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July 15, 2025

VIA ELECTRONIC FILING

TO: The Honorable Michelle L. Phillips, Secretary
New York State Public Service Commission
Three Empire State Plaza
Albany, NY 12223-1350

RE: Case 24-E-0165 – Proceeding on Motion of the Commission Regarding the Grid of the Future
Comments on the Grid Flexibility Potential Study and the first iteration of the Grid of the Future Plan

The New York Battery and Energy Storage Technology Consortium ("NY-BEST") is pleased to submit comments for consideration in the above referenced case in relation to the Grid Flexibility Potential Study Volumes I and II filed on January 31, 2025; the Grid Flexibility Potential Study Volume III filed on March 31, 2025; and the first iteration of the Grid of the Future Plan filed on March 31, 2025.

We greatly appreciate the Commission's consideration of our comments and recommendations. If you have any questions about these comments or need additional information, please contact us at 518-694-8474 or by email at info@ny-best.org. Thank you.

Respectfully submitted,

Dr. William Acker
Executive Director, NY-BEST

INTRODUCTION

The New York Battery and Energy Storage Technology Consortium (NY-BEST) is a not-for-profit industry trade association with a mission to grow the energy storage industry in New York. We act as a voice of the energy storage industry for more than 175 member organizations on matters related to advanced batteries and energy storage technologies. Our membership includes global corporations, start-ups, project developers, leading research institutions and universities, and numerous companies involved in the electricity and transportation sectors.[1]

NY-BEST and our members have been actively engaged in the implementation of the State's Climate Leadership and Community Protection Act (CLCPA)[2], including through the development and implementation of the State's Energy Storage Roadmaps. NY-BEST is committed to helping meet New York State's goal to deploy 6 GW of energy storage on the electric grid by 2030 and to direct 40% of the overall benefits of clean energy investments to Disadvantaged Communities. We recognize the tremendous opportunity for both Behind-the-Meter (BTM) and Front-of-the-Meter (FTM) energy storage, as well as managed and bi-directional Electric Vehicle (EV) charging, to support the State's goals for a flexible Grid of the Future. We applaud the Department of Public Service (DPS) and its consultants for the development of the Grid Flexibility Study and this important first step toward a comprehensive Grid of the Future Plan.

COMMENTS

We understand the Grid of the Future (GOTF) effort will be conducted in four phases:

- Phase 1: Conduct quantitative assessment of cost-effective, achievable potential for grid flexibility. Identify barriers and preliminary options for addressing barriers.
- Phase 2: Review Distributed System Implementation Plans (DSIPs) relative to prioritized list of evaluation elements. Update DSIP guidance for utilities.
- Phase 3: Develop a comprehensive plan for achieving long-term grid flexibility vision for New York. Establish a framework for updating the plan over time.
- Phase 4: Research, Development, Tests and Demonstrations.

The documents released to date, namely the three volumes of the Grid Flexibility Potential Study and the first iteration of the Grid of the Future Plan, comprise the first two phases of the GOTF initiative. We look forward to working with the Commission and Guidehouse to ensure that Phase 3 of the initiative lays out a comprehensive plan to realize the significant benefits identified in the Phase 1 Grid Flexibility Potential Study, including:

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[1] NY-BEST comments represent the interests of the organization as a whole and not the views of any single member. Our members have diverse interests and the organization's views are intended to be reflective of the energy storage industry collectively.

[2] New York State Climate Leadership and Community Protection Act, Chapter 106 of the Laws of 2019. Accessed here.

- There is significant opportunity to vastly expand grid flexibility by 2040. Specifically, New York's 2040 grid flexibility potential is over 8 GW, more than 6 times the State's current capability.[3] This could avoid nearly $3 billion per year in power system costs.[4]
- Of the 16 grid flexibility options modeled in the study, Electric Vehicle (EV) charging represents the single largest opportunity for grid flexibility, harnessed both from managed charging and bidirectional Vehicle-to-Grid (V2G) resources.[5]
- Grid flexibility provided by Behind-the-Meter (BTM) energy storage systems (ESS) is especially significant in Con Edison and National Grid territory.[6] Over 200 MW of BTM battery flexibility could be unlocked in NYC alone with permitting reform, particularly for indoor systems.[7]
- Default dynamic pricing could drive 700 MW to 1,800 MW of demand reduction by 2040, depending on the season.[8]
- Two critical grid flexibility options were not included in the quantitative analysis: managed and bidirectional charging of Medium and Heavy-Duty Vehicles (MHDVs), and Front-of-the-Meter (FTM) distributed ESS supplying power to the distribution grid. However, the study notes qualitatively that they can provide important grid flexibility value.[9]

The Phase 2 report, "First Iteration of the Grid of the Future Plan," provides an analysis of utility Distributed System Implementation Plans (DSIPs), the biannual filings by the six investor-owned utilities reporting on their progress toward the implementation of a Distributed System Platform (DSP). As described by the Commission in their 2017 Order,[10] a DSP is "an intelligent network platform" intended to enable widespread deployment and effective use of Distributed Energy Resources (DERs) on the grid by fostering "broad market activity that monetizes system and social values" and "enabling active customer and third-party engagement that is aligned with the wholesale market and bulk power system." The Phase 2 report assesses the strengths and shortcomings of the utility DSIPs in serving as an effective and standardized communication tool for the benefit of stakeholders including DER developers, government, and community advocates.

While NY-BEST understands the opportunity to leverage DSIP reports as a key tool in tracking progress toward GOTF initiatives, we were disappointed that the Phase 2 report focused on methodology more than content. We are looking forward to working with the Commission, Staff, and the Guidehouse team to inform and comment on the Phase 3 report, which should provide a more comprehensive plan for leveraging BTM storage, FTM storage, and V2G resources to achieve GOTF targets.

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[3] GOTF Vol 1 p7
[4] GOTF Vol 1 p45
[5] GOTF Vol 1 p44
[6] GOTF Vol 1 p46
[7] GOTF Vol1 p51-52.
[8] GOTF Vol 1 p47
[9] GOTF Vol 3 p14-17
[10] Case 15-M-0180, In the Matter of Regulation and Oversight of Distributed Energy Resource Providers and Products, Order Establishing Oversight Framework and Uniform Business Practices for Distributed Energy Resource Providers (issued October 19, 2017), Appendix A - Uniform Business Practices for Distributed Energy Resource Suppliers, p 2.

To that end, we recommend the Commission consider the following critical recommendations to include in Phase 3, the comprehensive Grid of the Future Plan, as further described below:

1. Direct each utility to establish a **Bidirectional Service Class**.
2. Establish a holistic vision for utilities to incentivize **DER deployment in high-need areas**.
3. **Expand services** that DERs are incentivized to provide.
4. Direct utilities to adopt **Flexible Interconnection standards** and streamline DER interconnection.
5. Direct utilities to remove interconnection barriers and establish revenue mechanisms and/or incentives for **bidirectional Electric Vehicle charging (V2G) and mobile batteries**.
6. Direct utilities to accelerate adoption of **Operational Technology (OT) and Information Technology (IT) improvements**, including machine-readable tariffs.
7. Direct utilities to develop a **"New York Nodes" plan** to create a market structure for flexible assets.
8. **Incentivize utilities to work with stakeholders** on GOTF initiatives.
9. Improve **utility reporting requirements** relating to distributed generation analysis and deployment.

1. Direct each utility to establish a Bidirectional Service Class.

Context: Bidirectional resources such as Front-of-the-Meter (FTM) energy storage systems (ESS), Behind-the-Meter (BTM)ESS, and vehicle-to-grid (V2G) assets, are uniquely positioned to support both localized load and the broader electric grid. Particularly when sited near load, these resources can provide efficient and cost-effective distribution system support. However, current tariff and rate structures are ill-suited to bidirectional resources; interconnecting a single FTM ESS, for example, currently requires navigating 17 separate sections of Con Edison's electric tariff—many of which were developed for different technologies and use cases. Further, existing tariffs do not incentivize optimized dispatch for bidirectional resources and result in higher costs for ratepayers. For example: the Dynamic Load Management (DLM) program, which was designed for traditional demand response resources, relies on baseline load profiles to assess performance metrics. As a result, energy storage assets are penalized for operating on non-DLM call days, despite the grid value and cost savings they could otherwise provide on those days. This fragmented and outdated approach will not support the scale of deployment needed to realize the GOTF vision. Instead, a more holistic and integrated framework is required.

Recommendations: We recommend that the Commission direct the Joint Utilities to develop a framework for a standardized Bidirectional Service Class tailored to Front-of-the-Meter (FTM) ESS, Behind-the-Meter (BTM) ESS, and V2G that can be adopted by each utility, in line with NineDot Energy's whitepaper, "Designing a Bidirectional Electric Rate to Power New York's Grid of the Future," included in Appendix A.

This service class should:

- Align price signals and rate design with grid needs, optimizing charging and discharging based on time- and location-specific system conditions. This would improve upon current rate structures that restrict charging windows without regard to local demand. For example, optimized charging windows could be set using day-ahead hourly pricing to avoid coincident peaks, reducing system demand and enabling more efficient grid integration. Further, utilities should have the capability to signal desired behavior to bidirectional resources in the event that local conditions are not fully reflected in day-ahead zonal pricing.
- Include clear, consistent interconnection requirements for FTM ESS, BTM ESS, and V2G, including provisions for flexible interconnection, as further discussed in Recommendation #3 below.
- Allow opt-out participation for FTM ESS in the Statewide Solar For All (S-SFA) program, which distributes VDER bill credits to low-income customers enrolled in the Energy Affordability Program (EAP) within each utility's service territory.
- Modify the Wholesale Distribution Service (WDS) under FERC jurisdiction to harmonize with the new Bidirectional Tariff. This is critical to ensure that WDS resources are eligible to provide value to the grid at the distribution-level, maximizing value to ratepayers.

To this end, **we recommend the Commission establish a Flexible Resources Working Group (FRWG)** in which the Joint Utilities and stakeholders can collaboratively design the framework for utility adoption and implementation of a Bidirectional Service Class.

2. Establish a holistic vision for utilities to incentivize DER deployment in high-need areas.

Context: Currently, the Joint Utilities employ a range of overlapping locational price signals to address high-need areas, including:

- Locational System Relief Value (LSRV) within the Value of Distributed Energy Resources (VDER) framework;
- Demand Response programs, such as Commercial System Relief Program (CSRP), Distribution Load Relief Program (DLRP), Term-Dynamic Load Management (DLM), and Auto-DLM;
- Non-Wires Alternatives (NWAs); and
- Con Edison Bulk Solicitation “Preferred Areas” designation.

These tools are intended to direct DER investment to areas of the grid where they can deliver the greatest value, but in practice, they are fragmented and often poorly aligned with DER financing and deployment needs. Each program faces distinct challenges.

In the case of LSRV, for instance,the Joint Utilities have raised valid concerns regarding the dispatchability and reliability of enrolled resources. Further, LSRV is not currently driving meaningful concentrations of project development. For example, of the 2.3 GW of projects in the Con Edison interconnection queue, only 35.5 MW are in LSRV zones.

In the case of DLM, programs designed primarily for other resources have resulted in inefficient use of ratepayer funds when it comes to energy storage. Many energy storage systems participating in DLM are dispatched for only a few hours per year, and are discouraged from cycling more frequently due to the "customer baseline" performance assessment methodology discussed above. Further, projects can only bid into the DLM program 1-2 years in advance; this is not aligned with the 3+ year development process of new energy storage resources. As a result, DLM does not incentivize development of new storage projects since DLM revenue cannot be contracted at a time to secure financing. It acts as a bonus rather than a driver.

Meanwhile, NWA processes remain complex, bespoke, and difficult to scale, producing only a limited number of projects relative to system needs.

The GOTF proceeding presents an opportunity to harmonize these overlapping tools into a unified strategy that delivers consistent market signals, ensures cost-effective outcomes, and accelerates DER deployment where it is most needed.

Recommendations: The Commission should use the GOTF Plan to articulate a holistic and streamlined framework for incentivizing DERs in high-need areas, with the goal of aligning program objectives, improving scalability, and reducing administrative burden. This framework should:

- Direct the Flexible Resources Working Group (FRWG) to evaluate improvements to LSRV that enhance its reliability and usability. This could include incorporating performance penalties to ensure dispatch certainty, while offering standard contracts that accelerate deployment and channel investment toward priority areas.
- Task the proposed FRWG with identifying opportunities to better align or consolidate LSRV, DLM, and NWA programs, and ensure the resulting program design encourages frequent and optimized cycling of energy storage systems, and supports project financing while maximizing value to ratepayers.
- Require the Joint Utilities to work collaboratively with stakeholders through the FRWG to design and implement this integrated approach, ensuring that programs are both technically effective and commercially viable.
- Include uniform and routine updates to Hosting Capacity Maps to direct project development to the targeted network areas in a comprehensive, coherent, and consistent manner.

By consolidating and reforming these programs under a unified strategy, the Commission can significantly improve the clarity, impact, and cost-effectiveness of DER deployment in high-value grid locations.

3. **Expand services that DERs are incentivized to provide.**

Context: DERs are capable of providing a broad spectrum of grid services (including supporting electrification, providing peak shaving in winter, providing power over longer durations, providing reactive power and voltage support, and providing wholesale services) but many of these capabilities remain uncompensated or underutilized under current utility regulations. Existing tariffs and compensation mechanisms largely reflect historical use cases and are not aligned with the emerging needs of an electrified, dynamic, and decarbonized grid.

As beneficial electrification accelerates and system flexibility becomes more valuable, it is critical that DER compensation frameworks evolve to recognize the full range of services these resources can provide and that price signals incentivize optimized DER value to the grid.

Recommendations:
The Commission should direct the Joint Utilities, in collaboration with stakeholders through the Flexible Resources Working Group (FRWG), to expand and modernize DER compensation frameworks as follows:

a. Improve the Demand Reduction Value (DRV) to better reflect evolving system needs. Reforms should include introducing Winter DRV hours to ensure relevance under evolving load profiles and increasing the number of eligible dispatch hours.
b. Facilitate providing Power Factor (PF) support under VDER and compensate appropriately. Dynamic Power Factor Correction (DPFC) technologies including ESS can provide real-time dynamic PF support, making the grid more efficient, reliable, and cost-effective. However, current VDER compensation is strictly based on real power (kW) injections. A non-unity PF introduced to support the grid will reduce real power exports during export windows, reducing revenue under the current compensation rules. Further, delivery tariffs charge a fee per kVAr, even if the kVArs introduced during charging are to support the grid, increasing costs. Interconnections have begun to require automatic power factor adjustment without commensurate compensation for DERs. The Commission should institute a new compensation mechanism for power factor support to capture and incentivize this value stream.
c. Expand the Offset Tariff to include ESS capable of synchronizing in real time with load. This would allow storage resources to offset new demand from electrification (e.g. EVs or heat pumps) with equal and opposite injections on the same feeder,

reducing net impact to the grid. Currently, Offset Tariff eligibility is limited to traditional generators.

d. Support long-duration energy storage (LDES) on distribution networks. As demand grows and more intermittent resources are added to the grid, a broader portfolio of energy storage resources of different durations will be needed. By 2030, in addition to 4-hour export windows, daily export windows of eight hours or more will also be required. Even today, based on an analysis of Con Edison's anticipated network loads in 2026, all load curves across 80+ distribution network areas will benefit from longer load-relief periods, in addition to the four-hour call windows currently used for DRV and DLM call events.[11] Export rate structures should be updated to reflect this additional value and incentivize distribution-connected LDES resources. The structures should consider the bidirectional nature of these resources, and should support a range of technologies accounting for a variation of Round Trip Efficiency (RTE) ratings of 45-90%.

e. Broaden the VDER and Standardized Interconnection Requirements (SIR) eligibility threshold to include projects up to 20 MW. The current size cap of 5 MW limits the participation of larger-scale DERs, such as community storage, that could offer substantial system benefits if integrated efficiently. Currently, many projects are forced to incorporate multiple Points of Interconnection (POIs) to be treated as distinct 5 MW projects on the same site, unnecessarily increasing project costs and complexity. In many cases a developer would choose to limit the project size to 5MW when the site could accommodate a larger size; for example, a site that could accommodate 7.5MW under the current rules would likely only have 5 MW built. Notably, distribution sited projects up to 20 MW are now possible in Con Edison territory under the Utility Dispatch Rights program, but these projects are not subject to the SIR, and instead undergo the Utility System Interconnection Study (USIS) process, which is less transparent. At minimum, utilities should be required to disclose this interconnection queue similar to SIR reporting.

f. Facilitate dual participation and wholesale market integration, particularly through aggregation models that allow DERs to participate in the wholesale market. Improved coordination between utilities and NYISO will be essential to unlock these capabilities without duplicative or conflicting requirements. Currently NYISO-participating resources are not always eligible to go through the SIR process even if they are less than 5 MW, creating significant barriers to interconnection. In addition to creating more efficient dual participation, the Commission should consider creating mechanisms for enabling distribution-connected DERs to provide some Ancillary Services products under mechanisms like a PSC-jurisdictional Bidirectional Service Class tariff or New York Nodes (see Recommendation #7 below), without being required to switch to a FERC-jurisdictional WDS tariff equivalent.

[11] NineDot Energy, "Designing a Bidirectional Electric Rate to Power New York's Grid of the Future," Appendix 4.

By expanding the suite of compensated DER services, the Commission can improve grid efficiency, enhance customer value, and support the deployment of flexible resources at scale.

4. **Direct utilities to adopt Flexible Interconnection standards.**

Context: Traditional interconnection standards treat DERs as inflexible, worst-case scenario contributors to grid constraints, limiting hosting capacity and delaying project timelines. In contrast, flexible interconnection (Flex IX) allows DERs to operate with utility oversight, enabling full output most of the year while curtailing or modifying operations during rare, grid- constrained periods. This approach significantly increases available hosting capacity and reduces the need for costly upgrades.

Under Flex IX, DERs can be managed using software controls, utility signals, or autonomous responses to system conditions. For example, utilities could temporarily block charging or discharging during localized peak load events, while allowing full operation during unconstrained times. Since curtailment of exported energy typically would occur when energy prices are low and grid need is minimal, the economic impact is modest, often limited to a low single-digit percentage of expected annual output for solar, and potentially negligible for storage or V2G.

Despite its benefits, Flex IX is not currently standard practice. Under today's rules, even highly controllable resources may be denied interconnection or forced to accept full-system upgrades, based solely on worst-case constraints during a small number of hours per year. Moreover, the existing mechanism for managing time-bound limitations (e.g. static operating schedules in Appendix K of the SIR) is inflexible and incompatible with long-term changes in load, generation, and grid constraints. Broader implementation will require resolution of both technical and policy issues, including how operational limits are communicated and how curtailment is equitably shared among DERs. Methods could include:

- Local autonomous control based on real-time sensing;
- Pre-published utility schedules of curtailment, issued either daily or monthly;
- Utility-initiated signals similar to demand response call events; or
- Utility DERMS-based coordination.

Recommendations: The Commission should direct the Joint Utilities to work with stakeholders through the Interconnection Technical Working Group (ITWG) and Interconnection Policy Working Group (IPWG) to:

- Standardize and implement Flex IX as an optional interconnection pathway across service territories;
- Define transparent technical methodologies for curtailment timing and magnitude; and

- Develop equitable policies for sharing curtailment among interconnected DERs (e.g. last-in-first-out, pro-rata, or market-based).

Accelerating adoption of flexible interconnection is critical to unlocking DER deployment at scale while maintaining safe and reliable distribution system operation.

5. **Direct utilities to remove interconnection barriers and establish revenue mechanisms and/or incentives for bidirectional Electric Vehicle charging (V2G).**

Context: As discussed in the Grid of the Future Flexibility Study, EV bidirectional chargers with V2G capability have incredible potential to unlock grid flexibility "by shifting charging load to an off-peak time period, where the demand on the grid is lower and the underlying costs to serve customers and/or grid greenhouse gas emissions are lower".[12] Managing charging load will become increasingly important with a growing EV fleet, and bidirectional capability is the next step to reduce strain on the grid. Presently, deployment of bidirectional chargers is disincentivized by a burdensome interconnection process and the lack of harmonization with the interconnection processes for unidirectional chargers and for paired ESS. Notably, ESS paired with EV chargers can provide significant benefits including immediate capacity to sites and load management technology to improve managed charging, particularly for MHDV fleets.

Recommendations:
NY-BEST recommends that the Interconnection Technical Working Group (ITWG) address interconnection barriers for bidirectional chargers and chargers paired with ESS relative to unidirectional chargers:

a. Address misalignment of timelines between the EV load study and the SIR process for bidirectional chargers paired with ESS. The SIR process for bidirectional chargers is often much longer than the load study for unidirectional chargers. Consequently, because the interconnection processes for unidirectional and bidirectional projects are not harmonized, scenarios may arise where unidirectional projects "jump the queue," receiving service determinations before older bidirectional projects that already started the interconnection process. This can directly reduce the hosting capacity remaining for the bidirectional project, creating significant uncertainty and delays in V2G development. As a result, developers are disincentivized from pursuing bidirectional EV projects.
b. Develop transparency and fairness for bidirectional interconnection. When a bidirectional charger paired with ESS is undergoing interconnection review, a unidirectional charger can claim the available substation capacity before the bidirectional project's CESIR study is complete. This gives unidirectional chargers an unfair advantage by effectively consuming capacity that the utility had indicated

[12] GOTF Vol 3 p14.

would be available to the bidirectional project. To address this, NY-BEST recommends a publicly accessible EV interconnection queue that allows for developers to plan electric vehicle supply equipment (EVSE) projects in accordance with available capacity.

c. Expand communication between distributed generation and EV load utility teams. NY-BEST members have reported limited communication between the distributed generation and EV load utility teams when interconnecting a bidirectional charger paired with ESS. Increased transparency between the utility teams and with the customer regarding project determination and timelines, is critical to advance the adoption of V2G technology that will benefit the EV fleet of the future.
d. Expand revenue mechanisms for bidirectional assets and increase state incentives for load management technology. Load management technologies, like V2G and ESS paired with bidirectional chargers, will require increased state incentives for deployment and new revenue mechanisms to compensate V2G capable vehicles for shifting load when the grid is strained and supporting integration of a growing EV sector. NY-BEST recommends the Commission consider exploring revenue mechanisms to financially compensate bidirectional chargers for managing EV load on the grid. Establishing a bidirectional tariff, as described in Recommendation #1 above, is one solution that will compensate flexible resources for managing load on the grid. Further, NY-BEST recognizes that additional incentives for load management technology may be needed to scale deployment. We recommend the Commission evaluate opportunities to streamline existing incentive programs and consider expansion of incentives where appropriate, in line with Grid of the Future goals.
e. NY-BEST recommends the ITWG address both the distributed generation and load side of EV interconnections. The Electric Vehicle Infrastructure Interconnection Working Group (EVIIWG) has solely focused on queue management for monodirectional charger load, while the ITWG is focused on the resources that provide energy. EV load directly interacts with the interconnection process for bi-directional chargers; thus, the two processes should be harmonized together in one working group.

6. Direct utilities to accelerate adoption of Operational Technology (OT) and Information Technology (IT) improvements, including machine-readable tariffs.

Context: Modernizing utility operational technology (OT) and information technology (IT) systems is a foundational requirement for integrating clean energy resources at scale. Advanced technologies (including Distributed Energy Resource Management Systems (DERMS), Advanced Distribution Management Systems (ADMS), modern metering infrastructure, and secure, high-speed communications) are essential to monitor, manage, and optimize a flexible and dynamic grid. Further, translating and interpreting static electric utility tariff leaves into actionable models for operating and dispatching distributed energy resources must be updated. Today, tariff documents and statements are updated in an electronic PDF format, following a process that is largely unchanged from 1996, resulting in a byzantine, cumbersome, and error-prone procedure. Indeed, the current method for publishing, accepting, revising, canceling, and disseminating utility tariff and rates is decades out of date. Utilities have used the Distributed System Implementation Plan (DSIP) process to develop and lay out plans for OT/IT adoption; however, the speed and scale of improvements have been severely limited.

Recommendations: In parallel with economic and technical rate/tariff design, the utility and Public Service Commission should invest in data and software innovation to achieve a Grid of the Future. This would ensure that market- and price-based signals for capturing the benefits and costs of grid-exporting energy resources are clear, objective, and widely available with near real-time updates. Grid of the Future rates should be designed to bypass conventional tariff leaf- and statement-based rates and formulas. Instead, all rates and all interval meter data (e.g., kW/kVAr imports/exports) should be formatted and transmitted via a computer program that can "translate" meter and rate data into costs and compensation. The program should show precisely how the billing determinants operate against the price for all line items in the billing period, and how the raw meter data (e.g. KYZ pulse counts) is calculated into kWh and converted into 5-min interval data and 30-min demand data used for billing purposes. Creating a clear, easy-to-follow protocol in a software platform would remove ambiguity in rate and billing calculations and create a modernized, transparent process to support the Grid of the Future. The Commission should direct the Joint Utilities to develop and adopt such a platform, as further described in Appendix A.

In addition, the Commission should direct utilities to accelerate investments in OT/IT systems that enable the integration and efficient dispatch of DERs, while ensuring that these investments are informed by market needs, customer use cases, and public policy objectives. Utilities should prioritize capabilities that enable time- and location-specific optimization of DERs, support grid visibility and situational awareness, and facilitate customer access to granular usage and billing data. OT/IT planning must also account for coordination with the New York Independent System Operator (NYISO) to enable secure, efficient communication and control between distribution-level resources and the bulk power system.

Where feasible, the Commission should identify opportunities for standardization across utilities to reduce costs, streamline market participation, and support statewide interoperability. This includes evaluating the potential benefits of adopting common platforms, protocols, and data formats. To maximize efficiency and avoid redundancy, utility investments should complement parallel innovations being made by DER companies and other private-sector actors. Stakeholder input, particularly from DER developers and customers, is essential to defining required system capabilities, but rate cases alone are not sufficient for this purpose.

We recommend the Commission direct the Joint Utilities to collectively work with stakeholders prior to the next DSIP filings to engage stakeholders early and substantively in identifying needed OT/IT capabilities.

7. **<u>Direct utilities to develop a "New York Nodes" plan to create a market structure for flexible assets.</u>**

Context: The *Norway Nodes* concept is a proposed framework for organizing flexibility markets in Norway's electricity grid, aiming to efficiently integrate DERs like solar, batteries, and flexible demand into grid operations. "Nodes" are geographically and electrically defined areas where there is a specific local constraint that can be addressed by harnessing local flexibility, both at the transmission and distribution levels. Within each node, participants can bid to reduce load or inject power at a specified time, and the utility selects bids based on need and cost-effectiveness. The platform sends localized price signals that reflect real-time grid conditions, enabling responsive and optimized DER behavior. The model depends on standardized data exchange and interoperable platforms to support broad participation, including from small-scale and residential DERs. This localized and transparent market design offers a promising model for how New York utilities could better incentivize flexible resources to manage future grid constraints and minimize the need for the capital investments needed to meet CLCPA and reliability goals.

Recommendations: The Commission should direct the Joint Utilities to develop a *New York Nodes* framework that lays out how and when the utilities could roll out an integrated flexibility marketplace similar to the *Norway Nodes* model, integrating with their broader DSP vision. In partnership with the FSWG, utilities should develop a pilot program for location-specific flexibility procurements, where small-scale DERs and electric vehicles can respond to real-time price signals to provide dispatchable load reduction or injection. Developing the pilot program would include developing a transparent methodology for how DER contributions would be valued and compensated, and standardized communication protocols to minimize barriers to entry. Finally, the Commission should explore options for coordinated dispatch or information-sharing between utilities and NYISO, to ensure that localized distribution-level flexibility also supports bulk system needs where appropriate.

To ensure stakeholder input, utilities should develop these plans through a collaborative process, potentially housed within the proposed Flexible Resources Working Group (FRWG).

8. **<u>Incentivize utilities to work with stakeholders on GOTF initiatives.</u>**

Context: While distributed energy resources (DERs) and demand-side flexibility can provide significant distribution deferral value in areas with capacity constraints, utility profit incentives remain primarily aligned with traditional capital investments. As noted in

Volume 1 of the Grid of the Future Flexibility Study, "Distribution deferral value is significant in locations with potential capacity constraints due to load growth. Realizing this value will require greater system visibility and control, *as well as system operator willingness to depend on grid flexibility as a distribution resource"* (emphasis added).[13] As DER deployment increases, utilities face a direct financial disincentive to rely on flexible solutions, since doing so reduces the opportunity to earn a return on capital investments. Without realignment of utility earnings mechanisms, efforts to scale grid flexibility will remain limited in both ambition and effectiveness. The Commission has previously recognized this tension, and the 2018 Synapse Energy Economics report, *Earnings Adjustment Mechanisms to Support New York REV Goals*, emphasized the importance of linking utility financial performance to outcomes that support system efficiency, DER integration, and customer value.

Recommendations: The Commission should establish a new Earnings Adjustment Mechanism (EAM) or other revenue stream that directly incentivizes utilities to partner with stakeholders in implementing Grid of the Future initiatives. The mechanism to incentivize utilities should:

- Reward utilities for measurable deployment of third-party flexibility that avoids or defers infrastructure investment;
- Include outcome-based metrics such as the development and implementation of a Bidirectional Service Class framework or a New York Nodes Plan; and
- Recognize and value robust stakeholder engagement processes, particularly through venues such as the Flexible Resources Working Group.

In the case of programs like New York Nodes, utilities could be compensated for operating the marketplace with mechanisms similar to other market operators. Aligning utility earnings with streamlined and scalable deployment of flexible resources is essential to accelerating New York's grid modernization and enabling cost-effective decarbonization.

9. **Improve utility reporting requirements relating to distributed generation analysis and deployment.**

Context: The Grid of the Future must be efficient, effective, and affordable. To maximize benefits to ratepayers, utilities should fully harness the power of flexible resources to avoid traditional infrastructure buildout whenever possible. However, current utility payment structures, which offer a guaranteed rate of return on capital investments, are inherently misaligned with this goal.

Recommendations: A key tool in addressing this misalignment is clear and transparent utility reporting that allows the Commission and stakeholders to understand the driving factors behind utility capital expenditure decisions and program outcomes. We recommend that prior to approving capital expenditures, the Commission ensures that utilities have

[13] GOTF Vol 1 p9.

sufficiently demonstrated that alternative solutions such as distributed generation and flexible resource deployment would not more cost-effectively satisfy the need. This should include an evaluation of the network exceedances, length of forecasted peak, and cost comparisons of third-party solutions compared to traditional infrastructure. Utilities should also be required to disclose more granular program outcomes for flexible resources, such as DLM, LSRV, NWS, etc (including number of bids, anonymized range of bids, number of projects selected, rationale for projects selected, and relevant cost-benefit analyses), to ensure that flexible, cost-effective alternatives are fully considered, transparently evaluated, and prioritized whenever feasible."

CONCLUSION

NY-BEST appreciates the work by the Commission, Brattle, DNV, and Guidehouse to support the development of flexible resources in New York State. As discussed in our above comments, we strongly agree that energy storage should play a critical role as a flexible asset in support of New York's energy transition, and we encourage the Commission to include the above initiatives in the final comprehensive Grid of the Future Plan. We stand ready to assist with any questions you may have on these comments. Thank you for the opportunity to share our input and feedback.

APPENDIX A
NineDot Whitepaper:
Designing a Bidirectional Electric Rate to Power New York's Grid of the Future

Designing a Bidirectional Electric Rate to Power New York's Grid of the Future

Today's Set of Tariff Kludges to a First-of-its-Kind, Integrated Bidirectional Service Classification (SC)

Thomas Cole, Storm King Mountain, c. 1850

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July 2025

WHITEPAPER

Designing a Bidirectional Electric Rate to Power New York's Grid of the Future

Today's Set of Tariff Kludges to a First-of-its-Kind, Integrated Bidirectional Service Classification (SC)

July 2025

Executive Summary

Electric Energy Storage is a vital component of New York City's energy transition. According to projections by the NYS Department of Public Service (DPS) and New York State Energy Research and Development Authority (NYSERDA), there will be 4,800 megawatts (MW) of electric energy storage operating in ConEdison service territory by 2035[1], making it one of the largest electric consumers.[2] Spurred by the Reforming the Energy Vision (REV) initiative, New York State and ConEdison pioneered a wide array of demonstration projects and pilot tariff programs designed for a broad array of battery energy storage system (BESS) use cases. However, deployment to date has been slow, and, in order to meet the State's storage deployment goals, it is necessary to evolve compensation mechanisms and rate structures for energy storage. We propose a roadmap to implementing a unique Service Classification (SC) that precisely incorporates the most-beneficial use cases for energy storage with accurate, time-differentiated, network-variant, and market-based pricing signals without compromising other ratepayers' energy costs. This *Bidirectional SC*, incorporating market signals for both charging and discharging bidirectional resources including electric energy storage and vehicle-to-grid resources, builds upon successful parts of existing revenue mechanisms and rate structures, while modifying others and introducing new components to maximize the value of these assets for operators, the grid, and ratepayers. A Grid of the Future Bidirectional SC Working Group, composed of representation from DPS, NYSERDA, ConEdison and other utilities, the NY Battery and Energy Storage Technology Consortium (NY-BEST), and NYC-focused industry stakeholders, should be formed to develop this tariff, giving consideration for implementation designed for accelerating energy storage deployments.

[1] "New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage," Department of Public Service and NYSERDA, December 2022, Case 18-E-0130 (In the Matter of Energy Storage Deployment Program), page 79.
[2] Appendix 1: Electric Storage Load Forecast for 2035

I. Energy Storage As a Leading Consumer of Electricity

By 2035, Electric Energy Storage systems in the ConEdison service territory will be one of the utility's largest class of electric consumers.[3] Based on projections by the Department of Public Service (DPS) in the 6 GW Energy Storage Roadmap , there will be 4.5 GW of electric energy storage in Zone J - much of it located on Con Edison's distribution system.[4] Based on a conservative assumption that 60% of the 2035 storage forecast is subject to Con Edison's charging tariffs, annual electricity sales to this type of customer-generator of 6.9 terawatt-hours (TWh)[5] would represent 14% of Con Edison's total 2023 electricity sales of 42.4 TWh, higher than all but two of the utility's existing rate class sales[6]. These Electric Energy Storage systems will consume the equivalent energy of 1.57 million New York households. Unlike all other existing and historical customer types[7], load/charge and export/discharge modes from each independent Electric Energy Storage system can be strictly managed to maximize benefits and minimize costs to its unique placement on a locationally-variant electric grid given that it is an elastic and controllable load in contrast with existing loads, which display low levels of demand elasticity.

Electric Energy Storage is a unique load in that it only exists to support other loads and the grid at large. Energy Storage systems do not consume for their own purpose, but charge electricity strictly to discharge it at more beneficial times for the grid, provide grid balancing, and power quality services. They increase the grid's hosting capacity of the other new loads introduced by the energy transition, such as electric vehicles and heat pumps, and other zero-carbon generators such as solar photovoltaics. Wide-scale deployment of real-time demand-responsive loads and optimized grid-interactive injections will create a seachange in how much electricity is delivered and when it is used.

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[3] Electric Energy Storage refers to storage technologies that have the ability to store energy and discharge electricity, including Stand-alone Electric Energy Storage systems or systems paired or co-located with other generating technologies on the same account.

[4] This growth can already be seen in Con Edison's interconnection queue.As of May 2025, there was 2.2 GW of energy storage in CECONY's Standardized Interconnection Requirement (SIR) Inventory.

[5] Appendix 1: Electric Storage Load Forecast for 2035

[6] Case 25-E-0072, Class Demand Study 2023, Exhibit___(DAC-1, page 159-161).

[7] Except for SC 11 (Buy-back Service), Customers are defined to *take* Delivery Service from ConEdison. By its nature, Electric Energy Storage both *takes* Delivery Service and *provides* Delivery Service in a bidirectional, time-shifted manner.

The proliferation of energy storage into the electric grid architecture has been a goal of the industry for more than fifty years. For example, ConEdison planned to deploy 2,000 MW of energy storage by 1967 through a hydroelectric pumped energy storage plant at Storm King Mountain. In ConEdison's 1962 Annual Shareholder Report: "The nature of Con Edison's growing electric load makes the economics of [storage] highly favorable. The greatest demands for electricity occur during the daytime hours on weekdays. Demand during nights and weekends drop to less than one-half...." Between 1962 and 1972, several hydroelectric pumped storage units (capacity totalling 1,250 MW[8]) were built in New York State to balance supply and demand. Relative to pumped-storage units, electric energy storage can accomplish the same objective with the advantage of being nested in the system close to loads. Electric energy storage technology is now readily available and the tariffs and programs surrounding their use need to be revisited to ensure that they are incentivizing the wide scale deployment in time to reach New York State's ambitious goals.

In the current ConEdison tariff, the majority of large Electric Energy Storage systems (over approximately 1,500 kW nameplate capacity) in New York City are treated as "standby generators" (pursuant to Service Classification 9 - Rate IV "General - Large - Standby Service" and Rate V "General - Large - Standby Service (Large)"). Standby Service classifications were designed to comply with Federal regulations following the Public Utility Regulatory Policies Act of 1978 (PURPA).[9] A response to the 1970s energy crisis, PURPA sought to promote the use of fossil-fuel-powered combined heat and power co-generation (CHP) systems due to their energy efficiency benefits. PURPA's mandates were met with opposition by the utilities given that they controlled both the generation and delivery of electricity and were met with opposition by utilities including ConEdison, which had previously refused to sell back-up power to CHP plants.[10] ConEdison led the legal battles nationally against the requirement to establish rates for the purchase and sale of power to CHP systems and cited concerns that setting standby rates "would result in higher rates for customers who will have to pay higher charges to cover fixed expenses when big customers are lost to cogeneration."[11] As a result, rates were as high as legally permissible by design to cover the utility's fixed expenses and discourage customers from adopting CHP systems. In summary, Standby rate designs are materially inappropriate for the use case of Electric

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[8] Form EIA-860, U.S. Energy Information Administration (EIA), 2022

[9] "Cogeneration: A Successful Response to the Energy Crisis?," *The Fordham Law Journal*, Charles M. Pratt, 1981

[10] "Con Ed Battles Energy Officials on Cogeneration," *The New York Times*, November 2, 1980

[11] Ibid.

Energy Storage systems and unintentionally discourage the realization of the value of these systems to a future grid.

II. Energy Storage Will be a Leading Supplier of Electricity and Can Be Optimized for Power Grid Efficiency and Reliability

By integrating forward-looking rate designs and market pricing signals, Electric Energy Storage systems can be installed to be optimally distributed across the Company's electric networks and temporally dispatched[12]. Optimized facilities should be simultaneously operated to:

- charge with excess electricity supplied from variable large-scale renewable or lower-carbon generators;
- provide load relief to prevent or mitigate critical situations on the electric grid[13];
- reduce marginal cost of service supporting widespread beneficial electrification including heat pumps and electric vehicle charging;
- enhance power system quality and efficiency[14];
- direct financial benefits of clean energy investments to low-income households and disadvantaged communities through guaranteed-saving utility bill credits[15]; and
- increase hosting capacity for distributed energy resources including net-metered, behind-the-meter and front-of-the-meter solar photovoltaics, by directly managing new loads and injections at feeder and sub feeder levels.[16]

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[12] ConEdison's 2022 Annual Shareholders Report states that "[e]nsuring clean energy can be dispatched when needed will be critical to the reliability of our grid going forward, and battery storage will become an essential component of our systems."

[13] ConEdison has multiple demand-response contingency programs designed for dispatchable technologies to prevent or mitigate critical situations on the electric grid, typically on a localized network-level basis, including the Distribution Load Relief Program (Rider T) and Auto-Dynamic Load Management Program (Rider AC)

[14] For example, in ConEdison's Non-Wires Solutions to Provide Demand Side Management for Sub-transmission and Distribution System Load Relief for the Jamaica Substation Project, the utility requested innovative Power Factor Correction solutions, March 16, 2023

[15] A Statewide Solar For All (SSFA) program that includes eligibility for automatically allocating bill credits generated by standalone Electric Energy Storage to low-income customers located in disadvantaged communities was adopted under the PSC Order Approving Statewide Solar for All Program with Modifications, May 18, 2024, Case 14-M-0224, Case 19-E-0735 and Case 21-E-0629
(Petition of New York State Energy Research and Development Authority Requesting Additional NY-Sun Program Funding and Extension of Program Through 2023).

[16] For example, the current ConEdison tariff includes a Single Party and Multi-party Offset Tariff in which a generating facility can directly offset the load of nearby customers. The Offset Tariff can be generalized to Electric

In the current Con Edison tariff, Electric Energy Storage systems can choose to use any of the following ways to capture the benefits of discharging:

- Behind the meter (BTM): The Electric Energy Storage System offsets load measured at an individual customer's eclectic meter. This compensation method is not widely used given the significant customization required.
- Front of the meter (FTM) on the distribution system: The Electric Energy Storage System offsets load at the circuit/feeder level on the distribution system. Storage systems export directly to the distribution grid using the Value of Distributed Energy Resources (VDER) Value Stack tariff (Rider R). This method is attractive because it remunerates systems for relieving the grid at the local feeder level providing the most value to the grid. However, Rider R fails to incentivize storage systems to discharge during beneficial hours outside the summer season.
- Transmission/wholesale/bulk system exports: Recently, this tariff has been opened to allow Electric Energy Storage systems to combine Demand-Response (Rider T) service with New York Independent System Operator (NYISO) markets. This method is highly complex. It fails to properly incentivize systems to capture many of the above-described local distribution benefits.

III. Current Energy Storage Market Signals and Rates are Piecemeal and Inconsistent

Beginning in 2014 with the Reforming the Energy Vision (REV) initiative, New York State and ConEdison have pioneered a diversity of first-of-their-kind demonstration projects[17] and pilot tariff programs[18], each specifically designed to test a singular energy-storage use case. The result of proactive experimentation is a series of competing programmatic and tariff kludges that now hinder the benefits of Electric Energy Storage systems and obscure the economic and market signals for developers. For example, the interconnection and operation of a single Electric Energy Storage system involves a combination of seventeen disjointed sections in ConEdison's currently effective electric tariff.[19] Each section has been appropriated from an unrelated customer type and is make-shift to fit a new use case. After a decade of testing and refining Electric Energy Storage technology use cases and programs, the

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Energy Storage (currently only conventional generation technologies are eligible) and broaden the proximity from physically adjacent to "grid" adjacent.

[17] See Appendix 2: Energy Storage Demonstration Projects in Zone J

[18] See Appendix 3: Pilot Tariff Programs

[19] See Appendix 5: Tariff Sections Related to Electric Energy Storage

industry requires a more holistic approach to program development and tariffs that incorporate lessons learned and lay the groundwork for its rapid scale-up.

Grid-connected Electric Energy Storage is starkly different from every existing electric service type. It is a disservice to grid operators, energy storage operators, and ratepayers to misclassify and cross-classify energy storage facilities within existing rate classes. Current regulations hamstring grid and energy storage operators from providing beneficial services at the lowest marginal cost. A new regulatory approach is required.

IV. A Roadmap to an Energy Storage-Specific Service Classification

We propose a roadmap to implementing a unique Service Classification (SC) that precisely incorporates the most-beneficial use cases for energy storage with accurate, time-differentiated, network-variant, and market-based pricing signals without compromising other ratepayers' energy costs. **A new Bidirectional SC should be fully integrated into the ConEdison tariff book, followed by other New York electric utilities.** An SC Working Group should regularly convene with representation of DPS, NYSERDA, ConEdison, and the Joint Utilities, the Long Island Power Authority (LIPA), NY-BEST, and NYC-focused industry stakeholders to draft the specific tariff leaves. The Group should give careful consideration to the roll out of the new tariff to ensure its introduction does not slow down energy storage deployment. One option to achieve this could be a phase-in period for the new SC in which Energy Storage operators can elect the new tariff or continue operating under the combination of old tariffs. This would enable the market to prove the new SC benefits and make any needed adjustments over time.

Suggestions for an initial SC-BESS roadmap principles and format are:

BIDIRECTIONAL SC RATE PRINCIPLES & STRUCTURE

1. **Bidirectional rates**: The rates provide the net value of optimized discharge to maximize grid benefits *and* optimized charging cycles that minimize grid costs. This is a consolidated SC that captures both the cost of charging and the value for grid injections and services.

2. **Storage-specific interconnection requirements**: The SC will include the application, grid impact study, deployment procedures, and operations of utility infrastructure to interconnect new Electric Energy Storage, including a process for modifying the operational characteristics from time to time to match evolving grid needs.
3. **Transparent rates and incentives**: The costs and value for charging, discharging, and providing grid services from Electric Energy Storage shall be based on location-based and time-based pricing signals. The same transparent cost and pricing structures should be used across all network areas rather than non-public or individually-negotiated contracts or incentive programs, network-specific pricing structures, first-come-first-serve provisions, or capacity or time-based caps. Such opaque structures "chill" the marketplace and cause fits and starts in development. Clear pricing signals are the most efficient way for markets to allocate investments for upfront capital costs needed to achieve the long-term operational value of Electric Energy Storage assets. Tariff structures and rates should be communicated and revised in a machine-to-machine readable API-based format, as described in the accompanying "Tariff2.0" whitepaper.
4. **Rationalized rate class to cover Electric Energy Storage at multiple market scales**

    Rate I: Small Behind-the-Meter (BTM) Resource

    Export nameplate rating of 50 kW or below co-located with on-site loads but separately metered from loads.[20]

    Rate II: Small Vehicle-to-Grid (V2G) & Managed Electric Vehicle (EV) Charging

    Export nameplate rating of 50 kW or below paired with fully-managed EV charging capacity up to 350 kW. Fully-managed means that charging load can be constrained to a day-ahead schedule of 50-350 kW

    Rate III: General BTM Resource

    Export nameplate rating larger than 50 kW co-located with on-site loads but separately metered from loads

    Rate IV: Community-scale Front-of-the-Meter (FTM) Resource

[20] By disaggregating and submetering energy storage from co-located behind-the-meter loads, capturing grid value and compensating for the economic benefits of energy storage dispatching is straightforward. The current treatment of Hybrid Facilities (energy storage co-located with electric generating equipment), including compensation methodologies and installation requirements for metering, telecommunications, and telemetry are applicable (Rider R H.5.b.(i)-(v).

Export nameplate rating 5,000 kW or below with no on-site load (except facility use) with no limitation on kVAr rating[21]

Rate V: General V2G & Managed EV Charging

Export nameplate rating of 5,000 kW or below paired with fully-managed EV charging capacity of any size.

Rate VI: Bulk FTM Resource

Export nameplate rating larger than 5,000 kW with no on-site load (except facility use)

5. **Low-income FTM Shared Savings tariff**: The tariff should also incorporate the Statewide Solar for All (SSFA) program, an opt-out program for all FTM resources that automatically provides shared savings to remote low-income residential utility subscribers participating in existing Energy Assistance Programs (EAPs) as electric bill credits. This program is designed to ensure that clean energy investments from Electric Energy Storage meet the State's Climate Leadership and Community Protection Act (CLCPA) mandate of allocating benefits to Disadvantaged Communities.[22]

ENERGY INPUT RATE STRUCTURES

6. **Day-ahead curved charging**: Day-ahead hourly pricing signals from the distribution utility operator at a sub-feeder or project-specific level should provide sufficient "off peak" delivered electricity with no marginal cost (i.e., no associated As-used Demand Delivery Charges). For each day, charging windows and sub-hourly demand rates (in kW) may vary, but sufficient kWh must be delivered to recharge facilities with no associated demand charges. This is intended to address the present misalignment of the needs of local systems with the present tariff structure for charging.[23]

[21] Under the SIR, distributed energy resources are studied based on the nameplate real power export rating (in kWac). The nameplate apparent power rating (in kVAac) and the capability of Smart Inverters (under the required UL-1741-SB standard) to dynamically adjust Power Factor (PF) (typically from -1 to +1) is not considered in interconnection studies.

[22] The CLCPA states that disadvantaged communities should receive 35% of overall benefits of spending on clean energy and energy efficiency programs, projects or investments, with the goal of achieving 40%.

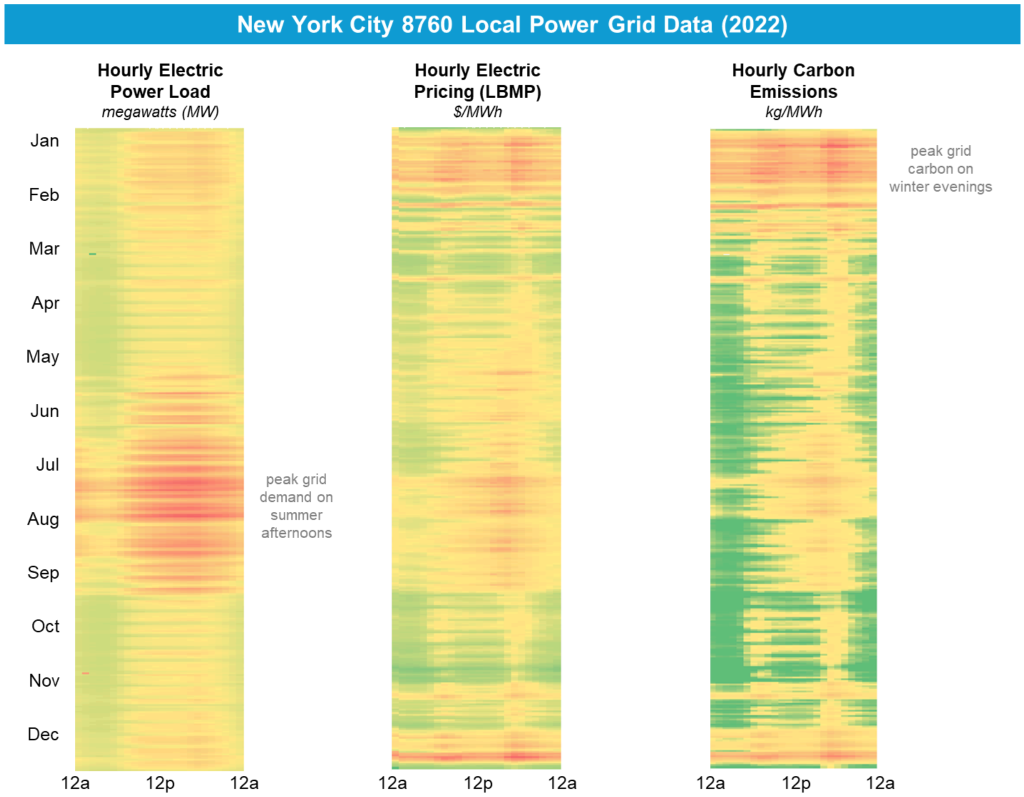
[23] This issue is being partially addressed with Con Edison's proposal for Rider Q, See Case 18-E-0130, In the Matter of Energy Storage Deployment Program: "Updated Rider Q, Standby Rate Pilot, Compliance Filing of Consolidated Edison Company of New York", Case 18-E-0130, October 18, 2024. The proposal is awaiting a PSC ruling.

7. **Voltage-level agnostic Contract Demand rates**: Contract Demand rates must be agnostic to distribution-circuit voltage level (e.g., Low Tension secondary voltage of 480 V or High Tension primary voltages of 4 kV, 13 kV, 27 kV, or 33 kV) for isolated Electric Energy Storage interconnections. Unlike for traditional customer classes with a distinction for shared and local equipment costs, there is no technical difference between these interconnections for FTM Electric Energy Storage resources. While traditional ratemaking principles design rates based on the voltage class of the local infrastructure (i.e., lower voltage customer class have higher rates reflecting increased local upfront capital costs), energy storage customer-generators are agnostic to the voltage class. Such customer-generators are located to provide the most benefits to the shared electrical system and it is inappropriate to be artificially treated as traditional load. Importantly, energy storage projects are responsible for the costs to build out of all interconnecting infrastructure, a major difference to traditional customers where such expenses are typically rate-based.[24]

8. **Managed EV Charging**: When coupled with bidirectional V2G export capability, EV charging, ranging from single residential units (5-15 kW) to large fleet operations (up to 20 MW with 50 or more charging heads), will be a significant new distributed energy resource (DER) with flexible grid support. Utility-managed charging, in which EV loads are carefully controlled (constrained) and can be temporarily ramped up/down to match day-ahead forecasts, can be an important demand-responsive resource.

9. **Reactive Demand Charge:** Traditional commercial load customers are obligated to pay a reactive power demand charge if their power factor (PF) falls below a certain level (approximately 95%) per General Rule 10.11 There are many traditional load customers that have low PFs increasing the effective peak load on the distribution network justifying this charge. However, batteries can be used to reduce or counter reactive power (kVAR) peaks in addition to real power (kW) offsets while exporting and importing energy. Smart Inverters provide non-zero reactive power components in addition to voltage support. Batteries exporting energy (or even importing energy) counter inductive loads by operating similar to how a traditional capacitor bank operates.

[24] Energy storage and other DERs fund interconnection costs upfront whether paying for upgrades/voltage equipment directly or indirectly via interconnection fees paid to ConEdison. This is in contrast to most load-serving customer accounts where the utility company funds additional infrastructure needed for lower voltage services thus meritting a higher fee for low voltage accounts. This paradigm is not extensible to BESS accounts.



10. **Carbon co-optimization pricing signal**: Real-time hourly pricing signals at a sub-feeder level to charge with excess renewable energy injections that would otherwise be curtailed due to risk of backfeeding, with positive/negative pricing[25] based on a transactive energy approach. This longer term effort could leverage the success of the AMI smart meter rollout in Con Ed's network.

ENERGY EXPORT RATE STRUCTURES

11. **15-year contracted $/kWh export value for 350 annual dispatched hours**: Replacement for current Demand Reduction Value (DRV) component of Value of Distributed Energy Resources (VDER) Value Stack Tariff. Rather than fixed Contracted Hours at the network-level, the grid operator can uniquely select up to 350 hours to dispatch each independent facility (resulting in a 4.0% capacity factor[26]) based on day-ahead localized grid patterns. This flexibility provides

[25] Currently, there is no environmental/carbon value for energy storage operations. New York City, in its Climate Mobilization Act (Local Law 97 of 2019), has formulated a time-of-use methodology for calculating the carbon impact of energy storage charging/discharging cycles.
[26] In 2019, 79 out of these 89 peaking units in New York City (NYISO Zone J) operated for less than 5 percent of the time (fewer than 500 hours). See: "The Fossil Fuel End Game: A Frontline Vision to Retire New York City's Peaker Plants by 2030," The PEAK Coalition (March 2021).

long-term planning for the grid operator and a bankable revenue stream for energy storage operators. A fulsome proposal, called "Manage Electric Export Resource Kilowatts at Advantageous Time," or MEERKAT, for this pricing signal is laid out in Appendix 4: Rate Design for Valuing the Real-World and Future-Proofed Benefits of Flexible, Dispatchable Grid Exports.

12. **Clean peak dispatch**: Day-ahead hourly pricing signal to provide grid exports when non-economic fossil-fuel "peaking" plants would otherwise be called to operate to meet local reliability standards.[27]

13. **Streamlined performance-based adders for localized "Tier 2" network areas**: A standardized approach to provide additional revenue to support the highest-stress areas is needed. There are currently a multiple of competitive utility programs[28] to identify and react to constrained grid areas that send mixed signals to energy storage developers.

14. **Value-based ancillary services**: Additional value stream, including, but not limited to, Dynamic Power Factor Correction, Reactive Power Controls, Frequency Control, Spin and Non-Spin Reserves, and Black Start should be integrated into the BESS tariff with well-defined pricing signals.[29] As of June 1, 2023, ConEdison has added reactive power compliance standards for developers without appropriately compensating for this additional system cost.

15. **Beneficial electrification demand-responsive offset export signal**: Expansion of existing Offset Tariff to Electric Energy Storage at a feeder, substation, and network area scales that values grid exports with real-time synchronization to new demands from nearby electric heat pumps, EV charging stations, and other new sources. For example, a dispatchable front-of-the-meter battery can export in a kW capacity to be equal and opposite to loads on the same feeder line. In essence, the virtually-paired battery with nearby loads are invisible to the upstream power grid.

16. **Support long-duration energy storage (LDES)**: Daily export windows of eight hours or more (i.e., 8+ MWh of storage capacity per 1 MW of export capacity) will be required by 2030. The

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[27] See Appendix 6 (Out-of-Merit Generator Usage in Zone J)
[28] Network-specific load relief programs include: DLRP Tier 2 networks, LSRV areas, DLM Clearing Prices, non-wires solutions, and "Preferred Locations" of the 2022 Bulk RFP.
[29] See, for example, "The Economics of Battery Energy Storage: How multi-use, customer-sited batteries deliver the most services and value to customers and the grid," Rocky Mountain Institute (September 2015).

Export Rate Structures should support a range of "C-Rates" and account for variation of equipment Round-Trip Efficiency (RTE) ratings of 40-95%. See Appendix 4 for a proposal to economically integrate 4-12-hour per day dispatches.

17. **Wholesale market** dual participation/aggregation (per FERC 2222) should be integrated into the Bidirectional SC.

V. Immediate Tariff Revisions to Directly Unlock Energy Storage

Prior to adopting a new Bidirectional SC, there is immediate need for a series of small, easy-to-implement tariff revisions with outsized impact on deployment. The proposed revisions fix the most misaligned shortcomings in the current rates structures. Without swift action, Electric Energy Storage will be inappropriately deployed and operated. The current tariff does not represent the most efficient use of ratepayer funding. See Appendix 7 (Proposed Immediate Tariff Leaf Revisions) for specific tariff revisions.

1. **Redesign the LSRV component of the VDER Value Stack Tariff to act as a more effective tool for dependable, locationally-specific, temporally-specific, seasonally-specific, and project-specific load relief**.
   Problem: The LSRV component of the VDER Value Stack has not been an effective tool for locationally-specific load relief due to lack of operational requirements for performance and dispatchability. While other programs, such the DLM and NWS programs, have driven locationally-specific load relief, these projects represent a very small fraction of projects in the interconnection queue. As a result, the overwhelming majority of projects on the interconnection queue[30] are not sited based on the locational grid needs, but rather economic interconnection costs.

[30] As of ConEdison's June 2025 SIR queue, there were 1,500 MW FTM energy storage projects in the interconnection queue for Zones H-J. Of this, roughly half (747 MW) were considered mature, as evidenced by 100% interconnection payments. At the same time, there were only 46 MW of accepted enrollments in the Auto-Dynamic Load Management Program for 2026. Consolidated Edison Company of New York, Inc. Report on Program Performance and Cost Effectiveness of Demand Response Programs - 2024, November 15, 2024, Case 14-E-0423

***Proposed Near Term Solution**:* A modified LSRV program can incorporate the most effective components of locational-based electric load relief programs, such as DLM and NWS. Unlike the aforementioned programs, this program can be designed to be efficiently and cost-effectively scaled as the dispatchable DER market matures, a critical program element given the rapid pace of growth in energy storage technology required to achieve NYS's clean energy goals.[31]

***Benefit to ratepayers**:* A revised LSRV program can ensure that electric energy storage is built in locations that are of the highest value to the system. This program could be designed to allow for efficient use of ratepayer funding unlike the existing options - NWS programs are not scalable and the DLM program design does not allow for efficient use of ratepayer funding.

2. **Charging rates do not reflect local demand patterns**

   ***Problem*:** General offpeak, peak, and superpeak As-used Daily Demand Delivery Charges do not reflect local demand patterns. The current rate design artificially limits benefits of Electric Energy Storage discharging by artificially constraining charging windows with non-technical, non-economic justification.

   Proposed Solution: Reinstate and extend the Rider Q pilot program.[32]

   ***Benefit to Ratepayers*:** Electric Energy Storage will charge during troughs of local feeder circuits to maximize localized peak-shaving, support additional beneficial electrification, and reduce localized marginal cost of service.

3. **Charging rates do not reflect the needs of local feeders**

   ***Problem*:** Current default fixed charging rates (e.g., flat kW charging over a 10-hour window) do not reflect the actual localized needs of the feeder circuits and substation networks.

   Proposed Solution: Allow for CESIR Interconnection Studies to incorporate curved charging options.

   Benefit to Ratepayers: Electric Energy Storage will charge to increase efficiency of local feeder

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[31] See Case 15-E-0751, NineDot Energy's Comments, February 26, 2025 for further details on a potential program structure.

[32] Con Edison released a proposal for the reinstatement of Rider Q, as per PSC's June 20,2024 Order, Case 18-E-0130, In the Matter of Energy Storage Deployment Program: "Updated Rider Q, Standby Rate Pilot, Compliance Filing of Consolidated Edison Company of New York", Case 18-E-0130, October 18, 2024. The proposal is awaiting a PSC ruling.

circuits to maximize localized peak-shaving, support additional beneficial electrification, and reduce localized marginal cost of service.

4. **Dynamic Load Management Program (DLM) does not incentivize the development of new storage projects, one of its stated goals**
   Problem**:** DLM contractual timelines from RFP to Vintage Year do not reflect the real-world multi-year timelines for deploying and interconnecting new Electric Energy Storage projects. The current DLM underperformance penalties are a disincentive to develop projects in the highest-value networks rather than low-cost networks, because DLM revenue cannot be contracted at a time to secure project financing (during a project development phase).
   Proposed Solution: Extend the contractual timelines within the DLM RFPs to reflect a three to four year development period.
   Benefit to Ratepayers: The DLM program was specifically designed to encourage new Electric Energy Storage projects in the most-beneficial areas for Load Relief with a bankable, contracted, multi-year revenue stream.

5. **Electric Energy Storage has the ability to provide Power Factor Support but is not compensated under the VDER tariff**
   Problem**:** Under current delivery and VDER tariffs, providing power factor (PF) support to the distribution grid both reduces revenue and increases costs. VDER compensation is strictly based on real power (kW) grid injections and a non-unity PF will reduce real power exports during export windows. Delivery tariffs charge a fee per kVAr, even if the kVArs introduced during charging events are to support the grid.
   Proposed Solution: Institute a new compensation mechanism for power factor support for energy storage.
   Benefit to Ratepayers**:** Dynamic Power Factor Correction technologies can provide real-time dynamic power factor support directly to the distribution grid during peak hours making the grid more efficient, reliable, and cost effective.

6. **Current rate design incentivizes high tension network interconnections for FTM Electric Energy Storage despite system benefits to low tension interconnections**

Problem: Current rate design penalizes low-tension interconnections despite the material benefits of this interconnection type to the utility and electric grid. The current rates for the low tension service reflect a double counting: *the tariffs incorporate system upgrade costs borne by the utility* as they were designed for building loads. *However, standalone storage projects are responsible for paying these system upgrade costs (related to transforming from low tension to high tension).* This disparity drove initial projects to be clustered in the non-network areas served by high tension primary overhead feeders.

Proposed Near Term Solutions: To solve the double counting problem, an energy storage project connected to the underground network should be effectively treated as part of the high-tension rate class. Con Edison Modified High Tension (MHT) Rates should enact tariff reforms that remedy this shortcoming to ensure that the interconnection method used for electric energy storage systems is determined by optimal value to the system rather than unequal tariff treatment. In addition, Con Edison should work with developers to establish a *Blockhouse Design Standard* for network interconnections. Finally, allowing developers to directly procure and construct low-tension interconnection equipment will help facilitate network connected projects. With extended lead times and supply chain constraints, developers are motivated to order equipment in a timely fashion to deliver projects on schedule.

Benefit to Ratepayers**:** The spatial distribution of energy storage will match load patterns and support highest-need network areas. In addition, low tension interconnection to the network has control benefits to the utility, which provide for a stronger, more reliable grid.

VI. Medium-Term Tariff Revisions Prior to Full SC Implementation

A series of other highly impactive tariff revisions require additional stakeholder engagement, but should also be implemented prior to the next major rate case:

1. Reform Term- and Auto-DLM program to better align with Electric Energy Storage operations, including: new Customer Baseline (CBL) methodology; dual participation in DLM and DRV value streams; and an extended contact term option to incentivize new development in high need areas in line with the original intent of the program,
2. Launch optional Call Event-based VDER Capacity Component Alternative 4 (ICAP-ALT4) as an alternative to default Alternative 3 (ALT3) based on *post hoc* analysis of injections during the Coincident Single Peak Hour (CP1),
3. A "Levelized Contract Demand" feature of Rider Q paired with the grid-beneficial Curved Charging Option that replaces the Standard Contract Demand Level (under SC9 Rates IV and V) (using *maximum* kW demand) with *average* charging kW during off peak hours,
4. Expand the use of DER developers' Letters of Credit (LOCs) for interconnection upgrade deposits to include 100% payments until the utility mobilizes for construction.[33],
5. Introduce Winter DRV hours to future-proof for a winter peaking power grid, and
6. Create an action-based Energy Storage Service Class Earned Adjustment Mechanism (ESSC-EAM) for the Company to work with industry stakeholders to launch SC-BESS.[34]

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[33] On February 14, 2025, the PSC issued an "Order Granting Petition with Modifications" in response to "New York Solar Energy Industries Association Seeking Modifications to the New York State Standardized Interconnection Requirements to Allow Use of Alternative Forms of Financial Security for Distribution Upgrades in Excess of $500,000 for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems." under CASE 24-E-0414. This order approves letters of credit for 25% interconnection payment and 100% interconnection payment under discreet cases. Expansion of the acceptance of LOCs for 100% interconnection payment until utility mobilization in all cases would be more impactful for the storage industry given the long project planning phases.

[34] See, for example, "Earnings Adjustment Mechanisms to Support New York REV Goals Outcome-Based, Program-Based, and Action-Based Options," Synapse Energy Economics (March 2018).

Appendix 1: Electric Storage Load Forecast for 2035

By 2035, DPS and NYSERDA forecast 2,300 MW of 4-hour-duration and 2,300 MW of 8-hour-duration energy storage for NYISO Zone J (New York City) and 200 MW of 4-hour-duration energy storage for Zone I (Dunwoodie, Westchester County), which represents a combined forecasted deployment of 28,400 MWh. Conservatively estimated based on current interconnection queues and NYSERDA incentive awards, 60% of this should be located on the distribution grid. Assuming a daily duty cycle and a round-trip efficiency of 90.0%, the annual energy consumption is expected to be: 60% x 28,400 MWh x 365 days / 90.0% =,100,000 MWh = TWh.

The table below compares projected annual energy consumption for Zone J storage to ConEdison's current electricity sales by customer type.

	Annual 2023 MWh Sold	Avg Customers	2035 energy storage relative usage	kWh per customer
Storage 2035 sales forecast	6,910,667			
Residential & Religious	13,461,534	3,055,636	0.51	4,405
General Small Commercial & Industrial	2,286,254	451,798	3.02	5,060
General Large Commercial & Industrial	24,527,434	136,961	0.28	179,083
Total Electricity Sales	42,385,107			

Source: Customer Demand Study, Page 161, Case 25-E-0072, Exhibit_(DAC-1)

Appendix 2: Energy Storage Demonstration Projects in Zone J

Examples of Electric Energy Storage demonstration projects in ConEdison territory include (not an exhaustive list):

- REV Commercial Battery Storage Demo Project to install four 1.0 MW / 1.0 MWh projects: approved by DPS in 2017, three projects (3.0 MW / 3.0 MWh) installed to date
- REV Storage on Demand Demo Project for mobile batteries: approved by DPS in 2017, no projects to date
- REV Electric School Bus V2G Demo Project: approved by DPS in 2017, five buses deployed to date
- Brooklyn-Queens Demand Management (BQDM) Non-wires Solution (NWS): launched in 2014, 1.5 MW of utility-sided energy storage deployed
- 2019 BQDM Extension Auction: launched in 2017, 4.0 MW of customer-sided energy storage deployed
- 2019 BQDM Prescriptive Energy Storage System Incentive Offering: launched in 2019 to procure 5.0 MW of customer-sided energy storage by 2020, no projects participated
- 2022 BQDM Prescriptive Energy Storage System Incentive Offering: launched in 2022 to procure 15.0 MW of customer-sided energy storage by 2026, no projects deployed to date
- Newtown Energy Storage Project NWS: launched in 2019 to procure approximately 10.0 MW of customer-sided energy storage by 2022, no projects deployed to date
- Water Street / Plymouth Street Energy Storage Project NWS: launched in 2019 to procure approximately 14.0 MW of customer-sided energy storage by 2021, no projects deployed to date
- Jamaica Substation Project NWS: launched in 2023 to procure 16.0 MW of Load Relief, including customer-sided energy storage by 2027
- 2019 Bulk Energy Storage Scheduling and Dispatch Rights Request for Proposal (RFP): launched in 2019 to procure and operate 300 MW by 2022, no projects deployed to date
- 2021 Bulk Energy Storage Scheduling and Dispatch Rights RFP: launched in 2021 to procure and operate 200 MW by 2024, no projects deployed to date
- 2022 Bulk Energy Storage Scheduling and Dispatch Rights RFP: launched in 2022 to procure and operate 200 MW by 2028, no projects deployed to date

Appendix 3: Pilot Tariff Programs

Capped and pilot tariff programs include (not an exhaustive list):

- Standby exemption (General Rule 20.3.3(b)) - limited to 25 MW of new energy storage
- Rider Q - limited to 50 MW of new energy storage (which do not quality for General Rule 20.3.3)
- Locational Service Relief Value (LSRV) areas - initially limited to 87.8 MW of new distributed energy resources (DERs) (reduced to 35.5 MW with launch of competing Non-Wires Solution programs)
- Market Transition Credit - limited to 547 MW of Community Distributed Generation with three tranches (program canceled and superseded by Community Credit)
- Community Credit - limited to 350 MW of Community Distributed Generation

Appendix 4: Rate Design for Valuing the Real-World and Future-Proofed Benefits of Flexible, Dispatchable Grid Exports

I. BACKGROUND ON CURRENT LOAD-RELIEF RATE DESIGNS

There are currently several active compensation mechanisms for dispatching distribution-connected battery energy storage systems. Each program is managed separately and each has a bespoke method for communicating dispatch signals, measuring event performance, calculating the monetary value of energy exports, and remunerating customer-generators. Some programs are "stackable," and others require participants to irrevocably opt out of other programs. A subset of active programs includes:

Load Relief Program	Export Windows (ConEd)	Compensation (ConEd)	Capacity Factor
VDER Value Stack Demand Reduction Value (DRV)	Predetermined 4-hour DRV call window during each summer non-holiday weekday (June 25-September 15), totaling 232-236 hours per year. Windows can be 11AM-3PM, 2-6PM, 4-8PM, or 7-11PM, based on the network area.	kWh exports during DRV call windows are compensated with VDER bill credits at a fixed $/kWh for 10 years (and then reset for a total term of 25 years). Bill credits may be allocated to remote subscribers through the Community Distributed Generation (CDG) or Remote Credit (RC) program and typically sold at a guaranteed discount. Initial DRV rate is set at time of interconnection payment, but the 10-year period starts at commencement of operations (independent of the time between these two milestones).	58-59 events = 232-236 hours = **2.6-2.7%**
VDER Locational Service Relief Value (LSRV)	10 or more LSRV Events of 1 to 4 hours duration per LSRV Event, called at least 21 hours in advance. LSRV Events overlap with DRV call windows.	Performance for each LSRV Event is based on the minimum kW during each hour of the Event. Compensation for each Event is the product of the Event performance and a fixed LSRV rate (in $/kW-Event). The LSRV rate is fixed for 10 years (and set to $0 thereafter). **LSRV adder is awarded on a first-come-first-serve basis for high-stress network areas, with a MW cap for each LSRV substation/network area.** At the end of the calendar year, the total LSRV compensation is calculated, divided by 12, and provided as equal VDER bill credits during the subsequent calendar year. Credits may be allocated to CDG or RC subscribers. Initial LSRV rate is set at time of interconnection payment, but the 10-year period starts at commencement of operations (independent of the time between these two milestones). LSRV is an adder to the DRV program.	10+ events overlap with DRV = **2.6-2.7% (equal to DRV)**
Term Dynamic Load Management (Term-DLM)	Term-DLM Events of 1 to 4 hours in duration during each Capability Period (May through September), called at least 21 hours in advance, with at least one Test Event. Windows can be 11AM-3PM, 2-6PM, 4-8PM, or 7-11PM, based on the network area.	Performance for each Term-DLM Event is based on the average kW during the Event relative to Customer Baseline (CBL) during the previous ten non-holiday weekdays. Performance under 80% for each Event is penalized with a 2% reduction in compensation. An average adjusted performance factor is multiplied by a Term-DLM incentive rate (in $/kW) at the end of the Capability Period and paid directly with an ACH payment or by check. The incentive rate is set with a clearing price of a sealed bid auction, based on local network area need, and is set for 3, 4, or 5 years. Average performance less than 40% translates to a negative adjusted performance factor and requires paying penalties to the utility. VDER resources may opt into Term-DLM and opt-out of DRV and LSRV programs, and return to VDER after Term-DLM enrollment period.	2-8 events x 4 hours = 8-32 hours = **0.1-0.4%**

Load Relief Program	Export Windows (ConEd)	Compensation (ConEd)	Capacity Factor
Auto Dynamic Load Management (Auto-DLM)	Auto-DLM Events of 1 to 4 hours in duration during each Capability Period, called at least 10 minutes in advance, with at least one Test Event. Events can be anytime 8AM-12AM, May through September. All Term-DLM Events are also called under the Auto-DLM program.	Performance for each Auto-DLM Event is based on the average kW during the Event relative to Customer Baseline (CBL) during the previous ten non-holiday weekdays. Performance under 90% for each Event is penalized with a 2% reduction in compensation. An average adjusted performance factor is multiplied by an Auto-DLM incentive rate (in $/kW) at the end of the Capability Period and paid directly with an ACH payment or by check. The incentive rate is set with a clearing price of a sealed bid auction, based on local network area need, and is set for 3, 4, or 5 years. Average performance less than 45% translates to a negative adjusted performance factor and requires paying penalties to the utility. VDER resources may opt into Auto-DLM and opt-out of DRV and LSRV programs, and return to VDER after Term-DLM enrollment.	Similar to Term-DLM = **0.1-0.4%**
Non-Wires Solutions (NWS) (e.g., Brooklyn-Queens Demand Management [BQDM], Jamaica Substation Project, Newtown NWS)	Utility-run solicitations for load relief for high-stress network area. Upfront incentive paid upon achieved Permission to Operate (PTO). NWS Events are called similar to Auto-DLM Events.	Performance for each NWS Event is based on the average kW during the Event. An average performance factor is multiplied by a NWS incentive rate (in $/kW) at the end of the Capability Period and paid directly with an ACH payment or by check. The incentive rate is set with a solicitation process, and is set for 10 years. NWS incentives are an adder on-top of the VDER DRV program. (A network's LSRV capacity is reset to 0 MW, upon administering a NWS solicitation and selected awardees.)	Events overlap with DRV = **2.6-2.7%** (Captured in DRV capacity factor)
Commercial System Relief Program (CSRP)	CSRP Events of 1 to 4 hours in duration during each Capability Period (May through September), called at least 21 hours in advance, with at least one Test Event. Windows can be 11AM-3PM, 2-6PM, 4-8PM, or 7-11PM, based on the network area. (Similar to Term-DLM.)	Performance for each CSRP Event is based on the average kW during the Event relative to Customer Baseline (CBL) during the previous ten non-holiday weekdays. A performance factor is multiplied by a fixed CSRP incentive rate (in $/kW-mo.) at the end of the Capability Period and paid directly with an ACH payment or by check. The CSRP incentive rate is fixed in the tariff, with different rates per borough/county. VDER resources may re-enroll each Capability Period, but must make a one-time, irrevocable decision to opt-out of DRV and LSRV. There are no penalties for underperformance.	Similar to Term-DLM = **0.1-0.4%**
Distribution Load Relief Program (DLRP)	DLRP Events of 1 to 4 hours in duration during each Capability Period, called at least 2 hours in advance, with at least one Test Event. Events can be anytime 6AM-12AM, May through September. All CSRP Events are also called under the DLRP program. (Similar to Auto-DLM.)	Performance for each DRLP Event is based on the average kW during the Event relative to Customer Baseline (CBL) during the previous ten non-holiday weekdays. A performance factor is multiplied by a fixed DLRP incentive rate (in $/kW-mo.) at the end of the Capability Period and paid directly with an ACH payment or by check. The DLRP incentive rate is fixed in the tariff, with different rates for Tier 1 and Tier 2 networks. VDER resources may re-enroll each Capability Period, but must make a one-time, irrevocable decision to opt-out of DRV and LSRV. There are no penalties for underperformance.	Similar to Auto-DLM = **0.1-0.4%**

Each of these compensation programs seeks to dispatch energy storage assets to meet localized power grid needs, optimized to provide grid load relief strictly during "peak-of-the-peak" events. As energy storage technologies are ubiquitously deployed and can be cycled more frequently, and the distribution power grid requires more localized flexibility (due to beneficial electrification, electric vehicle charging, and integration of more intermittent renewable generators), these oversimplified and cumbersome programs need to be unreservedly reassessed. **How energy storage is compensated to provide frequent and consistent localized grid relief is the most important component of any bidirectional tariff design.**

II. GENERAL PRINCIPLES FOR FLEXIBLE, FUTURE-PROOFED RATE DESIGN

Here, we propose a rate design basis for exports (also called "grid injections," "dispatches," or "discharges") that aligns with how real distribution networks are used to today and is also flexible to evolve over decades of growing and changing electric consumption patterns. Key assumptions about the export rate design are:

Hyperlocal: Each network area has a unique load curve, and energy exports must be designed to provide localized benefits. This can later be narrowed to a feeder or sub-feeder level.

Unique: Each energy storage asset can be dispatched with a unique project-specific call window, such that a "constellation" of distributed resources act in concert to provide global benefits. For example, two nearby 5-MW energy storage assets may be called with different dispatch windows.

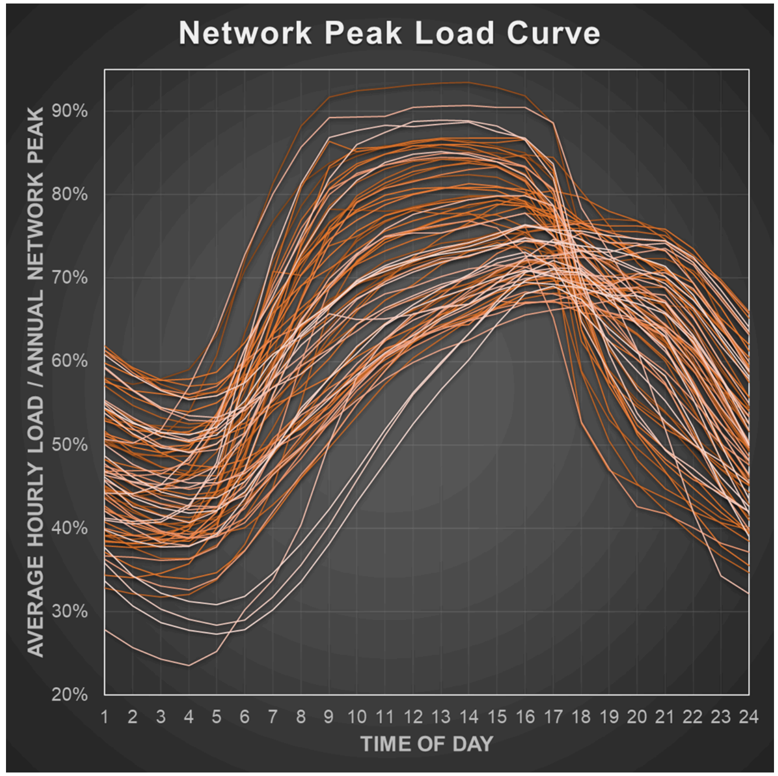
Longer-Duration: More than four hours of exports is required in all network areas. Longer-duration energy storage assets, up to twelve hours, shall be compensated under an export rate design. The New York wholesale-level "bulk" market, under the Capacity Accreditation Factors, has already incorporated this design.

Value-Based: The marginal value of exports for longer and longer duration events diminishes. For example, the first four hours of exports during a day (potentially not continuous) is the most beneficial; followed by the fifth and sixth hours; followed by the seventh and eighth hours; etc. The thirteenth hour has no additional benefits over the twelfth hour. The equivalent of duration-based Cost of Service (COS) study may elicit these values. (Note, however, the term "marginal" in the *Marginal* Cost of Service [MCOS] methodology is an anachronism. "Marginal" reflects a relatively small increase or decrease in local load/demand from a current baseline. However, as load is expected to double [+100% from the current baseline], a "marginal" analysis needs to be replaced by a "Systematic Cost of Service,"or SCOS, methodology.)

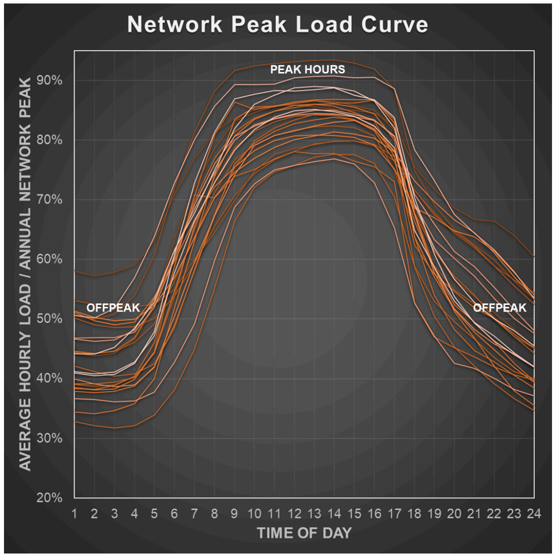
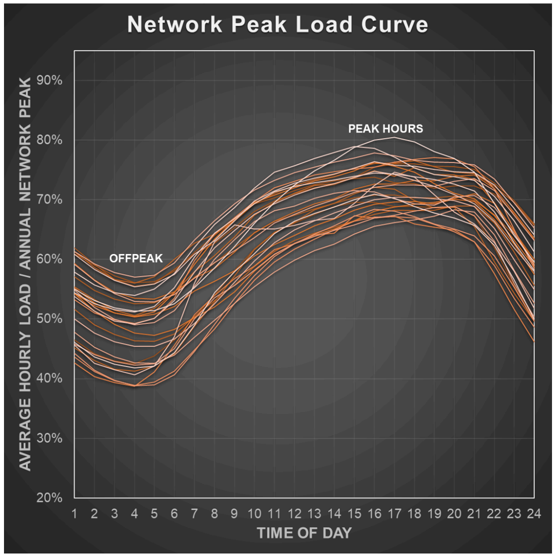
Bankable: Energy storage resource investors require long-term bankable rate designs (with fixed rates and number of annual dispatch hours for 15 or more years). However, resources are agnostic as to which hours are called, and this is infinitely flexible. Initially, resources can be called in a day-ahead sense based on hours "on" during the summer-peak season. This can be future-proofed allowing for nearer to real-time dispatching, sub-hourly calls, and full-year applications. The 15-year period is well-defined in complementary markets (including, for example, the ConEdison "Bulk" Request for Proposal [RPF] for localized dispatch rights and the proposed Indexed Storage Credit [ISC] financial-hedge design).

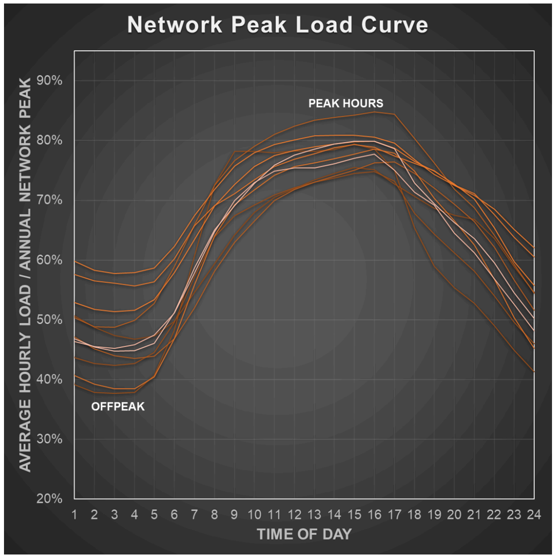
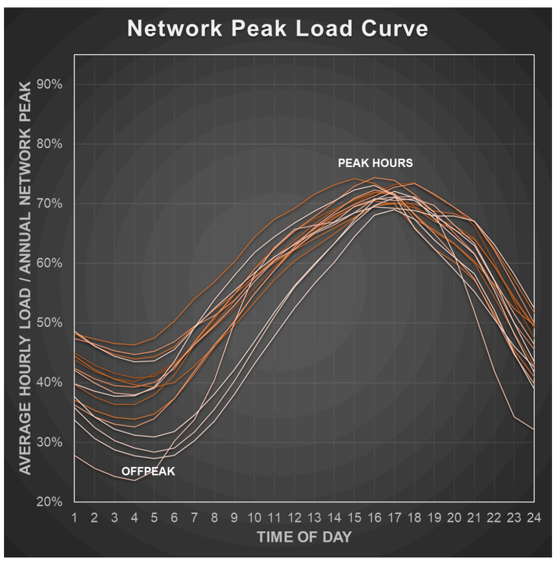
III. PROPOSAL BASED ON REAL CON EDISON NETWORK DATA

Based on real-world network-level data provided by ConEdison (ConEd), we analyze an initial version of an export rate design. The analysis is derived from the utility's Forecast 2026 Load by Network (downloaded from Hosting Capacity Map [HCM]).



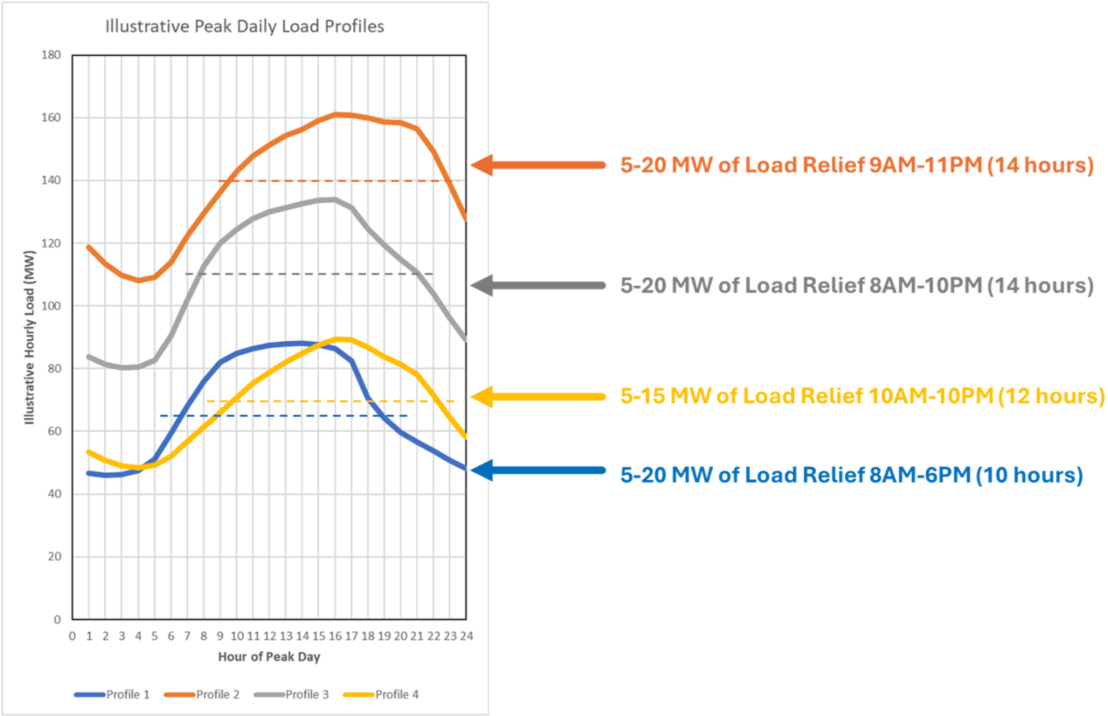
ConEd has over 80 different distribution network areas, each with a unique mix of consumers and daily consumption patterns. ConEd currently distinguishes the load shape with four export windows for distributed energy resource and demand-responsive (DR) load relief programs. The utility has four-hour eligible call windows: 11am-3pm, 2-6pm, 4-8pm, and 7-11pm. A handful of networks have shifted to six-hour call windows for one DR program. Based on an analysis of ConEdison's anticipated network loads in 2026, it's observed that there are multiple distinct groups of load curves. **All load curve groups benefit from longer load-relief periods than four-hour call windows.** The plot above is the average hourly load peak days for 82 ConEd networks. For this analysis, peak days are defined as the 60 days in the 2026 forecast with one or more top-consumption hour(s). The load data is normalized to the single peak hour of the year (such that 100% represents the estimated peak annual network load in 2026).

Load Curve Profile	Network Areas	Current Load Relief Need
	**Load Profile 1** 25 Network Areas Manhattan: Battery Park City, Beekman, Bowling Green, Canal, Chelsea, City Hall, Cortlandt, Empire, Fashion, Freedom, Fulton, Grand Central, Greeley Square, Herald Square, Hunter, Kips Bay, Madison Square, Midtown West, Park Place, Pennsylvania, Plaza, Rockefeller Center, Sutton, Times Square, Turtle Bay	Peak load primarily during business hours Load relief is required for 8+ hours
	**Load Profile 2** 29 Network Areas Bronx: Central Bronx, Fordham, Northeast Bronx, Riverdale, Southeast Bronx, West Bronx Brooklyn: Brighton Beach, Crown Heights, Flatbush, Ocean Parkway, Park Slope, Prospect Park, Ridgewood, Sheepshead Bay, Williamsburg Manhattan: Central Park, Harlem, Triboro, Washington Heights, Yorkville Queens: Flushing, Jackson Heights, Jamaica, Long Island City, Maspeth, Rego Park, Richmond Hill, Sunnyside Staten Island: Fresh Kills	Peak load from noon to midnight Load relief is required for 8+ hours

Load Curve Profile	Network Areas	Current Load Relief Need
	**Load Profile 3** 11 Network Areas Brooklyn: Bay Ridge Manhattan: Columbus Circle, Cooper Square, Greenwich, Hudson, Lenox Hill, Lincoln Square, Roosevelt, Sheridan Square Queens: Long Island City	Peak load from 8 AM to 5 PM Load relief is required for 8+ hours
	**Load Profile 4** 17 Network Areas Staten Island: Fox Hills, Wainwright, Willowbrook, Woodrow Westchester: Buchanan, Cedar Street, Elmsford No. 2, Granite Hill, Grasslands, Harrison, Millwood, Ossining West, Pleasantville, Rockview, Shrub Oak Mohansic, Washington Street, White Plains	Late morning to early evening peaking Load relief is required for 6+ hours

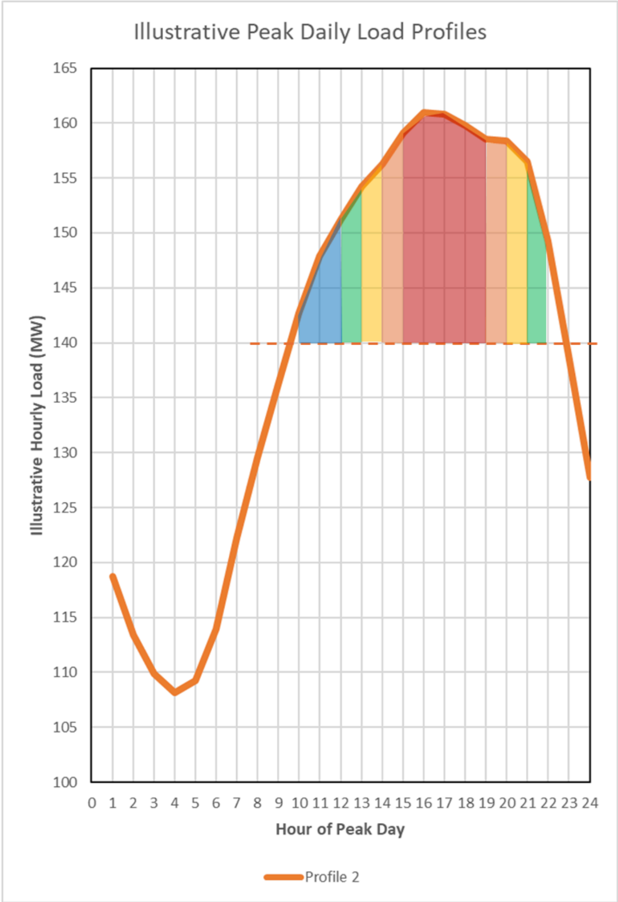
For each of these generalized “families” of network load curves, there is a need for more than four hours of grid support. Some networks support loads that double or triple from offpeak to peak times. Others have broad peaks that last for long durations.

For this illustrative analysis, we adopt a characteristic example for each Load Profile, as the average peak-day network load for each of the four Profiles:



For example, a typical “Profile 2” network area has a peak-load shape that goes from 110 MW overnight to 160 MW at the “peak-of-the-peak” and a broad 12-hour peak period from 10 AM to 10 PM. An optimized constellation of dispatchable, distribution-connected energy storage resources would provide about 20 MW of load relief during the four-hour “peak-of-the-peak” and a lower level of exports during an additional eight hours.

An example optimized grid export profile is:



20 MW "Super Peak" Load Relief (4-hour call window)

18 MW "Shoulder Peak" Load Relief (two 1-hour call windows)

16 MW "Peak Load" Relief (two 1-hour call windows)

12 MW "Subpeak Load" Relief (two 1-hour call windows)

8 MW "Edge Peak" Load Relief (2-hour call window)

In general, each Call Event can be consecutive hours or distributed throughout a day. For example, the Super Peak hours can be 3-7pm or can be 2-4pm and 6-8pm. Each separate project can have project-specific Events that are dispatched day-ahead (by 5pm the previous day to support offpeak charging. For example, one project may have the Super Peak during 3-7pm and another may have 5-9pm.

An example compensation program for the twelve hours of exports is:

Load Peak	**Super**	**Shoulder**	**Peak**	**Sub**	**Edge**
Call Window Duration	**4 hr**	**+2 hr**	**+2 hr**	**+2 hr**	**+2 hr**
Battery Duration Needed	4 hr	6 hr	8 hr	10 hr	12 hr
5-MW BESS Capacity	20 MWh	30 MWh	40 MWh	50 MWh	60 MWh
Call Events Per Year	80	60	50	40	30
Dispatch Hours	320	120	100	80	60
Cumulative Export Hours	320	440	540	620	680
Asset Capacity Factor	**3.7%**	**5.0%**	**6.2%**	**7.1%**	**7.8%**
Compensation ($/kW-y)	$300	+$100	+$70	+$25	+$5
Compensation ($/kWh)	**0.9375**	**0.8333**	**0.7000**	**0.3125**	**0.0833**
Grid Valuation ($/kW-y)	**$300**	**$400**	**$470**	**$495**	**$500**

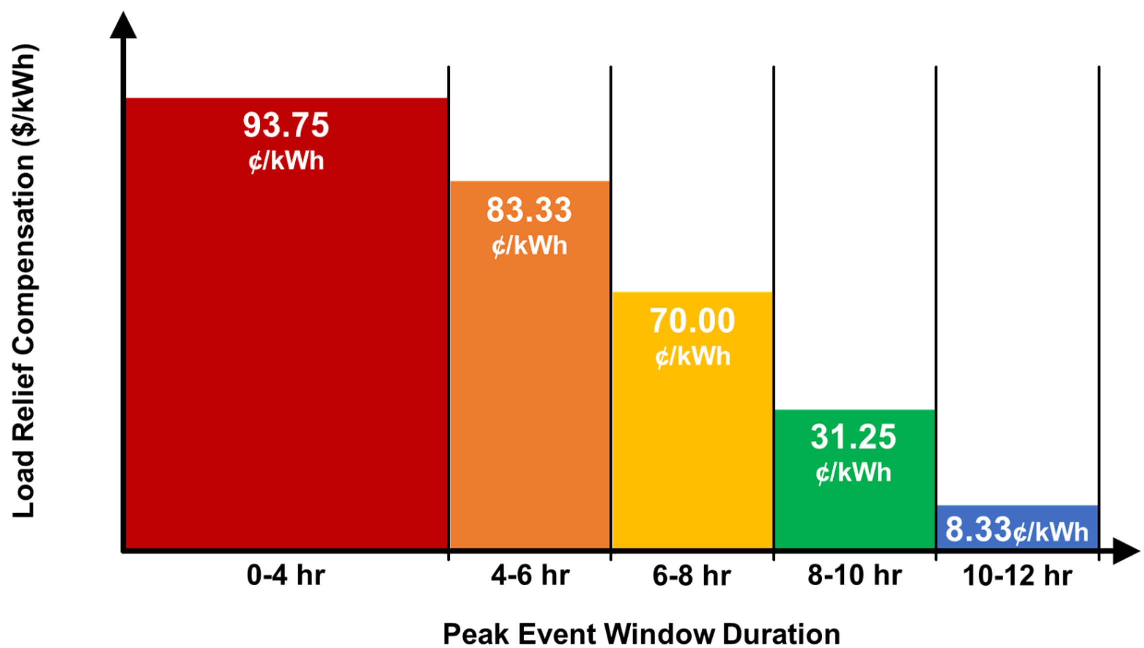
This means that the first four hours of daily exports, up to 320 hours per year on 80 days, is valued at 93.75 cents/kWh. The subsequent two hours of daily exports, up to 120 hours per year on 60 days, is valued at 83.33 cents/kWh, and so on.

Over a single export day, the hourly assignment of grid-export monetary valuations is:

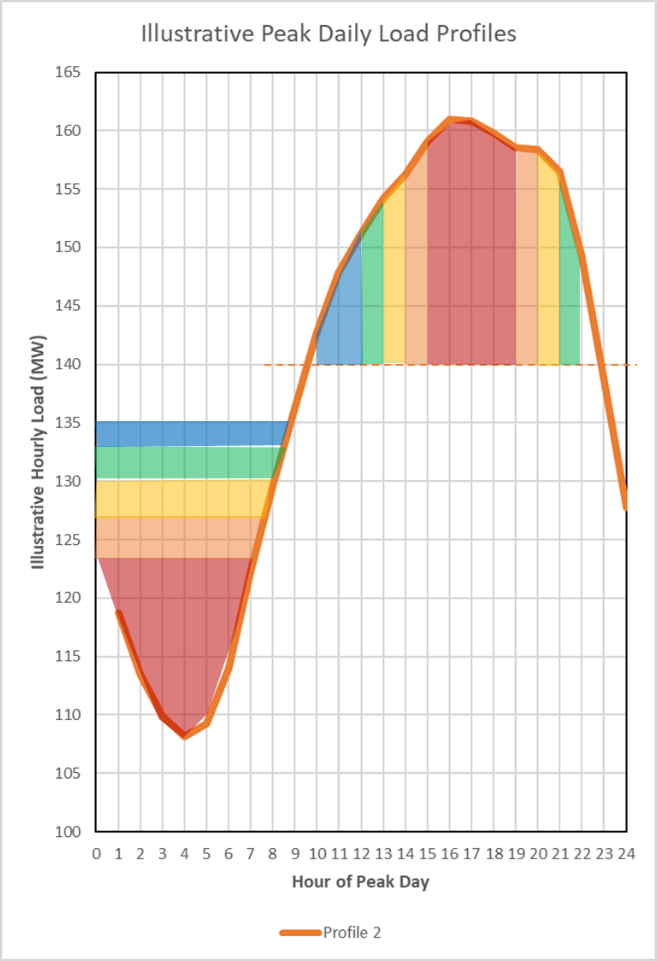
Hour of Day	Export Value ($/kWh)
8 AM – 9 AM	**0**
9 AM – 10 AM	**0**
10 AM – 11 AM	**0.0833**
11 AM – 12 PM	**0.0833**
12 PM – 1 PM	**0.3125**
1 PM – 2 PM	**0.7000**
2 PM – 3 PM	**0.8333**
3 PM – 4 PM	**0.9375**
4 PM – 5 PM	**0.9375**
5 PM – 6 PM	**0.9375**
6 PM – 7 PM	**0.9375**
7 PM – 8 PM	**0.8333**
8 PM – 9 PM	**0.7000**
9 PM – 10 PM	**0.3125**
10 PM – 11 PM	**0**
11 PM – 12 AM	**0**

In essence, a four-hour limited asset would be compensated for exports during the 3-7 PM window. A six-hour asset would export 2-8 PM; an eight-hour asset would export 1-9 PM; a ten-hour asset would export 12-10PM; and a twelve-hour asset would export 10 AM-10 PM. A developer would have to weigh equipment and operational costs versus the anticipated revenue to select the optimal duration to construct and use.

An alternative method of representing the reduced value for longer-duration exports is in this diagram:

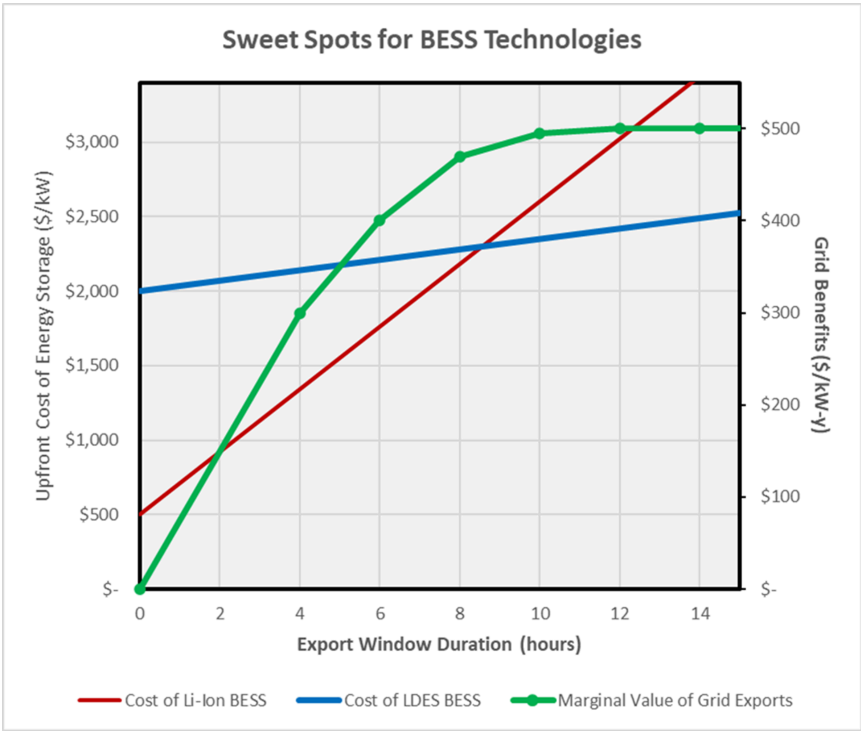


Note that the time-shifting nature of energy storage exports requires consumption during offpeak times:



In this example, the optimized load "curve" would become more like baseload energy consumption. This network use pattern is ideal for integration of variable renewables, in which the energy supply becomes variable and the energy demand becomes fixed.

Another way to depict the marginal value of longer-duration energy storage resources is to convert the $/kWh export compensation figures into $/kW-year revenue. For example, ideal performance of a four-hour asset is equivalent to $300/kW. Building two additional export hours adds $100/kW, for a total of $400/kW of grid value. This math is described in the “Grid Valuation” row in the table above, with a cap of $500/kW for a twelve-hour asset. The green line in the graph below plots the grid benefits as the duration-window expands.



Traditional lithium-ion (Li-ion) energy storage devices have a relatively low fixed cost and high marginal cost for adding more duration. For example, an eight-hour Li-ion battery is almost twice the cost of a four-hour battery. Li-ion batteries are most cost-effective for about 3-to-8-hour duration.

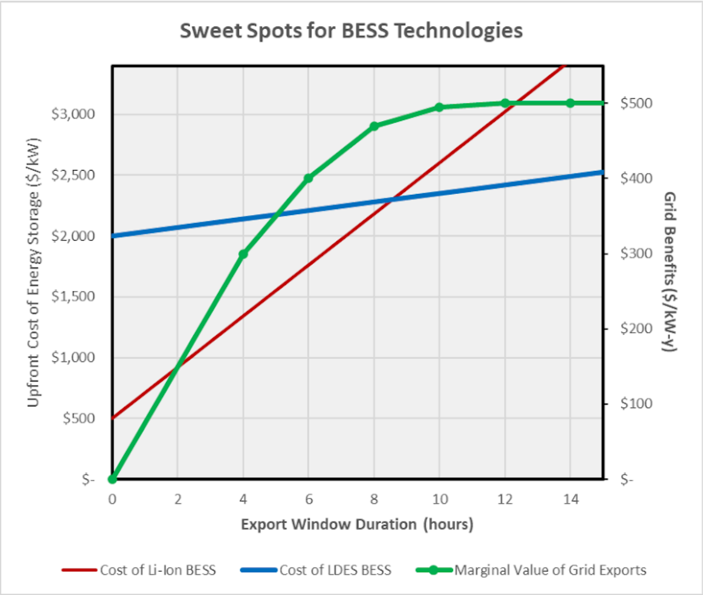
Long-duration energy storage (LDES) has a higher fixed cost, but a lower marginal cost per unit kWh. Doubling the energy capacity is much less than twice the cost. LDES is cost-effective for 8-to-12-hour duration.

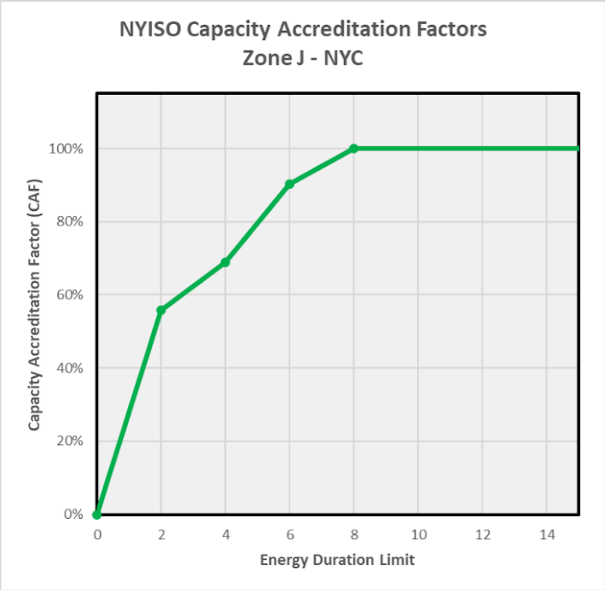
This proposed tariff design supports shorter duration exports and has opportunity for longer-duration technologies.
This analysis correlated to the finding of the NYISO in their Final Capacity Accreditation Factors (CAF) for energy storage resources (ESRs), with an eight-hour asset providing about 1.5x the value of a four-hour asset in New York City (Zone J) (100.00%/68.84%). For the example, above, the relative value is 1.6x ($470/$300).

Final CAFs based on the 2024 LCR Case

CARC	Rest of State	GHI	NYC Locality	LI Locality
2-Hour Energy Duration Limited	55.42%	56.16%	55.93%	52.76%
4-Hour Energy Duration Limited	64.47%	67.95%	68.84%	78.94%
6-Hour Energy Duration Limited	91.77%	91.92%	90.41%	91.53%
8-Hour Energy Duration Limited	100.00%	100.00%	100.00%	99.72%
Landfill Gas	59.67%	--	--	--
Solar	15.64%	15.62%	15.18%	11.62%
Offshore Wind	--	--	--	31.56%
Land-based Wind	12.89%	--	--	--
Limited Control Run of River	32.78%	41.23%	--	--
Large Hydro	100.00%	--	--	--
Large Hydro with partial Pump Storage	100.00%	--	--	--
Generator	100.00%	100.00%	100.00%	100.00%

Plotting the marginal value curves of longer duration energy side-by-side clearly shows the correspondence.





IV. SUMMARY

In this Appendix, we reviewed the current set of rate designs which considerably underutilizes energy storage assets, with capacity factors of 0.1-2.7%. A more realistic rate design with export capacity factors of 3.7-7.8%, optimized for real-world load profiles, is proposed. This is a bridge design toward the ideal use-case of daily cycling for energy storage assets, with a capacity factor of 16.7% for daily use of a four-hour battery and 50.0% for a twelve-hour battery. Over the next decades, with an influx of clean, zero-carbon intermittent generation and load growth of 200-300%, such regular energy storage demands are sensible. The proposed rate-design principles are flexible, use-specific and bankable.

The proposed export component of the bidirectional tariff is to be called: **M**anage **E**lectric **E**xport **R**esource **K**ilowatts at **A**dvantageous **T**imes, or **MEERKAT**.

A group of meerkats (called a mob) work together to "pop up" whenever there's something to be observed in their local environment. Meerkats are highly intelligent, social, cooperative animals. In the same way, a group of distributed energy storage assets will "peak" whenever the local power grid requires support.

The sun comes up on distributed energy storage!

Appendix 5: Tariff Sections Related to Electric Energy Storage

Tariff sections related to Electric Energy Storage include:

Tariff section	Leaves	# of Pages
General Rule 4.6: High Tension Service	31-32.1	3
General Rule 8: Customer Use of Generating Equipment	77-79	3
General Rule 10.11: Reactive Power Demand Charge	92-93	2
General Rule 17: Special Services Performed by the Company at a Charge	122-130.1	10
General Rule 20: Standby Service and Standby Service Rates	152-170	37
Rider M: Day-Ahead Hourly Pricing	214-218	5
Rider Q: Standby Rate Pilot	239-243.13	18
Rider R: Value Stack Tariff for Customer-Generators (VDER)	244-254.1	60
Rider T: Commercial Demand Response Program (CSRP and DLRP)	268-281.1	18
Rider AC: Term- and Auto-Dynamics Load Management Programs (DLM)	327.19-327.26	8
General Rule 25: Supply and Supply-rated Charges and Adjustments	328-336.1	11
General Rule 26: Additional Delivery Charges and Adjustments	337-359.1	30
Form G: Application for Rider R or Standby Service and/or Buy-back Service	382-386.1	14
Service Classification No. 9: General – Large	444-459.4	24
Service Classification No. 11: Buy-back Service	461-477.2	19
Addendum – Standardized Interconnection Requirements and Application Proce New Distributed Generators and/or Energy Storage Systems 5 MW or Less Con in Parallel with Utility Distribution Systems (SIR)	–	98
Addendum – Uniform Business Practices for Distributed Energy Resource Supp (UBP-DERS)	–	26
17 Tariff sections		**386**

Appendix 6: Out-of-Merit Generator Usage in Zone J

ConEdison, as the local Transmission Owner (TO), typically calls to dispatch 300-800 MW of uneconomic, out-of-merit (OOM) power generators in Zone J (NYC) to maintain local reliability of the distribution and lower-voltage transmission systems and to manage constraints on the high-voltage transmission system. Four out-of-market action types for reliability are used: Local Reliability Rule (LRR ~300 MW of uneconomic dispatch), Day-Ahead Reliability Units (DARU ~200 MW of uneconomic dispatch), Supplemental Resource Evaluation (SRE ~40 MW of uneconomic dispatch), and Forecast Pass (FP ~5 MW of uneconomic dispatch) (see table below). For over a decade, the NYISO Market Monitoring Unit has repeatedly recommended that OOM dispatching be limited as much as possible. Day-ahead and real-time dispatching of Electric Energy Storage assets at a network- or subzonal-level represents an economic method to reduce or eliminate out-of-market electric generation. (Sources: 2011-2022 *State of the Market Report for the NYISO Markets*, Potomac Economics)

Year	Out-of-Merit Commitment Type (MW)				Total (MW)
	LRR	DARU	SRE	FP	
2010	298	419	76	12	**805**
2011	162	280	59	8	**511**
2012	141	287	33	23	**484**
2013	234	299	34	4	**572**
2014	250	183	36	3	**472**
2015	288	82	30	2	**401**
2016	226	63	16	1	**306**
2017	373	120	14	2	**509**
2018	437	156	60	1	**653**
2019	389	133	58	1	**571**
2020	388	143	14	1	**545**
2021	256	150	38	0	**444**
2022	327	160	25	1	**512**
Average	**290**	**190**	**36**	**5**	**522**

Appendix 7: Proposed Immediate Tariff Leaf Revisions

1. Reinstate Modified High Tension (MHT) Rates
Tariff Section: General Rules 4.6.2, Leaf 32, Characteristics of Service – High Tension Service
Modification: High tension service is being supplied to certain buildings without a requirement for high tension protective switch equipment meeting Company specifications between the Company's incoming high tension feeders and the Customer's transformer facilities, provided the Customer was supplied with such modified high tension service prior to January 1, 1998, ~~or~~ entered into a transformer purchase and/or maintenance agreement with the Company by some later date specified by the Commission, or for Electric Energy Storage systems, and all of the following conditions are satisfied…

2. Reinstate and Extend Standby Rate Pilot (Rider Q)
Tariff Section: Rider Q, Leaves 239-240, Standby Rate Pilot
Modifications **B. Eligibility**: This Rider is available for up to a total of ~~125~~ 500 MW, with MWs measured by the distributed generator's nameplate rating capacity or inverter capability, as follows: (1) 75 MW is reserved for customers that have qualified under General Rule 20.3.3; and (2) ~~50~~ 425 MW is available to standby customers, either new or existing, that do not qualify under General Rule 20.3.3. If the Customer or the Company terminates the Customer's service under this Rider, the program size will be reduced by the associated MWs and those MWs will not be available for re-use by any Customers. **C. Application and Term of Service**: A Customer applying for service under this Rider must submit a completed "Application for Net Metering or Standby Service and/or Buy-Back Service" set forth in Application Form G in the General Rules. Applications to participate under Rider will be considered until the Pilot is fully subscribed, or if received by December 31, ~~2021~~ or until a unique Electric Energy Storage SC is created, whichever is sooner. The term of service under this Rider is ten years from the date the Customer commences taking service under this Rider or until this Rider expires, whichever is sooner. If a Customer makes a one-time election to terminate its service under this Rider, the Customer will revert back to its otherwise applicable rate. If there is no prior rate, the Customer will be subject to its otherwise applicable rate. **E. Applicable Networks and Time Periods**: The rates and applicable time periods under Option B and the measurement hours under Option C will vary based on the Customer's location and are based on event call windows for the Company's Commercial System Relief Program ("CSRP"). A separate set of rates under Option B is available for Customers in a CSRP network who are also in a Distribution Load Relief Program ("DLRP") Tier 2 network. The

CSRP event call windows and DLRP Tier 2 networks will be available on the Company's website. Alternatively, Customer-variant applicable time periods may be individually determined based on the results of a localized interconnection study.
Problem: General offpeak, peak, and superpeak As-used Daily Demand Delivery Charges do not reflect local demand patterns. The current rate design artificially limits benefits of Electric Energy Storage discharging by artificially constraining charging windows with non-technical, non-economic justification.
Benefit to Ratepayers: Electric Energy Storage will charge during troughs of local feeder circuits maximize localized peak-shaving, support additional beneficial electrification, and reduce localized marginal cost of service.

3. CESIR Interconnection Studies Incorporate Curved Charging Option
Tariff Section: Addendum – Standardized Interconnection Requirements (SIR) Appendix K – Energy Storage System Application Requirements Application Requirements (n)
Modification: n. Indicate any specific operational limitations that will be imposed (e.g., will not charge or discharge across PCC between 2-7 pm on weekdays; ESS will not charge at any time that would increase customers peak demand, etc.). Charge/discharge at any time (24 hours) be assumed by the utility if not provided. Utility will provide at least one interconnection option with a time-variant charging sequence in hourly or sub-hourly intervals during identified localized off-peak hours to minimize impact on given substation or feeder that realizes a complete charging cycle including efficiencies and losses (e.g., a table of kW charging rates that varies in 30-minute intervals).
Problem: Current default fixed charging rates (e.g., flat kW charging over a 10-hour window) do not reflect the actual localized needs of the feeder circuits and substation networks.
Benefit to Ratepayers: Electric Energy Storage will charge to increase efficiency of local feeder circuits to maximize localized peak-shaving, support additional beneficial electrification, and reduce localized marginal cost of service.

4. Extend Dynamic Load Management (DLM) Enrollment Term
Tariff Section: Rider AC, Leaf 327.22, Term- and Auto-Dynamic Load Management Programs
Modification: **C. Application**: Participants shall enter into a Program Agreement with the Company. The ability to complete these Program Agreements is awarded based on an open, pay-as-bid, Request for Proposal ("RFP") process which considers the price per kW offered, the quantity of proposed load relief, the network the load relief will be provided in, and the program the applicant is applying for. All bids will be for single Aggregations (including sub-Aggregations) and will be considered at the Aggregation level. Program Agreements associated with an Aggregation or a Direct Participant solely comprising Electric Generating Equipment may exercise an advancement of the Vintage Year up to four times with no penalty or Early Exit Fee.
Problem: DLM contractual timelines from RFP to Vintage Year do not reflect the real-world multi-year timelines for deploying and interconnecting new Electric Energy Storage projects. The current DLM underperformance penalties are a disincentive to develop projects in the highest-value networks rather than low-cost networks, because DLM revenue cannot be contracted at a time to secure project financing (during a project development phase).
Benefit to Ratepayers: The DLM program was specifically designed to encourage new Electric Energy Storage projects in the most-beneficial areas for Load Relief with a bankable, contracted, multi-year revenue stream.

5. VDER Dynamic Power Factor Correction (DFPC) DER Component
Tariff Section: Rider R, Leaf 253.4.5 (new), Net Metering and Value Stack Tariff for Customer-Generators, Charges and Credits – Value Stack Tariff
Modification: h. Dynamics Power Factor Correction ("DPFC") Value Stack Component [to be determined at a $/kVAr rate that compensated for $/kW losses and revenue and $/kVAr operating costs]
Problem: Under current delivery and VDER tariffs, providing power factor (PF) support to the distribution grid both reduces revenue and increases costs. VDER compensation is strictly based on real power (kW) grid injections and a non-unity PF will reduce real power exports during export windows. Delivery tariffs charge a fee per kVAr, even if the kVArs introduced during charging events are to support the grid.
Benefit to Ratepayers: DPFC technologies can provide real-time dynamic power factor support directly to the distribution grid during peak hours making the grid more efficient, reliable, and cost effective. DPFC technologies include smart inverters installed with Electric Energy Storage systems (certified to UL-1741-SB standards) with an expected range of kilovolt-amperes reactive (kVAr) of -1 to +1.

6. Clean Energy For All (CEFA) Tariff Program
Tariff Section: Rider R, Leaf 249.4.7-249.4.8 (new), Net Metering and Value Stack Tariff for Customer-Generators, Remote Net Metering, Remote Crediting, and Community Distributed Generation
Modification: e. Clean Energy For All low-income customer crediting program [program details to be determined using parts of current Community Distributed Generation (CDG) Net Crediting Program and Energy Affordability Program (formerly Low-Income Discount Program)]
Problem: Under current VDER tariff, FTM Electric Energy Storage systems are encouraged to provide guaranteed financial discounts to large, creditworthy Remote Credit satellite customers.
Benefit to Ratepayers: Monthly energy bill discounts from clean energy projects are automatically provided to low-income residential customers, which is mandated by the State's Climate Leadership and Community Protection Act (CLCPA).

Appendix 8: Tariff2.0: Machine-Readable Rates and Open Rate Engines for Grid of the Future Tariffs

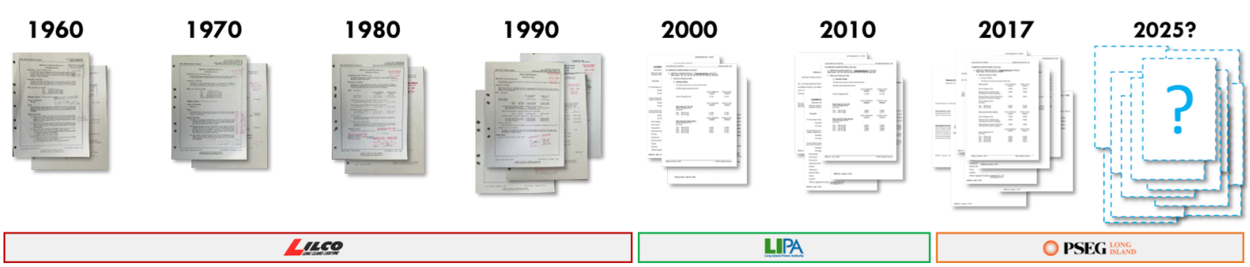
Market- and price-based signals for capturing the benefits and costs of grid-exporting energy resources need to be clear, objective, and widely available with near real-time updates.

Currently, translating and interpreting static electric utility tariff leaves into actionable models for operating and dispatching distributed energy resources is a byzantine, cumbersome, and error-prone procedure. The current method for publishing, accepting, revising, canceling, and disseminating utility tariff and rates is decades out of date.

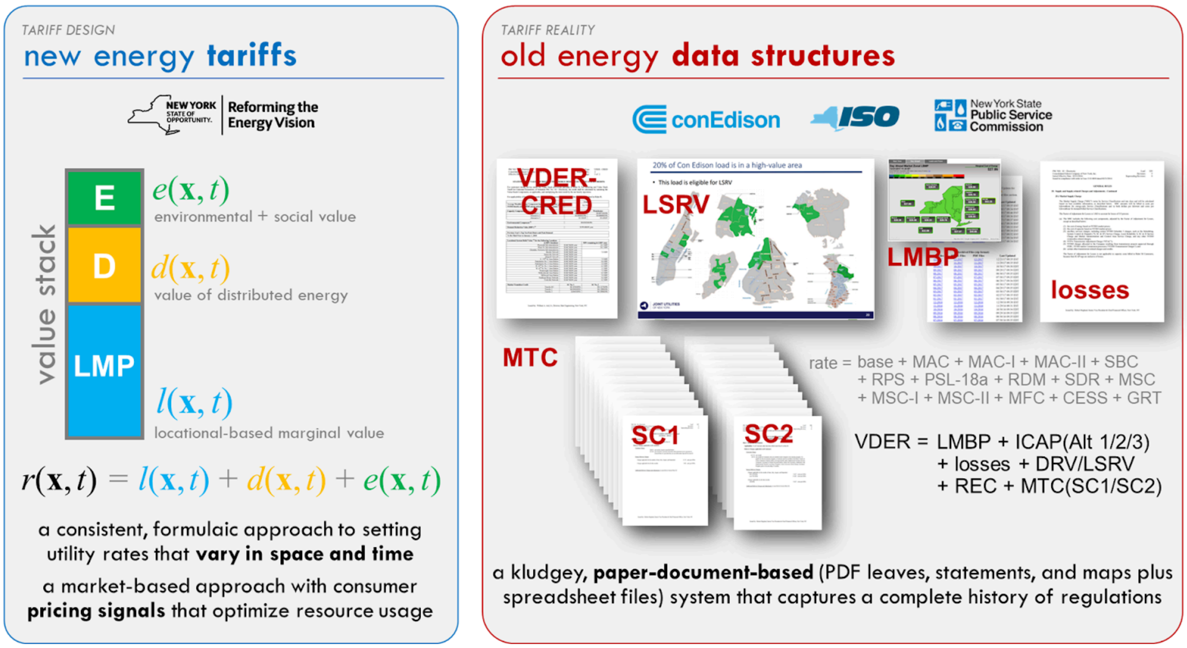
New York's method for storing and sharing utility tariffs and rates

Today, tariff documents and statements are updated in an electronic PDF format, following a process that is largely unchanged from 1996 (at the beginning of deregulation with digital WordPerfect files) or the 1950s (with the introduction of monthly market-based power supply costs set by the spot price for coal). The New York State Department of Public Service (DPS) Electronic Tariff System (ETS) online database is largely unchanged since its introduction in 1996.

An evolution of utility tariffs over six decades



Currently, every energy market participant must manually process documents as they are updated (monthly, at a different frequency, or from time to time) and enter rate data into their own internal formats. More importantly, each market participant must program their own rate and tariff algorithms for translating the operational profile of a resource (e.g., five-minute import/export interval meter readings for kW real power and kVAr reactive power) into monetary costs and compensation/revenue.



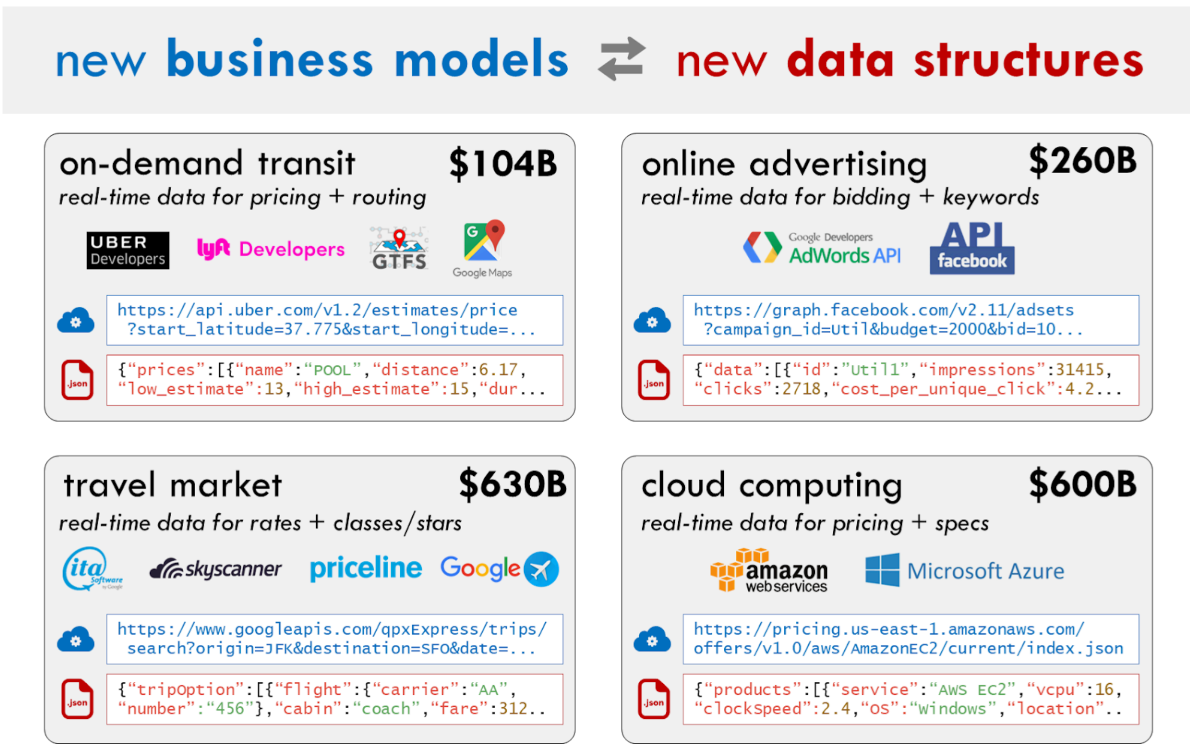
The reality of distributed energy marketplaces is stacks and stacks of tariff documents

Each distribution utility maintains an independent rate database and bill/crediting calculation platform. An unaudited interpretation of complex and nuanced tariff clauses into tariff formulas can result in improper use cases for distributed energy resources.

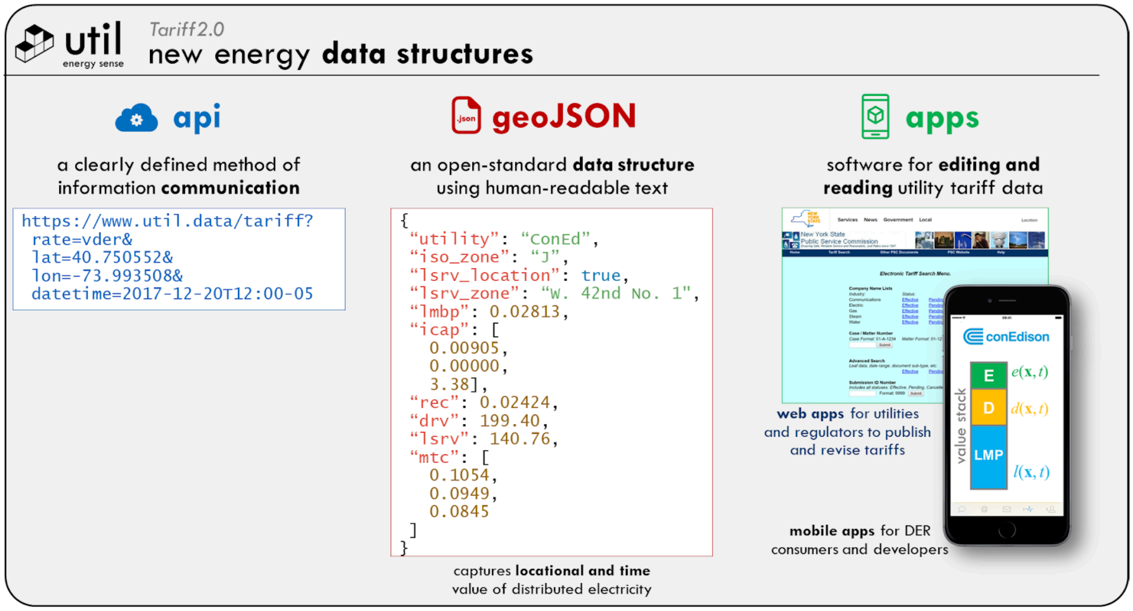
As an example, Appendix 1 compiles the individual rate components and rates required to calculate the electric costs and revenue for a single day of operations of a typical 3-megawatt distribution-connected battery energy storage system in Con Edison territory. Daily revenue is determined based on 33 rate components, delivery costs are based on 46 components, and supply costs are based on 32 components. In total, there are 83 rate components that are published in 28 different locations. For a typical operating year, 8,899 rates (with some updated hourly, monthly, biannually, annually, or on an ad hoc frequency) plus 315,360 interval measurements for real kW power load/imports and injections/exports and reactive kVar power (5-minute interval) data are required to compute the 12 monthly utility statements under a typical service classification. The meta-data about an electric account is captured in at least 32 variables. So, in total nearly 325,000 data elements are needed to calculate bills for an individual electric utility account.

This outdated method for storing, sharing, and computing utility rates and bill engenders:

- **Information asymmetry**: There is a lack of transparency for electric utility rates and tariffs. Data are hard to access and comprehend.
- **Principal-agent problems**: There is a lack of granular pricing for electricity. Price signals do not reflect localized and temporal costs and benefits of bidirectional flows.
- **No applications for behavioral economics**: Real consumers don't make choices based on a purely rational dollar-and-cents approach. A smart platform set can A/B test user behavior based on monetary and non-monetary signals.
- **Inefficient market design**: Lack of communication and improper price signals disrupt the transition to efficient distributed energy marketplaces.



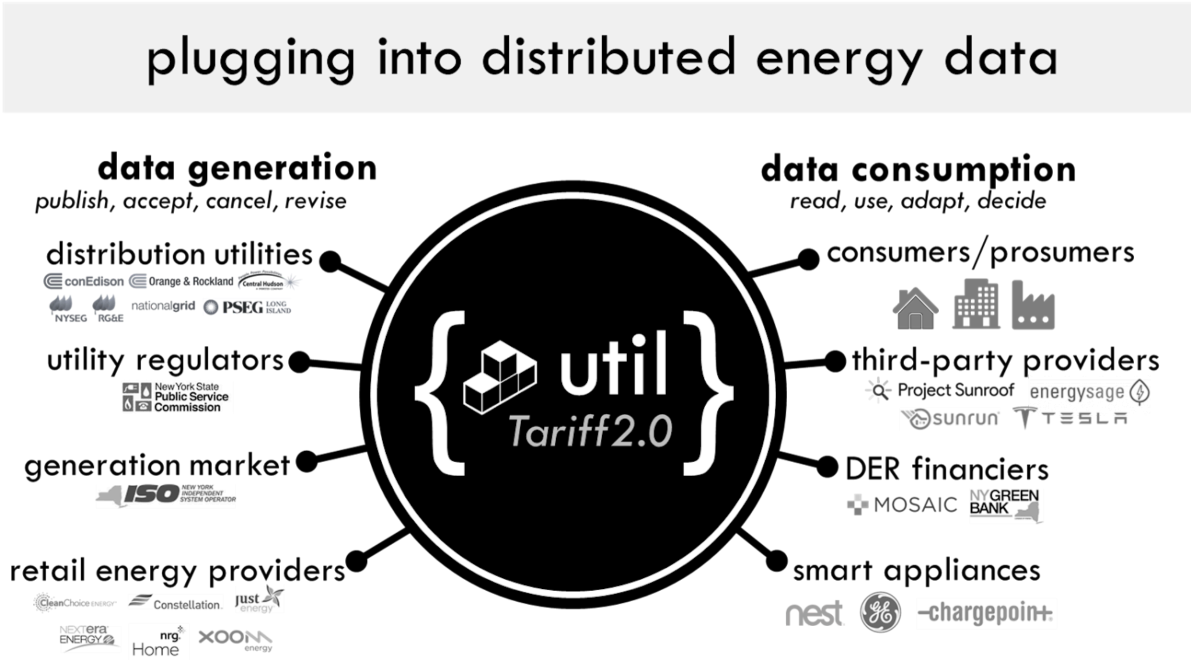
Marketplaces in other distributed-asset industries have robust and trusted methods for generating and sharing price signals. For example, transportation network companies (TNCs) such as Uber have algorithms for matching real-time and spatially-diverse supply and demand. Internet web services companies price cloud bandwidth and data utility services. Online advertising uses real-time data for bidding on specific keyword searches.



To effectively integrate and operate beneficial bidirectional energy resources, distribution electric utilities should adopt similar data sharing platforms. The gold standard method is the API JSON format, a lightweight text-based data interchange.

At its outset, a Bidirectional Service Class should be designed to bypass conventional tariff leaf- and statement-based rates and formulas. Instead, all rates and all interval meter data (e.g., kW/kVAr imports/exports) should be formatted and transmitted via API as an JSON-based service, similar to how the OpenADR standard is used. For meter data, a format similar to the Green Button data can be used. The procedure for enabling and permissioning data sharing to customer-generators and third-parties (e.g., project investors) should be straightforward and well-defined, as opposed to bilaterally-negotiated Data Security Agreements. The computer program for translating meter and rate data into costs and compensation should be openly available for all consumer-generator. Proposed revisions to underlying rate structures should be accompanied by an updated version of the computer program, for all parties to review and give comments.

In summary, in parallel with economic and technical rate/tariff design, the utility and Public Service Commission should invest in data/software innovation to achieve a "Grid of the Future."


plugging into distributed energy data
data generation
publish, accept, cancel, revise
distribution utilities
utility regulators
generation market
retail energy providers
data consumption
read, use, adapt, decide
consumers/prosumers
third-party providers
DER financiers
smart appliances
{util Tariff2.0}

Appendix 8A: Data elements for a typical energy storage customer-generator

The following 32 data inputs and setting are required to determine what set of rates are applicable to a customer:

Customer Specification	Customer Selection
Account Number	00000-00000-0
Prior Account Number	00-0000-0000-0000-0
Account Name	BATTERY PARK
Service Address	22 BATTERY PLACE ESS NEW YORK, NY 10004
Meter Number	000000000
Customer-generator type	A.9: Stand-alone Electric Energy Storage technology
kW nameplate rated capacity	3,000 kW
Date of 25% interconnection payment[35]	MM / DD / YYYY
Date of Operations[36]	MM / DD / YYYY
Customer Class	SC 9 / EL9 - Service Classification No. 9 General - Large (Non-residential)
Standby Service	Yes (required for A.9)
Contract Demand[37]	1,340 kW, Less than 1,500 kW (SC 9 - Rate IV)

[35] Interconnection upgrade deposit date is used to set the relevant components of the Value of Distributed Energy Resources (VDER) Value Stack, including the Demand Reduction Value (DRV) rate, Locational Service Relief Value (LSRV) MW Allocation and rate, and Environmental and Community Components (if eligible).
[36] The beginning of first full billing cycle ("TO" date) after achieving Permission to Operate (PTO) (Step 10 of the New York State Standardized Interconnection Requirements (SIR)) sets the "clock" for contractual VDER components (e.g., 10-year DRV and 25-year Environmental component), exemptions (e.g., 15-year Buy-Back Service exemption), and rate qualifications (e.g., 10-year Rider Q Term of Service).
[37] Contract Demand is set by Customer-generator in Form G: Addendum to Application for Service: Application for Rider R or Standby Service and/or Buy-Back Service (Leaves 382-386.1). The Contract Demand level may be adjusted from time to time by Customer or utility. In this example, a 3,000 kW x 4 hour = 12,000 kW battery with 90% round-trip efficiency (RTE) will consume 13,400 kWh over the 10-hour off-peak period (10 PM to 8 AM) with a flat demand of 1,340 kW.

Customer Specification (con't)	Customer Selection
Contract Demand under SC 11 (Buy-Back Service)[38]	N/A, exempt for 15 years, greater than 1,500 kW
Service Type	Non-Standard
Tension	H - High Tension Alternating Current
Phase	Three phase
Voltage Class	13,200 volts
Standby Phase-In[39]	No
Rider Q (Standby Rate Pilot)	Yes (one-time election)
Rider Q Option	B (Locational Variant Daily As-used Demand Pricing)
Rider Q Commencement	MM / DD / YYYY
Rider J (BIR - Business Incentive Rate)	No
Rider J Commencement	N/A
Rider R (VDER Value Stack)	Yes
Host Account Type	Remote Crediting (RC)[40]
NYISO Load Zone	J (NYC)
Commercial System Relief Program (CSRP) Network Area	Northeast Bronx
CSRP Network Event Call Window	4 PM to 8 PM 16:00 to 20:00 EDT

[38] Contract Demand under SC 11 is the export power in excess of Contract Demand. For example, for a 3,000-kW nameplate capacity battery with a 1,340-kW Contract Demand, this is 1,660 kW (3,000 - 1,340).
[39] Under the Allocated Cost of Service (ACOS) Order, existing Standby Customers have a "phase-in" period to transition to revised Contract Demand Delivery and As-used Daily Demand Delivery Charges.
[40] A RC Host Site requires a monthly RC Satellite Account Allocation Table for distributing VDER credits to up to 10 offsite Customers (each with an unlimited number of accounts), as well as data about Host Site and Satellite Account Credit Banks. Other Host Account Type options are Community Distributed Generation (CDG) (with or without a utility-administered Net Creding arrangement with a Satellite account-specific Savings Rate) and participation in the upcoming utility-administered Statewide Solar for All (SSFA) program.

Customer Specification (con’t)	Customer Selection
Distribution Load Relief Program (DLRP) Tier 2 Network (2024)	Yes
Supply Type	Full Service
Rider M (Day-ahead Hourly Pricing)	Yes (Mandatory - A.9 of Rider R)
Municipality	City of New York

Customer Specification	Customer Selection
Account Number	00000-00000-0
Prior Account Number	00-0000-0000-0000-0
Account Name	BATTERY PARK
Service Address	22 BATTERY PLACE ESS NEW YORK, NY 10004
Meter Number	000000000
Customer-generator type	A.9: Stand-alone Electric Energy Storage technology
kW nameplate rated capacity	3,000 kW
Date of 25% interconnection payment[41]	MM / DD / YYYY
Date of Operations[42]	MM / DD / YYYY
Customer Class	SC 9 / EL9 - Service Classification No. 9 General - Large (Non-residential)
Standby Service	Yes (required for A.9)
Contract Demand[43]	1,340 kW, Less than 1,500 kW (SC 9 - Rate IV)

[41] Interconnection upgrade deposit date is used to set the relevant components of the Value of Distributed Energy Resources (VDER) Value Stack, including the Demand Reduction Value (DRV) rate, Locational Service Relief Value (LSRV) MW Allocation and rate, and Environmental and Community Components (if eligible).

[42] The beginning of first full billing cycle ("TO" date) after achieving Permission to Operate (PTO) (Step 10 of the New York State Standardized Interconnection Requirements (SIR)) sets the "clock" for contractual VDER components (e.g., 10-year DRV and 25-year Environmental component), exemptions (e.g., 15-year Buy-Back Service exemption), and rate qualifications (e.g., 10-year Rider Q Term of Service).

[43] Contract Demand is set by Customer-generator in Form G: Addendum to Application for Service: Application for Rider R or Standby Service and/or Buy-Back Service (Leaves 382-386.1). The Contract Demand level may be adjusted from time to time by Customer or utility. In this example, a 3,000 kW x 4 hour = 12,000 kW battery with 90% round-trip efficiency (RTE) will consume 13,400 kWh over the 10-hour off-peak period (10 PM to 8 AM) with a flat demand of 1,340 kW.

Customer Specification (con't)	Customer Selection
Contract Demand under SC 11 (Buy-Back Service)[44]	N/A, exempt for 15 years, greater than 1,500 kW
Service Type	Non-Standard
Tension	H - High Tension Alternating Current
Phase	Three phase
Voltage Class	13,200 volts
Standby Phase-In[45]	No
Rider Q (Standby Rate Pilot)	Yes (one-time election)
Rider Q Option	B (Locational Variant Daily As-used Demand Pricing)
Rider Q Commencement	MM / DD / YYYY
Rider J (BIR - Business Incentive Rate)	No
Rider J Commencement	N/A
Rider R (VDER Value Stack)	Yes
Host Account Type	Remote Crediting (RC)[46]
NYISO Load Zone	J (NYC)
Commercial System Relief Program (CSRP) Network Area	Northeast Bronx
CSRP Network Event Call Window	4 PM to 8 PM 16:00 to 20:00 EDT

[44] Contract Demand under SC 11 is the export power in excess of Contract Demand. For example, for a 3,000-kW nameplate capacity battery with a 1,340-kW Contract Demand, this is 1,660 kW (3,000 - 1,340).
[45] Under the Allocated Cost of Service (ACOS) Order, existing Standby Customers have a "phase-in" period to transition to revised Contract Demand Delivery and As-used Daily Demand Delivery Charges.
[46] A RC Host Site requires a monthly RC Satellite Account Allocation Table for distributing VDER credits to up to 10 offsite Customers (each with an unlimited number of accounts), as well as data about Host Site and Satellite Account Credit Banks. Other Host Account Type options are Community Distributed Generation (CDG) (with or without a utility-administered Net Creding arrangement with a Satellite account-specific Savings Rate) and participation in the upcoming utility-administered Statewide Solar for All (SSFA) program.

Customer Specification (con't)	Customer Selection
Distribution Load Relief Program (DLRP) Tier 2 Network (2024)	Yes
Supply Type	Full Service
Rider M (Day-ahead Hourly Pricing)	Yes (Mandatory - A.9 of Rider R)
Municipality	City of New York

The following 83 data outputs for delivery, supply, and export electric rate components specific to the hypothetical energy storage Customer are required to calculate the costs and revenue for a single hour of operations:

#	Electric Rate Component	Rate	Unit	Type	Source Document	Rates per Year
1	Customer Charge[47]	66.00	$/month	Delivery	Leaf No. 452.2	1
2	Contract Demand Delivery Charge[48] (High Tension Service)	0.78	$/kW-month	Delivery	Leaf No. 452.2	1
3	Contract Demand Exceedance Allowance[49]	10	%	Delivery	Lead No. 164	1
4	Contract Demand Exceedance Surcharge Multiplier (10-20%)	12	#	Delivery	Lead No. 164	1
5	Contract Demand Exceedance Surcharge Multiplier (>20%)	24	#	Delivery	Lead No. 164	1
6	As-used Daily Demand Delivery Charges (June, July, August, and September) (Monday through Friday, 4 PM to 8 PM)	0.8802	$/kW-day	Delivery	Leaf No. 243.7	1
7	As-used Daily Demand Delivery Charges (June, July, August, and September) (Monday through Friday, 8 AM to 10 PM)	0.3204	$/kW-day	Delivery	Leaf No. 243.7	1

[47] On a monthly bill statement, this component is described as a "Basic Service Charge."
[48] These Contract Demand Delivery and three As-used Daily Demand Charges are for non Phase-In Standby Customers.
[49] There is a significant punitive penalty for Standby Customers exceeding the kW Contract Demand in any billing cycle.

#	Electric Rate Component (con't)	Rate	Unit	Type	Source Document	Rates per Year
8	As-used Daily Demand Delivery Charges (all other month) (Monday through Friday, 8 AM to 10 PM)	0.5822	$/kW-day	Delivery	Leaf No. 243.7	1
9	Maximum As-used Daily Demand Integration Interval	30	minutes	Delivery	Leaf No. 84	1
10	Reactive Power Demand Charge	2.38	$/kVar	Delivery	Leaf No. 93	1
11	Maximum Demand Reactive Adjustment for Reactive Power Demand[50]	-1/3	#	Delivery	Leaf No. 93	1
12	Monthly Adjustment Clause (MAC)	0.353	¢/kWh	Delivery	MAC Statement 150	12
13	Adjustment Factor – MAC (MAC Reconciliation) (bills rendered monthly)	0.2858	¢/kWh	Delivery	MAC-ADJ Statement 150	12
14	Adjustment Factor – MAC (Uncollectible-bill Expense) (bills rendered monthly)	0.0039	¢/kWh	Delivery	MAC-ADJ Statement 150	12
15	Adjustment Factor – MAC (Transition Adjustment) (bills rendered monthly)	0.0007	¢/kWh	Delivery	MAC-ADJ Statement 150	1
16	Revenue Decoupling Mechanism (RDM) Adjustment (SC 9)	(0.1500)	¢/kWh	Delivery	RDM Statement 33	2
17	Billing and Payment Processing (BPP) Charge (Full Service Bill - Electric Only Account)	1.28	$/Bill	Delivery	Leaf No. 353	1
18	System Benefits Charge (SBC) (Energy Efficiency Tracker Surcharge)	0.00	¢/kWh	Delivery	SBC Statement 14	1
19	System Benefits Charge (SBC) (Clean Energy Fund Surcharge)	0.65	¢/kWh	Delivery	SBC Statement 14	1
20	System Benefits Charge (SBC) (Integrated Energy Data Resource Surcharge)	0.00	¢/kWh	Delivery	SBC Statement 14	1

[50] Electric bills incorrectly note that a 95% ratio of kVar reactive power to peak kW demand (rather than 1/3). Bills point customers to coned.com/reactivepower (which has not been available since 2017) and previously stated: "To encourage businesses to reduce their use of reactive power, we will be introducing a new reactive power charge. Large commercial customers will be charged when their power factor, or efficiency, is less than 95 percent."

#	Electric Rate Component (con't	Rate	Unit	Type	Source Document	Rates per Year
21	Clean Energy Standard Delivery Surcharge (CESD) (Costs associated with Tier 2 Maintenance Contracts)	0.0000	¢/kWh	Delivery	CESD Statement 2	1
22	Clean Energy Standard Delivery Surcharge (CESD) (Costs associated with Backstop Charges)	0.0272	¢/kWh	Delivery	CESD Statement 2	1
23	Dynamic Load Management (DLM) Surcharge (SC 9 - Rate IV) (CSRP & Term-/Auto-DLM Component)	0.22	$/kW-Contract Demand	Delivery	DLM Statement 9	1
24	Dynamic Load Management (DLM) Surcharge (SC 9 - Rate IV) (DLC & DLRP Component)	0.13	$/kW-Contract Demand	Delivery	DLM Statement 9	1
25	Delivery Revenue Surcharge (SC 9 - Rate IV)	0.319119	$/kW-Contract Demand	Delivery	SRD Statement 14	1
26	Value of Distributed Energy Resources (VDER) Cost Recovery - Supply Charge (High Tension Standby Customers served under SC 9) (Energy Component)	NA	NA	Supply	VDER-CR Statement 9	1
27	Value of Distributed Energy Resources (VDER) Cost Recovery - Supply Charge (High Tension Standby Customers served under SC 9) (Environmental Component - Market Value)	NA	NA	Supply	VDER-CR Statement 9	1
28	Value of Distributed Energy Resources (VDER) Cost Recovery - Delivery Charge (High Tension Standby Customers served under SC 9) (Capacity Component - Market Value - NYC)	0.01	$/kW-Contract Demand	Delivery	VDER-CR Statement 9	1
29	Value of Distributed Energy Resources (VDER) Cost Recovery - Delivery Charge (High Tension Standby Customers served under SC 9) (Capacity Component - Out of Market Value)	0.00	$/kW-Contract Demand	Delivery	VDER-CR Statement 9	1
30	Value of Distributed Energy Resources (VDER) Cost Recovery - Delivery Charge (High Tension Standby Customers served under SC 9) (Environmental Component - Out of Market Value)	0.0000	$/kWh	Delivery	VDER-CR Statement 9	1

#	Electric Rate Component (con't)	Rate	Unit	Type	Source Document	Rates per Year
31	Value of Distributed Energy Resources (VDER) Cost Recovery - Delivery Charge (High Tension Standby Customers served under SC 9) (Demand Reduction Value (DRV))	0.01	$/kW-Contract Demand	Delivery	VDER-CR Statement 9	1
32	Value of Distributed Energy Resources (VDER) Cost Recovery - Delivery Charge (High Tension Standby Customers served under SC 9) (Locational System Relief Value (LSRV))	0.01	$/kW-Contract Demand	Delivery	VDER-CR Statement 9	1
33	Value of Distributed Energy Resources (VDER) Cost Recovery - Delivery Charge (High Tension Standby Customers served under SC 9) (Community Credit)	0.05	$/kW-Contract Demand	Delivery	VDER-CR Statement 9	1
34	Tax Sur-credit (SC 9 - Rate IV)	0.00	$/kW-Contract Demand	Delivery	TAX Statement 2	1
35	EV Make-Ready Surcharge (SC 9 - Rate IV)	0.02	$/kW-Contract Demand	Delivery	EVS Statement 5	1
36	Arrears Management Program Recovery Surcharge	0.20	$/kW-Contract Demand	Delivery	AMP Statement 1	1
37	Merchant Function Charge (SC 9) (Supply-related charge)	0.0778	¢/kWh	Delivery	Leaf No. 335 and MFC Statement 154	1
38	Merchant Function Charge (SC 9) (Credit and collection-related charge)	0.0321	¢/kWh	Delivery	Leaf No. 335 and MFC Statement 154	1
39	Merchant Function Charge (SC 9) (Uncollectible-bill expense associated with the Market Supply Charge)	0.0022	¢/kWh	Delivery	MFC Statement 154	12
40	Merchant Function Charge (SC 9) (Transition Adjustment)	(0.0288)	¢/kWh	Delivery	MFC Statement 154	12
41	Clean Energy Standard Supply Surcharge (Costs associated with Renewable Energy Credits and Alternative Compliance Payments)	0.3418	¢/kWh	Delivery	CESS Statement 9	1
42	Clean Energy Standard Supply Surcharge (Costs associated with Zero Emission Credits)	0.3635	¢/kWh	Delivery	CESS Statement 9	1

#	Electric Rate Component (con't)	Rate	Unit	Type	Source Document	Rates per Year
43	Clean Energy Standard Supply Surcharge (Costs associated with Offshore Wind Renewable Energy Credits)	0.0000	¢/kWh	Delivery	CESS Statement 9	1
44	Clean Energy Standard Supply Surcharge (Environmental Component Credit - Market Value of the Rider R Value Stack)	0.0134	¢/kWh	Delivery	CESS Statement 9	1
45	Market Supply Charge - Capacity (Rider M customers) (NYC)	13.15	$/kW-month	Supply	MSC-CAP Statement 111	12
46	Installed Capacity (ICAP) Tag Peak Hour (New York Control Area (NYCA) peak hour from the previous calendar year)[51]	7/28/2023 17:00	date	Exports / Supply	NYISO Gold Book 2024	1
47	Gross Receipts Tax - Percentage Increase in Rates and Charges (Non-residential Service) (City of New York) (Delivery Rates and Charges)	2.2195	%	Delivery	GRT Statement 19	2
48	Gross Receipts Tax - Percentage Increase in Rates and Charges (Non-residential Service) (City of New York) (Commodity Rates and Charges)	2.4066	%	Supply	GRT Statement 19	2
49	Factor of Adjustment for Losses	1.071	#	Exports	Leaf 329[52]	1
50	Day-ahead Market Zonal Locational-Based Marginal Pricing (LBMP) (7/15/2024, Hour Beginning (HB) 0:00 EDT, Hour Ending 1:00 EDT) (Zone J - NYC)	46.31	$/MWh	Exports / Supply	www.nyiso.com	365
51	Zone J LBMP HB 1:00 - HE 2:00	37.05	$/MWh	Exports / Supply	www.nyiso.com	365
52	Zone J LBMP HB 2:00 - HE 3:00	33.67	$/MWh	Exports / Supply	www.nyiso.com	365
53	Zone J LBMP HB 3:00 - HE 4:00	32.42	$/MWh	Exports / Supply	www.nyiso.com	365
54	Zone J LBMP HB 4:00 - HE 5:00	31.83	$/MWh	Exports / Supply	www.nyiso.com	365

[51] Con Edison uses the "constrained" NYCA peak hour during non-holiday weekdays in July and August, matching the NYISO Market Administration and Control Area Services Tariff (MST) but uses a different definition for peak hour under MSC-CAP and VDER Capacity Component - Alternative 3.
[52] Note: The Factor of Adjustment for Losses was revised 8/1/2023, but is incorrectly labeled on Leaf Nos. 246 and 462 as 1.066 (the previous rate).

#	Electric Rate Component (con't)	Rate	Unit	Type	Source Document	Rates per Year
55	Zone J LBMP HB 5:00 - HE 6:00	32.34	$/MWh	Exports / Supply	www.nyiso.com	365
56	Zone J LBMP HB 6:00 - HE 7:00	40.02	$/MWh	Exports / Supply	www.nyiso.com	365
57	Zone J LBMP HB 7:00 - HE 8:00	41.01	$/MWh	Exports / Supply	www.nyiso.com	365
58	Zone J LBMP HB 8:00 - HE 9:00	44.19	$/MWh	Exports / Supply	www.nyiso.com	365
59	Zone J LBMP HB 9:00 - HE 10:00	48.86	$/MWh	Exports / Supply	www.nyiso.com	365
60	Zone J LBMP HB 10:00 - HE 11:00	55.53	$/MWh	Exports / Supply	www.nyiso.com	365
61	Zone J LBMP HB 11:00 - HE 12:00	65.17	$/MWh	Exports / Supply	www.nyiso.com	365
62	Zone J LBMP HB 12:00 - HE 13:00	73.36	$/MWh	Exports / Supply	www.nyiso.com	365
63	Zone J LBMP HB 13:00 - HE 14:00	86.66	$/MWh	Exports / Supply	www.nyiso.com	365
64	Zone J LBMP HB 14:00 - HE 15:00	131.27	$/MWh	Exports / Supply	www.nyiso.com	365
65	Zone J LBMP HB 15:00 - HE 16:00	166.51	$/MWh	Exports / Supply	www.nyiso.com	365
66	Zone J LBMP HB 16:00 - HE 17:00	188.88	$/MWh	Exports / Supply	www.nyiso.com	365
67	Zone J LBMP HB 17:00 - HE 18:00	215.70	$/MWh	Exports / Supply	www.nyiso.com	365
68	Zone J LBMP HB 18:00 - HE 19:00	202.81	$/MWh	Exports / Supply	www.nyiso.com	365
69	Zone J LBMP HB 19:00 - HE 20:00	151.51	$/MWh	Exports / Supply	www.nyiso.com	365
70	Zone J LBMP HB 20:00 - HE 21:00	97.25	$/MWh	Exports / Supply	www.nyiso.com	365
71	Zone J LBMP HB 21:00 - HE 22:00	71.68	$/MWh	Exports / Supply	www.nyiso.com	365
72	Zone J LBMP HB 22:00 - HE 23:00	59.64	$/MWh	Exports / Supply	www.nyiso.com	365
73	Zone J LBMP HB 23:00 - HE 24:00	47.59	$/MWh	Exports / Supply	www.nyiso.com	365

#	Electric Rate Component (con't)	Rate	Unit	Type	Source Document	Rates per Year
74	Value of Distributed Energy Resources Value Stack Credits - Phase 2 - Capacity Component - Alternative 3 (NYC)	13.15	$/kW-month	Exports	VDER-CRED Statement 82	12
75	Value of Distributed Energy Resources Value Stack Credits - Phase 2 - Environmental Component	NA	$/kWh	Exports	VDER-CRED Statement 82	1
76	Value of Distributed Energy Resources Value Stack Credits - Phase 2 - Demand Reduction Value (DRV)	0.85360	$/kWh	Exports	VDER-CRED Statement 82	1
77	Value of Distributed Energy Resources Value Stack Credits - Phase 2 - Locational System Relief Value (LSRV)	140.76 14.076	$/kW-year $/kW-Event	Exports	VDER-CRED Statement 82	1
78	Value of Distributed Energy Resources Value Stack Credits - Phase 2 - Community Credit	NA	$/kWh	Exports	VDER-CRED Statement 82	1
79	SC 11 Customer Charge	Exempt for 15 years	$/month	Exports	Leaf No. 463	1
80	SC 11 Delivery Service Contract Demand Charge (High Tension Service below 138 kV)	Exempt for 15 years	$/kW-Contract Demand (SC 11)	Exports	Leaf No. 463	1
81	Sales Tax (Nonresidential energy services, New York State)	4.500	%	Delivery / Supply	tax.ny.gov	1
82	Sales Tax (Nonresidential energy services, New York City)	4.000	%	Delivery / Supply	tax.ny.gov	1
83	Sales Tax (Nonresidential energy services, Metropolitan Commuter Transportation District (MCDT))	0.375	%	Delivery / Supply	tax.ny.gov	1
	TOTAL ELECTRIC RATE COMPONENTS: **83**	TOTAL DELIVERY COMPONENTS: **46** TOTAL SUPPLY COMPONENTS: **32** TOTAL EXPORT COMPONENTS: **33**			UNIQUE DATA SOURCES: **28**	RATES PER YEAR: **8,899**

Interval meter data for a typical summer use-case

Off-peak charge window: **10 PM to 8 AM** (22:00 to 8:00) Off-peak charge rate: **1,340 kW**

CSRP peak export window: **4 PM to 8 PM** (16:00 to 20:00) Export rate: **3,000 kW**

Idle windows: **8 AM to 4 PM** (8:00 to 16:00) and **8 PM to 10 PM** (20:00 to 22:00)

Time Interval (in EDT)	Real Power Imports (kW / kWh)	Actual Reactive Power[53] (kVar) / Power Factor[54] (%)	Real Power Exports (kW / kWh)
7/15/2024 0:00 - 0:05	**1,340.00 kW / 111.67 kWh**	0 / 100.00%	0
7/15/2024 0:05 - 0:10	**1,340.00 kW / 111.67 kWh**	0 / 100.00%	0
7/15/2024 0:10 - 0:15	**1,340.00 kW / 111.67 kWh**	0 / 100.00%	0
…	**…**	…	…
7/15/2024 7:45 - 7:50	**1,340.00 kW / 111.67 kWh**	0 / 100.00%	0
7/15/2024 7:50 - 7:55	**1,340.00 kW / 111.67 kWh**	0 / 100.00%	0
7/15/2024 7:55 - 8:00	**1,340.00 kW / 111.67 kWh**	0 / 100.00%	0
7/15/2024 8:00 - 8:05	**0**	0 / 100.00%	**0**
7/15/2024 8:05 - 8:10	**0**	0 / 100.00%	**0**
7/15/2024 8:10 - 8:15	**0**	0 / 100.00%	**0**
…	**…**	…	**…**
7/15/2024 15:45 - 15:50	**0**	0 / 100.00%	**0**
7/15/2024 15:50 - 15:55	**0**	0 / 100.00%	**0**
7/15/2024 15:55 - 16:00	**0**	0 / 100.00%	**0**
7/15/2024 16:00 - 16:05	0	0 / 100.00%	**3,000.00 kW / 250.00 kWh**
7/15/2024 16:05 - 16:10	0	0 / 100.00%	**3,000.00 kW / 250.00 kWh**
7/15/2024 16:10 - 16:15	0	0 / 100.00%	**3,000.00 kW / 250.00 kWh**
…	…	…	**…**
7/15/2024 19:45 - 19:50	0	0 / 100.00%	**3,000.00 kW / 250.00 kWh**

[53] Dynamic Volt-Ampere Reactive Control on UL-1741-SB power inverters can be enabled to offset fluctuations on the local feeder circuit. Enabling dynamic power factor correction inappropriately reduces real kW power exports or real kW power imports with no compensation. Utilities do not provide statistics on kVar measurement on primary feeders, so developers are unable to estimate the cost and revenue impacts on providing this ancillary service. This is a possibility that providing kVar support can induce a monthly delivery cost based on the $2.38/kVar Reactive Power Demand Charge.

[54] Power Factor (PF) is measured as Real Power divided by Apparent Power, where Apparent Power (kVA) is the square root of $(\text{Real Power})^2 + (\text{Reactive Power})^2$.

Time Interval (in EDT)	Real Power Imports (kW / kWh)	Actual Reactive Power[53] (kVar) / Power Factor[54] (%)	Real Power Exports (kW / kWh)
7/15/2024 19:50 - 19:55	0	0 / 100.00%	**3,000.00 kW / 250.00 kWh**
7/15/2024 19:55 - 20:00	0	0 / 100.00%	**3,000.00 kW / 250.00 kWh**
7/15/2024 20:00 - 20:05	**0**	0 / 100.00%	**0**
7/15/2024 20:05 - 20:10	**0**	0 / 100.00%	**0**
7/15/2024 20:10 - 20:15	**0**	0 / 100.00%	**0**
…	**…**	…	**…**
7/15/2024 21:45 - 21:50	**0**	0 / 100.00%	**0**
7/15/2024 21:50 - 21:55	**0**	0 / 100.00%	**0**
7/15/2024 21:55 - 22:00	**0**	0 / 100.00%	**0**
7/15/2024 22:00 - 22:05	**1,340.00 kW / 111.67 kWh**	0 / 100.00%	0
7/15/2024 22:05 - 22:10	**1,340.00 kW / 111.67 kWh**	0 / 100.00%	0
7/15/2024 22:10 - 22:15	**1,340.00 kW / 111.67 kWh**	0 / 100.00%	0
…	**…**	…	…
7/15/2024 23:45 - 23:50	**1,340.00 kW / 111.67 kWh**	0 / 100.00%	0
7/15/2024 23:50 - 23:55	**1,340.00 kW / 111.67 kWh**	0 / 100.00%	0
7/15/2024 23:55 - 24:00	**1,340.00 kW / 111.67 kWh**	0 / 100.00%	0
Total Intervals 24 hours / 5 minutes = 288 intervals/day **105,120 intervals / year**	Daily kWh Imports 10 hours / 5 minutes = 120 charge intervals @ 111.67 kWh = **13,400.00 kWh**	Peak Reactive Power **0 kVar** **PF = 100.00%**	Daily kWh Exports 4 hours / 5 minutes = 48 discharge intervals @ 250.00 kWh = **12,000.00 kWh**
Total Interval Data 105,120 intervals x 3 meter read signals **315,360 meter data elements**			