uplight

April 7, 2025

Secretary Rosemary Chiavetta
Commonwealth Keystone Building
Second Floor
400 North Street
Harrisburg, Pennsylvania 17120

RE: IN THE MATTER OF M-2025-3052826: ACT 129 ENERGY EFFICIENCY AND CONSERVATION PROGRAM - TENTATIVE IMPLEMENTATION ORDER

Dear Secretary Chiavetta,

Uplight appreciates the opportunity to provide these comments to the Tentative Implementation Order issued on February 20, 2025.

Respectfully submitted,

/s/ Adam Farabaugh

Adam Farabaugh
Director, Market Development
Email: adam.farabaugh@uplight.com

BEFORE THE PUBLIC SERVICE COMMMISSION

In the Matter of the Energy Efficiency and	**)**	**Docket No. M-2025-3052826**
Conservation Program	**)**	
	)	

April 7, 2025

Tentative Implementation Order Comments

Pursuant to the NOTICE TO ALL ELECTRIC DISTRIBUTION COMPANIES AND ALL INTERESTED PARTIES published on March 7, 2025 in the Pennsylvania Bulletin, Uplight appreciates the opportunity to provide comments on the Tentative Implementation Order regarding Phase V of the Energy Efficiency and Conservation Program. Uplight is a demand response provider in the U.S. across multiple technologies and we will focus our comments on the Tentative Implementation Order in regards to the peak demand reduction goals. Specifically, Uplight makes the following recommendations to the Commission:

1. Uplight recommends that the Commission increase the demand response contributions to the peak demand reduction targets to the median of the Realistic Achievable Potential (RAP) and the Maximum Achievable Potential (MAP) which is 316 MWs - bringing the total state-wide peak demand reduction target to 760.5MWs.
2. Uplight recommends adjusting the means by which peak demand reduction is measured through Commission adoption of an alternative reduction amount where peak demand reduction is measured across all hours of called events.
3. Uplight recommends that the EDCs be encouraged to bid their DR resources into the PJM market.
4. Uplight recommends against the Connected Thermostat Optimization daily dispatch design.
5. Uplight recommends including BTM battery storage programs in the EDC’s portfolios and measuring the B/C ratio across all of the DR programs as opposed to individually.
6. Uplight agrees with the Implementation Order recommendation to allow for peak demand reduction targets to be met either with EE or load-shifting programs but also recommends setting a higher peak demand reduction target as compared to the energy savings target.
7. Uplight recommends establishing a low-income peak demand reduction target for each EDC.

Uplight recognizes the challenge of creating a peak demand reduction goal for each of the EDCs, which requires integrating inputs from the Act 129 legislation, the Demand Response Potential Study, the Energy Efficiency and Peak Demand Reduction Market Potential Study, and the 2026 TRC Final Implementation Order. However, we suggest that the Commission could update how peak demand reduction is measured in a way that enables tapping into the full suite of cost-effective demand response available in Pennsylvania. We further believe that a number of the inputs into the DR potential study don't reflect actual market conditions and, due to how the Realistic Achievable Potential (RAP) peak demand reduction amounts are set, result in significantly lower MW amounts.

Uplight respectfully urges the Commission to adopt an alternative methodology for measuring peak demand reduction.[1] Moving beyond the 100 highest hours would better align with how DR resources provide value in the Commonwealth and allow the EDC's to more fully leverage cost-effective demand response solutions.

We also believe that several inputs in the DR Potential Study, particularly the cost assumptions and avoided capacity values, understate what is realistically achievable. When updated, these cost effectiveness will increase substantially, supporting the Commission's authority to establish additional incremental peak demand reduction requirements consistent with the statute.

Capacity costs in PJM have increased substantially from $28.92/MW-day in the '24/'25 Base Residual Auction (BRA) to $269.92/MW-day in the '25/'26 auction[2]. Monitoring Analytics, the Independent Market Monitor for PJM, stated in their "Analysis of the 2025/2026 RPM Base Residual Auction" report that "the capacity market is getting tighter," which will result in higher capacity prices particularly if market design changes are not implemented.[3] Additionally, transmission and distribution system costs are projected to grow from approximately $3 billion to almost $4 billion per year by the end of 2026 which will further place upward pressure on customer

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[1] 66 Pa. C.S. § 2806.1(d)(2).

[2] https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx

[3] https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_D_20241206.pdf

rates.[4][5][6] These increasing costs require increased investment in peak demand reduction programs to minimize cost increases for ratepayers.

Act 129 was developed during a period of relatively flat load growth and as a result, it focused primarily on energy reductions; however, it still authorizes programs that target peak reductions. We believe it is critical for Pennsylvania to invest in peak demand reduction programs due to the rising impact that peak load is having on customers' bills. We urge the Commission to maximize the amount of peak load reduction that the EDCs can achieve, as doing so will result in the greatest benefit to residents of the Commonwealth. It will also position Pennsylvania to better respond to rising capacity auction prices in PJM.

INCREASE PEAK DEMAND REDUCTION GOALS

Uplight believes that using cost assumptions reflective of current market prices and using the latest PJM Base Residual Auction (BRA) results will yield significantly higher cost effectiveness results, thus increasing the amount of cost effective peak demand reduction that can be delivered from demand response programs. We recommend that 316MWs, the median of the Realistic Achievable Potential (RAP) and the Maximum Achievable Potential (MAP), be adopted as the peak demand reduction target for demand response programs. This amount, added to the 444.5MWs, assumed to be delivered by the energy efficiency program's contribution to peak demand reduction, would bring a new total peak demand reduction target to 760.5MWs.

The peak demand reduction goals proposed in the Tentative Implementation Order are based on the DR Potential Study, which included three DR programs with a cost/benefit ratio greater than 0.8. These were: C&I Load Shifting, Connected Thermostat Optimization, and EV Managed Charging. Water Heating Load Management and Behind-the-Meter Storage were excluded. The cost estimates for these programs are higher than comparable benchmarks. The statewide average acquisition cost used in the DR Potential Study for demand response in Pennsylvania was $166,881 per MW-year. This amount far exceeds the proposed ~$118k per MW-year ($325/MW-day) PJM BRA price cap limit for the '26/'27 auction.[7] Moreover, other utilities are

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[4] Avoided Cost and T&D Capacity Study. April 2024: https://www.puc.pa.gov/pcdocs/1855615.pdf
[5] First Energy Companies 2024 proposed rate increase $502 million (R-2024-3047069); PECO 2024 proposed rate increase of $464 million (R-2024-3046931);
[6] PJM. Transmission Congestion Can Increase Costs: https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/congestion-fact-sheet.pdf
[7] https://www.pjm.com/pjmfiles/directory/etariff/FercDockets/8720/20250220-er25-1357-000.pdf

implementing DR programs at a much lower cost. PSE&G New Jersey for example, in a state with a similar DR program construct and also within PJM, was recently approved for its demand response program where the total cost to deliver (including incentives) was approximately $52,027 per MW-year.[8] Adjusting costs to be more reflective of existing market conditions will greatly improve DR cost effectiveness, which will in turn result in much higher MW forecasts.

The benefits calculated in the DR Potential study utilized the 2026 Total Resource Cost (TRC) Test Final Order,[9] which requires the five most recent Base Residual Auction (BRA) results to be averaged as an avoided capacity value. Avoided capacity is one of the primary drivers for total benefits delivered and utilizing the five most recent BRA's generates an average avoided capacity value of $31,741/MW-year. However, in the latest BRA, the '25/'26 auction, the price increased dramatically to $98,521/MW-year - nearly nine times higher than the prior year. While there is uncertainty in any future auction, using past auction results during a period with profound change on both the demand and supply side dramatically underestimates both the current avoided capacity costs as well as likely future results.

As a result of overestimating costs and underestimating benefits, the DR program economics used in the potential study yield significantly less peak demand reduction potential. Specifically, two of the DR programs were not included while other DR programs in the market such as Behavioral Demand Response were omitted. These economics make the MAP scenario look unattractive; however, if appropriate cost estimates and avoided capacity cost values are used, the MAP scenario could be cost effective. A comparison of the Phase V DR Potential Study costs, PSE&G NJ's DR program costs, and the avoided capacity calculation approaches are shown in Table 1 below.

[8] Program total cost of $25,941,115 for the entire demand response program across the triennium (2.5 years) with projected portfolio MW performance of 199.44 MW. (($25,941,115 / 199.44 MW) / 2.5 years) = $52,027 per MW-year.
https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1362726
[9] https://www.puc.pa.gov/pcdocs/1855583.pdf (pg 39)

Metric	Phase V Demand Response Potential Study	Revised Scenario: PSE&G NJ Program Costs and Actual ‘25/’26 BRA Results
Program Cost: $/MW-year	$166,881	$52,027
Avoided Capacity Costs (Benefit)	$31,741 / MW-year comparison (using 5 year average)	$98,521/ MW-year[10] (using ‘25/’26 BRA results)

Table 1: Original vs Revised scenario of cost effectiveness

The Tentative Implementation Order adopted the DR Potential Study’s RAP MW totals, which was 163.2 MWs for the C&I Load Shifting Program, the Connected Thermostat Optimization Program, and the Electric Vehicle Managed Charging Programs. Collectively, these three programs have erroneously been estimated to have a benefit/cost ratio greater than 0.8. If the Study used correct assumptions, one would see that a substantial amount of cost effective MWs have been left on the table. Table 2 below compiles the RAPs and MAPs for all of the DR programs analyzed in the DR Potential Study.

[10] 25/25 BRA Clearing price for Capacity Performance Resources of $269.92 per MW-day for the RTO: https://www.monitoringanalytics.com/reports/Reports/2024/IMM_Analysis_of_the_20252026_RPM_Base_Residual_Auction_Part_A_20240920.pdf

DR Program	Phase V DR Potential Study RAP (Summer & Winter Average MWs)	Phase V DR Potential Study MAP (Summer & Winter Average MWs)
C&I LOAD SHIFTING	119.4	227.75
CONNECTED THERMOSTAT OPTIMIZATION	26.45	52
DOMESTIC HOT WATER LOAD MANAGEMENT	31.9	70.5
ELECTRIC VEHICLE MANAGED CHARGING	17.35	48.1
BEHIND THE METER BATTERY STORAGE	14.58	23.24
THERMAL STORAGE WITH HEAT PUMP	0.46	0.92
DR Program Total	210.14	422.51
C&I, Thermostat, EV DR Programs Only (>0.8 B/C Ratio)	163.2	327.85

Table 2: Comparison of DR Program RAP and MAP MW Totals

While re-doing the DR Potential Study at this time is unrealistic, Uplight recommends that the Commission increase the demand response contributions to the peak demand reduction targets to the median of the Realistic Achievable Potential (RAP) and the Maximum Achievable Potential (MAP) across all DR Programs modeled as the basis for Phase V peak demand reduction targets. As noted in the Demand Response Potential Study, the MAP scenario reflects nearly twice the peak demand reduction of the RAP scenario. We believe this more ambitious target is justified based on revised real-world inputs that better reflect current market conditions. This would generate approximately $15M in additional avoided capacity costs for ratepayers using '25/'26 BRA results. Table 3 below pulls together the totals from the EE and Peak Demand Reduction Potential Study, the DR Potential Study cost effective RAP, and the total peak demand reduction target described in the Tentative Implementation Order. It then compares these totals to a recommended revised scenario total MW amount of 316MWs, which is the median between the RAP and MAP. Utilizing the same MW contributions from the EE and Peak Demand Reduction Potential Study and the revised amount yields a new peak demand reduction target of 760.5MWs.

Approach	Phase V Peak Demand Reduction from EE (MWs)	Phase V DR Potential Study (Summer & Winter Average MWs)	Total Peak Demand Reduction Target
PA EE Potential Study	479	-	-
DR Potential Study Total Recommendation	-	163.1	-
Tentative Implementation Order	444.5 (assumed)	163.1	607.6
Revised Scenario Recommendation	444.5	316	760.5

Table 3: Comparison of Potential Studies, Tentative Order, and Revised Scenario Peak Demand Reduction Totals

PEAK 100 HOURS MEASUREMENT

The Act 129 legislation, passed in 2008, requires that peak demand reduction be measured over the highest 100 hours of demand in a year. This was during a time of flat load growth and avoided energy usage was more valuable than avoided capacity. However, over the past several years this dynamic has shifted dramatically with rapidly increasing demand not only in Pennsylvania but across PJM as well as the closures of many generating stations across the state. To address this growing need for peak demand, Act 129 includes language that allows for the Commission to approve an alternative reduction approach provided that an EDC's portfolio plans have an overall benefit/cost ratio greater than 1. Per Act 129:

> *By May 31, 2013, the weather-normalized demand of the retail customers of each electric distribution company shall be reduced by a minimum of 4.5% of annual system peak demand in the 100 hours of highest demand. The reduction shall be measured against the electric distribution company's peak demand for June 1, 2007, through May 31, 2008."*
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> *If the commission determines that the benefits of the plans exceed the costs, the commission shall set additional incremental requirements for reduction in peak demand*

for the 100 hours of greatest demand or an alternative reduction approved by the commission.[11]

Uplight recommends that the Commission adopt an alternative reduction amount where peak demand reduction is measured across all hours of called events. Events would be defined as the hours for which PJM calls a pre-emergency or emergency event or when an EDC has a distribution-level constraint for which an event is called. Doing so will align events specifically to how DR is valued within the BRA. The current proposed construct of using the peak 100 hours will lead to a DR resource delivering fewer MWs during actual emergency events, resulting in a higher clearing price leading to higher costs for consumers.

SUPPLY AND DEMAND RESOURCE CONSIDERATIONS

One of the main determinations within the DR potential study for making the recommendation for the demand resource pathway was that demand resources wouldn't compete with existing supply resources under CSPs. While the wholesale C&I DR market is fairly robust, the residential DR market is largely non-existent in Pennsylvania. Allowing EDCs to bid their DR resources into the PJM market would alleviate many of the issues for determining when to call events and how measurement should occur. Further, revenues from PJM could be used to directly offset program costs. EDCs could also pursue Price Responsive Demand, which would help lower overall capacity prices. As an example, the electric utilities in New Jersey have been directed to bid their demand response resources into the PJM BRA and to use revenues to offset program costs.[12] Uplight recommends encouraging EDCs to bid their DR resources into the PJM market.

CONNECTED THERMOSTAT OPTIMIZATION - DAILY DISPATCH

Uplight recommends against the Connected Thermostat Optimization daily dispatch design that the DR Potential Study recommended. There are a number of reasons for this. The first is that daily dispatch was utilized because the statute originally required peak demand reductions to be quantified using the highest 100 hours of peak demand unless an alternative approach was authorized. The greatest contributor to avoided costs is avoided capacity. DR delivered at times when the grid is most stressed will deliver the greatest value and will balance the costs of

11 https://www.legis.state.pa.us/WU01/LI/LI/CT/HTM/66/00.028.006.001..HTM#:~:text=(2)%20The%20commission%20shall%20direct,will%20not%20achieve%20the%20required

12 https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1362726

delivering these MWs including financial, comfort, and convenience. Having resources called upon every single non-holiday, weekday, whether or not they are needed will lead to customer fatigue and diminished reductions even on the days that the grid is actually stressed. Smart thermostat demand response programs typically are only called on ten to twenty times a year only on peak days which can generate on average 1kW of load shift per household. A daily dispatch construct would reduce this kW amount substantially and have a much smaller effect on actual capacity prices.

Second, this construct, and specifically the operations of the thermostat described in the DR Potential Study, are most valuable when a customer is enrolled in a time-of-use rate. Smart meters are 100% deployed in Pennsylvania and TOU rates are available at each of the EDCs but have low rates of adoption. This thermostat daily dispatch construct is better served to customers through TOU rates which, for the most part, is already paid for by customers. The daily dispatch construct also is also not active demand response as there is no actual event being called to the device but rather just setting a schedule in advance which is pushed to the devices. A more cost effective way to achieve the same load reductions is incenting customers to switch to a time-of-use rate and implementing the daily dispatch construct as part of the offering.

Third, there is no participating customer compensation under the daily dispatch construct. Participating customers in thermostat DR programs typically receive $50 to $100 per year which is recommended as participating customers in a load flexibility program tend to receive ~90% of the benefits delivered from the program[13]. Under the daily dispatch Connected Thermostat Optimization design in the DR Potential Study, customers won't receive any payments for their contributions to peak demand reduction which diminishes the direct customer benefit of a DR program.

BEHIND THE METER BATTERY STORAGE

The BTM Battery Storage program was found to be cost-ineffective in the DR Potential Study. However, Uplight is concerned that this is partially attributed to the program cost and benefit assumptions that were discussed previously. Dominion Energy in Virginia recently proposed a Residential Battery Energy Storage Pilot that was just below a B/C ratio of one in its base case

[13] https://www.brattle.com/wp-content/uploads/2025/02/New-Yorks-Grid-Flexibility-Potential-Volume-I-Summary-Report.pdf (pg 8)

Total Resource Cost analysis.[14] A full scale program deployed in Pennsylvania has the potential to exceed a cost/benefit ratio of one particularly if exporting power to the grid and not only operating as a demand response resource (i.e. not exporting power to the grid).

In addition, battery storage offers a relatively new and unique opportunity to test customer adoption and useability, interactions with the distribution system, and reliability of events. Battery storage costs will continue to decrease over time and as more customers install solar on their homes, more will be looking to also install battery backup for the resiliency aspect and being self-sufficient. Without EDC battery storage programs, there will be resources in the field that could positively contribute to overall system cost reductions and increase reliability.

Uplight recommends that BTM battery storage programs are included in the EDC's portfolios and measure the B/C ratio across all of the DR programs as opposed to individually. This will allow for EDCs to evaluate customer and grid impacts from these systems particularly prior to FERC Order 2222 coming into effect in PJM where behind-the-meter energy storage systems will be a part of an EDC's system.

EDC FLEXIBILITY BETWEEN EE AND DR TO DELIVER PEAK DEMAND REDUCTIONS

Uplight agrees with the Implementation Order recommendation to allow for peak demand reduction targets to be met either with EE or load-shifting programs. However annual energy reductions are becoming less valuable than they previously have compared to energy reductions during the coincident peak. Measures that generate greater coincident peak savings are generally going to return higher cost effectiveness B/C ratios due to higher avoided capacity and avoided transmission and distribution costs. Because of this, demand response programs are going to return greater benefits, particularly when the full avoided capacity cost is used as opposed to the previous 5 year average.

Due to the increasing value of peak demand reduction, Uplight recommends setting a higher peak demand reduction target as compared to the energy savings target as more benefits will be delivered from the same dollar invested while ensuring legislative requirements are still met.

[14] https://www.scc.virginia.gov/docketsearch/DOCS/831%4001!.PDF

LOW INCOME PEAK DEMAND REDUCTION CONTRIBUTION

In the Tentative Implementation Order there was a carve out for energy savings goals for low-income customers. However, there was no carve out for peak demand reduction goals within the low-income sector. Approximately 90% of the benefits of a load flexibility program are delivered to the participating customers in the program through the form of incentives. The remaining 10% of benefits accrue to all customers in the form of lower rates[15].

Many load-shifting programs rely on technologies that tend to be more expensive and are primarily adopted by higher income households. Enrolling these devices, typically already bought and paid for, generally results in programs with greater cost effectiveness. In order for low-income households to adopt these communicating technologies and participate in demand response programs, additional up-front incentives for the device and installation are required. However these additional costs hurt overall program cost-effectiveness therefore should be removed from the benefit/cost calculation.

Energy burden is increasingly an issue in Pennsylvania and across the country.[16] Any customer incentive dollars from any utility program help alleviate a customer's energy burden. This is also true for demand response participation incentive dollars and the same dollar going to a low-income household compared to a higher income household has a much greater impact on energy burden. A $100 DR participation incentive for a typical low-income household would decrease energy burden by .5% compared to just .1% for a typical household receiving the same $100.[17]

Uplight recommends establishing a low-income peak demand reduction target for each EDC. The low-income consumption target is approximately 7% of the total goal across all of the EDCs. Choosing a percentage greater than this will allow EDCs to have a greater impact on energy burden with the Act 129 programs. Uplight also recommends that the cost effectiveness for the low-income carve out be tracked but not considered in approving these programs and also be removed from the total portfolios cost tests as many of the benefits delivered to low-income households are not captured within cost effectiveness tests such as the impact on energy burden.

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[15] https://www.brattle.com/wp-content/uploads/2025/02/New-Yorks-Grid-Flexibility-Potential-Volume-I-Summary-Report.pdf (pg 8)
[16] https://www.aceee.org/energy-burden
[17] https://www.aceee.org/sites/default/files/proceedings/ssb24/assets/attachments/20240722163059859_6a161e7c-2877-4e45-b909-9e36559f584e.pdf

SPECIFIC QUESTIONS ASKED:

Should Phase V peak demand reduction targets be designed around DDR programs like in Phase III or EE programs like in Phase IV, or should peak demand reduction targets reflect a mix of the two, like in Phase I?

The Phase V peak demand reduction targets should be designed around Dispatchable Demand Response programs as in Phase III but still be allowed to use EE programs to contribute to achieving the target. The goal amount should be high enough to incent meaningful amounts of both EE that achieves significant coincident peak demand reductions as well as robust load-shifting programs that reduce peak demand.

Should the Commission set targets based on summer peak demand reductions or winter peak demand reductions?

The Commission should set targets for both summer and winter based upon a weather normalized percentage of the season's peak in the year previous. This means that an incremental percent reduction is achieved year over year opposed to hitting a percent reduction amount and then staying flat for the remainder of the Phase. For example, setting a peak reduction target of 2% of the previous year's weather normalized seasonal peak demand will generate 2% of savings in the first year and then in the second year an additional 2%.

If peak demand reductions in both seasons are a priority, should the Commission establish separate targets for each season or a single target based on the composite performance across the two seasons?

The Commission should establish two separate goals for each season because reliability is just as important in the winter season, which generally has a slightly lower peak demand in Pennsylvania. Further, the load shifting resources utilized to meet the goals may differ between summer and winter.

If EE&C Plans can include DR programs, what conditions determine the hours over which performance will be measured?

As described above in the PEAK 100 HOURS MEASUREMENT section, Uplight recommends measuring performance over the hours for which events occur. Events should include all PJM pre-emergency and emergency events as well as any events called by an EDC for local distribution constraints or system tests.

During which summer(s) or winter(s) are peak demand reductions from DR programs measured for purposes of determining compliance?
Summer and winter peak demand reductions should be measured individually across events in their respective seasons.

Stakeholders should provide comments regarding allocation of budget to the five program types in responses to that section.
We recommend that the Commission not determine or have a preference for budget allocation across each of the five load-shifting programs included. Instead, the cost effectiveness of the entire load-shifting portfolio should be utilized. Further, EDCs should also include programs that are not included within these five as they see fit and the Commission should approve them as part of their demand response portfolio provided it exceeds a Total Resource Cost Test B/C ratio of 1. Further, as described above, the peak demand reduction targets should be increased as compared to the energy consumption reduction targets to incent greater benefits to be delivered to the system. However, the Commission should not recommend how much of the budget goes to energy efficiency or dedicated peak demand reduction programs provided the goals for each are met.

CONCLUSION

Uplight appreciates this opportunity to provide these comments and looks forward to engaging throughout this proceeding.

OVERVIEW OF UPLIGHT

Uplight is a technology provider to over 80 electric and gas utilities across three continents providing utility customer engagement and grid-edge asset management software solutions to help utilities achieve their goals. Collectively, Uplight manages over 5 GWs of flexible capacity across multiple device classes enabling entities to effectively manage their DER assets inside and outside of wholesale markets. Uplight implements solutions including Behavioral Home Energy Reports, Online Energy Usage Portals, Online Utility Marketplaces, Electric Vehicle Charging Data Management, and both residential and commercial demand response programs. Additionally, with utilities across the country, Uplight implements DER management solutions connecting behind the meter resources to the grid control room and other backend utility systems keeping the grid powered up reliably and cost effectively.