COMMENTS OF ADVANCED ENERGY UNITED AND THE ALLIANCE FOR CLEAN ENERGY - NEW YORK

re: Proceeding on Motion of The Commission Regarding the Grid of The Future. (Case 24-E-0165)

INTRODUCTION

Advanced Energy United ("United") and the Alliance for Clean Energy New York ("ACE NY") appreciate the opportunity to submit comments responding to the Public Service Commission's Notice Soliciting Comments on the Grid Flexibility Potential Study ("Flexibility Study") filed on January 31, 2025, and the first iteration of the Grid of the Future Plan ("Plan") filed on April 15, 2025.

United is a national association of businesses that works to accelerate the move to 100% clean energy and electrified transportation in the U.S. The term advanced energy encompasses a broad range of products and services that constitute the best available technologies for meeting our energy needs today and tomorrow. These include electric vehicles ("EVs"), energy efficiency, demand response ("DR"), energy storage, solar, wind, hydro, nuclear, heat pumps (air- and ground-sourced), and smart grid technologies. United represents more than 100 companies in the $374 billion U.S. advanced energy industry, which employs 4.1 million U.S. workers and over 231,600 in the state of New York.

ACE NY is a member-based organization with a mission of promoting the use of clean, renewable electricity technologies, transportation electrification, and energy efficiency in New York State to increase energy diversity and security, boost economic development, improve public health, and reduce air pollution. ACE NY's diverse membership includes companies engaged in the full range of clean energy technologies as well as consultants, academic and financial institutions, and not-for-profit organizations interested in their mission.

On April 18, 2024, the Commission opened the Grid of the Future docket ("GotF") with an Order Instituting Proceeding. This proceeding aims to unlock innovation and investment in flexible resources like Distributed Energy Resources ("DERs") and Virtual Power Plants

("VPPs") to achieve clean energy goals while managing costs and maintaining reliability.[1] United and ACE NY fully support these goals and commend the Commission for conducting both the Flexibility Study and the Plan (collectively referred to as the "Grid Reports"), which provide stakeholders with valuable information on the market potential of flexible grid resources and the current state of distribution system planning in New York. These comments focus on what we believe to be important outcomes of this proceeding and how the Grid Reports support those outcomes. In addition, we have also included an independent report by Current Energy Group ("Current"), commissioned by United, that describes DSP grid functions, lessons learned from other jurisdictions, and near-term DER deployment opportunities. United and ACE NY look forward to working with the Commission and Department of Public Service Staff ("Staff") throughout the duration of the docket.

RECOMMENDED CONSIDERATIONS IN THE GRID OF THE FUTURE DOCKET

The following sections provide what United and ACE NY believe to be important outcomes that should be considered in the GotF, or at the very least, clearly stated future actions to be taken within this docket, other existing dockets, or newly created dockets. We have categorized these outcomes under the umbrella of the following four categories: 1) Valuing Grid Flexibility; 2) DER Program Design Improvements; 3) Simplifying Customer Engagement & Program Participation; and 4) Utility & Regulatory Structures to Enable Flexibility. In the following sections, United and ACE NY introduce each of these recommended considerations at a relatively high level, and if applicable, discuss how they relate to the Grid Reports. In summary, our recommendations are as follows:

Valuing Grid Flexibility

- Enhance the Value of Distributed Energy Resources ("VDER") Tariff/Program for Aggregators Tariff/Program for Aggregators
- Create a Version of VDER that Provides for Payments or Tradeable Credits
- Differentiate Compensation for Technologies Injecting Power into the Grid

[1] Proceeding on Motion of the Commission Regarding the Grid of the Future, Case 24-E-0165, Order Instituting Proceeding, at 3 (N.Y. Pub. Serv. Commission Apr. 18, 2024).

VALUING GRID FLEXIBILITY

Enhance the Value of Distributed Energy Resources Tariff/Program for Aggregators

United and ACE NY believe improvements can be made to the Value of Distributed Energy Resources ("VDER") tariff/program so it will be more attractive to aggregators (organizations that combine and manage the participation and monetization of multiple DERs). This will incentivize DER participation and contribute to grid flexibility. The Plan notes, "[o]ne notable success at the distribution level is the Commission's VDER proceeding which resulted in statewide implementation of a 'value stack' compensation mechanism which combines the values of bulk- and distribution-level benefits."[2]

The VDER tariff itself has been a useful tool, but it requires iteration and evolution to drive deployment of DERs. As the Commission continues to evaluate whether changes need to be made to the values of the components within the value stack that makes up VDER, the GotF can help set guidance and better understand the full potential of DERs in addressing system needs. If there is a delta between the value of flexible DERs identified in the GotF and the realizable value under VDER, it will be critical to ensure that either the VDER evolves to capture these values or that other policy mechanisms can be employed to ensure that New York sees the optimal level of development of DERs to meet its ambitions climate and clean energy goals in the most cost-effective manner. We note that aggregator participation has had a salutary effect on the growth of utility DLM programs and could, we believe, deliver an analogous outcome for VDERs with the institution of proper policies.

Create a Version of VDER that Provides for Payments

A limitation of VDER is that it only provides compensation in the form of bill credits. VDER's reliance on a bill credit compensation model, and lack of a payment compensation option, limits the growth of the DER industry in the state. Without payments, such as are provided through New York's successful utility Dynamic Load Management ("DLM") programs and many

[2] DNV, *First Iteration of the Grid of the Future Plan*. NYSERDA and DPS (March 31, 2025), p. 34

VPP programs in other states, aggregators are unable to utilize payment-based business models to scale in New York. As a result, the only "aggregators" in VDER are currently community solar and storage providers, who must recruit customers and either be paid by them, serve as their retail commodity provider, or be paid by their commodity provider.

From an economic standpoint, there may be no difference between a bill credit model, where a customer saves $10 and then pays the aggregator $1 for its services (net savings of $9) and a payment-based model, where the aggregator getting $10 and pays the customer $9. However, there is a significant difference in terms of customer perception and which types of business models each model facilitates. One of the implications of having only one compensation model available is that aggregators will view VDER as competition to DLM, when the two programs should be complementary.

We suggest a revision to the VDER program that either allows for payments directly from the utility, or that allows aggregators some means of monetizing VDER credits, such that they could be sold to load-serving entities or utilities.

Part of such a change might include developing a new "flexible VDER" option that provides such direct payments, but that also makes participation contingent on providing energy when requested by the utility. This might be like the existing DLM programs, but with long-term and environmental components from the current VDER program.

Differentiate Compensation for Technologies Injecting Power into the Grid

United and ACE NY believe that operational characteristics of DERs that can be dispatched to inject (also called exporting) power into the grid warrant a distinct compensation approach than is used for DR that results in customer load reductions. Establishing differentiated compensation for injecting power would require compensating DERs for total energy dispatch, measured at the device level (*e.g.,* battery inverter) – rather than relying only on baselines to determine compensation. ConnectedSolutions in the Northeast already incentivizes DERs to inject power, increasing the positive impact of DERs on the grid and offering a model for Behind-the-Meter ("BTM") battery program design that New York can emulate. Properly incentivizing injections can lead to greater available capacity and other grid services associated with DERs, while also supporting increased DER adoption.[3]

Unlike traditional DR, DERs that can inject into the grid are capable of bringing a customer's consumption from the grid down to zero and then creating negative usage (i.e., energy exports) to help serve the load of neighbors. This can ease strain on the distribution and transmission systems as well as mitigating generation peak demand. Accordingly, BTM batteries should be compensated for total energy dispatched, regardless of baselines or whether exports occur.

DERs that dispatch onsite energy can create a seamless experience for customers who do not want to change behaviors or curtail usage but can be compensated for utilizing onsite DERs like solar plus storage or Vehicle-to-Home ("V2H") and Vehicle-to-Grid ("V2G") to reduce their consumption from the grid and/or export to the grid. This expands the addressable market for DR by reaching customers who do not wish to adjust behaviors for a DR payment.

Further consideration is needed to balance how DERs with dispatchable energy operate with existing programs, including Net Energy Metering ("NEM") or VDER. Many states allow customers engaged in other programs, like NEM, to offer battery availability and performance-based compensation for specific grid events. The vast majority of BTM batteries at residential premises are installed with rooftop solar engaged in net metering. Excluding these resources from being compensated for meeting called capacity shortage events will necessarily limit the potential of these resources to scale to meaningfully participate in grid flexibility (either in peak reduction or in localized non-wires programs).

[3] ConnectedSolutions is a utility-run virtual power plant (VPP) program in the northeast (Massachusetts, Rhode Island, Connecticut, and parts of New York). It enables homeowners and businesses to earn incentives by allowing utilities to use energy stored in behind-the-meter batteries, smart thermostats, or electric vehicles during times of peak grid demand. The goal is to reduce stress on the grid, defer infrastructure build-out, lower carbon emissions, and pass savings onto participants.
Participants are rewarded with performance-based payments—calculated based on average kW discharged during dispatch events. Homes retain backup power capability and can opt out of events if necessary. *See* https://www.cleanegroup.org/initiatives/energy-storage-policy-and-regulation/connectedsolutions/

While the Commission recently made the distinction that NEM compensates for energy and that battery storage associated with these systems cannot be compensated on a pay-for-performance basis in DLM programs, there is an opportunity to revisit this conclusion and to develop a more complete factual record on the issue that examines the unique characteristics and capabilities of BTM solar paired with storage. Under the current paradigm, there is a likelihood that a NEM customer with battery storage participating in DLM would not be fully compensated for the value that they provide to the grid. While the goal is to create net benefits for all customers, compensation for BTM storage participating in NEM or VDER will not achieve any benefits if it is not adequate to encourage customers to utilize their private capital to install and enroll these devices.

Enable Virtual Power Plant Operations

We recommend the Commission identify and make the necessary changes to regulatory frameworks and technical standards to enable the operation of VPPs, which aggregate DERs and provide flexible capacity to the grid, offering more stability and responsiveness. As VPPs spread across the country, regulatory approaches are crucial to drive desired outcomes, so it is important to avoid creating too many headwinds or barriers to entry for DER providers.
Non-utility aggregators should be given the right to participate in retail programs offered by the utilities by aggregating individual customers and DERs into VPPs and receive compensation directly from the utilities for that performance.

Regulation should foster a competitive market for DER aggregators, to encourage innovation in both the products and the offerings available to consumers. As a threshold matter, the Commission should clarify that DER aggregators are not directly regulated entities but are subject to the conditions set by the Commission for eligibility to be a vendor in any VPP program.

Given the Uniform Business Practices for DER and other such rules that the Commission is poised to adopt, it will have sufficient authority over retail programs to ensure that DER aggregators are sufficiently vetted and are commercially fit, willing, and able to provide the technical and financial services they need to do to facilitate customer payments and DER performance.[4]

Establish a Balance Between Dynamic Pricing and Resource Compensation

Dynamic pricing for electricity usage, which varies based on grid conditions, provides an incentive for customers to shift or reduce load during higher priced periods. DERs can enable changes in consumption, which ultimately can benefit the entire customer base if those changes occur at optimal times for the grid. We believe it is important to strike a balance between dynamic pricing and ensuring adequate compensation for DER providers that creates the proper financial incentive to deploy DERs and maximizes grid benefits. The compensation levels for DERs responding to dynamic pricing should reflect both the flexibility of the resources they provide and the value they bring to the grid.

This issue was acknowledged in the Grid Reports. The Plan discusses DER compensation in the context of market design and notes that New York's market design presents a regulatory barrier to the efficient integration of DERs due to the complexity of electricity systems and the slow pace of market development. The Flexibility Study notes how the electricity grid requires continuous balance between supply and demand, with generation and consumption occurring almost simultaneously. The Study also properly considered the importance of hourly data for grid flexibility by stating:

> The modeling for the Grid Flexibility Potential Study included hourly granularity when accounting for the operation of grid flexibility options and their value to the New York power system. The hourly dispatch of the options will vary from day to day depending on the needs of the power system and the highest value opportunities to use grid flexibility. In Section II of this report, we illustrate how the portfolio of grid flexibility

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[4] New York State Department of Public Service. (n.d.). Distributed Energy Resource (DER) Regulation and Oversight. *See* https://dps.ny.gov/distributed-energy-resource-der-regulation-and-oversight

> measures modeled for the Grid Flexibility Potential Study could be dispatched to provide value across peak and average load days in the summer and winter.[5]

Provide Incentives for Demand Response

Currently, DR does not receive a deployment incentive. Renewable resources receive out-of-market payments in the form of renewable energy certificates or offshore renewable energy certificates, nuclear plants receive zero-emission credits, and bulk storage resources will receive index storage credits. Wholesale DR is only paid market prices for capacity, energy, and/or ancillary services, while retail DR is paid under rates that are intended to be equal to or less than utility marginal costs of service for transmission and distribution.[6]

There is a significant amount of DR that has been procured at these market prices. It is highly likely that more could be procured if DR were also to receive above-market payments like the resources noted above. Given that load curtailment has no emissions or environmental impacts of any kind and provides the additional value of reducing strain on grid infrastructure, it is arguably deserving of above-market payments to help drive greater deployment. Whether structured as limited one-time payments for signing up, or ongoing incentives for continued participation, incentives for DR could help encourage broader participation by customers in DR programs.

The Flexibility Study acknowledges the significant potential of DR by stating:

> While New York has long been a national leader in energy efficiency (*e.g.*, ranking #3 in ACEEE's state energy efficiency scorecard), our analysis of data from the U.S. Energy Information Administration and Federal Energy Regulatory Commission ("FERC") suggests that 17 states have a greater ability to reduce peak demand through DR capability. While DR capability naturally varies across markets due to regionally varying

[5] Brattle Group, *Grid Flexibility Study Potential Volume III: Supplemental Analysis*. NYSERDA and DPS. (March, 2025), p. 2

[6] Currently, DR is not compensated for capacity in utility programs because doing so would create a "double counting" issue and preclude their participation the NYISO's capacity DR and DER programs. As the Commission understands the ability to stack sources of value is critical to maximizing participation.

> factors such as differences in customer mix and marginal system costs, this state-level benchmarking suggests that there is room for New York to expand and scale its grid flexibility offerings.[7]

In this proceeding, the Commission should consider ways to incentivize addition DR participation in utility programs including (a) providing the same type of environmental component that VDER provides; (b) adding a capacity component that is at least as large as that available through the NYISO; (c) $/MW incentives; or (d) incentive for technology to enable participation in the NYISO's DER participation model.

Create Economic DER/DR Programs as Alternatives to NYISO Programs

Developing new economic programs for DR and other DERs that offer more flexibility and are more effective than current New York Independent System Operator ("NYISO") programs, which might be considered cumbersome or impractical, would provide the opportunity to animate large groups of existing customers willing to provide load flexibility who are currently prevented from doing so by onerous requirements to participate in the existing NYISO DER participation model. The Commission is aware of this issue as stated in the Plan:

> The Reforming the Energy Vision ("REV") initiative builds on NYISO's wholesale market to develop retail-level DER markets, facilitating services like DR and energy storage. While this encourages investment in DERs and supports energy transition, it's a work in progress, as market mechanisms and stakeholder participation are still evolving to ensure comprehensive market access and coordination. In 2024, NYISO's implementation of new market rules to integrate DERs is a step forward, allowing aggregations of DERs over 10 kilowatts ("kW") to participate in the wholesale electricity market. However, the 10-kW minimum size requirement has posed a barrier for smaller resources, potentially limiting widespread adoption. Despite these challenges, the

[7] Brattle Group. *Grid Flexibility Potential Volume I: Summary Report.* NYSERDA and DPS (Jan. 2025), p. 17.

ongoing development of this market under FERC's Order 2222 is seen as a positive step in advancing the integration of DERs into the grid.[8]

In addition to the NYISO's exclusion of essentially the entire residential customer class, as well as small commercial customers, the NYISO's DER rules are built upon a systemic foundation designed half a century ago to accommodate large generators hundreds or even thousands of MW in size. Not surprisingly, these rules are ill-suited for customers less than one-hundredth that size.

Chief among these burdensome requirements, and one which acts as a *de facto* barrier to DR resources' participation in DER is the requirement that all DER resources have telemetry with six-second granularity, the need to submit meter data the following day, and the general level of burden with navigating the host of requirements associated with participating in the NYISO capacity and energy markets that DERs will face. Navigating these requirements is something that aggregators can largely spare customers from, but even some smaller aggregators may face issues with these requirements.

It is understandable that generators providing regulation service should have to have six-second telemetry. It is not at all clear why loads participating in the hourly energy, 30-minute, or 10-minute reserves need to have six-second granularity. While establishing six-second telemetry can cost between $10,000 and $30,000, one-minute telemetry might cost as little as one-tenth that amount. NYISO has recently suggested that it will consider ideas for developing a less burdensome "DER Lite" alternative that would perhaps not be as expensive to participate in but might also not allow participation in certain NYISO markets (like regulation or reserves.)[9] United and ACE NY are supportive of such efforts, but it is by no means clear that they will be developed. As noted above, another possibility would be for NYSERDA to provide

[8] DNV. *First Iteration of the Grid of the Future Plan*. NYSERDA and DPS (March 31, 2025), p. B-27.
[9] New York Independent System Operator. *Engaging the Demand Side: 2025 Project Update*. (April 4, 2025)
https://www.nyiso.com/documents/20142/50614388/ETDS%202025%20Project%20Update_Final%20(1).pdf/5d4f2eed-4b51-4ab6-1bfd-6528e69f1f42

incentives to overcome telemetry or other barriers that prevent Special Case Resources ("SCRs") from becoming DERs.

If less burdensome telemetry requirements for DERs are not developed, and NYISO provides no vehicle by which existing SCRs a cost-effectively participate in DER (potentially facing a huge revenue reduction in the downstate region where capacity is most needed) it may be necessary for those SCRs to exit the NYISO market. In that case there, as also suggested above, is a role for the utilities to include capacity payments in their DLM programs.

Ideally, there will not be an any friction between NYISO and retail programs. Retail programs can be established and designed to be compatible with a NYISO that is friendly to DERs at all scales creating the ability of flexible loads to "stack" the value they provide at the retail/utility level with the capacity, energy, and ancillary services they can provide at the wholesale level.

DER PROGRAM DESIGN IMPROVEMENTS

Consider Energy Efficiency and Incorporate Behavioral DR

United and ACE NY support acknowledging the value of energy efficiency and behavioral DR as resources that provide grid benefits. Behavioral changes can contribute significantly to overall demand reductions. It would serve the grid to consider opportunities to expand energy efficiency and behavioral DR through this proceeding.

In the supplemental analysis to the Plan, there are references the value of energy efficiency and explicit concerns that if New York reduces energy savings, there will be grid flexibility implications. Referring to the New Efficiency New York interim review, this analysis states:

> A consequence of this transition is that retrofits and electrification will be prioritized for ratepayer funding over other energy efficiency measures such as lighting or behavioral energy efficiency. A barrier for energy efficiency measures aimed at reducing peak load is insufficient recognition and compensation for the benefits they provide in lowering peak demand. Current energy efficiency programs set targets and evaluate performance of programs based on their "annual energy savings", *i.e.,* annual reduction

in MWh of electricity sales by utilities. As a result, the time-varying value of load reductions is not fully considered in the design of programs and their incentive levels. Potential solutions to updating the performance metrics are being discussed by stakeholders in the NE:NY proceedings. Stakeholders are discussing whether the annual sales reduction metric remains appropriate to drive and assess performance across different types of energy efficiency and electrification initiatives. Utilities proposed shifting from an annual energy savings measure to a lifetime energy savings measure to better reflect and enable the evolution of the NE:NY portfolios towards longer-lived, deeper efficiency measures. Other stakeholders endorsed the use of an alternative single metric, *i.e.*, the Total System Benefits ("TSBs") metric developed by the Natural Resources Defense Council and adopted in 2021 by the California Public Utilities Commission, as a unifying way to aggregate all electric system benefits and environmental externalities across different resources including efficiency, electrification, and DR. The TSB incentivizes the California program administrators to target energy conservation in capacity shortfall hours because those hours have the highest utility avoided costs. Energy saved in these hours provides much greater benefit than in other hours, thus focusing effort toward the most beneficial conservation measures.[10]

Energy efficiency plays an important, albeit passive, role in managing the grid. All energy efficiency resources provide reductions at peak times, with some providing more than others. Any reduction in energy efficiency outcomes will have an impact on usage at peak times, with some providing more than others. Any reduction in energy efficiency outcomes will have an impact on usage at peak times. Ending behavioral energy efficiency, including the Home Energy Report ("HER") program, is a primary example of this challenge.[11] For example, the 2020 PG&E HER demonstrated an average per customer load impacts of 2.4%. These peak

[10] Brattle Group. *Grid Flexibility Potential Volume III: Supplemental Analysis*. NYSERDA and DPS. (March 2025) p. 21.

[11] New York State Department Public Service Commission, *Order Authorizing Non-low- to Moderate Income Energy Efficiency and Building Electrification Portfolios for 2026-2030,* Case 14-M-M-0094, Case 18-M-0084, Case 25-M-0248, (May 15th, 2025) https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7bC05AD596-0000-CD3D-BE14-8B9DB94D216D%7d

benefits go away should energy efficiency investments go down.[12]

Behavioral Demand Response ("BDR") programs have a long history of generating significant load reductions during peak day events. This program design has been deployed in a variety of geographic areas and utilities across the U.S. While there is some variability due to differing climate zones, customer base attributes, and myriad other factors, independent evaluations have consistently found statistically significant load reductions resulting from the program. Specifically, these evaluations have found an average per customer impact of 0.03- 0.17 kW per event, with the vast majority of events seeing reductions of 0.04-0.08 kW per customer. In context of overall usage, these BDR programs caused customers to use 1.5- 4% less energy during peak events. In the Study, BDR is listed as having the potential to avoid over 500 MW in the summer months.[13]

Fully Integrate EVs as Flexible Resources

The Study identifies EV charging as "the single largest opportunity for grid flexibility."[14] We support utilizing EVs as flexible resources in grid operations and planning. This includes supporting both V2H and V2G technologies, where EVs can both supply power to homes or the grid, and serve as grid assets during peak demand times. Full integration of EVs as flexible resources in operations and planning will require a cohesive suite of interconnection rules, Time-Varying Rates ("TVR") (both dynamic and static), utility programs at the distribution level, aggregated access to the wholesale market, and upfront incentives to offset higher technology costs in the near term. Market access, in the form of interconnection rules, creates the primary barrier fundamental to operation.

Also extremely important for managed bidirectional changing is access to appealing rate structures for customers. This may be particularly important for bidirectional charging, as a recent studies have shown that without meaningful deltas between the on-peak and off-peak

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[12]Nexant, *PG&E HER 2020 Energy and Demand Savings Early EM&V* (Jan. 3, 201) https://pda.energydataweb.com/api/view/2594/PGE%202020%20HER%20Energy%20and%20Demand%20Savings%20Report%20%5BFinal%5D%20CALMAC%20PGE0466.01.pdf

[13] Brattle. *Grid Flexibility Potential Volume I: Summary Report*. NYSERDA and DPS (Jan. 2025), p. 47.

[14] Brattle. *Grid Flexibility Potential Volume I: Summary Report*. NYSERDA and DPS (Jan. 2025), p. 9.

periods of TOU rates, customers can not financially justify investment in additional bidirectional functionalities.[15] Encouraging managed charging via rate structures also has benefits from renewable integration; Plan rightfully identified the ability of flexible EV charging load as a means to utilize excess solar generation. "Our assessment of future New York power system conditions also identified the middle of the day as an attractive time for charging (if it can be accommodated by the Medium-and Heavy-Duty Vehicles ("MHDVs") charging needs) due to the potential for curtailed solar output."[16] Such a solution could be ideal for workplaces and co-located solar. There needs to be a clear pathway towards equipment payback for customers and enticing enough rewards for specific program participation.

Another effective approach to lower barriers to managed charging and widespread bidirectional participation is leveraging vehicle and Electric Vehicle Supply Equipment ("EVSE") submeters for program or rate participation. Separate generation meters can cost hundreds to thousands of dollars, and submeters have demonstrated their value in New York managed charging programs. Submetering can support both managed charging and bidirectional charging by allowing customers to take advantage of EV rates while avoiding costly meter installation.

Incentives in the near term can secure more grid assets in operation that provide the valuable services bidirectional vehicles offer. Retail VPP and the wholesale market participation opportunities through aggregators can generate incentives that in turn spur the adoption of more bidirectional charging-enable vehicles. Ease of customer participation is key in enabling grid services through EVs.

Fully Integrate Electric Building Technologies

Electric buildings should be incorporated as flexible resources in grid operations and planning. Similar to EVs, the electrification of home heating offers an opportunity to expand the number

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[15] Andersen, D., & Powell, S. *Policy and Pricing Tools to Incentivize Distributed Electric Vehicle-to-Grid Charging Control*. Energy Policy, 198, 114496. (2025) https://doi.org/10.1016/j.enpol.2025.114496
[16] Brattle. *Grid Flexibility Potential Volume III: Supplemental Analysis*. NYSERDA and DPS. (March 2025) p. 14-15.

of kilowatt-hours that can be leveraged in load flexibility or efficiency programs. In particular, heat pumps and electric water heaters paired with smart thermostats, smart panels, and/or advanced metering infrastructure can respond to TVR and live signals from grid operators to curtail demand. These appliances can become part of VPPs along with distributed generation and storage. Some electric appliances, including induction stovetops and heat pumps now have batteries integrated within them with the explicit goal of "enhance[ing] grid flexibility and support[ing] smarter energy management."[17]

The Study identifies HVAC potential by identifying it as one of the largest sources of flexibility in 2030 and 2040.[18] In the summer, high-efficiency heat pumps can lower peak air conditioning demand by approximately 20% as compared to traditional cooling equipment. In the winter, peak shaving can be achieved by intentionally incentivizing the uptake of high-efficiency cold climate equipment or ground-source heat pumps (individually or as part of thermal energy networks). Additional work is needed and could be appropriately done in the next phase of GotF, to identify the avoided cost value of high-efficiency cold climate heat pumps and ground-source heat pumps so that appropriate incentive levels can be set.

Develop Interconnection Standards for V2H and V2G

United and ACE NY recommend implementation of expedited or special interconnection standards for non-exporting V2H systems and exporting V2G systems. This would streamline the deployment of these technologies and increase their adoption. At a baseline it is critical that as more "bidirectional-capable" vehicles and EVSEs come into the market so that customers not operating in parallel to the grid do not need to go through a formal interconnection process. If not properly handled there could be a point where every charger installed would need to go through the interconnection process, which would create bottlenecks for both consumers and utilities. Many new DER technologies, including vehicle systems, implement software locks to limit or eliminate grid export, known as power control

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[17] *Carrier and Google Cloud Join Forces to Strengthen Grid Resilience with AI-Powered Home Energy Management Systems.* (March 5, 2025). https://www.prnewswire.com/news-releases/carrier-and-

[18] Brattle. *Grid Flexibility Potential Volume I: Summary Report*. NYSERDA and DPS (Jan. 2025), p. 7.

systems. It is important that regulators and utilities familiarize and allow these bidirectional-enabling certification standards such as UL 3141. While much of the industry and relevant standards are still nascent it is critical not to over-prescribe certain standards. The Commission is aware of the importance of specialize bidirectional chargers and energy management software:

> Bidirectional charging, where an EV can export electricity to a building (Vehicle-to-Building), or to another load such as an appliance or another EV (Vehicle-to-Load), (Vehicle-to-Vehicle), or to the grid (V2G) is another option for MHDVs to offer grid flexibility. Bidirectional charging requires a specialized bidirectional charger and energy management software to communicate between devices. In the case of V2G, an interconnection agreement with a local utility and communication between the vehicle and the utility/aggregator is also required.[19]

In the case of parallel operation (both export and non-export) interconnection pathways should be clear, standardized, and streamlined specifically for vehicles with reasonable, cost-based interconnection fees. When considering vehicles as a DER, it is important to categorize interconnection size by the inverter rating rather than battery capacity. Operation and capability are determined by the inverter rating and considering battery size can lead to vehicle systems being subject to higher review requirement pathways compared to other DERs.

Prioritize Flexibility Over TOU Windows for Battery Participants

For battery participants, allowing flexibility in how batteries are used, so they are prepared for grid needs rather than being constrained to specific TOU windows should be considered. This would provide more options for batteries to be used effectively during grid emergencies or high-demand events. More advanced, TVR designs can provide customers a price signal that supports investing in a BTM battery to manage on-peak costs by utilizing the battery to optimize dispatch of energy to serve onsite load. However, when batteries are engaged in the

[19] Brattle. *Grid Flexibility Potential Volume III: Supplemental Analysis*. NYSERDA and DPS. (March 2025) p. 15.

primarily economic activity of optimizing the customer's usage to achieve bill savings by responding to TOU windows, the dispatch and performance of the batteries may not optimally line up with the moments of most severe system need.

Optionality for customers with BTM batteries, including those with rooftop solar engaged in NEM or VDER, can allow the batteries to be optimized for performance of grid services rather than economic arbitrage of the customer bill.

One option is not inherently better than the other but speaks to the different customer preferences and comfort levels with utilizing their batteries for certain use cases. At the end of the day, customers with batteries expect to enjoy resilience benefits in the event of a grid failure.

In a program approved by the North Carolina Utilities Commission for Duke Energy, customers receiving an incentive to install a BTM solar+storage facility have the option of taking service under a flat, non-TVR and participating in utility-called dispatch events (for compensation that is additional to net metering) or taking service under a TOU rate with critical peak pricing on event days. This type of optionality is good for consumer choices but also can provide learnings about how customer batteries perform under either scenario.

SIMPLIFYING CUSTOMER ENGAGEMENT & PROGRAM PARTICIPATION

Provide Customer Education and Engagement

Customer engagement and engagement is crucial to driving customer participation and program success and if not given the proper resources, could negatively impact grid flexibility potential. The Plan identified this by stating the following:

> Grid flexibility potential estimates are most sensitive to assumed maximum achievable participation rates. This finding is supported by the observation that participation rates vary widely in demand flexibility programs across the U.S. Customer participation in grid flexibility offerings is affected by a variety of technical, economic, and behavioral

> barriers; a focus on strategies for increasing customer engagement will be key to realizing grid flexibility potential. Simple, transparent program incentive structures and streamlined enrollment processes of effective strategies to increase program participation.[20]

Successful customer education and engagement requires having the resources to do so. We recommend the Commission allocate a dedicated budget for customer education and engagement, including the promotion of advanced software tools that empower consumers to understand and participate in DER programs and TOU rates. Beyond basic rate comparison or DER recommendations, customer-facing platforms that are informed by the same engines used for utility rate design, bill calculation, and impact analysis offer a more accurate and trustworthy view of cost and benefit—critical for driving confident customer action.
We also believe that for customer education and engagement to be successful in driving participation, simplified messaging should be emphasized. This includes providing clear, consistent, and tailored messaging that helps customers navigate increasingly complex rate structures and program options. When supported by robust backend analytics and billing engines, messaging can be paired with scenario modeling, personalized bill projections, and intuitive digital interfaces, making it easier for all customer segments to engage meaningfully with flexible grid programs.

Expand Time-of-Use (TOU) Pricing, Consider Default Enrollment

To increase adoption and demand-side flexibility, we recommend the availability of TOU pricing should be expanded to incentivize customers to shift energy consumption to off-peak times. We also recommend the Commission evaluate if TOU should be the default rate for all non-residential customers with an option to opt out. As New York's grid shifts to winter-peaking through increased electric heating, TOU can help mitigate increases to peak demand and the associated system costs.

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[20] Brattle. *Grid Flexibility Potential Volume III: Supplemental Analysis*. NYSERDA and DPS. (March 2025) p. 10-11.

Expanding TOU pricing is a strategic, high-impact policy that aligns directly with the Plan by promoting demand-side flexibility, reducing system costs, and supporting decarbonization. TOU rates, which vary electricity prices by time of day, encourage customers, especially residential users, to shift consumption away from peak hours. This shift reduces grid stress, enhances reliability during periods of high demand, and delays or avoids costly infrastructure upgrades such as new substations or peaker plants. In doing so, TOU supports key state goals of affordability and resiliency.

By aligning electricity use with periods when renewable generation is most abundant (e.g., midday solar or overnight wind), TOU pricing also helps decarbonize New York's power mix. As DERs like rooftop solar and battery storage proliferate, TOU can provide the price signals that guide when to charge or discharge batteries, enabling customers to optimize for both cost and carbon emissions. This makes every household a more active grid participant and turns flexible demand into a vital clean energy resource.

Making TOU enrollment the default for non-residential customers while allowing them to opt out—can dramatically increase participation and unlock grid-wide benefits. Evidence from other states shows that opt-out designs consistently result in over 90% enrollment, compared to very low participation in voluntary programs. With smart meter infrastructure already deployed across much of the state, New York is well-positioned to implement default TOU broadly. Pairing this with customer education, bill protections, and digital tools can ensure equitable outcomes while accelerating the transition to a smarter, more sustainable grid.

In short, default TOU pricing is a foundational policy for realizing New York's vision of a flexible, decarbonized, and customer-centered grid. It leverages pricing, technology, and behavioral insights to reduce emissions, improve reliability, and lower system costs, making it a natural complement to the state's broader clean energy and grid modernization agenda.

Streamline Enrollment and Simplify Customer Messaging

To maximize grid flexibility potential, it is important that the process for enrolling in DER and rate programs is simple and easy to understand. This includes eliminating unnecessary barriers to participation and providing a single, easy-to-understand point of entry for customers to enroll in these programs. The Flexibility Report acknowledges that complexity can limit participation:

> The design of program/tariff options is complex and prevents some technologies from monetizing the value of grid flexibility to the full extent possible. New York has various utility and wholesale programs, tariffs, and markets for flexibility, and some technologies have multiple options to choose from. The compensation mechanisms are often complex, and it is not easy for customers to gauge the potential benefit of enrolling. Combining multiple value streams is difficult, both due to the complexity and because in some cases, different sources of value are compensated through different programs that may not allow simultaneous participation.[21]

We also support streamlined enrollment because of additional challenges that Low-to-Moderate Income ("LMI") and Disadvantaged Community ("DAC") may experience and appreciates the Commission's identification of these challenges in the Study:

> Besides financial constraints, individuals in LMI and DAC households may face time constraints due to multiple jobs, caregiving responsibilities, or other socioeconomic challenges (also referred to as "time poverty" 102). Therefore, streamlining enrollment in grid flexibility programs is key. Combining different types of grid flexibility programs (e.g., bill payment assistance, rate options, energy efficiency, and grid participation) into one streamlined package can greatly simplify and boost enrollment. Automatically enrolling customers (while providing an opt-out option) when purchasing grid-connected technologies could further alleviate time poverty as well as boost overall enrollment, resulting in increased benefits for consumers and the grid. Where income eligibility is a

[21] Brattle. *Grid Flexibility Potential Volume I: Summary Report*. NYSERDA and DPS (Jan. 2025), p. 55.

factor in program participation, conducting income verification alongside other assistance programs such as the Supplemental Nutrition Assistance Program (“SNAP”), transit, or energy assistance programs can also expedite the process, reducing the administrative burden on both customers and utilities. This integration simplifies access to multiple services and reduces friction during the enrollment process.[22]

Offer Supplier Consolidated Billing

We recommend that the Commission allow for Supplier Consolidated Billing (“SCB”), where customers receive one bill that includes both their supplier charges and utility charges. This would reduce complexity and make it easier for customers to engage with innovative products and services without the inconvenience of managing multiple bills.

SCB is an arrangement in the utility market where a third-party provider (“TPP”), rather than the local utility company, issues a single consolidated bill to the customer. The bill includes both the utility charges for delivery service and the TPP charges for supply services. The goal of SCB is to enhance the competitive energy market by giving suppliers more flexibility with the products they can offer.

Allowing third-party providers to directly bill customers for the new products and services can be enabled by the deployment of Advanced Metering Infrastructure (“AMI”) meters and the interval usage data they collect is critical to ensuring a return on the customers’ investment in smart meters. When TPPs can offer a single, consolidated bill to customers, containing all electric charges, they are not confined by the limitations of the utility bill. As a result, TPPs can be more innovative and show customers how their energy usage is affecting their overall bill.

SCB works hand in hand with TOU rates, VPPs, and DR programs and enables TPPs to provide one innovative bill for a whole suite of products and technologies aimed to reduce customers’ usage and help New York meet its goals.

[22] Brattle. *Grid Flexibility Potential Volume III: Supplemental Analysis*. NYSERDA and DPS. (March 2025) p. 32.

Suppliers are currently providing billing in other places (Texas, Illinois, and Alberta) and recently, Maryland approved an SCB program. Adequate rules and guidelines would be identified to make the program successful. TPPs would purchase the utilities' receivables and incur collection risk similar to how the utilities do it today. Customers would have more of a direct relationship with their TPP, thus fostering more trustworthy and reliable participants in the market. TPPs would gain the flexibility to offer the most innovative products and services to customers.

UTILITY & REGULATORY STRUCTURES TO ENABLE FLEXIBILITY

Create Performance-Based Incentives for Grid Flexibility

United and ACE NY believe the Commission should consider performance-based incentives mechanisms for utilities to achieve grid flexibility goals. Any Performance Incentive Mechanism ("PIMs") should be tied to meeting specific grid reliability and efficiency targets and system cost increase mitigation. PIMs are in addition to any cost-recovery utilities receive for costs designed to enable grid flexibility. Given load growth forecasts and increasingly complicated DER configurations, a performance-based approach would incentivize the utility for re-prioritizing investments and customer programming to match the need for grid flexibility. PIMs could be tied to a range of outcomes, including grid visibility hardware/software improvements, demand reduction (for instance, reducing peak load and locational nodal/substation congestion), customer reliability and satisfaction (tied to System Average Interruption Duration Index ("SAIDI") and Customer Average Interruption Duration Index ("CAIDI"), etc. and/or customer control), efficiency targets, and enrollment in DR-specific rate relief programming (TOU, etc.). Together, utilities would have numerous practical avenues to address grid constraints through rate base and operation and maintenance expenses to optimize grid flexibility across the utility system.

We appreciate the Flexibility Study's acknowledgement of incentive mechanisms as a method to more rapidly realize grid flexibility's potential value. The Study found that a "portfolio of grid flexibility measures could avoid $2.9 B annually in power system costs by 2040" and $2.4B of that could be returned to ratepayers. Moreover, the Study's modeled grid flexibility options are all cost-effective by 2040.[23] These technologies and grid management tactics are available now. For instance, residential DR aggregation can scale near term to provide broad and locational grid relief resulting in quantifiable system and customer benefits. However, business-as-usual reliability investment planning, while still necessary, does not sufficiently consider, value or accommodate the range of DERs and systemwide load variability that grid flexibility can provide. In order to drive the changes needed, the utilities should be able to reshape their business models to value grid flexibility advancements.

Fully Implement Integrated Energy Data Resource (IEDR) Program

We recommend full implementation of the Integrated Energy Data Resource ("IEDR") program, which centralizes energy data and provides more accurate information for market participants, improving decision-making and system integration. As described in the Plan:

> The IEDR platform hosted by the NYSERDA is 'a centralized state-wide platform that provides access to energy data and information from New York's electric, gas, and steam utilities, and other sources, to support new and innovative clean energy business models that serve to benefit New York energy customers.[24]

Centralized access to billing-quality customer energy usage and demand data were to have been a foundational element of the IEDR, but progress in providing this capability remains elusive. These data are useful for several reasons, and they are the lifeblood of DR resources. NYISO requires the submission of utility-grade customer usage data for both enrollment in its DR and DER programs and for performance measurement and settlement after events.

Currently, DR resources must access this data and significant effort and cost from each utility, most of which use different systems. This creates a cost and a burden for aggregators. The IEDR promises to centralize and simplify this process. There are many other things that the IEDR is being asked to be, but this is by far the most important from a DR standpoint.

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[23] Brattle. *Grid Flexibility Potential Volume I: Summary Report.* NYSERDA and DPS (Jan. 2025), p. 8.
[24] DNV, *First Iteration of the Grid of the Future Plan*. NYSERDA and DPS (March 31, 2025), p. 14

Incentivize DER-Enabling Technology

As noted above, we support offering incentives for technologies that enable DERs, such as telemetry systems that allow for better monitoring and control of resources. DER-enabling technology may not cleanly fit into the category of DER or grid flexibility, but if it is clear that the technologies support DERS, they should be considered a part of the DER investment. Support from NYSERDA could help accelerate the deployment of these enabling technologies.

CONCLUSION

United and ACE NY appreciate the opportunity to provide comments in the GotF and looks forward to future discussions.