March 20, 2023

VIA ELECTRONIC FILING
Hon. Michelle L. Phillips
Secretary to the Commision - New York State Public Service Commission
Three Empire Plaza
Albany, New York 12223

Re: Case 18-E-0130 – In the Matter of Energy Storage Deployment Program.

Dear Secretary Phillips:

NineDot Energy (NineDot) appreciates the opportunity to provide these brief comments to the Department of Public Service (DPS) regarding the proposals made under New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage filed by the New York State Energy Research and Development Authority (NYSERDA) and DPS Staff, in the above-referenced proceeding, on December 28, 2022.

We are available to discuss these comments further and can be reached at adam@nine.energy or +1-516-398-9482.

Respectfully submitted,

Adam B. Cohen, Ph.D.
Co-Founder and Chief Technology Officer
adam@nine.energy

Linda Tatlow
Regulatory Analyst
linda@nine.energy

About NineDot Energy

NineDot is a leading community-scale, clean energy developer with a growing portfolio of projects across a range of technologies. NineDot is creating innovative energy solutions that support a more resilient electric grid, deliver economic savings and reduce carbon emissions. We plan to develop, build and operate more than 400 megawatts of clean energy systems by 2026 that will strengthen the local power grid infrastructure and provide clean, reliable and resilient power to tens of thousands of New York homes and businesses. On August 9, 2022, NineDot celebrated a ribbon cutting ceremony for its first battery energy storage system located in the Pelham Gardens neighborhood of the Bronx.

Executive Summary

NineDot commends the DPS and NYSERDA for their commitments to the goals of transitioning the State to a clean energy economy, protecting the economic interests of ratepayers, and allocating the benefits of clean energy to traditionally-underserved communities. In June 2018, the Storage Roadmap ("2018 Roadmap") filed in Case 18-E-0130, proposed a 3.0 gigawatts (GW) storage deployment goal by 2030, codified later that year in the Climate Leadership and Community Protection Act (CLCPA). In 2022, Governor Hochul proposed to double the goal to 6 GW and the 6 GW Roadmap ("Roadmap") proposes policies and funding that result in the *least cost path* to achieve the ambitious target and sets a viable path for energy storage to support an 85% greenhouse gas (GHG) reduction by 2050.

NineDot supports the budget proposal within the Roadmap as a responsible use of ratepayer funds that will provide environmental, financial, and social-equity benefits to ratepayers. The analysis quantified that while the procurement of storage increased costs slightly in the near term, it provided ***net cost savings* for the New York electricity system of nearly $2 billion** (net present value-NPV) through 2050.[1] In addition, storage deployment will create additional local economic benefits and improved health impacts which are not captured in that figure.. Based on the storage deployment schedule laid out in the Roadmap, we estimate that energy storage projects will generate **over $1 billion in construction spending** through 2030, contributing to local, prevailing wage construction jobs as well as many permanent green jobs from on-going operations and maintenance, ancillary software, banking employment, analysts, etc.

NineDot encourages the Public Service Commission ("the Commission") to approve the Roadmap proposal without delay, codifying the 6 GW storage goal and approving the proposed budget. NineDot believes the Roadmap provides a solid foundation for achieving the 6 GW goal, but the challenges ahead are steep and time is of the essence. As of the date of the Roadmap, it was estimated that an additional 4.7 GW of new projects must be contracted by 2027 to meet the 2030 goal. Yet, only 0.13 GW (2% of the 6 GW goal) had been completed since the 2018 Roadmap as of November 2022.

[1]New York's 6 GW Energy Storage Roadmap:Policy Options for Continued Growth in Energy Storage
CASE 18-E-0130: In the Matter of Energy Storage Deployment Program, December 28, 2022, pages 80-81

As a result, energy storage deployment across New York State must realize a 13-fold increase per year through 2030 to reach the 6.0 GW goal. Achieving this growth rate will require a stable market support framework as presented within the Roadmap as well as addressing several market structure barriers which are impeding growth.

NineDot supports the framework set out for retail storage incentives in the Roadmap that prioritizes **geographic-specific, upfront declining blocks.** NineDot makes the following recommendations with respect to implementation, which are detailed further in the comments:

- Approve the full budget according to the allocations laid out in the Roadmap - the full budget will be necessary to ensure progress toward our goals.
- Ensure large early blocks and realistic contingencies are embedded in planning to ensure NYS goals are met. Given that the retail incentive program proposed in the Roadmap is built upon the previously approved and authorized Market Acceleration Bridge Incentive program, NineDot respectfully requests that its rollout be expedited as soon as possible in 2023.
- Incentive allocation should reflect the unique role energy storage can play in Downstate electricity markets and providing environmental justice (EJ) benefits.

NineDot recommends the **creation of an opt-out savings program for low income subscribers** administered by the utility to address the inequity in the distribution of clean energy benefits to Zone J disadvantaged communities. There may be an opportunity for NYSERDA and New York state to leverage Federal funding being released to support environmental justice initiatives, such as the U.S. Environmental Protection Agency's (EPA) Greenhouse Gas Reduction Fund.

NineDot also provides additional recommendations for addressing **market structure barriers** to storage deployment including:

- Modifications to rate structures and programs including the Value of Distributed Energy Resources (VDER) and Dynamic Load Management (DLM) programs and reinstatement of Con Edison's Modified High Tension (MHT) and Rider Q rates

- Addressing siting and permitting challenges in New York City and improving transparency of hosting capacity maps
- Creating a working group to lay a solid foundation for retail storage deployment in Long Island

NineDot further recommends that the Commission direct an annual review of progress toward the new target, and we urge DPS and NYSERDA Staff to continue to work with industry to identify and remove deployment barriers, adjust programs where necessary and advance new initiatives.

Retail Incentive Program Design Recommendations

NineDot has deep experience and expertise in New York's retail storage market and makes the following recommendations with respect to the retail storage incentive proposals:

- **Approve the proposed budget expeditiously given the ongoing need to make retail storage pencil within NYS:** The storage development process is long, complex and costly. Projects require three to six years to reach completion, owing to a wide array of hurdles related to siting, design, permitting, interconnection, construction, financing, equipment procurement, and customer acquisition.

- **The proposed budget for retail storage (present value of $438 million) is necessary to achieve a steady pipeline of projects.** NineDot believes the budget proposal is warranted given the significant progress that is required to achieve NYS' project goals. Contrary to expectations embedded in the 2018 Roadmap, battery project costs have risen exponentially since the pandemic, with increases seen in all line items, particularly battery and interconnection costs.[2] While incentives incorporated within the Federal Inflation Reduction Act of 2022 will alleviate some of this burden, they are not sufficient to offset the "missing money" gap. In order to avoid a boom and bust cycle, the program size should be large enough to support the ongoing rollout of incentive blocks, providing developers with the stability and visibility necessary to plan well thought out projects.

[2] The price of batteries rose sharply as evidenced by the lithium carbonate index (CNY/T), which rose 1,000%+ in the two years ended December 2022. Interconnection fees have also risen sharply as the most desirable sites have been taken and energy storage developers bear the majority of grid modernization costs needed to accommodate battery storage solutions.

- **Ensure large early blocks and realistic contingencies are embedded in planning to ensure NYS goals are met:** NineDot supports the Roadmap proposal to rollout large early funding blocks commensurate with the backlog of projects that has developed since the last round of retail storage incentives in 2021. When considering the program elements, we encourage realistic time and budget contingencies to be built into the implementation plan that reflects the complicated nature of building a *new energy infrastructure*. The rapid rollout of storage projects is complicated by a myriad of factors. This can be seen in the slower than expected progress towards the goals established in 2018:
  - 130 MW of energy storage, only 10% of the 1.3 GW of total projects contracted or awarded by NYSERDA, had been installed as of December 2022[3] This represents just 2% of the State's current 6 GW goal by 2030, an advancement of 4% toward the State's previous goal of 3 GW by 2030 in the five years since it was set, and 8% of the 1.5 GW interim target for 2025.
  - 354 MW of storage projects, or 40% of the total granted NYSERDA awards under the first Market Acceleration Bridge Incentive (MABI) Program, were approved prior to the end of 2019 and have not yet been completed as of December 2022.[4]
  - 100 MW of storage projects that received NYSERDA awards in the MABI Program have since been canceled.[5]

  It cannot be overemphasized that **a steady pipeline of projects will be needed to achieve our goals**. Retail projects average more than three years from interconnection request to commissioning, so storage projects must be contracted by 2027 at the latest to reach the 2030 goal. We believe that the incentives should be weighted towards the earlier years in order to allow for inevitable delays and project cancellations. In addition, as the number of *active* projects in the queue increases, interconnection time frames may lengthen given resource constraints and bottlenecks at utilities and project service providers.

  Given the lack of storage incentives over the past two years, **<u>the program should create an</u>**

[3] New York's 6 GW Energy Storage Roadmap:Policy Options for Continued Growth in Energy Storage CASE 18-E-0130: In the Matter of Energy Storage Deployment Program, December 28, 2022
[4] NYSERDA
[5] New York's 6 GW Energy Storage Roadmap:Policy Options for Continued Growth in Energy Storage CASE 18-E-0130: In the Matter of Energy Storage Deployment Program, December 28, 2022

<u>**eligibility pathway for projects that are delivered during 2023, in time for the summer peak period**</u>, including projects that are released prior to the implementation plan. This will allow some projects that have become unviable due to cost increases over the past year to proceed. **In addition, incentives should be rolled out for projects and geographies with more developed implementation plans and not held back while others are developed.**

NineDot supports the upfront declining block structure, which will provide capital at a critical time for project development. Given the high upfront costs associated with developing battery storage, providing an upfront incentive payable when projects achieve operations is an effective policy tool to alleviate some of the financing burden, while protecting ratepayers from the many construction risks in these projects. NineDot also believes a declining block structure will be an efficient use of ratepayer funds as battery costs are expected to decline over time, particularly as the Inflation Reduction Act impacts begin to take effect.

- **Prevailing wage requirements should mirror those under Federal regulations:** NineDot supports the creation of good-paying green jobs through compliance with the prevailing wage requirement. NineDot encourages adoption of a similar standard to that required under the Federal Inflation Reduction Act of 2022 to ease the administrative burden of complying with differing Federal and State requirements. The same timing rules and exclusions with respect to this requirement, including the grandfathering and safe-harboring rules, should apply to projects.

- **Incentive allocation should reflect the unique role energy storage can play in Downstate electricity markets and providing environmental justice (EJ) benefits:** NineDot fully supports NYSERDA's recognition of the critical role of storage assets located Downstate in achieving the state's clean energy goals, noting that ***in a least-cost scenario, at least two-thirds of storage will be located Downstate.***[6] Downstate resource allocation should reflect population density, energy use and the higher amount of the cost burden assumed by these residents. Due to its ultra-high space efficiency and minimal physical footprint, energy

[6] New York's 6 GW Energy Storage Roadmap:Policy Options for Continued Growth in Energy Storage CASE 18-E-0130: In the Matter of Energy Storage Deployment Program, December 28, 2022

storage is one of the only clean energy resources whose deployment can be reliably scaled in Downstate's densely-populated, space-constrained environments.

Battery storage is uniquely suited for displacing peaker plants, which are disproportionately located downstate. As noted in the Roadmap, "power generation during peak times, particularly downstate, is often far more polluting than typical operation, and results in significant impacts on cost and health outcomes for nearby residents." As a result, the Department of Environmental Conservation's 2019 Peaker Rule established phased in limits to NO_X emissions, which take effect in May 2023. This will impact the oldest peaker plants (capacity of 3.4 GW) that contribute "94% of NO_X emissions on high ozone days while providing only 36% of the gross load."[7] However, as noted in the Roadmap *"some of these units may stay online if there is not sufficient capacity to provide necessary grid services."*[8]

Deployment of energy storage will bring benefits to disadvantaged communities given the unique ability of energy storage projects to dispatch clean energy in constrained areas at times of peak demand. Within New York City, the peaker-plant fleet is disproportionately located near low-income communities and people of color. According to the Peak Coalition,

Figure 1: Peaker Sites by Capacity and Age

Source: The Fossil Fuel End Game, Peak Coalition, March 2021, Page 19

[7] The Peak Coalition, The Fossil Fuel End Game, March 2021, page 6

[8] New York's 6 GW Energy Storage Roadmap:Policy Options for Continued Growth in Energy Storage

CASE 18-E-0130: In the Matter of Energy Storage Deployment Program, December 28, 2022 approximately 750,000 New York City residents live within one mile of a peaker plant; of those people, 78% are either low income or people of color as seen in the figure below.[9] These "peakers," seen in Figure 1, are largely more than 55 years old, and tend to have the highest pollutant emissions.

In addition, peaker plants are remarkably expensive for ratepayers. Because of expensive capacity payments to peaker plant owners and inefficient equipment, electricity from peaker plants in New York City is orders of magnitude more expensive than the average cost of electricity in the rest of the state.[10] Compensation under the VDER framework allows for lower incentive rates relative to other parts of the state.

- **Automatic fund rollover for canceled projects:** NYSERDA should develop a mechanism to automatically reallocate incentives for cancelled projects within open funding blocks in their respective categories. NineDot also recommends that NYSERDA size program solicitations to include an attrition rate,recognizing that 100% of projects are not likely to be completed for a variety of reasons. Incorporating project attrition in program solicitations will help to ensure that the programs reach the 6 GW target by 2030.

- **An incentive cap of 15,000 kWh *disincentivizes* the most efficient project designs and should be removed.** Under a "least-cost" framework, retail battery projects should be sized as close to 5 MW as possible given that they have the lowest unit economics. This has also been demonstrated in the successful upstate community solar market. A 15,000 kWh artificially incentives projects with higher unit costs by focusing on 3.75 MW assets for NYC (with a 4-hour call window) and 3.00 MW assets for LI (with a 5-hour call window). NineDot believes that application of *any* incentive cap will artificially impede progress towards the State's goals.

[9] The Peak Coalition, The Fossil Fuel End Game, March 2021, page 6
[10] The PEAK Coalition, 2020. Dirty Energy, Big Money: How private companies make billions from polluting fossil fuel peaker power plants in New York City's environmental justice communities – and how to create a cleaner, more just alternative.

- **NineDot supports program entry requirements that incentivize the most viable projects and ambitious but achievable milestones** to prevent non-viable and speculative projects from tying up incentives that could be deployed by more feasible projects. In line with NYC's RSIP Block 4 rules, if the utility requires a coordinated electric system interconnection review (CESIR), proof that **100% interconnection upgrade payment** has been made should dissuade non-viable projects from applying. Given rising interconnection costs, this payment will likely become a more meaningful investment in future incentive rounds relative to past blocks. In NYC, FDNY approval should **not be required** to be eligible to reserve incentives given the lengthy process; at this point, only one battery has received FDNY approval.

Recommendations for Low Income Economic Benefits:

7.5 Questions for Stakeholder Comment

1. For programs supporting bulk and off-site retail projects, how should incentive programs and procurements be best designed towards ensuring that at least 35% of proposed program funding is utilized to benefit disadvantaged communities and drive peaker plant emissions reductions, beyond a program focus on Zone J as proposed in Section 7.2?

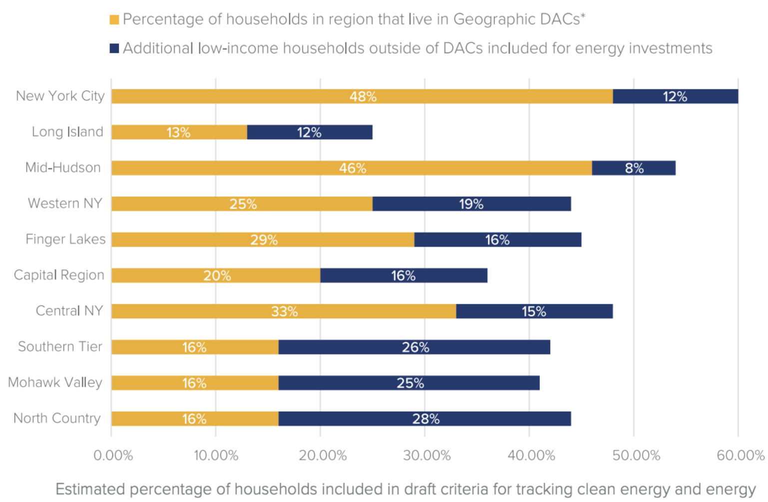
Table 1: Draft DAC Tracts by Region

Region	% of tracts identified as draft DACs
New York City	45%
Long Island	12%
Mid-Hudson	45%
Western NY	32%
Finger Lakes	35%
Capital Region	22%
Central NY	36%
Southern Tier	18%
Mohawk Valley	19%
North Country	15%
Total	**35%**

Source: New York State's Draft Disadvantaged Community Criteria, www.climate.ny.gov

The CLCPA includes a requirement that disadvantaged communities receive at least 35 percent of the benefits of clean energy programs. Several community solar programs allocate ***economic benefits*** to disadvantaged communities by passing on guaranteed bill savings to utility customers. However, project subscribers are required to be customers within the same utility territory as the project. As more than 95% of the 1 GW of community solar has come online upstate, **ratepayers within Zone J are largely excluded from the economic benefits of clean energy.**

Figure 2: Percentage of Draft DACs by Region (Includes DACs for purposes of clean energy investments)

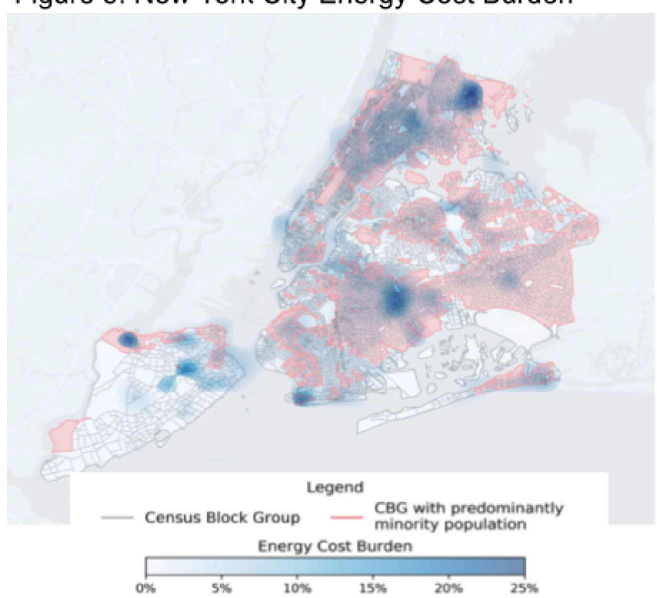


Source: New York State's Draft Disadvantaged Community Criteria, www.climate.ny.gov

At the same time, New York City (Zone J) has the highest level of DAC census tracts within NYS, with 45% of all census tracts considered DACs versus 35% for the State, as can be seen in Table 1. When census tracts that qualify as DACs for energy efficiency and clean energy investments are included, this number rises to 60% for New York City, significantly higher than the average for all other NYS regions of 42% (shown in Figure 2).

Energy affordability issues are particularly pronounced in New York City as has been shown in several studies. According to research published by the NYC's Mayor's Office, 609,850 families were considered energy burdened, defined as those that pay more than 6% of their income towards energy bills, in 2017. Of those, over 460,000 were considered low income under federal definition (less than 200% of the federal poverty level).[11] The spatial map in Figure 3 also demonstrates how widespread the issue is across the city. This problem has grown over the past few years with the Covid pandemic. **<u>The lack of direct clean energy savings programs available for disadvantaged communities within NYC is a major shortcoming in NYS's clean energy policy and needs to be addressed.</u>**

Figure 3: New York City Energy Cost Burden



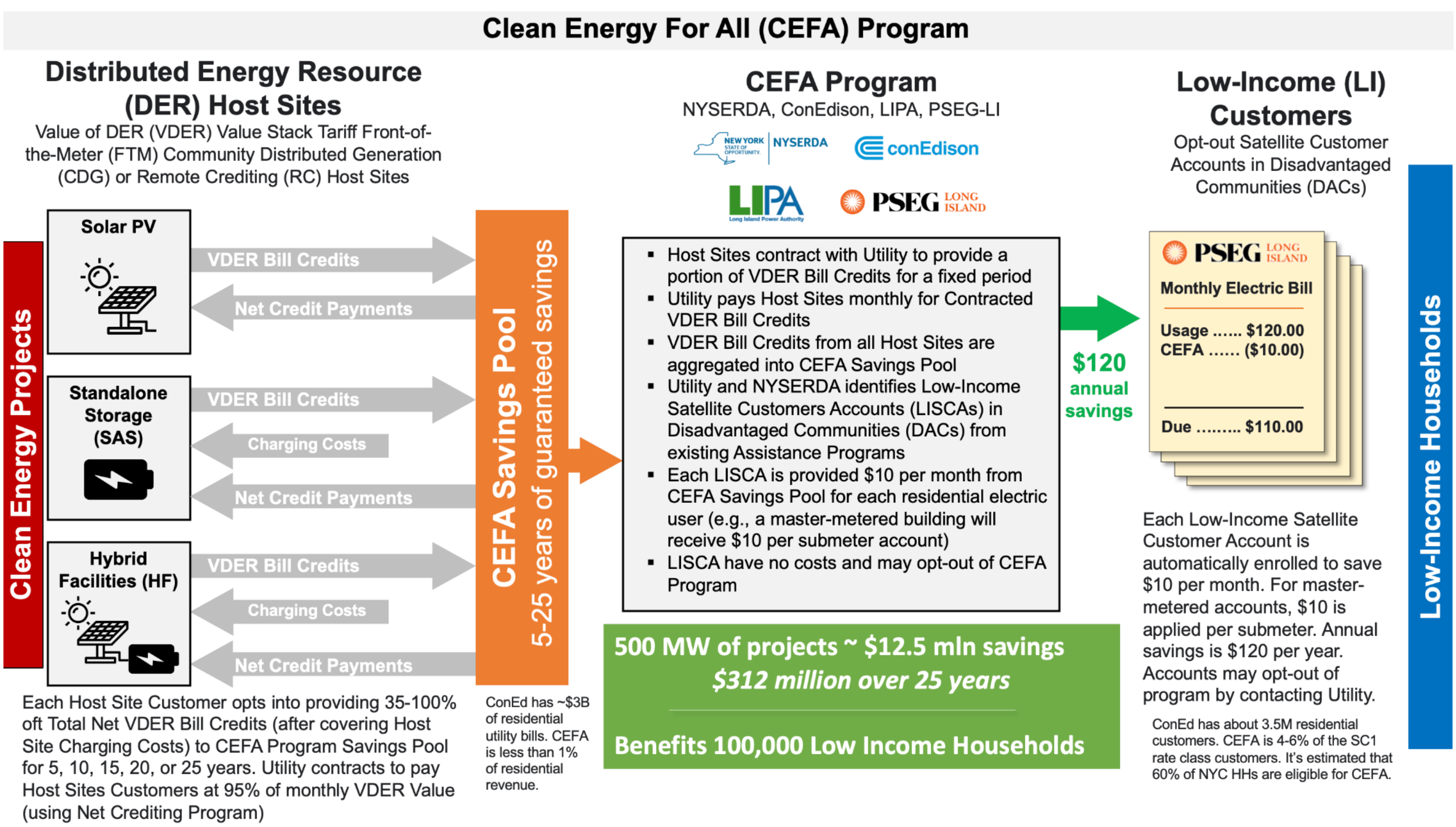
Source: Constantine Kontokosta, Vincent Reina, Bartosz Bonczak, Energy Cost Burden for Low Income and Minority Households, 2020

[11] Understanding and Alleviating Energy Cost Burden in New York City NYC Mayor's Office of Sustainability and the Mayor's Office for Economic Opportunity August 2019

Establish a Clean Energy For All (CEFA) opt out program for disadvantaged communities

Currently, there are no established incentives or mechanisms in place to pass on the benefits from community storage projects to disadvantaged populations in New York State, a major objective of the State's energy policy. Mechanisms should be put in place that incentivize storage projects to provide economic benefits to low income communities; this would solve the problem of the lack of access of Zone J ratepayers to equitable economic benefits.

NineDot recommends the development of a state-wide low income opt out program managed by the utilities, "Clean Energy For All", which could be modeled after the Expanded Solar For All (E-SFA) program launched by National Grid in October 2022. This type of program could potentially provide benefits to a larger number of low-income customers across the state. The first two phases of the E-SFA program are expected to generate $720 million in savings to low income subscribers over the next 25 years[12]. In a Statewide E-SFA program all low-income customers within a given utility territory – whether in a Community Choice Aggregation (CCA) community or not – would be automatically enrolled to benefit from Community Distributed Generation (CDG) savings and could



instead opt-out at their discretion. This differs from opt-out CDG programs which serve low-income customers in a defined CCA community.

The utilities are the most appropriate party to manage such a program and pass on benefits to low income subscribers given that the billing framework already exists, including ratepayers enrolled in energy affordability programs and other qualifying data. In addition, housing the program within a known utility will likely garner wider acceptance among low income populations given that it alleviates administrative burdens and is an existing, known entity, alleviating low income subscribers' fears of fraud.

The program should be designed with an appropriate structure and consumer protections to ensure a smooth roll out and administration by the utilities. The utility should buy credits the month they are generated by clean energy projects, with certifications that they are being correctly allocated. This could be reinforced with publicly-available monthly allocation reports to the DPS. Consumer protections could include lifetime fixed caps on administrative fees and interest payable on unallocated credits so that the utilities make prompt payments to consumers. These measures should help avoid problems experienced with consolidated billing for solar projects.

Vehicle-to-Grid

Currently, there are no direct incentives for bidirectional electric-vehicles (EVs) / Electric Vehicle Supply Equipment (EVSE) or make-ready funding dedicated to installing bidirectional EVSE. Bidirectional, or Vehicle-to-Grid (V2G), hardware and installation costs are sufficiently higher than traditional EVSE hardware. As a result, the vast majority of EVSEs being installed today are unidirectional. This represents a missed opportunity to turn the load growth of EV charging demand from a pure load liability to a source of grid reliability.

The retail storage incentive eligibility should also be broadened to include V2G project charger costs given the grid resiliency and flexibility benefits these projects would bring. The battery storage capacity inherently present in electric vehicles can in theory be compensated by utility programs like DLM, VDER and demand response. However in practice most EVs are not enrolling in such programs given the lack of V2G incentives. Given the nascent nature of V2G technology, incentives for these projects could be structured with multi-year incentive payments, including an upfront portion (e.g., 50% upfront) and a performance based performance, which could be paid out over time (e.g., 10% annually over five years). Since the incentive would be tied to the charger itself and not EV battery packs, it should be relatively cost effective in terms of the effective storage capacity that will participate in grid reliability programs.

New York State has the potential to be a global leader in the deployment of V2G infrastructure as a grid resource, and the retail storage incentive program is the natural implementation pathway.

Addressing Other Market Barriers

The 2018 Roadmap provided a logical and effective multi-year framework for overcoming market barriers for retail energy storage beyond upfront "missing money" incentives, including but not limited to: delivery service rate design; supply and delivery costs; modifications to the VDER Value Stack program; and the Dynamic Load Management (DLM) demand-response program. The updated Roadmap is largely silent on the progress to-date on these initiatives and needs to make midcourse corrections.

The majority of the current policies for tariffs and interconnections procedures related to energy storage projects were established prior to the availability of safe, cost effective and modular energy storage technology. NineDot has identified existing and foreseeable market challenges that will impede the speed and scale of retail market acceleration. NineDot suggests modifications that will greatly increase the pace with which energy storage is deployed across New York State, with a focus on the near-term market acceleration in downstate territories of Con Edison (Zones J, H, and I) and PSEG-LI (Zone K). These modifications are small, easy-to-implement tweaks to existing programs that will have an outsized impact on the industry to achieve NYS' 2030 goal.

I. Recommendations for Modifications to VDER

1. **Introduce "Seven-year Storage CESIR Sabbatical Studies."** A dispatchable front-of-the-meter (FTM) energy storage operates differently from other distributed energy resources. A FTM solar energy generator exports power strictly when the sun is shining and will continue to follow the same seasonal and daily grid-injection profile for its lifetime. The charging and discharging profile of a FTM energy storage system (ESS) can be very simply adjusted with software settings. However, under the current Standardized Interconnection Requirements (SIR), an interconnection study performed prior to building a FTM ESS will define the charge/discharge curve for the lifetime of the asset (35+ years). For example, an interconnection study may constrain a charging window to 1-8am and a discharge window to 2-6pm during summer weekdays. There is no current mechanism to amend these windows.

Clearly, the distribution grid will operate starkly differently in 2030, 2040 and 2050 than it does in 2023. It is shortsighted not to incorporate a well-defined procedure to regularly revisit charge/discharge dynamics. For example, as the grid decarbonizes, one expects excess zero-marginal-cost clean energy during summer afternoons. Hence, batteries should be charging during daytime periods by 2040 rather than discharging. Further, it is expected that New York will be a winter-evening peaking system with the wide scale adoption of heat pumps and electric vehicles. FTM ESS can play an enabling role in this transition if its operations are systematically adjusted to match localized grid needs.

For all FTM ESS projects greater than 1 MW the utility operator and project owner should restudy the charge/discharge dynamics on a seven-year cycle (starting with the date of Permission to Operate). For example, a project that goes online in 2023 will revisit its operating profile in 2030, 2037, 2044, etc. The parties will negotiate in good-faith to optimize the operating profile with then-prevailing cost and compensation structures.

2. **Create better-aligned VDER Capacity Component Alternative structure.** The current framework for compensating dispatchable VDER assets including energy storage for avoided Installed Capacity (ICAP) is academic and devoid of real-world benefits. Under the required Alternative 3 ("Alt3"), a dispatchable asset is retrospectively compensated based on its exports during the single coincidence peak hour ("CP1") of the New York State load ("NYCA Peak"). Energy storage operators must predict the peak hour and are unable to estimate project revenue until the following year. Grid operators are unable to rely on the performance of the fleet of energy storage assets to provide actual relief, negating the assets' dispatchability capability. The Alt3 program design, while effective within an economist's model of a marketplace, is a lose-lose for actual energy storage operations and grid operations.

   NineDot proposes an optional Capacity Component Alternative 4 (Alt4) that better aligns the financial and technical risks and rewards between asset and grid operators:

   - The utility calls up to five two-hour ICAP Events and communicates the Events 21 hours in advance. The utility selects the ICAP Events based on predictions of the NYCA Peak (Statewide), utility service territory peak, or ISO-zonal peak. Note that LIPA's current Alt3 program already is strictly based on Zone K rather than NYCA peaks. There is no limitation on season, day of week, or hour of day when ICAP Events may be called.

- During each ICAP Event, an asset's performance is measured as the minimum kW during the two-hour window
- At the end of each calendar year, an asset's ICAP Tag is the average during the five events. If the ICAP Tag is less than 80%, then the Adjusted ICAP Tag is deducted by 2% for every 1% below 80%. There is no adjustment for performance above 80%. The Adjusted ICAP Tag floor is 0% with no negative performance factor.
- For the following calendar year, the VDER Capacity Component is the monthly Capacity Rate (the same as Alt3) multiplied by the Adjusted ICAP Tag.

This Capacity design adopts lessons from LSRV and DLM programs and provides less risk utilities who can more-optimally predict the performance of dispatchable assets. Additionally, DPS should mandate that utilities must not impose discharge-window restrictions that obstruct the grid injections during peak hours (including potential CP1 events or Alt4 ICAP Events).

3. **Future-proof and extend VDER Demand Reduction Value (DRV) component.**
    - **Create winter peaking DRV rates.** The CLCPA codified the State's goal to reduce greenhouse gases by 85% by 2050 as well as the interim goal of a 40% reduction by 2030. Buildings are one of the largest contributors to greenhouse gases across the state and achieving the goal will require wide-scale building electrification. With this shift to meet heating loads with electricity rather than fossil fuels, winter electric loads will rise significantly, creating winter peaks on the distribution system. A New York winter-peaking system is anticipated around 2030. Yet, the current DRV program is primarily designed to support summer-period relief (with the exception of NYSEG and RGE which include January DRV hours). Utilities should select additional Winter DRV Hours (maintaining the current $/kWh rates) to "future-proof" energy storage resources to provide grid benefits into the next decade.
    - **Extend DRV contracted period to 15 years.** DPS and the Joint Utilities have recognized the need to provide at least 15 years of bankable revenue for energy

storage resources. 15-year contracts are the standard for utility-run bulk procurements and the proposed ISC program. The principal pathway for nearterm deployment through 2026 is the retail-scale market. As such, the main contracted compensation, namely the DRV component, should be locked to 15 years (rather than the current 10 year term). DPS should fix the discrepancy in bankability and risks between these markets.

- **Move towards localized DRV rates.** Over the long-run, DRV rates should be disaggregated by substation or network area based on the next-generation localized Marginal Cost of Service (MCOS) studies. "MCOS 2.0" studies should factor in: localized load growth, evolving load shapes, localized penetration of variable renewables, and opportunities to enhance DER hosting capacity to estimate $/kW-y values for local demand reduction. Similar studies are routinely performed with Benefit-Cost Analyses (BCAs) for demand-response and non-wires alternative (NWA) programs. Hence, there is an accepted MCOS methodology to capture current and future value. An updated DRV/MCOS program will obviate the crude distinction between non-high-stress zones and high-stress LSRV zones with network-specific $/kWh rates.

4. **Revise VDER and SIR limits to 10 megawatts.** Community-scale front-of-the-meter (FTM) energy resources are a "sweet spot" in the New York State market. This is due to the following attributes:
   - small enough to provide localized distribution-grid benefits,
   - faster to design and build than utility-scale projects (roughly half the time),
   - standardized (as they are not customized to a specific behind-the-meter customer's needs),
   - gain economies of scale, and
   - allow for the virtual transfer of economic and financial benefits to specific customer groups, including households in disadvantaged communities.

These features underlie the rapid growth of Upstate New York's successful community solar market.

Community-scale projects are currently limited to 5 megawatts (MW), due to the eligibility in participating in the VDER Value Stack Tariff and the eligibility to follow the State's standardized interconnection process. Distribution-connected projects larger than 5 MW must follow a utility-specific, non-standard interconnection process (except for PSEG-LI/LIPA territory with a 10-MW SIR limit). This arbitrary cutoff is artificially slowing the deployment of the optimal community-scale market.

The 5-MW cutoff is technically unsound. A typical medium-voltage (MV) distribution feeder circuit can host a maximum of roughly 3.5 MW of grid injections. A community-scale project will connect to two independent MV feeders. The 5-MW limit means that 2.0 MW or more of viable hosting capacity is wasted. Project sizes can increase by at least 40% with little to no impact on the distribution system upgrade costs and gaining additional economies of scale. The *least cost pathway* to deploy scalable energy storage resources in New York by 2030 is to expand the SIR/VDER limit to 10 MW.

Note that there is precedence for this capacity expansion. VDER projects were initially limited to 2 MW and the cap was raised by 2.5x. Also, other jurisdictions set higher distributed generation thresholds, such as the Independent Energy System Operator (IESO) in Ontario, which defines mid-sized distributed energy storage systems as 500kW-10MW in its Distribution System Code.

II. Recommendations for Con Edison Program Modifications

1. **Barriers developing projects within Con Edison's underground network have resulted in a concentration of distribution-scale energy storage in specific New York City neighborhoods.** NineDot strongly agrees with the Roadmap analysis that near-term energy storage deployment should be a function of: (1) where the State's major demand centers and anticipated load growth are and (2) where variable renewable energy projects (i.e., offshore wind and distributed solar energy generation) will be interconnected. The Roadmap analysis appropriately demonstrates that the majority of the State's energy storage facilities prior to 2030 will be located downstate (in New York City [NYISO Zone J] and Long Island [NYISO Zone K]) which has an outsized share of the population, load, and upcoming interconnection of wind resources. Similarly, the spatial diffusion of retail-scale energy storage within each utility territory and ISO zone should match: (1) where there is high value to the distribution grid based on load pockets, and (2) where distribution-connection solar energy is deployed. However, there is a major structural barrier to achieving these intended distribution-grid impacts.

   The current utility tariff framework is having the unintended consequence of clustering an outsized portion of community-scale energy storage in a small handful of specific non-high-value downstate neighborhoods[13].

   Solution: Con Edison relaunches its Modified High Tension rate

   As described in the Appendix, there is an emerging clustering program for distributed storage host sites in New York City is caused by a mismatch between the actual cost of delivery service for charging batteries and the existing tariffs that bifurcate Con Edison's localized distribution-grid topology. **In certain areas of New York City, the utility rates to charge a battery are a staggering 16 times higher than other areas, even though**

[13] Without careful and intentional action to remedy this problem, local opposition to the proliferation of energy storage in certain sections of New York City may inhibit deployment across all of the State's most-important market (including the potential for moratoria and/or additional permitting or zoning obstacles similar to those encountered by solar developers in multiple upstate municipalities).

the actual utility-grid impacts and local cost differences are *de minimus*. This cost-mismatch is a remnant of energy storage being inappropriately categorized under conventional Standby and Buyback service classes. *In the medium-term, energy-storage-specific Service Classification schedules must be established. In the near term, there is a need for an expeditious and feasible solution that requires little to no additional or structural changes to the tariff.*

The resolution is for Con Edison to **restart entry to its Modified High Tension (MHT)** program that's been available in its delivery tariff since 1985 (but has been largely underutilized since 1998) for isolated energy storage sites**.** The MHT program enables energy storage host sites to be under equitable delivery rates in all neighborhoods of New York City rather than artificially and inappropriately imposing higher rates in specific locations. In 1998, in a major rate case, Con Edison and DPS removed MHT as a customer opt-in program but retained the right for Con Edison to bilaterally negotiate MHT agreements with customers. DPS should swiftly act to require Con Edison to work with energy storage host sites to select MHT service rates.

2. **More frequent hosting capacity map updates**: The size of the interconnection queue relative to actual development reveals a significant amount of speculation embedded in the market. One cause for this is hosting capacity maps that do not reflect the most up to date hosting capacity for storage projects, resulting in unpredictable interconnection costs. Developers hold a position in the queue until interconnection studies come back, which at a minimum take 85 business days, during which time the developer assumes site control expenses. This problem could be somewhat alleviated by hosting capacity maps that provide greater transparency as to available capacity with more frequent updates to this information as well as inclusion of other proposed projects in the interconnection queue.

3. **Reinstate and expand network-optimized delivery service rate design (Con Edison Rider Q).** Distributed energy storage is a unique grid resource. For every unit of Load Relief delivered during peak periods, even *more* energy must be drawn from the power grid at an earlier time (due to roundtrip efficiency losses). For example, exporting 5.00 MW of power during a four-hour demand-response event requires 23.5 MWh of energy to be drawn from the distribution system (assuming an 85% efficiency rating). The calculus for determining *when* the charging energy is drawn is based on (a) localized feeder-level load patterns, and (b) the costs for charging (including Contract Demand and As-Used Demand rates). For example, charging during overnight "off peak" hours (typically 10pm-8am) requires 2.35 MW of demand. Alternatively, charging over the five lowest demand hours (e.g., 12-5am) requires a 4.70 MW load.

   Ideally, the *lowest-cost* charging curve should also be the *most-beneficial* to the local distribution grid. Con Edison's Rider Q pilot program was specifically designed to encourage distribution-connected energy storage to charge during the most-beneficial times. Rider Q has lapsed and requires reinstatement as a permanent program without constraints on the number of MW allowed to participate.

   Additionally, the Rider Q program requires modification to align costs with local grid constraints and benefits. The current Rider Q program (under Option B) adjusts the As-Used Demand rates and the associated hours for the "peak" and "super peak" periods to discourage adding load during the least-grid-beneficial times. However, the program makes no adjustments to the "off peak" hours which are maintained as 10pm-8am across the service territory. A *global offpeak window* is inconsistent with localized feeder- and network-level load patterns. The results of utility interconnection studies often constrain charging to a *local off peak window* that doesn't correspond to the *global off peak window*, such as 2-10am or 3-11am. As such, the technically-ideal charging curve requires paying "peak" As-Used Demand charges and can make otherwise bankable projects become uneconomic. Practically, this discrepancy causes multiple rounds of negotiation between project developers and the utility causing significant delays and consuming limited engineering resources.

   The straightforward solution is to modify Rider Q to have the "off peak" hours adjustable based on the outcome of interconnection impact studies rather than globally defined.

A more sophisticated Rider Q modification is to allow utility-defined "sculpted" charging curves with sub-hourly (e.g., 15-minute) load shapes (e.g., 2.00 MW from 1:00-1:15am, 1.65 MW from 1:15-1:30am, 1.25 MW from 1:30-1:45 am, etc.) rather than "flat" or constant c. In this proposed Rider Q Option, the *Effective Contract Demand* should be *average* load rather than the *peak* maximum load. Otherwise, there will be a mismatch between the technical benefits and economic cost.

III. Recommendations for the Dynamic Load Management Program

A focus of the 2018 Roadmap was outlining improvements to utility Dynamic Load Management (DLM) demand-response (DR) programs. The suggestion had dual priorities: providing bankable revenue for distribution-connected energy storage projects and localized Load Relief certainty for grid operators. The DLM program was retooled in 2021 and has had two years of operations. Over the past two years, a number of deficiencies in the program design have been identified that have a deleterious impact on energy storage projects, utility operations, and end-customers. A series of small modifications to utility DLM tariffs and solicitations are required.

1. **DLM compensation should be additive to the VDER framework.** For energy storage projects operating under the VDER program (up to 5 MW), the DLM program is an opt-in program that replaces the distribution components of the Value Stack (namely the Demand Reduction Value [DRV] and Locational Service Relief Value [LSRV] components) during the contract period. As such, no energy storage operator will rationally enter a DLM bid that is lower than these VDER components. In Con Edison territory, no DLM participant will bid lower than $199.40/kW-y in a non-high-stress network (or $340.16/kW-y within a high-stress LSRV zone). Hence, for energy storage assets, cleared DLM bids will always be greater than at least $199.40/kW-y. For any accepted bid, the utility will be directly paying a larger incentive than the baseline DRV rate. Along with a new FTM energy storage CBL methodology, the DLM program should be modified for such assets to strictly be *additive* to the existing VDER revenue. For example, if a DLM cleared bid is $250/kW-y for a network area, enrolled FTM energy storage assets will be paid $(250-199.40)/kW-y = $50.60/kW-y for performance during DLM events while being able to dual participate in DRV revenue streams. This DLM

improvement provides surety to the utility that assets will respond to grid events while not over-incentivizing.

2. **Dual participation in DRV and DLM should be permitted.** Dual participation in VDER distribution value streams and the DLM incentive program will help establish a viable community distributed generation (CDG) energy storage market, with off-site subscribers earning guaranteed-saving bill credits (with a priority for low-income households in disadvantaged communities). Without DRV+DLM dual participation, energy storage host sites are motivated to maximize revenue by opting into the DLM program and having fewer bill credits available for offer. Further, as ISO wholesale-market-aggregation dual participation tariffs are established, there is a high likelihood that energy storage assets will opt out of the DRV, energy, and capacity components of VDER and there will be no marketable bill credits. This outcome is incongruous with the CLCPA mandate to have the benefits of clean energy projects flow to disadvantaged communities.

3. **DLM projects are not bankable and awards should be deferrable for up to four years**. DLM is designed to provide a bankable 3- to 5-year contracted revenue stream to energy storage projects. However, the contract must be put in place only one year in advance of required operations for any Vintage Year. Distribution-connected energy storage typically takes 3 or more years to deploy. The DLM has no real-world impact on project bankability, because assets must be underwritten years before a DLM award can be contracted. In practice, DLM provides no additionality to energy storage deployment and is strictly an optional program for already-existing assets. The DLM program should be modified so that awards for energy storage assets can be deferred for up to four Vintage Years with no penalty, to provide ample time to underwrite and develop projects and fairly account for project delays that are out of the control of the developer. In lieu of large upfront penalties for delays, an improved structure could be a percentage reduction in the DLM value for each additional year it takes for the project to come online.

4. **DLM contracts should be 15 years.** The DLM term should be adjusted to 15 years to mirror the approach to the utility's bulk solicitations and the ISC term. The Joint Utilities recently petitioned DPS that energy storage requires long-term contract periods and the same rationale applies to the DLM program design.

5. **The CBL methodology should be modified to allow for better use of batteries.** The DLM program has adopted Customer Baseline (CBL) methodologies from conventional DR programs (e.g., CSRP and DLRP). Front-of-the-meter (FTM) energy storage operates differently than conventional behind-the-meter (BTM) DR assets, and the existing CBL methodologies are misapplied. Under the existing CBL methodologies, a FTM storage asset is disincentivized from providing real-world Load Relief. DLM performance is measured as grid exports during Call Events relative to exports during the previous non-Event days. However, exports during non-Event days are also beneficial to the distribution grid. A FTM energy storage asset that exports during *every* summer peak event (approximately 60 times per summer) provides more distribution grid value than an asset that exports only during DLM Events (approximately 5-8 times per summer). An asset that cycles more frequently also provides more lifetime greenhouse gas (GHG) reductions. Yet, under the current DLM design, the asset's revenue is reduced when it provides additional grid services and GHG reduction. A new FTM storage CBL methodology should be designed that strictly measures performance as grid exports during DLM events (and not relative to previous days), similar to how the VDER Locational Service Relief Value (LSRV) component is determined.

IV. Recommendations to Address Other Market Barriers

1. **Permitting and siting issues:** There is a strong need to streamline the process for permitting sites, which requires significant time and coordination among different agencies. A typical project within NYC requires **10-16 permits** with the DOB and FDNY both having several different permit requirements, and taking an average of three to four years for completion. We propose two solutions, which if adopted, would greatly increase efficiencies of the development process.

- Create a budget for a NYSERDA-based NYC siting team that interfaces with all of the different agencies required to obtain permits to streamline the process. This would greatly streamline the process, alleviating the need for project teams to figure out the complicated permitting process and the many layers involved.
- Standardize permitting process in other areas of NYS using technology. We suggest creating a streamlined permitting tool modeled off of SolarApp+, a software tool designed by NREL to streamline permitting for rooftop solar arrays across jurisdictions, alleviating the heavy lift for small towns. A **similar platform ("StorageApp")** could be created to provide a streamlined front end, consistent approval process for storage projects for the rest of the state.

2. **Rate structures and incentives in Long Island territory need to be systematically addressed.** Long Island (Zone K) represents an important market for retail storage particularly with 9 GW of offshore wind slated to come online in this market. The Roadmap calls for 1.5 GW energy storage projects in Zone K by 2030. However, the current retail delivery and supply rate structures do not support the development of storage. NineDot recommends the formation of a working group that brings together NYSERDA, DPS, LIPA, and PSEG-LI to set the direction of the retail storage program in Long Island, including defining RSIP funding, VDER rates, and charging tariffs.

Appendix: Con Edison Modified High Tension Program

Background to Storage Clustering Problem

Con Edison's electric distribution infrastructure in New York City (NYISO Zone J) includes an underground network system (e.g., covering all of Manhattan and the majority of Brooklyn and Queens) and an overhead non-network system (e.g., covering all of Staten Island and some areas of the Bronx). Both of these topographies can be seen in Figure 4.

Figure 4: ConEdison Network and "Non-Network Topologies

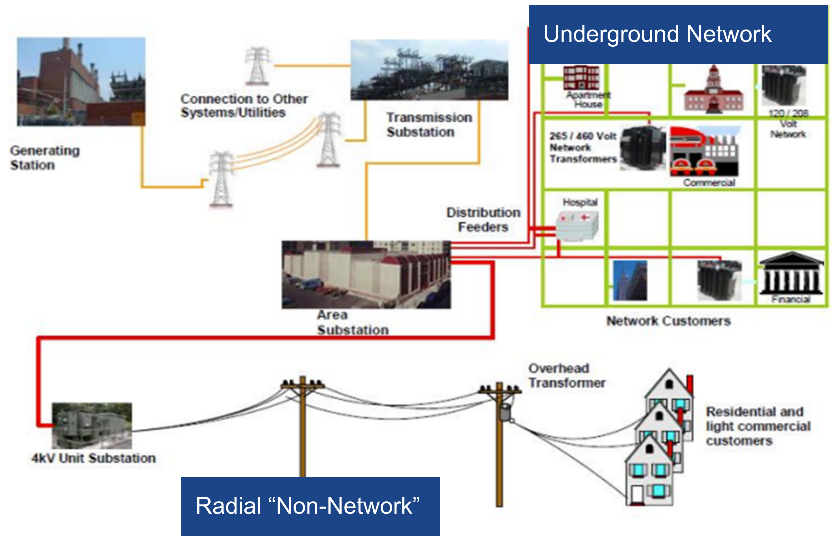
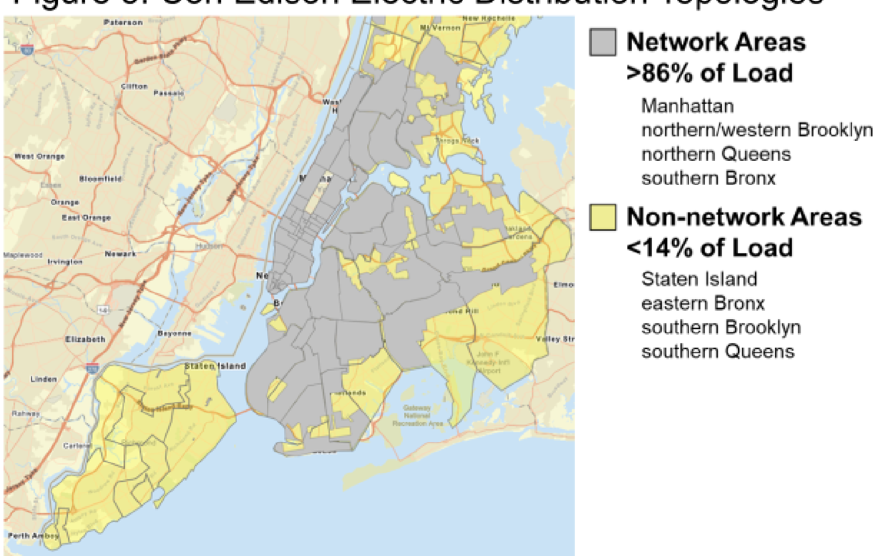


Figure 5: Con Edison Electric Distribution Topologies



More than 86% of New York City's electric load is served by network service and less than 14% is served by non-network service (a map of which is included in Figure 5). Hence, it is expected that the majority of energy storage host sites should be interconnected in network areas.

However, energy storage developers have preferentially targeted 84% of projects and 87% of installed capacity to *non-network* areas (based on projects in

Table 2: Customer Load and Interconnection Queue by Network

Distribution Grid Type	Customer Load	Energy Storage Interconnection Queue (down payments paid)
Network (Underground)	>86%	13%
Non-network (Overhead)	<14%	87%

the Con Edison SIR Inventory with interconnection upgrade down payments as of February 28, 2023).

This deviation from the beneficial diffusion of distributed energy storage is further illustrated based on the borough-level clustering analysis:

Staten Island only serves 6% of New York City's electric load yet is set to host 42% of distributed-connect energy storage. Based strictly on load, Staten Island – which is fully served by Con Edison's non-network grid topology – will host 7x more than its equitable share of energy storage projects[14]. The striking energy-storage cluster problem is poised to have a long-term adverse impact on expeditiously deploying energy storage across all parts of New York City, at all capacity scales (including the residential, retail, and bulk scales), and at all market types (VDER, non-wires program, and utility-owned assets) by introducing strong community opposition and a string of new permitting, zoning, and approval barriers. By proactively solving the cluster issue with simple, forward-looking utility regulations (and without AHJ involvement), the industry can avoid a likely multi-year delay in deployments in the State's most-important energy storage market.

Table 3: Distribution of Electricity Load and Interconnections by Borough

NYC Borough	Customer Electric Load		Projects in Energy Storage Interconnection Queue*		
	MW	%	#	MW	%
Manhattan	5,022	44%	1	3.5	2%
Brooklyn	2,574	23%	8	38.7	19%
Queens	1,961	17%	11	37.6	18%
Bronx	1,093	10%	10	40.9	20%
Staten Island	712	6%	21	87.4	42%
Total	11,362	100%	51	208.1	100%

*Interconnection deposits made.

[14] Note that Staten Island also has a much greater penetration of distributed PV assets (currently 128 MW; solar/load ratio of 17.4%) relative to Manhattan (11 MW; 0.2% penetration) which has siting constraints for PV. Distributed energy storage should be a localized complement to intermittent energy sources and enhance hosting capacity, so the proportion of energy storage should not simply be a function of peak demand. Nevertheless, is it plainly observable that Staten Island's share of energy storage projects is biased.

This mismatch between network and non-network energy storage deployment is the direct result of inequitable delivery rates. Non-network interconnections are less expensive, shorter to construct, and less complex compared to network connections[15]. These upfront cost and development-duration barriers are well-known and manageable by retail energy storage developers. The less obvious but harder-to-resolve inconsistency relates to on-going operational delivery costs for charging energy storage projects with network interconnections. The rates make most network-connected storage projects uneconomic and unbankable. Network-interconnected energy storage have been required to take low-tension (LT) service at the secondary voltage level (typically 277/480 V)[16] versus non-network projects which can opt into high-tension (HT) primary service (typically at 13 or 27 kV). For a traditional load-bearing customer, the main technical difference between LT and HT service is whether medium-voltage (MV) transformers, associated switchgear, and network protectors are procured and installed by the end-customer or the utility. For energy storage projects

Table 4: Comparison on Contract Demand Charges by Network

Service Type	Low Tension	High Tension
Distribution Grid Type	underground secondary **network**	overhead primary **non-network**
Rate Class	SC9-IV (LT)	SC9-IV (HT)
Standby Contract Demand Cost	$8.04/kW-mo.	$0.50/kW-mo.
Sample Energy Storage Project	3,000 kW / 12,000 kWh standalone energy storage system 85% round trip efficiency (RTE) off-peak charge window over 10 hours 14.1 MWh imported to fully charge (includes 5.0% Constant Demand buffer)	
Contract Demand	1,480 kW	1,480 kW
Monthly Delivery Cost	$11,899	$740
Annual Delivery Cost	$142,790	$8,880
Lifetime Cost (Present Value)	$2.32 million	$0.14 million
$/kWh Cost Before Tax	**$190/kWh**	**$12/kWh**
$/kWh Cost After Tax	**$207/kWh**	**$13/kWh**

[15] Overhead feeder line extensions are less costly than underground trenching. ‘N-1’ standards are simpler to construct on a single auto-loop non-network feeder versus ‘N-2’ standards requiring three redundant primary circuits.
[16] Con Edison issued a moratorium on HT service to retail BESS projects on the network systems (under its EO-2022 standard).

interconnected under the SIR process, all costs associated with such equipment are fully borne by the customer, so this distinction is moot. While a network-connected energy storage site is nominally paying upfront for a HT interconnection, the customer is treated as a LT customer under the utility tariff (Con Edison Service Classification 9).

The difference between HT and LT utility rates is dramatic and has material impacts on the bankability and viability of energy storage projects on the network system. Under the on-going Allocated Cost of Service (ACOS) proceeding, the anticipated Standby Contract Demand charges are outlined in Table 4.

This means that the same 3.0-MW energy storage equipment installed on Con Edison's network system must tolerate an additional $194/kWh, or 16x increase, in charging costs over the project lifetime, while receiving no additional revenue or benefits from the VDER Value Stack program (which has no distinction between the distribution-grid value of network and non-network exports)[17]. These uneven LT/HT economics are the basic structural barrier inhibiting the wide scale and equitable deployment of retail-scale energy storage across Zone J and enforcing the *de facto* concentration of project development in non-network areas of Southern Staten Island and the Northeast Bronx.

MHT Solution to Clustering Problem

The Modified High Tension (MHT) program was introduced by Con Edison in 1985 to allow LT customers to convert to HT rates by purchasing medium-voltage (MV) equipment from the utility (accounting for any bidirectional transformer losses). Given that energy storage customers already purchase all MV equipment prior to interconnection, they are eligible for such a MHT program. The MHT program is designed for an isolated customer site that shares no assets with other ratepayers but is measured and metered at secondary voltages. An MHT customer pays for service under the corresponding HT rate (adjusted for transformer losses). The opt-in MHT program was terminated in 1998 while grandfathering then-existing MHT customers with no expiry date. However, the current tariff allows Con Edison to pursue bilateral MHT agreements with customers on a case-by-case basis without Commission approval. NineDot requests that:

[17] These additional ongoing operating expenses are in addition to substantial upfront interconnection equipment costs.

- Con Edison reinstate a MHT program for network-connected energy storage to be negotiated in good faith immediately following a CESIR study and prior to the deadline for a 25% interconnection upgrade deposit, or
- DPS develops an opt-in MHT program specifically for energy storage systems.

Without establishing such a MHT program, retail-scale energy storage in New York City clustering within less than 14% of the distribution grid is likely to accelerate, and installed capacity will ultimately be capped well below the State’s deployment targets.

An alternative solution to MHT is to introduce HT/primary service on the network system (under the EO-2022 standard). In general, this alternative solution is inadequate. New HT interconnections typically take two additional years of design, engineering, construction, and commissioning, resulting in an avoidable delay in deployment across more than 86% of New York City’s retail market. A large number of new energy storage resources taking HT/EO-2022 service may also adversely impact utility feeder processing. The MHT solution service is the simpler, most cost effective, scalable, technically beneficial, and fastest to implement solution.

MHT will rapidly expand the addressable market for retail-scale energy storage projects in New York City by 6x with little to no new technical requirements.