usage assumptions; and weekly Rate Coach emails that provide personalized usage information and peak-period feedback. These tools would remain central to any future opt-out TOU implementation. Additional enhancements, such as expanded online functionality to support opt-out requests or more personalized customer bill-impact information, may also be considered.

6. Customer Protections

> Customer protections help reduce concerns about bill impacts and improve acceptance of TOU rates, particularly during the initial transition period. Utilities incorporate protections that allow customers to gain experience with the new rate while limiting financial risk, however, these practices also bring additional costs. PHI would evaluate customer protection options as part of future implementation planning.

Customer protections are a common feature of TOU transition strategies. The most common protection is bill protection, under which customers receive credit if their TOU bill exceeds what they would have paid under the legacy rate during an initial transition period. California utilities generally offered one year of bill protection, while some utilities use shorter-term bill guarantees. Bill protection allows customers to gain experience with the new rate while reducing concerns about potential bill impacts. However, bill protection and more specifically shadow billing can be costly since it requires billing customers twice and making changes to the information technology investment and providing credits. California utilities reported the implementation of bill protection as the most complicated part of their opt-out TOU deployment.

Practices regarding shadow billing vary. Some utilities track customers' bills under both the new and legacy rates internally but do not routinely display the comparison to customers. Others provide comparative bill information or personalized bill impact estimates before customers are transitioned. Experience across utilities suggests that bill protection can be more effective than routine shadow billing because it allows customers to experience the rate without financial risk while avoiding information overload or confusion. There are also different implementations for the duration of bill protection ranging from three months to a year, and sometimes with gradual removal of bill protection.

Many utilities also use bill impact analysis to identify customers who are expected to benefit immediately from TOU participation. These customers can be targeted in early deployment phases or receive tailored communications highlighting expected savings. Positive customer experience among these customers helps build broader acceptance of TOU rates.

PHI has not yet identified a preferred customer-protection framework for opt-out TOU deployment, recognizing the cost and complexity of the options detailed above. One option that may be considered is maintaining opt-in participation for certain customers such as LMI customers or delaying the transition of these customers until a later phase of implementation. PHI also expects that customer education and ongoing outreach would serve as important customer-protection mechanisms by helping customers understand the new rate structure and available options.

7. Implications for Decoupling

> As customers shift usage in response to TOU pricing, utilities may experience changes in revenue collection patterns and bill distributions. These changes create interactions with existing revenue recovery mechanisms that warrant consideration during implementation planning. PHI's existing decoupling framework provides a foundation for managing potential revenue impacts, although additional evaluation may be considered as TOU becomes the default residential rate.

Revenue shortfalls associated with customer protections are often recovered through future rates or other regulatory mechanisms. As customer usage shifts under TOU pricing, utilities may experience changes in revenue collection patterns that need to be considered within broader regulatory frameworks. These issues are generally manageable when implementation is coordinated with existing revenue recovery and rate adjustment mechanisms. Maintaining alignment between customer incentives and utility financial objectives remains an important consideration throughout the transition process.

PHI currently operates under a full revenue decoupling mechanism through the Bill Stabilization Adjustment (BSA). Most residential TOU offerings are currently included within the broader residential BSA class, meaning that any revenue increases or decreases associated with TOU participation are ultimately reconciled across the entire class. In the case of a transition to an opt-out residential rate, it would be reasonable to expect that any revenue recovery impacts due to the TOU rates and customer response to these rates would be addressed by decoupling. As PHI gains more experience with opt-out TOU, the impact of TOU rates will already be reflected in the Company’s cost of service and revenue requirement calculations, and the impact that will be mitigated through decoupling would be minimal.

8. Metering

> Advanced metering infrastructure is a foundational element of TOU programs because it enables interval-based billing and customer analytics.

> Utilities that implement opt-out TOU generally do so after achieving widespread AMI deployment. PHI's existing AMI infrastructure already supports TOU rates, positioning the company well for a potential future transition, and will require additional operational adjustments to enable large-scale adoption.

Opt-out TOU implementation generally occurs after widespread deployment of advanced metering infrastructure. Interval data supports not only accurate billing but also customer education, bill comparison tools, usage analytics, and program evaluation. Customers with insufficient interval data or unresolved meter communication issues are often excluded from participation until those issues can be addressed.

Customers lacking interval data frequently require separate treatment during implementation. In some cases, these customers are temporarily excluded from the transition until metering infrastructure is upgraded. Experience from other jurisdictions suggests that broad AMI deployment significantly simplifies TOU implementation and improves customer experience.

PHI's existing AMI infrastructure already supports TOU billing through Company's SAP billing system, so a transition to opt-out TOU rates would not require significant new metering and billing investments.[35] However, implementation would require operational changes, including updating customer records, re-coding rate assignments, and ensuring that billing and customer-facing systems accurately reflect customers' rate options. PHI's primary metering challenge for a future opt-out TOU deployment would likely involve scaling existing capabilities to a larger customer population rather than deploying additional metering or IT infrastructure.

9. Internal Processes and IT

> Behind-the-scenes operational readiness is an important component of a successful TOU transition. Utilities frequently identify billing systems, customer service capabilities, and information technology infrastructure as key enablers of large-scale deployment. PHI expects operational and technology readiness to be an important consideration in a future opt-out TOU implementation, and would need to assess and prepare billing systems, customer service capabilities, and IT infrastructure.

[35] Currently less than 1% of PHI residential customers do not have AMI infrastructure.

Information technology and billing systems usually represent some of the most significant implementation challenges associated with TOU deployment. Successful transitions require billing systems that can accommodate interval billing and TOU rate calculations before large numbers of customers are transitioned. Many utilities undertake substantial billing system upgrades and testing efforts prior to deployment.

Employee training is also a critical component of implementation readiness. Customer service representatives are often the first point of contact for customers and play an important role in explaining rates, discussing savings opportunities, and resolving customer concerns. Successful deployments typically include dedicated training programs, detailed customer service scripts, and ongoing coordination between implementation teams and customer-facing staff.

PHI expects that information technology and business-process considerations could represent a significant component of an opt-out TOU transition. Potential requirements include customer rate changes, billing-system modifications, online customer functionality, and customer-service support. Existing processes such as billing exception management and rate-change workflows could likely be adapted for a broader deployment; however, the full scope of required IT enhancements cannot be determined until implementation details are further developed.

10. Potential Implementation and Transition Costs

> Transitioning customers to opt-out TOU rates requires investments in customer outreach, technology, workforce readiness, and program administration. Utilities report a wide range of implementation costs depending on the scale of deployment and the scope of supporting activities. For PHI, implementation costs would depend on the final program design, with customer engagement, operational readiness, and system support likely representing key areas of investment.

Implementation costs vary considerably across utilities and depend on the scope of customer education, technology upgrades, workforce training, and outreach efforts. There is a range of implementation cost estimates, although direct comparisons are difficult because utilities include different categories of costs in their estimates.

Customer communications and outreach often represent a significant portion of implementation costs. Investments range from relatively modest education programs to large-scale statewide marketing campaigns. Customer outreach and education are generally viewed as essential investments because customer understanding and acceptance are key determinants of overall program success. Ongoing post-transition engagement can often be delivered at a fraction of the cost of the initial marketing campaign while still providing meaningful benefits to customers.

Aligned with the industry expectations, PHI expects customer education and marketing to represent one of the largest cost categories associated with an opt-out TOU transition. IT upgrades, customer-service preparation, billing-system modifications, and ongoing customer engagement are also likely to be potential cost drivers. There may be costs due to secondary effects such as increased customer inquiries, longer call-center wait times, delayed billing, operational backlogs associated with large-scale rate changes and more frequent rate changes, and broader customer satisfaction concerns.