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January 9, 2025

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

RE: *Resource Adequacy in Pennsylvania*, Docket No.: M-2024-3051988

Dear Secretary Chiavetta:

Attached for filing in the referenced matter are the comments of the Philadelphia Energy Authority on issues raised in the Commission's Technical Conference on Resource Adequacy in Pennsylvania, held November 15, 2024.

Respectfully Submitted,

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Enclosures

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Resource Adequacy in Pennsylvania	: : : :	Docket No.: M-2024-3051988

COMMENTS OF THE PHILADELPHIA ENERGY AUTHORITY IN RESPONSE TO ISSUES RAISED IN THE COMMISSION'S TECHNICAL CONFERENCE ON RESOURCE ADEQUACY IN PENNSYLVANIA

Pursuant to the Pennsylvania Public Utility Commission's ("Commission") November 15, 2024 Notice of Technical Conference on Resource Adeqaucy in Pennsylvania ("Technical Conference") Pa. PUC Docket No. M-2024-3051988 held November 25, 2024, and the Commission's subsequent notice of November 26, 2024 extending the period for comments in this docket to January 9, 2025, the Philadelphia Energy Authority ("PEA") hereby files its comments on issues raised in the conference. PEA is grateful for this opportunity to provide its responses to certain topics raised by the Commission.

Introduction

1. PEA is a body politic and corporate, created by the City of Philadelphia under the Pennsylvania Municipality Authorities Act, 53 Pa. C.S. § 5601 et. seq., established in 2010 with the purpose of building a robust, equitable clean energy economy in Philadelphia. PEA works to make Philadelphia a national model for implementing energy strategies that improve the health and well-being of the community and local economy, including the City's most vulnerable

residents. PEA assists the City in the development of long-term energy related projects including energy efficiency projects for City facilities, such as efficiency retrofits of the Philadelphia Museum of Art and the City's Municipal Office Building, and the ongoing conversion of all City streetlights to LED fixtures, and renewable energy projects, such as the recently completed 70 MW Adams County Solar Project. In 2016, PEA launched the Philadelphia Energy Campaign, a $1 billion, 10-year investment in energy efficiency and clean energy projects to create 10,000 jobs. To date, PEA has helped launch over $904 million in projects, and created over 7,600 jobs.

2. PEA also operates programs to install and/or finance the installation of energy efficiency improvements and renewable energy systems for residents and businesses in the City. PEA created and manages the Built to Last program, which coordinates delivery of repairs and energy improvements for low-income single-family housing from multiple Philadelphia programs and funding sources, and acts as the Program Administrator for Philadelphia's Commercial Property-Assessed Clean Energy (C-PACE) program, which provides funding for commercial energy efficiency projects. PEA's Solarize program has installed a total of nearly 20 MWs of residential solar in the City. The program has grown rapidly in the last two years with the introduction of a solar lease product – earlier this year Solarize installed solar on its 3,000th home. Half of these homes went solar in just the last 12 months, and forty-five percent of that growth has come from low-income customers, who achieve energy savings with no money down.

3. PEA's affiliate, Philadelphia Green Capital Corp. ("PGCC"), is the successful co-applicant with the Pennsylvania Energy Development Authority for the U.S. Environmental Protection Agency's Solar for All program under the federal Inflation Reduction Act, and PEA will assist PGCC in implementing the program in Philadelphia and the four surrounding counties. Solar for All grants are targeted exclusively to residents earning less than 80 percent of Area Median

Income or residing in Low Income and Disadvantaged Community census tracts, as defined by the U.S. Department of Energy, and are required by law to result in 20 percent electric bill savings for customers.

Summary

4. The primary objective of the Commission in this proceeding, as the Commission's Chair and Vice Chair articulated at the Technical Conference, is to meet the increasing demand for electric services by providing safe, reliable and affordable services to all consumers in the Commonwealth of Pennsylvania. PEA suggests that these objectives can be achieved, in substantial part, through increased use of distributed energy resources ("DERs"), including both local generation and smart building energy management, deployed to provide day-ahead and/or real time demand response ("demand flexibility").This combination both reduces utility capacity needs and adjusts load in response to wholesale market conditions. PEA believes utilities can and should move from *planning for* the peak to *planning* the peak.

5. These results are achievable with current technology. In other parts of the country solar generation, including a high proportion of residential solar, has become one of the largest producers of power on the system. On the load management side, behind-the-meter ("BTM") load management controllers for everything from residences to campuses and industrial facilities are becoming more affordable and available, and microgrid controllers which allow co-management of generation and storage with building loads have become increasingly sophisticated. What is missing is the regulatory integration of the customer and community capabilities with the needs of

the grid. The Federal Energy Regulatory Commission's ("FERC") Order 2222[1] and related RTO tariffs are a step in the right direction, but there is much that the Commission can do to move this forward. BTM resources are typically not designed primarily for export but face regulations that assume that they are. There are many approaches to customer demand flexibility some of which are substantially under the Commission's jurisdiction. Integrated Distribution Planning can play an important role in assuring that DERs can benefit not only customers who install them but all grid customers.

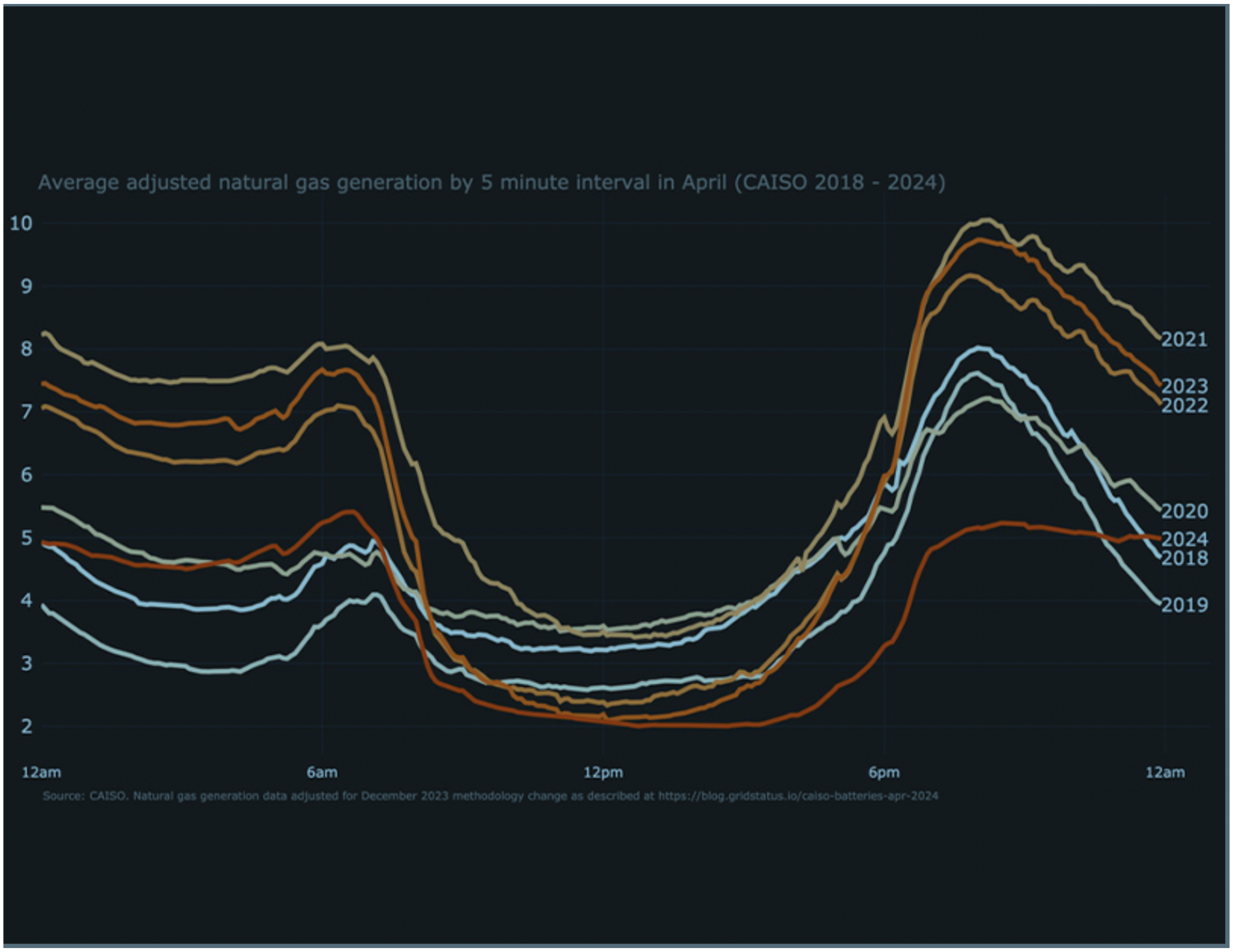
Expanding the Role of DERs and Demand Flexibility

6. As highlighted at the Technical Conference, Pennsylvania's generation capacity is caught between a rock and a hard place. On the one hand coal-fired power plants are retiring rapidly. On the other, the PJM queue is clogged with potential solar plants withering on the vine as interconnection processes grind grudgingly, and equipment for new gas fired powerplants faces a worldwide shortage. These events coincide with expected dramatic increases in load from building and vehicle electrification and artificial intelligence buildout. These difficulties are largely beyond the Commission's jurisdictional reach. Locating smaller DERs on the distribution system is not without its difficulties but is often comparatively easier to accomplish and is more susceptible to Commission action.

7. The grid in a number of states is evolving to include far more intermittent resources and far more DERs. California's generation mix now includes approximately 30 percent solar of

[1] *Participation of Distributed Energy Res. Aggregations in Mkts. Operated by Reg'l Transmission Orgs. & Indep. Sys. Operators,* Order No. 2222, 172 FERC ¶61,247 (2020), *order on reh'g*, Order No. 2222-A, 174 FERC ¶ 61,197, *order on reh'g,* Order No. 2222-B, 175 FERC ¶61,227 (2021).

which over a third – or 13 percent of the state's total – is residential.[2] California and Kauai Island, Hawaii have each experienced significant periods in which 100 percent of load was served by non-fossil resources.[3] California has managed this with increasing amounts of battery storage. As the following chart shows, natural gas generation (and the height of its ramp curve) was substantially reduced duing times of peak load in April of 2024:



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[2] *California State Energy Profile*, EIA, provides totals for small scale solar PV (2,881 thousand MWh) which are not included in system generation totals of 19,279 thousand MWh, https://www.eia.gov/state/print.php?sid=CA#tabs-4

[3] A. Lazo, *California hits milestones toward 100% clean Energy – but has a long way to go,* CalMatters (August 20, 2024), https://energynews.us/2024/08/20/california-hits-milestones-toward-100-clean-energy-but-has-a-long-way-to-go/
Derrill Holly, Hawaii Co-op Hits 100% Renewable milestone, NRECA (January 2, 2020), https://www.electric.coop/hawaii-kauai-island-utility-cooperative-hits-100-percent-renewable

Source: RTO Insider[4]

Battery storage in California grew from 500 MW in the summer of 2020 to 11,200 MW in June of 2024.[5] This was not a one for one tradeoff with natural gas, but appears to reflect a significant reliability achievement. Solar generation coupled with battery storage is not an intermittent power plant, but a dispatchable one, and 100 MW of residential installations of solar plus storage, assuming a communication mechanism for dispatch, can have the same electrical value for the system as 100 MW of other dispatchable generation.[6]

8. Incorporating DER, particularly solar, in integrated resource planning can reduce grid costs. In a recent report, Why Solar for All Costs Less, Vibrant Clean Energy demonstrates that by using using sophisticated grid modeling the grid can meet capacity needs at reduced cost in both business as usual and carbon-constrained scenarios.[7]

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[4]Ayla Burnet, *How Much are Batteries Displacing Natural Gas on CAISO's Grid?*, RTO Insider (January 5, 2025). https://www.rtoinsider.com/92778-could-batteries-displace-natural-gas-caiso-transition/

[5] Id.

[6] Of course there are detailed differences depending on the locations on the system of differently sized components, and batteries typically have a 4 hour discharge period.

[7] C. Clack and A. Choukular, *Why Solar for All Costs Less: A New Roadmap for the Lowest Cost Grid*, Vibrant Clean Energy, LLC (2020) at 3, https://vibrantcleanenergy.com/wp-content/uploads/2020/12/WhyDERs_ES_Final.pdf

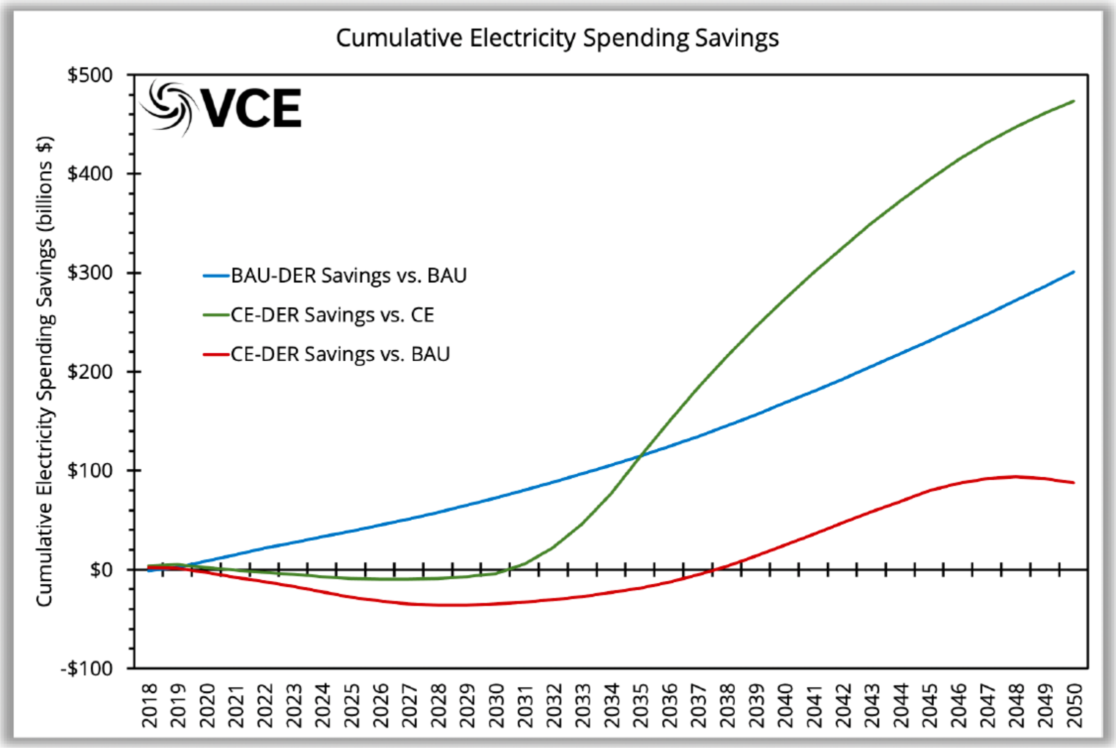

Figure ES-1: The cumulative electricity system due to the augmentation of the WIS:dom-P software to include distribution planning.

The blue line represents savings without a carbon constraint. The green and red lines represent respective savings against a carbon-constrained non-DER scenario and against business as usual (where no allowance is made for the benefits of carbon reduction). In other words, independent of Pennsylvania's carbon agenda, turning to DERs as a major component of resource adequacy is a good economic decision.

9. The US Deparment of Energy ("DOE") in its report Pathways to Commercial Liftoff: Virtual Power Plants confirms that aggregations of DER managed as virtual power plants are lower cost than other forms of capacity both stand-alone and when certain direct benefits are considered:[8]

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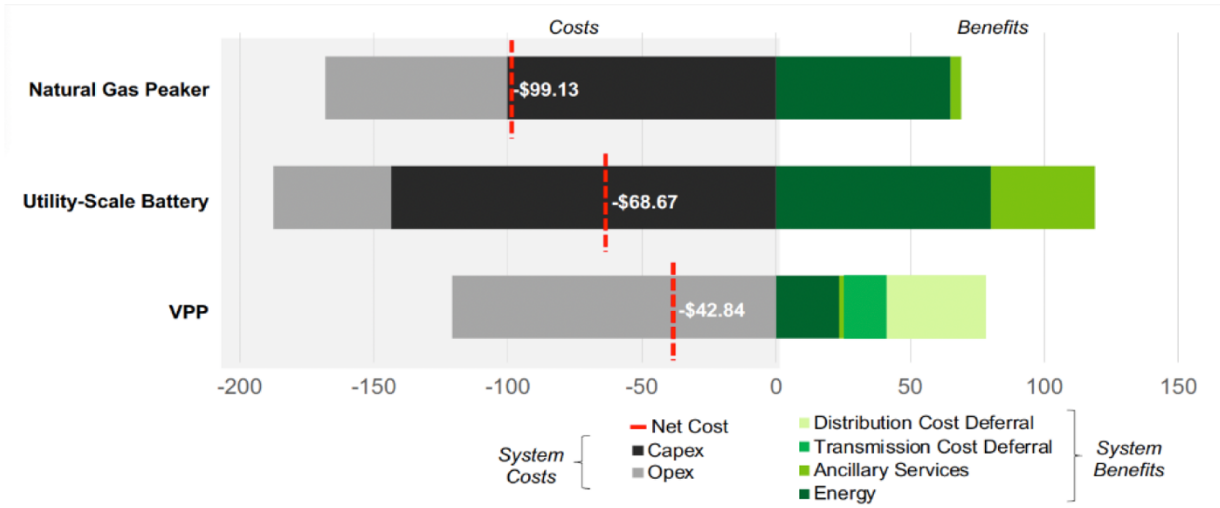
[8] J. Downing, N. Johnson, et al., *Pathways to Commercial Liftoff: Virtual Power Plants*, DOE (September 2023), *available at* https://liftoff.energy.gov/vpp/

Net cost to a utility of procuring peaking capacity, Net cost per kW-yr



Note: Net cost to a utility of procuring 400 MW of peaking capacity are shown in $/kW-yr in 2022 dollars. In the chart, the deferred T&D costs are represented as benefits of the VPP. Benefits of emissions reduction and resilience are not shown; when included, VPP net cost is lower, though actual emissions impact will vary by local grid mix. VPP in analysis consists of smart thermostats, smart water heating, home managed EV charging, and BTM battery demand response. Utility studied is assumed to have 50% renewable generation mix, with resource adequacy needs in summer and winter. DER penetration assumptions and VPP participation rates reflect national averages and utility experience. 8760 hours were considered and resources must be able to operate in 63 peak hours (when top 400 MW are needed) spanning 7 months, for 7 consecutive hours at a time. Costs exclude enabling grid software and hardware such as sensors and metering that would also contribute non-VPP services such as reducing reliance on meter readers, enabling time-varying rates, and data collection for energy use analytics. For detail on enabling grid software and hardware, see appendix
Source: The Brattle Group, Real Reliability: The Value of Virtual Power (2023).

10. In addition to direct transmission and distribution. savings local generation and load management resources provide numerous advantages, including:

- They eliminate line losses when serving BTM customers.
- They diversify power supply and reduce the size of contingencies.
- They manage demand at times of peak load and thereby reduce both the wholesale price at the times it is greatest and the system requirements for peak capacity and ramping capacity.
- They draw third-party investment that reduces any direct or indirect burden or cost to ratepayers (especially at a time when electrification of both transportation and HVAC and demand for artificial intelligence applications are expected to grow dramatically).

- When managed by third party aggregators, they reduce expense to EDCs of information management and transfer since aggregators provide the infrastructure to communicate with customer DERs.
- Local investment provides local employment and builds local wealth.
- Local clean energy reduces pollution levels.
- Through aggregation, DERs can provide the same ancillary services to the grid that wholesale generation provides, including frequency regulation, voltage and reactive power support.
- Local generation and storage deployed as microgrids provides resilience to customers, to critical facilities, and to communities.
- If the distribution system is segmented to operate as local and regional islands in emergencies, DER exports can support continued operation of the regional islands, providing broader resilience.

Managing DERs

11. Achieving the many benefits that DERs offer the grid requires effective management tools – DERs must respond when the grid needs them. The grid's traditional way of managing resources is dispatch, and even RTO electric markets which rely on auction pricing to set the dispatch order ultimately rely on direct dispatch. Early efforts at demand response have been based on a simplified version of this model. Programs involved fixed commitments to reduce load by fixed amounts usually with pricing set at a single price for the entire program and either a specific trigger for response or a limited number of "calls" per time period for each resource. Time of use pricing is an even more blunt instrument with, typically, a single price differential for

large blocks that in many cases have grown out of sync with the actual load curve. The result is that the price is almost always wrong – it bears no relationship to the wholesale price at the time the DER is actually called to perform. Either local resources are being underpaid and have too little incentive to join up, or they are being overpaid at additional cost to ratepayers. This has not been a major problem at the limited scale achieved in most such programs, but will rapidly become a lager problem if they scale up.

12. PEA suggests that to make a meaningful contribution to resource adequacy DER deployment should more closely follow the needs of the grid and be compensated at parity with wholesale pricing. Closely following grid requirements is now possible through the development and expanding commercial availability of controllers that can manage all loads in a building or facility. Residential customer home controllers can manage smart thermostats, smart appliances, EV chargers, and water heaters to substantially shape customer load. (These currently cost between \$100 - \$600 though the price can be expected to continue to decline).[9] If the home includes solar and storage the controller can be upgraded to a microgrid controller capable of islanding the home for resilience. With or without all of these elements, the home controller is capcable of responding flexibly to the needs of the grid. Under this model, customers can support the grid by optimizing and reshaping the customer's aggregate electric demand. Industrial facilities or whole campuses can use more sophisticated controllers to manage many more proceses and multiple forms of generation and storage to the same ends at a larger scale.

13. The controls and connectivity currently available for DERs and collections of DERs behind a single meter are already more sophisticated than the communication and control

[9] See, K.Ouedraogo. et al, *Feasibility of low-cost energy management system using embedded optimization for PV and battery storage assisted residential buildings*, Science Direct (2023) https://www.sciencedirect.com/science/article/abs/pii/S036054422300316X#:~:text=Nowadays%2C%20the%20main%20obstacle%20to,from%20100%24%20to%20600%24.

technologies typically deployed by EDCs at the periphery of the grid. Controls that allow a residence to participate in an aggregation that responds to hourly (or more frequent) needs of the grid will need to provide automated demand flexibility to be effective. (Large sophisticated facilities may benefit from a full time system operator, but underlying automation makes that possible.) Automated controls can be programmed to reflect a customer's preferences and can be subject to customer override as needed. Manual coordination often worked poorly in demand response programs with relatively large and sophisticated customers and is completely unrealistic for a residential customer with limited time to devote to manually managing home resources. Programming and managing a home controller, by contrast, can typically be accomplished through a simple screen interface, such as a cellphone.

Delivering DER Services to the Grid

14. The capability of DERs to provide services to the grid requires both legal and physical support. Signals from the grid must be delivered to the DERs, and delivery of demand reductions and excess generation to the grid must be established in either contractual or tariff frameworks and be compensated at contractual or tariff rates. Different actors – utilities, independent aggregators, community choice aggregations, and electric generation suppliers ("EGS") – can all act as the aggregating agent; many different forms of communication to DERs (and from them, if needed) are possible; and communications can range from direct remote dispatch to simple communication of market prices. All of the contractual versions fall within the broad rubric of Virtual Power Plants ("VPPs"). A uility operated aggregation is more typically characterized as a "Demand Flexibility Tariff." Though there are important distinctions, they both have similar functionality and deliver demand flexibility to the grid. Both are referred to hereafter as demand flexibility aggregations ("DFAs").

15. DFAs can be designed to operate based on a range of signalling and "dispatch" arrangements ranging from direct control of customer resources by the DFA to DFA non-mandatory price signals to customer controllers. In between are mandatory dispatch instructions that are not hard wired, price signals that the customer must indicate acceptance of that are followed by dispatch instructions, and optioal participation at certain preset price levels. Some direct-control DFAs give customers the ability to override DFA commands, while others do not. A DFA that is, or is partnered with, a Commission-licensed EGS can directly include price signals in regular rates offered to its customers. Alternatively, VPP payments for load modification can be conducted outside of the EDC settlement system. A Demand Flexibility Tariff, clearly operates entirely within the EDCs billing system and, unlike EGS pricing, requires advance approval by the Commission of the tariff.

16. It sould be clear that these different approaches have consequences both for the customer and for the DFA. VPPs will be obligated to make firm bids in PJM markets, and DFAs that do allow customer overrides, or that operate by non-mandatory price signals, will likely be compelled to have internal reserves or external hedges (or both) to manage their risks. VPPs will face wholsale market prices, but for non-EGS operated VPPs there is no assurance that customers will be given full value or information about market values. EDCs are less costrained in pooling demand flexibility responses for their own account, but would need Commission approval to use surplus energy acquired from DFAs for default service. Direct dispatch by a DFA assures response for the grid. However, PEA has serious concerns about DFAs that do not allow customer overrides at the very least in emergencies. By contrast, a price signal model allows the customer to set its controller to take advantage of grid pricing while taking into account the customer's other needs and interests. This model empowers the customer, yet insures allignment with the grid operator

through accurate pricing. PEA encourages a new view of the EDC's role, in which the EDCs collaborate with their customers to assure the collective adequacy of supply of a diverse mix of resources.

17. VPPs can pursue different business models. At one end of the spectrum are vendors who install a particular class of their own proprietary equipment, such as batteries or smart thermostats under contracts that allow the vendor to manage that equipment as a part of a VPP. At the other end is a VPP that operates as a platform, which allows multiple technologies, supplied through multiple installers, to participate in the same VPP. PEA is exploring creation of a VPP that leans toward the platform model for a variety of reasons. Technologies ranging from batteries (alone or coupled with solar), smart thermostats, smart water heaters, other smart appliances, and electric vehicle ("EV") chargers (along with the EV batteries), can provide value to the grid in a VPP and shape customer load. If multiple separate assets participate in different aggregations, they may operate at cross purposes, which is to the benefit of neither the customer nor the grid.

18. PEA leans toward a platform approach because it allows competition at several levels. PEA is considering establishing a VPP in connection with a program that would assist residents and businesses with installing both VPP eligible resources and other energy efficiency measures, and also provide guidance, implementation, and financing for all customers, as well as subsidies for low-income customers. PEA also supports appliances and technology choices for customers. PEA additionally seeks (as it has done successfully with its solarize program) to expand business opportunities for smaller, diverse, Philadelphia-based businesses to participate in the energy efficiency space. PEA, however, is not advocating that the Commission require specific business models, but rather, PEA wishes to assure that platform-based approaches are not precluded or disadvantaged.

19. PEA believes that the expansion of this model will unleash investment by customers and communities, or third-party developers on their behalf. Customers and communities will be incentivized to invest for reasons including cost savings, carbon reduction, resilience, and energy democracy. While resources acquired by, or on behalf of, customers will primarily be sized to meet the needs of the customer or customers served by the resource,[10] they will frequently have some spare capability (or the customers' needs will be flexible) so that the resources can contribute through an aggregation. The EDCs' role of serving customers will evolve from assuring one-way delivery to assuring two-way delivery of power.

20. While demand flexibility can be structured in many ways, PEA notes that there is no principled reason why multiple types of programs cannot operate at the same time, giving customers a choice. If they do, however, no customer should participate in and receive compensation for the same service from more than one program. At a minimum, customers signing up for a program should certify that they are not enrolled in more than one program for the same service. Monitoring compliance should be a collaborative effort with PJM and the EDCs. To the extent that EDC meter data is required for program verification, the EDCs should be aware of duplicate data authorizations. The Commission would have least ability to monitor independent, direct-pay aggregators.

21. Similar considerations may apply to solar net-metering tariffs. These legally required tariffs[11] are not intended to provide load management to the grid, but rather incentive compensation for solar installations. Peak load increasingly occurs at times when the sun is not shining, and there is likely to be little overlap between net-metering export credits and high grid

[10] PEA is aware that following the Hommrich decision (Hommrich v. Pa. Pub. Util. Comm'n., 231 A.3d 1027 (Pa. Cmwlth. 2020)) there have been instances of virtual net metering installations used primarily for exports, but the Commission can limit eligibility to appropriately sized resources. This is, in any event, a problem only for export resources. No-one will buy a larger refrigerator to save more by shutting it off.
[11] 73 P.S. §§ 1648.1—1648.8.

needs. By coupling battery storage with solar, a customer is likely to eliminate net exports at midday and to be capable of providing demand flexibility. Careful thought should be given to whether it is possible or practical to participate in both programs at once.

Integrated Distribution Planning

22. Based on the cosiderations discussed above, PEA strongly encourages the Commision to initiate integrated distribution planning ("IDP") by EDCs. IDP will necessarily work differently than integrated resource planning when EDCs owned generation, but the need is the same – to encourage long term investment in generation capacity and assure that transmission and distribution investments are consistent with delivering that capacity. The Commission has limited ability to require construction of power plants or transmission lines under the Federal Power Act,[12] and both the FERC[13] and Pennsylvania law[14] favor competitive electricity supply. However, to the extent that EDC standard offer supply remains an important element of the overall energy supply, the Commission can encourage a longer average duration with a laddered portfolio that provides short term flexibility at the margin. This would be consistent with current statutory authorization for contracts as long as 20 years,[15] and would have the ancillary benefit of allowing the EDCs to support deployment of additional renewable energy resources. The Commission could also consider, for example, require reporting from EGSs on the duration of their portfolios and their ability to maintain supply in a tight market. The Commission could also seek a more direct voice in PJM transmission planning and RTO capacity market design based on its IDP conclusions.

[12] 16 U.S.C. §§ 791-825r.
[13] 18 CFR Part 35 Federal Register Vol. 65, No. 4, Docket No. RM99-2-00, Order No. 2000, Regional Transmission Organizations (1999).
[14] Act of Dec. 3, 1996, P.L. 802 No. 138 codified at 66 Pa. C.S. §§2800 et seq.
[15] 66 Pa. C. S. § 2807(e)(3.2).

23. At the level of the distribution system, the Commission has substantial authority. For the most part, PEA does not encourage efforts to directly plan the siting of DERs, which would limit customer and community ability to meet their needs. There is a role, however, for EDC procurement of DER services under long term contracts to reduce distribution system congestion and defer the need for distribution system upgrades. These "non-wires alternatives" can substantially reduce system costs.[16] More importantly, the Commission can clear barriers for DER entry and assure that the distribution system is planned to accommodate two-way participation by customer resources. The levels of demand flexibility pricing should provide a signal, and clearing barriers to DER participation in markets will allow customers and communities to and their private partners to invest. Commission action on demand flexibility and interconnection procedures should pave the way for capacity additions.

Interconnection

24. Currently, the Commission's interconnection rules take the grid as a fixed resource and treat interconnection as a privilege that is accorded only to the fortunate for whom there is available space. Moreover, the inequities of the legacy grid have been shown to fall disproportionately on disadvantaged communities.[17] The cost allocation system for interconnection upgrades was created for wholesale generators, not for retail customers and the current model is neither equitable between customers nor based on any analysis of the benefits to the grid of reducing barriers to entry for particular customers. PEA suggests that the IDP should

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[16] See C. Berendt and B. Brown, *Distribution Support Service Agreements: A New Market Pathway for Microgrids*, IDEA EDUCATION FOUNDATION (2020), chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://higherlogicdownload.s3.amazonaws.com/DISTRICTENERGY/UploadedImages/c31a0440-a2fa-4b05-a8a3-41e62fcafd78/A_New_Path_Forward_for_Microgrids_-_DSSAs.pdf.

[17] Eric Niiler, *An Outdated Grid Has Created a Solar Power Economic Divide,* Science (September 18, 2021), https://www.wired.com/story/an-outdated-grid-has-created-a-solar-power-economic-divide/.

aim for a distribution grid that supports a diverse array of additional power sources for customers, including customers and community direct provision, and that moves toward an expectation of two-way operation.

25. PEA believes that the benefits of DER expansion described above justify a greater level of EDC support for interconnection capacity systemwide. In addition, PEA suggests that the Commission consider whether interconnection for LMI customers should be included in its universal service and energy conservation plans[18] and, additionally, require EDCs to pursue efforts to remedy historic inadequacies in underserved areas. We understand that, in many cases, utilities can achieve significant improvements in export capacity simply by updating relay settings that assumed limited exports. In brief, PEA recommends that IDP reflect an alternative view of the grid in which EDCs support customers and community investments in BTM resources.

26. PEA suggests that the Commission consider a number of other improvements to the interconnection process. Where customers create microgrids or install BTM generation and storage resources, interconnection should be based on the customer's expected operation of the resource and demonstrated control capability, rather than counterfactual worst case scenarios. For example BTM generation is generally intended to serve BTM load and will not result in full capacity exports, and batteries can be expected not to charge at peak system load. EDCs should provide increased transparency on required costs and upgrades in the application process and they should provide better hosting capacity maps.[19] Applications for smaller BTM generation should

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[18] 52 Pa. Code § 54.74.

[19] *See e.g.,* Pepco Holdings Regional Capacity Planning map, https://exelonutilities.maps.arcgis.com/apps/dashboards/abe9ee736f814d1692334627066f426b; *see also* Puget Sound Energy Generating Hosting Capacity map, https://pugetsoundenergy.maps.arcgis.com/apps/webappviewer/index.html?id=980fc190ffd648489a492f8363a1d2cc.

be able to be completed on-line (including payment), and inspection by upload of photographs is being used by utilities in other parts of the country. Finally, in connection with IDP, the Commission can require utilities to focus distribution upgrades in areas where where past underinvestment has disproportionally affected disadvantaged communities and where the system will benefit from more demand flexibility from DERs.

Conclusion

PEA encourages the Commission to move toward a future in which customer participation in generation and load management is the rule not the exception. We believe that customers and community investment can make a substantial contribution to resource adequacy.

Respectfully submitted,

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January 9, 2025