STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 18-E-0130 - In the Matter of Energy Storage Deployment Program.

ORDER ESTABLISHING ENERGY STORAGE GOAL AND DEPLOYMENT POLICY

Issued and Effective: December 13, 2018

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At a session of the Public Service Commission held in the City of New York on December 13, 2018

COMMISSIONERS PRESENT:

John B. Rhodes, Chair
Gregg C. Sayre
Diane X. Burman, concurring, in part and dissenting, in part
James S. Alesi

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BY THE COMMISSION:

INTRODUCTION

Energy storage technologies offer New York numerous benefits and may serve many critical roles in achieving the State's clean energy goals. The Public Service Commission (Commission) recognized the value of energy storage in adopting the Clean Energy Standard (CES) in 2016, which includes a goal that 50 percent of the electricity consumed in New York by 2030 will be generated from renewable energy sources (the "50 by 30" goal).[1] As intermittent renewable power sources like wind and solar provide a larger share of New York's electricity needs, energy storage will be used to smooth and time-shift renewable

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[1] Case 15-E-0302, et al., Large-Scale Renewable Program and a Clean Energy Standard, Order Adopting a Clean Energy Standard (issued August 1, 2016) (CES Framework Order).

generation output and reduce the need to curtail these resources at certain off-peak times. Similarly, under the Commission's Reforming the Energy Vision (REV) proceeding, New York has been transforming its electricity system into one that is cleaner and smarter, as well as more resilient and affordable. Energy storage technologies will play an increasingly important role in this REV transformation.

As New York's electric grid becomes smarter, more decentralized and cleaner, energy storage will be flexibly deployed to store and dispatch energy when and where it is most needed. Energy storage will also allow New York to meet its peak power needs without solely relying on the oldest and dirtiest peak generating plants, many of which lay mostly idle and are approaching the end of their useful lives.

On June 21, 2018, the Department of Public Service (DPS or Staff) and the New York State Energy Research and Development Authority (NYSERDA) filed the "New York State Energy Storage Roadmap and DPS/NYSERDA Staff Recommendations" (the Roadmap), in order to provide the Commission with a range of options to satisfy the newly enacted Public Service Law (PSL) §74.[2] PSL §74 directs the Commission to establish a statewide energy storage goal for 2030, and a deployment policy to support that goal.[3]

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[2] Case 18-E-0130, New York State Energy Storage Roadmap and Department of Public Service / New York State Energy Research and Development Authority Staff Recommendations, (filed June 21, 2018) (Roadmap).

[3] PSL §74 was enacted on November 29, 2017 by Chapter 415 of the Laws of 2017, and was subsequently amended on November 5, 2018, by Chapter 324 of the Laws of 2018. On December 11, 2018, the Legislature sent further edits to the Governor for review (i.e. Bill No. A11099/S8602-A).

The Roadmap makes specific recommendations regarding actions that the Commission may take to encourage the development of energy storage in New York. Broadly, the recommendations in the Roadmap fall within seven categories: (1) retail rate actions and utility programs; (2) utility roles and business models; (3) direct procurement; (4) market acceleration incentives; (5) soft-cost reductions; (6) "clean peak" actions; and, (7) wholesale market actions. Through these recommendations, the Roadmap provides a comprehensive strategy to encourage the deployment of 1,500 megawatts (MW) of energy storage by 2025, and a 2030 energy storage deployment target of up to 3,000 MW.

The Roadmap anticipates that the deployment of 1,500 MW of energy storage by 2025, and between 2,800 and 3,600 MW by 2030, will result in reductions in system peak load demand during critical periods, increases in the overall efficiency and resiliency of the electric grid, and displacement of fossil fuel-based generation. The Roadmap identified an array of resulting public benefits, including: over $3 billion in gross lifetime benefits to New York's utility customers; creating approximately 30,000 jobs; mitigating the impacts of climate change from approximately 2 million metric tons of avoided greenhouse gas (GHG) emissions; and, improving public health by avoiding criteria air pollutant emissions such as nitrogen oxides (NO_x), sulfur oxides (SO_x), and particulate matter.

By this order, the Commission ensures compliance with PSL §74 by establishing a statewide energy storage goal for 2030, along with a deployment policy to support that goal. As discussed below, the Commission adopts many of the recommendations from the Roadmap, which will address barriers that have been impeding energy storage technologies from competing with other resources in a technology-neutral manner.

The Commission's actions will accelerate the market learning curve, drive down costs, and speed the deployment of the highest-value energy storage applications.

Successful implementation of the recommendations will also advance a number of State goals. The 2015 New York State Energy Plan sets forth three statewide clean energy targets to be met by 2030, including: (1) the 50 by 30 goal; (2) a 40 percent reduction in GHG emissions from 1990 levels; and, (3) a 600 trillion British thermal units increase in energy efficiency.[4] The CES Framework Order adopted the 50 by 30 goal as part of a strategy to achieve the 40 percent reduction in GHG emissions.[5] Further, the State has committed to an economy-wide GHG emissions reduction target of 80 percent by 2050.[6]

Realizing these ambitious clean energy and carbon dioxide (CO_2) reduction objectives will require contributions from a variety of resources. Energy storage will be a critical component in enabling renewables to provide the needed amount of penetration to reduce GHG emissions sufficiently to satisfy the CES and State Energy Plan targets.

Pursuant to PSL §74, the Commission adopts a statewide energy storage goal of installing up to 3,000 MW of qualified storage energy systems by 2030, with an interim objective of deploying 1,500 MW of energy storage systems by 2025. This order also describes and adopts a suite of energy storage deployment policies and actions to help eliminate barriers

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[4] The Energy to Lead: 2015 New York State Energy Plan. Available at: https://energyplan.ny.gov/Plans/2015.

[5] CES Framework Order. The CES is divided into a Renewable Energy Standard (RES) and a Zero-Emissions Credit (ZEC) requirement, both of which support carbon dioxide-free resources.

[6] See Executive Order No. 24 (2009) 9 NYCRR §7.24. See also Executive Order No. 2 (2011), 9 NYCRR §8.2.

inhibiting deployment and support the State's achievement of that goal. These energy storage deployment policy efforts will require continued collaboration with NYSERDA, the Long Island Power Authority (LIPA), the New York Independent System Operator, Inc. (NYISO), the New York Power Authority (NYPA), the New York Green Bank (NYGB), the New York State Department of Environmental Conservation (DEC), and the State's investor-owned utilities (IOU).[7]

SUMMARY OF THE ROADMAP

The Roadmap describes a long-term (2026-2030) vision for energy storage deployment, though its primary focus is to identify opportunities, use cases, and implementable actions to support deployment of various energy storage applications in the near-to-medium term (2019-2025). The Roadmap is technology-neutral and acknowledges that a range of energy storage solutions will be deployed to best meet customer and system needs.[8]

The Roadmap includes a host of recommendations to address barriers that impede energy storage from reaching its full potential, with an emphasis on near-term bridging

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[7] The IOUs include Consolidated Edison Company of New York, Inc. (Con Edison), Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Corporation d/b/a National Grid, New York State Electric & Gas Corporation, and Rochester Gas and Electric Corporation.

[8] PSL §74(1) defines a "qualified energy storage system" as a "commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy using mechanical, chemical, or thermal processes to store energy that was generated at one time for use at a later time."

mechanisms and reforms. The Roadmap recommendations fall into seven general categories, including:

1) Retail Rate Actions and Utility Programs: Improve customer delivery rates and programs like dynamic load management (DLM) programs to send more accurate price signals.
2) IOU Roles: Incentivize utilities to manage the full customer bill, leveraging assets such as Non-Wires Alternatives (NWA) and unused real estate to reduce ratepayer costs.
3) Direct Procurement Approaches: Use direct procurement approaches through utility NWAs, the Renewable Energy Standard (RES), and the State's "Lead by Example" initiatives to expand the market for energy storage.
4) Market Acceleration Incentive: Utilize bridge incentives to accelerate soft and hard cost reductions.
5) Address Soft Costs, including Barriers in Data and Finance: Reduce soft costs by, for example, expanding access to more granular system load data and increasing access to a skilled workforce.
6) Clean Peak Actions: Develop approaches to CO_2 reduction compensation that varies with time, and integrate the DEC's draft combustion turbine peaking unit regulations into energy storage policy.
7) Wholesale Market Actions and Distribution/Wholesale Market Coordination: Reform wholesale and retail market rules to better enable and coordinate energy storage services when technically and economically feasible.

Beyond offering specific recommendations to enable greater energy storage deployment, the Roadmap delineates the roles and responsibilities of each of the relevant entities involved. It also specifies the entities needed to directly implement recommended actions, if appropriate. In addition to the Commission, several State agencies and entities would have a role in implementing the recommendations in the Roadmap, including NYSERDA, NYISO, NYPA, LIPA, NYGB, DEC, and the IOUs.

PUBLIC NOTICE AND HEARINGS

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rulemaking (Notice) was published in the State Register on July 11, 2018 [SAPA No. 18-E-0130SP1]. The minimum time period for submission of comments pursuant to the SAPA Notice expired on September 10, 2018. In addition, on July 17, 2018, the Secretary to the Commission (Secretary) issued a Notice Soliciting Comments and Announcing Technical Conferences, which invited stakeholders to submit written initial comments by September 10, 2018, and reply comments by September 24, 2018. The notice also invited interested stakeholders to three technical conferences held by DPS and NYSERDA, in collaboration with the NYGB, NYISO, LIPA, and PSEG Long Island. These conferences were held on July 31, 2018 in New York City, on August 7, 2018 in Long Island, and on August 21, 2018 in Albany.[9]

In addition, a Secretary's Notice Soliciting Comments and Announcing Public Statement Hearings was issued on October 5, 2018, inviting any interested entities to two Public Statement Hearings, which were held on October 23, 2018 in

[9] To ensure proper consultation with interested stakeholders, Staff and NYSERDA solicited stakeholder feedback through individual and group meetings with energy storage developers, renewable energy developers, system integrators, power producers, trade groups, the IOUs, LIPA, NYPA, and the NYISO. Further input was received through other DPS stakeholder initiatives, including the Value of Distributed Energy Resources (VDER) Working Groups.

Colonie, and on October 24, 2018 in New York City. The notice also requested any additional comments on the Roadmap by October 31, 2018. In response to the SAPA Notice and the Secretary's notices, over 40 comments were filed by organizations and individuals. A complete summary of these comments is included in Appendix A, and responses to specific comments are addressed in the discussion below.

LEGAL AUTHORITY

The Commission has broad jurisdiction, power, and duties over the "[m]anufacture, conveying, transportation, sale, or distribution of . . . electricity . . ."[10] Furthermore, PSL §5(2) instructs the Commission "[t]o encourage all persons and corporations subject to its jurisdiction to formulate and carry out long-range programs . . . with economy, efficiency, and care for the public safety, the preservation of environmental values and the conservation of natural resources." The Commission's supervision of electric corporations includes the responsibility to ensure that all charges made by such corporation for any service rendered shall be just and reasonable.[11] PSL §66 empowers the Commission to "[p]rescribe from time to time the efficiency of the electric supply system." The Commission may exercise this broad authority to direct regulatory standards to execute the provisions contained in the PSL. Additionally, the Commission has the authority to direct the treatment of DER by electric corporations.[12]

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[10] PSL §5.

[11] PSL §65.

[12] PSL §§5(2), 66(1), 66(2), 66(3), 66-c, 66-j, and 74.

Pursuant to PSL §74, the Commission is required, by December 31, 2018, to establish, in consultation with NYSERDA and LIPA,[13] a statewide energy storage goal for 2030, and a deployment policy to support that goal. As prescribed therein, the energy storage deployment policy shall address the following:

1) avoided or deferred costs associated with transmission, distribution, or generation capacity;
2) minimization of peak load in constrained areas;
3) systems that are connected to customer facilities and systems that are directly connected to transmission and distribution facilities;
4) cost-effectiveness;
5) the integration of variable-output energy resources;
6) reducing GHG emissions;
7) reducing demand for peak electrical generation;
8) improving the reliable operation of the electrical transmission or distribution systems; and,
9) any other issues deemed appropriate.

The Commission is also required to submit annual reports on the achievements and effectiveness of the policy to the Governor, the Temporary President of the Senate, and the Speaker of the Assembly. The actions directed by this order are within the Commission’s regulatory authority indicated above, and fulfill the requirement that the Commission establish a statewide energy storage goal and deployment policy.

[13] While the currently effective provisions of PSL §74 only refer to consultations with NYSERDA and LIPA, further amendments that would require additional consultation with the NYISO have passed the Legislature and been sent to the Governor. Although those amendments are not yet law, the Commission already deems such consultation to be appropriate and has engaged the NYISO in discussions.

STATE ENVIRONMENTAL QUALITY REVIEW ACT

On June 25, 2018, in compliance with the State Environmental Quality Review Act (SEQRA), the Commission accepted, as complete, a Draft Generic Environmental Impact Statement (GEIS) analyzing the probable environmental impacts related to potential actions recommended in the Roadmap.[14] A notice of completion of the Draft GEIS was published in the Environmental Notice Bulletin on July 11, 2018, announcing that comments on the Draft GEIS will be accepted until August 10, 2018.[15] No written comments were received on the Draft GEIS. The Commission accepted the findings of the Final GEIS as complete on September 12, 2018.[16]

The Commission has considered the information in the Final GEIS with respect to the decisions made in this order, and hereby adopts the SEQRA Findings Statement, attached to this order as Appendix B, prepared in accordance with Article 8 of the Environmental Conservation Law and 6 NYCRR Part 617.

DISCUSSION

I. Energy Storage Deployment Goals

Achieving the State's ambitious system, clean energy and CO_2 reduction goals will require contributions from a variety of resources, and energy storage will be a critical resource for

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[14] Case 18-E-0130, Order Accepting Draft Generic Environmental Impact Statement as Complete (issued June 25, 2018), Confirming Order (issued July 13, 2018).

[15] See DEPARTMENT OF ENVIRONMENTAL CONSERVATION: ENVIRONMENTAL NOTICE BULLETIN STATEWIDE NOTICES (issued July 11, 2018) available at: https://www.dec.ny.gov/enb/20180711_not0.html.

[16] Case 18-E-0130, Resolution Accepting Final Generic Environmental Impact Statement as Complete (issued September 12, 2018).

enabling New York’s clean energy future. According to the Acelerex analysis, which was prepared to support the Roadmap’s recommendations, nearly $2 billion in gross lifetime benefits are expected by 2025 with the deployment of 1,500 MW of energy storage, and over $3 billion in benefits are expected to accrue with the deployment of 2,800-3,600 MW by 2030.[17] In addition, over one million tons of CO_2 emissions will be avoided over the life of the energy storage assets.[18]

To determine ranges of anticipated energy storage deployment that could result in net positive benefit to ratepayers, Acelerex prepared an analysis that examined electric grid needs that could be met by energy storage, in a least-cost combination of resources, to achieve the State’s renewable generation and GHG reduction goals, and to help guide the Commission’s development of energy storage deployment goals. The study does not reflect an upper bound on ratepayer benefits, nor does it maximize the amount of storage that can be deployed in the State. Acelerex also modeled an aggressive timeline for retiring all pre-1990 combustion turbine peaking units in New York City and Long Island by 2025, resulting in 3,600 MW of energy storage being deployed in the State by 2030.[19] While storage can play a critical role in providing peaking services, it is not practical to suggest that storage may be the only solution in reducing the need for peaking generating units. Consequently, a goal below 3,600 MW, the upper range of the Acelerex study, is the most prudent option in estimating a 2030 deployment target.

[17] Roadmap, Appendix K.

[18] Appendices A-B of the Roadmap contain more details on the types of storage and its benefits.

[19] Roadmap, Appendix K, p. 17.

For the reasons described above, and in recognition of the Acelerex modeling, the Commission finds it timely and necessary to adopt an energy storage deployment goal of 1,500 MW of energy storage by 2025. In addition, the Commissions adopts an aspirational deployment goal of 3,000 MW of energy storage by 2030. These deployment goals are coupled with comprehensive energy storage deployment policies and actions that will help accelerate cost reductions, reduce barriers to the monetization of energy storage services that would otherwise go uncompensated, and improve project economics by sending appropriate price signals to the marketplace.

Beginning in 2020, and each third year thereafter, the Commission will conduct a review of the progress towards achieving the energy storage deployment goals and the effectiveness of the energy storage deployment policies and actions in meeting those goals. This triennial review will supplement Staff's yearly "State of Storage" report, as discussed in the Accountability section below, that will present progress towards achieving the energy storage targets as well as impediments that may slow deployment and their potential solutions. The triennial review will help provide certainty to the varied market participants that the deployment goals and associated policies will be realistic and adjusted accordingly based on market conditions. If significant variances occur from anticipated progress, the Commission will consider taking corrective actions based on this triennial review.

II. Retail Rate Actions and Utility Programs

A. Delivery Service Rate Design

Roadmap Recommendations

Instead of applying preexisting Standby and Buyback Services to energy storage customers, the Roadmap suggested that utilities should develop a new rate that incorporates a more granular time- and location-varying daily as-used demand rate. For example, Con Edison has undertaken a pilot program under the "Rider Q" tariff that includes a 10-year rate lock. This tariff would serve as an opt-in rate for any demand-metered customers, with limits on participation to prevent large impacts on non-participating customers. In addition, the Roadmap proposed that opt-in rules should be developed, and that implementation should be standardized across utilities to the extent possible.

Comments

Borrego Solar Systems, Inc. (Borrego), Energy Technology Savings, Inc. (ETS), Enel Green Power North America (the Enel Group), Institute for Policy Integrity at NYU School of Law (IPI), Ingersoll Rand (IR), O'Connell Electric Company, Inc. (O'Connell Electric), NYPA, New York Battery and Energy Storage Technology Consortium (NY-BEST), and Sunrun, Inc. (Sunrun) generally agree that Standby Service should be more granular by time and location to best capture actual benefits of energy storage and its ability to respond to price signals that correspond to the system-wide and locational value provided by the resource. City of New York (The City) and New York State Smart Grid Consortium (NYSSGC) support designing delivery rates to send accurate price signals to the market, and NYSSGC further recommends encouraging deployment of distribution and bulk system energy storage systems as opposed to customer sited "Behind the Meter" (BTM) systems that tend to benefit fewer customers. The City further recommends the elimination of contract demand charges for dispatchable energy storage. EnergyNest AS (EnergyNest) and ETS comment that the economic benefits to the energy storage operator will be substantially reduced if the project is made to absorb electric grid fees.

Some commenters, like Borrego and GI Energy, urge caution in applying charges to distribution or bulk-connected energy storage that differ from what traditional wholesale generators would incur. The Enel Group suggests that only a fixed adder that covers the cost for delivery across the distribution system should be added onto the Locational Based Marginal Price (LBMP) charging rate. The IOUs argue that modifying retail rate designs within a proceeding focused on a single resource type like energy storage is inappropriate. The IOUs maintain that demand charges for commercial customers are the most appropriate method for recovering fixed costs. They also suggest that it is premature to expand the Rider Q program on a statewide basis before seeing the results of the current pilot.

Determination

As the State continues to move toward greater penetration of Distributed Energy Resources (DER) at the distribution level, it is imperative that delivery rates more accurately reflect how costs are incurred by the utility to serve load. Storage technologies can effectively respond to price signals that correspond accurately to the system-wide and locational value provided by the resource, and more accurate delivery rates will encourage this behavior.

Currently, customers with energy storage may incur legacy Standby and Buyback Services in place at each utility to recover electric grid costs and to compensate for injections. Standby Service seeks to ensure that customers who generate on-site and still depend on the electric grid to ensure that they have access to electricity when their needs exceed their generation or when their generator fails, are charged an appropriate level for this backup service. Buyback Service similarly is intended to ensure that customers who provide net injections of energy into the electric grid pay the appropriate cost of that resource’s use of the grid.

More granular time- and location-varying daily as-used demand rates will provide energy storage developers with a more appropriate fee to pay for those costs to the electric grid that the resource will create, and therefore provide a more accurate price signal to energy storage to locate in the most beneficial areas and service territories. Commenters almost universally agree with this conclusion. Existing Commercial Standby and Buyback rates, however, are among the most theoretically pure rate designs available for aligning an individual customers' contribution to system costs with the rates such customers pay, thereby sending accurate price signals to those customers.

Due to limitations in interval metering, mass-market Standby and Buyback Service rates are limited to billing-determinants-based flat fees and volumetric energy usage over a billing period. With interval demand-capable metering becoming much more widely available due to the rollout of Advanced Metering Infrastructure (AMI) throughout New York, mass market Standby and Buyback Service can be measured and billed on the basis of demand in the same manner as the rates applicable to larger customers.

Staff in the VDER Rate Design Working Group are expected to issue a Whitepaper on Standby and Buyback Service Rate Design and Residential Voluntary Demand Rates (Whitepaper on Standby Service) that addresses Standby and Buyback Service rates for all DER, including energy storage.[20] In addition to the substantive makeup of Standby and Buyback Service rates that will be addressed in the Whitepaper on Standby Service, the applicability of current tariffs requires Commission guidance.

The universe of projects that Standby and Buyback Services apply to is relatively small, due to various exemptions that have been applied over the years. Projects eligible for Net Energy Metering (NEM) and the Value Stack, for example, have generally been exempt from participation in these rates, which are intended to pay for grid availability and maintenance costs that are otherwise absorbed by non-participants. Since the number of these exempt projects has historically been low, the non-participant cost shift has not required Commission action. As DER deployment increases and the potential for cost-shifting expands, the applicability of these charges must be addressed in a comprehensive fashion for all DER, not just energy storage.

The Commission's Order on Value Stack Eligibility Expansion and Other Matters (Expanded Eligibility Order) requires newly eligible Value Stack projects using technologies not previously eligible for NEM to apply Standby or Buyback Service provisions that would otherwise be applicable to non-

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[20] See Case 14-M-0101, Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016) (Track Two Order) (directing Staff to address a number of rate design issues, including Standby Rates); Case 14-M-0101, et al., Notice of Rate Design Issues to be Addressed in VDER Proceeding (issued July 21, 2017)(assigning a number of the Track Two Order Rate Design issues to the VDER Rate Design Working Group); and, Matter 17-01277, Value of Distributed Energy Resources Working Group Regarding Rate Design, VDER Value Stack and Rate Design Working Group Process and 2018 Schedule (filed December 22, 2017)(including a Standby Rates and Buy-Back Rates Staff Whitepaper in the 2018 work schedule).

VDER users.[21] Energy storage paired with renewable generation was previously eligible for the Value Stack, and therefore is presently not required to use Standby and Buyback Service. Stand-alone energy storage, energy storage systems paired with consumption load, and regenerative braking systems are among the technologies newly-eligible for Value Stack compensation, and thus required to accept Standby and Buyback Service. While the recent reforms in the Expanded Eligibility Order are consistent with the Roadmap's recommendations, more work is needed on this issue due to its complexity, overlap with other areas, and the critical effect it has on the business case for energy storage.

The Commission agrees with the Joint Utilities that the appropriate venue for resolution of these issues and potential reforms is the VDER Rate Design Working Group process, where the Staff Whitepaper on Standby Service will be evaluated.[22] The VDER Rate Design Working Group is the most appropriate venue to avoid having technology specific rules on issues that are likely universally applicable to all DER.

The working group process can also more effectively evaluate Con Edison's Rider Q pilot in order to determine whether that tariff should be a template for future reforms. While the general format of the Rider Q pilot rates is a reasonable example that other utilities could follow to design more granular Daily As-Used Demand charges, its exact details may not be applicable to the other electric IOUs and therefore additional information and process is necessary to develop such

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[21] See Case 15-E-0751, et al., Value of Distributed Energy Resources, Order on Value Stack Eligibility Expansion and Other Matters (issued September 12, 2018). While Standby Service rates would apply to these projects, compensation for net hourly injections would continue to be based on the Value Stack rather than on existing Buyback Service rates.

[22] Matter 17-01277, VDER Rate Design Working Group.

rates that could be adopted by the Commission. For example, Con Edison is unique in New York as the only utility to have both an On-Peak and Super-Peak Daily As-Used Demand charge as well as differing Commercial System Relief Program (CSRP) call windows, and one of only two utilities with differing Distribution Load Relief Program (DLRP) payment rates based on customer location.

The Commission will look to the VDER Rate Design Working Group as it further develops recommendations on Standby and Buyback Service rates that build upon recent reforms. Staff engaged in the Roadmap recommendations shall collaborate with the working group to ensure that recommendations properly support the valuable compensation of, and deployment of, storage.

B. Costs for Storage Charging and Discharging

Roadmap Recommendations

The Roadmap suggests that rules for charging and discharging must be re-examined so that the desired benefits of energy storage are encouraged. The Staff Proposal on Value Stack Eligibility Expansion[23] recommended a number of relevant changes to charging and discharging rules. The impacts and outcomes of these approaches, as well as various details such as the application of other taxes and fees, need to be examined in the context of the various energy storage use cases identified in the Roadmap. Challenges associated with distribution-connected energy storage providing wholesale-only, and wholesale and retail services combined, also require examination. The

[23] Case 15-E-0751 et al., supra, Staff Proposal on Value Stack Eligibility Expansion (filed May 22, 2018).

Federal Energy Regulatory Commission's (FERC) recent Final Rule[24] enables energy storage located on distribution circuits to charge at the LBMP when providing wholesale services, whereas the costs of charging exclusively for distribution-related services varies. The Roadmap concluded that more information is needed in order to establish the applicable rules.

Comments

Borrego, GI Energy, ETS and Enel Group assert that energy storage should not be penalized for exporting electricity through the application of demand charges. NPS and Enel Group recommend that charging and discharging rates should be defined in very specific daily, monthly, and seasonal timeframes for stand-alone energy storage. EnergyNest supports a level of electric grid fees that are minimal or non-existent. LIPA indicated its interest in working with stakeholders on developing rate structures that facilitate BTM energy storage. Borrego urges Staff to consider a delivery rate design for Front-of-the-Meter (FTM) standalone energy storage that accurately reflects the costs and benefits of serving these resources. GI Energy commented that FTM energy storage should not be disadvantaged in favor of bulk power generation. NPS recommends the charging and discharging rules and rates should be defined in very specific daily/monthly/seasonal timeframes for standalone energy storage.

The Enel Group argues that: metering and billing costs should be covered in fixed charges; interconnection costs should

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[24] Docket No. RM18-9-000, et al., Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Final Rule re Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, (FERC Final Rule, Order 841) 162 FERC ¶ 61,127 (issued February 28, 2018), p. 5.

only cover the service transformer and drop connecting to the building; the variable daily demand charge should reflect the coincident peak charges for both the bulk and distribution system which have temporal, locational, and seasonal variations; the kW variable contract demand charges should be a function of the maximum kW that a battery consumes from the grid; and, for distribution-connected resources, charging should include LBMP along with a fixed adder that covers the cost for delivery across the distribution system.

Determination

Unlike other types of DER that generate electricity or reduce demand, energy storage systems are categorically not generators, and must first charge with electricity before being capable of supplying injections into the electric grid. The Commission's Expanded Eligibility Order will help align some of the charging and discharging rules applicable to energy storage and prevent some of the retail rate arbitrage and other inequities to non-participants that could occur with the use of energy storage at the distribution level.[25]

The Commission now requires that a customer with stand-alone energy storage receiving Value Stack compensation be charged for consumption at the utility's Mandatory Hourly Price (MHP) rate, resulting in both charges and credits accurately reflecting hourly energy values. For customers installing energy storage largely to manage their BTM consumption, the customer will not be required to be served under the MHP rate for charging when the injecting energy storage system is sized to not exceed 115 percent of the customer's peak consumption

[25] Case 15-E-0751 et al., supra, Expanded Eligibility Order, p. 16.

load.[26] However, such customers are permitted to opt into hourly pricing if requested.

While these recent reforms are consistent with the Roadmap's recommendations, more work is needed on this issue due to its complexity, overlap with other areas, and the critical effect it has on the business case for energy storage. Many commenters suggest caution and further study before applying the legacy electric grid charges to energy storage.

Based on the Roadmap's recommendations and stakeholder comments, the Commission concludes that the appropriate application of delivery service costs for discharging and charging energy storage needs additional evaluation and stakeholder feedback. While the Expanded Eligibility Order is a step in the right direction, its focus is on expanding the reach of VDER compensation to clean technologies that were previously ineligible for NEM. Further evaluation is needed regarding this complicated and far-reaching topic, which shall be included within the Staff Whitepaper on Standby and Buyback Rates. The DLM Program Improvement section below and the Delivery Service Rate Design section above are also relevant to the evaluation of the issues addressed here.

C. VDER Value Stack

Roadmap Recommendations

The Roadmap recommends a number of refinements to the Value Stack and other VDER policies, including adding stand-alone energy storage eligibility for VDER compensation. The Roadmap further suggests that expanding the Distribution Relief Value (DRV) rate lock from 3 years to 7 years could reduce financing costs. Furthermore, the Roadmap recommends a DRV call signal for top utility system hours, similar to the existing

[26] Id., p. 17.

CSRP call signal, which provides 21-hour notice before a forecasted event. In addition, the Roadmap recommends that the utilities examine whether utilizing this CSRP call signal achieves the necessary purpose without the need to create any additional signal. The Roadmap also recommends future examination of the best mechanisms for substantiating the value of the DRV, which is currently developed through Marginal Cost of Service (MCOS) studies. Finally, the Roadmap recommends continuing to include Locational System Relief Value (LSRV) within the Value Stack for the time being, but recommends that LSRV be best considered within expanding NWAs in the future.

Comments

Most commenters agree that stand-alone energy storage should be eligible for the Value Stack tariff, and that the DRV lock should be longer than is presently required. Solar Energy Industries Association (SEIA) comments that only seven years of compensation for DRV significantly shortchanges this resource, and that the amortization period of the avoided cost that informs the MCOS value should match the period over which a DER is eligible to receive compensation. Borrego argues that the DRV should be fixed for the life of the tariff. O'Connell Electric believes that the VDER tariff needs to be completely revamped before adding energy storage. GI Energy requests that the mechanics of payment and billing under the Value Stack be clearly defined. NY-BEST argues that the unused LSRV avoided cost value should be added back into the DRV value until a more comprehensive solution can be implemented. Key Capture Energy (KCE) suggests that each utility define a separate tranche of high value locations for energy storage to aid developers in selecting locations. Stem, Inc. (Stem) recommends including the capacity value of non-exporting energy storage discharge. Alliance for Clean Energy New York, Inc. (ACE NY) argues that local pollutants, such as NO_x and SO_2, should be included in the Environmental or "E" Value calculations.

Borrego and NY-Best support a call-signal-based DRV mechanism, but Borrego further suggests refining it by: narrowly tailoring call signals' duration to meet the distribution need; requiring a minimum of five call signals per year; providing bonus payments to production in response to call signals over 15 total cumulative hours; and having the DRV value spread over less than 15 signals called in a calendar year. GI Energy recommends that the utility call signal go out at least an hour prior to the 5 a.m. NYISO Day-Ahead Market bid close. The Joint Utilities recommend existing CSRPs be employed to address DRV rate lock extensions and call signals for top utility hours.

KCE makes several recommendations, including: clarifying that energy storage will receive the nodal and not the zonal price for both charging and discharging as a VDER project; defining a capacity value for energy storage to ensure the projects can become profitable sooner; establishing four hours as the amount for full credit and allowing partial credit for lower duration projects; awarding two streams of environmental credits for projects (i.e., for overall GHG emission reduction and for localized emissions based on NO_x/SO_x for those projects in environmental justice areas); setting a 7-year DRV lock-in; and, requiring that each utility should define a separate tranche of high value locations for energy storage.

NYPA supports various measures, including: allowing the utilities sufficient time to streamline and gain more experience in the NWA solicitation and selection processes before considering phasing out LSRV; allowing sufficient time for extensive record development, including deliberation and stakeholder feedback to help design a mechanism that accurately captures the E Value; accounting for local emissions' value and impacts on environmental justice communities; and, identifying and monetizing the full range of retail services energy storage is capable of providing.

Determination

The Roadmap recommendations regarding the Value Stack and other VDER policies have either already been adopted by the Commission, or are in various stages of administrative and stakeholder review. On March 9, 2017, the Commission adopted the Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (VDER Order), which specified the compensation methodology for technologies and project types that had previously been eligible for NEM based on PSL §66-j and §66-l, as well as projects that paired energy storage with a NEM-eligible technology.[27] The VDER Order required that the VDER tariffs be expanded beyond NEM-eligible technologies to all DER in a technology-neutral, value-focused manner as soon as practicable.

The Commission also recognized that further refinement of the Value Stack components should be examined in Phase 2 of the VDER proceeding, which includes the Value Stack Working Group.[28] A number of Staff whitepapers and Commission orders addressing refinements to the VDER initiative have resulted from the working group process, including the Expanded Eligibility Order and the Staff Draft Whitepaper Regarding VDER Compensation for Avoided Distribution Costs (Draft Whitepaper on Avoided

[27] Case 15-E-0751 et al., supra, Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017).

[28] Matter 17-01276, In the Matter of the Value of Distributed Energy Resources Working Group Regarding Value Stack.

Distribution Costs).[29] The Roadmap's recommendation that the Value Stack be expanded to standalone energy storage was adopted by the Commission in the Expanded Eligibility Order.[30] The order expanded Value Stack compensation to a number of new technologies, including standalone energy storage (i.e., storage that is not paired with generation), regenerative braking systems (whether or not paired with a separate battery), and Vehicle-to-Grid (V2G) systems.

The Draft Whitepaper on Avoided Distribution Costs recommends various refinements to the DRV and LSRV components of the Value Stack.[31] These recommendations include: a new method for calculating the DRV that would provide more value certainty and potentially a 7-year lock; replacing the "de-averaged" DRV with the system-wide marginal cost estimates used generically for each utility's energy efficiency Benefit-Cost Analysis (BCA); and, continuing to include LSRV within the Value Stack. Staff also recommends that the utilities examine whether utilizing the CSRP call signal for the DRV would achieve the necessary purpose without the need to create any additional signal.[32]

The Draft Whitepaper on Avoided Distribution Costs also includes recommendations on the future examination of the best mechanisms for substantiating the value of the DRV, which is currently developed from MCOS studies. Those recommendations are now being considered by stakeholders in the Value Stack

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[29] Case 15-E-0751, supra, Draft Staff Whitepaper Regarding VDER Compensation for Avoided Distribution Costs (filed July 26, 2018).

[30] Case 15-E-0751, supra, Expanded Eligibility Order, p. 16.

[31] Case 15-E-0751, supra, Draft Whitepaper on Avoided Distribution Costs, pp. 5-9.

[32] Id.

Working Group, and Staff is expected to file a final whitepaper in that proceeding, which will be subject to a formal notice and comment process. The Commission declines to adopt energy-storage specific recommendations by this order, but the Commission will look to the VDER Rate Design Working Group as it further develops recommendations. Staff engaged in the Roadmap effort shall collaborate with the Value Stack Working Group to ensure that Value Stack and other VDER policy recommendations properly support the valuable compensation of, and deployment of, storage.

D. CO_2 Reduction Benefits and Shaping the E Value

Roadmap Recommendations

The Roadmap recommends creation of a four to eight-hour window for a statewide peak E Value that varies by season. The Roadmap defines peak seasons as June through September, and January through February, and considers off-peak seasons as October through December, and March through May.

For energy storage systems that charge from electric grid energy, the Roadmap recommends that the net CO_2 benefits should be calculated based on an assumed peak/off-peak delta, which should then become the resource’s E Value. Systems that can demonstrate they charge entirely from renewable energy, such as in a paired storage plus renewables configuration, should receive the full CO_2 benefit displaced during peak hours. An annual assessment was also suggested to determine whether a more dynamic E Value is appropriate based on changing system conditions and given assumptions about increasing renewables penetration in certain zones.

The Roadmap further recommends that the Value Stack Working Group should evaluate and consider the shaped E Value recommendations above to inform a DPS Staff Whitepaper on this topic. As explained, the shaped E Value is initially expected to have the same fixed 25-year, statewide attributes as the current E Value. However, the benefits of a more regional (i.e., upstate vs. downstate) or zonal shaped E Value were recommended to be examined along with a more dynamic shaped E Value that adjusts every year. According to the Roadmap, the IOUs should immediately begin incorporating a shaped E Value approach in the various BCA analyses they conduct.

Comments

AEMA recommends that the E Value be time and season-sensitive to ensure incentives for energy storage are fully captured. Borrego supports the Roadmap's proposed four to eight-hour window that varies seasonally, but recommends that it be made available on an opt-in basis to all energy storage, including those installed before adoption. EnergyNest suggests that certain thermal energy storage systems be granted an E Value, and recommends allowing assets to discharge into the peak window as they are able and willing. MTA supports peak E Value from resources which can demonstrate capability to charge entirely from renewable resources, and notes that regenerative braking meets these criteria because it provides electricity as needed without any emissions. Joint Comments of Azure Mountain Power, Bloom Energy, the City of New York, Environmental Defense Fund, the Institute for Policy Integrity at New York University School of Law, Natural Resources Defense Council, New York City Environmental Justice Alliance, and WattTime (Joint IPI), ETS, and NYCEJA favor shorter and seasonably flexible windows to pilot new rate designs and enable market signals. GI Energy and IPI support the Roadmap's E Value proposal and suggest working to identify the value of other avoided pollutants. Hydrostor, Inc. (Hydrostor) supports the Roadmap's data driven approach to quantifying the CO_2 emission reductions. LIPA stresses that an accurate E Value should involve the IOUs and agreements among participating parties.

NY-BEST, the City, Joint IPI, and NYCEJA support expanding the current scope of the E Value to include reducing local pollutants, particularly in the environmental justice communities. NRDC recommends Staff develop a framework to assess the E Value using granular data. Stem states that the Roadmap erred in not referring to the marginal generator at the time of charging, and that the CO_2 benefit is the same whether it is charged with renewables or not. It also recommends that Staff adopt an overall framework that values CO_2 reduction achieved in the shifting of energy independent of the E Value as constructed today. The City and Enel Group support the development of a more granular E Value that accounts for differences in emissions between energy storage and electric grid power.

The IOUs agree that reflecting a shaped E-Value would provide improved price signals, although it would be premature to adopt the technology-specific recommendations from the Roadmap at this time since this issue is being addressed by the VDER Value Stack Working Group.

<u>Determination</u>

As more renewables are deployed in the State, energy storage will have a greater role in avoiding renewable curtailment, particularly during off-peak periods, as well as shifting zero-emissions renewable energy to times that displace fossil fuel generation. The Acelerex study determined that 2,800 MW of energy storage deployed by 2030 could reduce CO_2 emissions by two million metric tons over the life of the energy storage assets, equivalent to the emissions of 400,000 cars in a year.[33] Under the Value Stack, eligible resources receive the E Value as a proxy for the value of CO_2 emissions reductions.[34] Currently, the E Value is fixed throughout the year, thus it is only an approximation of the resource's actual CO_2 benefits because emissions vary on an hourly, daily, seasonal, and multi-year basis.

As the Roadmap indicates, resources providing CO_2 reduction benefits need compensation that is stable over time in order to encourage financing and long-term investment, while at the same time is sufficiently dynamic to provide appropriate price signals that reflect the actual benefits of the resource. The Commission agrees that shaping the E Value will help achieve these outcomes, will better reflect marginal CO_2 emissions, and will provide stronger incentives for investments in renewables that provide the most CO_2 reduction benefits. The Roadmap states that the increase in benefits that a dynamic E Value provides to both stand-alone energy storage and solar and energy storage is on the order of 5 percent or less. Nonetheless, the Commission agrees that sending this more dynamic price signal to the marketplace should be further evaluated since greater renewable penetration in the electric grid will likely increase this benefit considerably.

Commenters are generally supportive of a more dynamically priced E Value, and have a number of recommendations on quantifying CO_2 emission reductions, the subject of which continues to be addressed in the VDER Value Stack Working Group. For example, many commenters support expanding the current scope

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[33] Roadmap, p. 35.

[34] The E Value is calculated as the higher of the most recent Tier 1 REC price under the RES or the Social Cost of Carbon (SCC), net of the expected Regional Greenhouse Gas Initiative (RGGI) allowance values.

of the E Value to include the public health benefits of reducing local pollutants, particularly in environmental justice communities. The City recommends a resiliency adder that compensates energy storage used in critical community facilities, while Hydrostor suggests that the valuation of CO_2 reduction should account for the ability of long-duration energy storage such as Advanced Compressed Air Energy Storage to replace fossil generation. The MTA suggests that regenerative braking should receive the E Value.

The VDER Value Stack Working Group has had a number of meetings and presentations on these topics. Staff should continue evaluating these options and the benefits of a more regional or zonal shaped and dynamic E Value. Staff is directed to issue a whitepaper by July 1, 2019, that evaluates the Roadmap's recommendations on the E Value, reflects the progress made in the VDER Value Stack Working Group and the stakeholder input submitted in this proceeding, and that includes concrete recommendations to guide implementation.

E. Dynamic Load Management Program Improvement

Roadmap Recommendations

The Roadmap recommends a number of changes to IOU DLM programs for the Summer 2020 capability period, including providing more revenue and programmatic certainty through longer-term participation. As proposed, the IOUs should be required to offer an option for multi-year DLM program participation agreements where terms of participation remain unchanged for three to five years, or longer, based on the specific utility circumstances. These agreements could be competitively procured, offered at a premium or a discount, as appropriate, based on best forecasting, and also include penalties for non-performance so that the load relief is not subject to excessive de-rating in system contingency planning.

The Roadmap also recommends that the IOUs should change higher priority designations (i.e., Con Edison Tier 2) within their DLM program to remain unchanged for periods of three to five years or longer based on the specific utility circumstances. An orderly transition is also suggested for DLM resources participating in Tier 2 locations in the event a Tier 2 circuit designation is superseded by an NWA procurement.

Other recommendations in the Roadmap address programmatic changes that would help accommodate the characteristics of energy storage resources. In particular, the IOUs should establish a "premium" auto-DLM resource category, such as Con Edison's Smart Grid Demonstration project, which requires high performance factors, availability, multi-year participation commitments, visibility and reliability. Further, the IOUs should establish a component of DLM participation for energy storage where performance can be directly sub-metered at the energy storage system, rather than be determined from baseline load data. Additionally, the Roadmap recommends that on days requiring DLM performance, energy storage systems operating to meet the specified dispatch window should not be negatively impacted by monthly kW demand charges under existing distribution rates.

The Roadmap also recommends that the IOUs should consider ways to limit fossil fuel generators from being advantaged by changes that emphasize multi-year and dispatchable DLM participation. In addition, the Roadmap indicates that fossil generation participation should be in compliance with any final rule adopted based on the DEC's proposed peaking unit regulations.

Comments

AEMA, Enel Group, EnergyNest, MTA, NY-BEST, NYPA, and Sunrun support the Roadmap's recommendations for establishing longer-term rule and price certainty for utility DLM programs. AMEA believes the revenue certainty would give developers and aggregators a better business case to implement automation or other technologies. EnergyNest requests that the definition of energy storage system should include high-grade, heat-based thermal energy storage. Enel Group believes that the premium auto-DLM resource needs further exploration. NY-BEST suggests Staff should engage with stakeholders before the IOUs file changes to DLM programs. Sunrun encourages the adoption of a tariff-based demand response procurement approach for BTM solar plus energy storage, and allowing residential and NEM customers to be eligible.

Joint Utilities argue that the recommendations are not needed and could create a rate lock untethered to grid needs, arbitrage opportunities, and other aberrations to the existing programs. They also argue that the premium service proposal based on performance is unnecessary as the current DLM programs already expect consistent and high performance levels from participants. Instead, they recommend participation be fixed at three- to five-year terms with resources acquired via competitive procurements that include performance penalties and participation measured on a sub-metered basis.

Determination

Most commenters support the Roadmap recommendations to establish longer-term rule and price certainty in the IOU's DLM programs, although the Joint Utilities argue that the present DLM programs are working fine. The Commission agrees with NY-BEST's comment that the current DLM program structure results in a bias toward short-term, low-capital investment solutions because of the short horizon of the revenue stream. In addition to continuing to operate the tariffed DLM programs, the Commission orders the electric IOUs to hold a competitive procurement for DLM resources, for a minimum of a three-year term. The Commission recommends between a three and five-year term, or longer based on the specific utility circumstances for the 2020 Summer capability period and thereafter.

The Commission further agrees with NY-BEST that locking the rates for resources procured in this fashion for the full term would provide a hedge to all ratepayers, and stimulate more participation and investment in the programs. This change will provide more revenue certainty for developers through longer-term participation. These agreements would be offered at a premium or a discount, as appropriate, based on the most recent IOU load forecasting, and include penalties for non-performance. For example, utilities with MCOS results trending downward might offer long-term contracts at a discount as a hedge against diminished incentive payments, whereas utilities with increasing MCOS results might offer a premium.

Within this procurement, utilities shall establish a premium auto-DLM resource category, as recommended in the Roadmap, that requires higher performance factors than is currently required, including stringent availability and multi-year participation commitments. Moreover, the procurement shall include limitations on fossil generators similar to what is provided in current programs, and require that their participation be in compliance with any final rule adopted based on any final rule resulting from the DEC’s pre-proposal draft outline Express Terms for 6 NYCRR Part 222, Distributed

Generation Sources.[35] Each electric IOU shall file their proposals in the next annual DLM report.[36]

The Commission rejects or defers other recommendations proposed in the Roadmap. Allowing performance to be based on submetering will conflict with existing DLM program rules that require flexible baseline readings, and is rejected. Basing performance on baseline load data is the most common method used for this purpose, and it ensures that ratepayers only pay for concrete reductions in load under the program parameters. Additionally, the Roadmap's recommendation that monthly kW demand charges not be impacted by injections during call periods could create a complicated matrix of rate exceptions for those participating in DLM programs. Customers can manage this injection process to avoid deleterious effects on their monthly demand bills, and accordingly we decline to adopt this Roadmap recommendation.

The Commission rejects the recommendation in the Roadmap to lock in higher priority DLM designations for periods of three-to five years, or longer. As the Commission stated in a previous order related to the designation of Distribution Load Relief Program Tier 2 Networks at Con Edison,[37] priority areas are intended to respond to an electric grid need in specific

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[35] See Draft Express Terms of 6 NYCRR Part 222, Distributed Generation Sources (May 16, 2018), available at: http://www.dec.ny.gov/docs/air_pdf/replacepart222.pdf.

[36] Case 14-E-0423, et al., Proceeding on Motion of the Commission to Develop Dynamic Load Management Programs, Order Adopting Program Changes With Modification and Making Other Findings (issued April 19, 2018).

[37] Case 17-E-0741, Petition of Consolidated Edison Company of New York, Inc. for Approval of Changes to Commercial Demand Response Programs with Associated Tariff Amendments, Order Approving Changes to Commercial Demand Response Programs with Modifications (issued April 20, 2018).

locations, and premium payments are provided as a result. Ratepayers should not pay for these premium resources if the priority electric grid need is no longer present. Further, sufficient revenue certainty will be available to DLM resources participating in the long-term resource procurement described above.

Finally, the Roadmap recommended that the utilities develop an orderly transition for DLM resources participating in Tier 2 locations where a Tier 2 circuit designation is superseded by an NWA procurement. Previously, when utilities implement NWA projects, the Commission has approved utility proposals to restrict eligibility to participate in the general tariff DLM programs, and has instead required demand response (DR) resources to participate in the NWA-specific DR program offering instead. Due to the annual nature of DLM program participation, this has not previously posed a significant concern, but must be addressed with longer-term contracts. These longer-term DLM designations require consideration of how these resources should be integrated into the NWA project, especially since an NWA project may require load relief during different time periods than the existing Commercial System Relief Program (CSRP) or Distribution Load Relief Program (DLRP) event call windows. The electric IOUs are directed to further evaluate this issue, and report on their findings and proposed operational procedures as part of their annual DLM program evaluation for 2019.

The Commission rejects Sunrun's request to adopt a tariff-based DR procurement approach for BTM solar plus energy storage, and make residential and NEM customers eligible to participate in DLM programs. Allowing customers to participate in both the NEM or the Value Stack and DLM programs would result in a double-payment for the same benefit stream. DLM programs are justified, and incentive payments for performance in such programs are designed, based on a benefit-cost analysis which includes the value of avoided utility infrastructure, avoided energy payments during demand response events, and environmental benefits. Many of these same benefit streams are already included as part of the Value Stack methodology, and participating customers would receive payment for these benefits twice if compensated through both the Value Stack and DLM programs.

The Commission approves EnergyNest's requests that the definition of energy storage system should be broad enough to include high-grade, heat-based thermal energy storage. As described by EnergyNest, its thermal energy storage technology could provide additional electric generation as part of a DR event call by increasing the usual production of a bottom-cycling combined heat and power (CHP) facility during an event.[38] Pursuant to PSL §74, a qualified energy storage system includes a commercially available thermal process technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy.[39] Provided that use of such technology results in a measurable deviation from the customer's usual baseline load during an event, as discussed above, there is no reason not to allow these technologies to participate in DLM programs.

[38] A bottom-cycling CHP facility is defined as a process by which waste heat is converted to useful electrical energy, contrasting a top-cycle CHP facility where waste heat from electrical generation is used by the facility.

[39] PSL §74(1).

III. Utility Roles

A. Earnings Adjustment Mechanisms

Roadmap Recommendations

The Roadmap recommends that Earnings Adjustment Mechanisms (EAMs) be universally applicable to all utilities so that they have incentives to consider resources like energy storage to reduce overall ratepayer costs. Load factor, in particular, is recommended as a basis for an EAM that could be effective in helping incentivize deployment of energy storage and other DER. Storage is uniquely qualified to improve load factors, as it increases off-peak load and decreases peak load, and can make the most significant improvement to load factor per unit of any technology, according to the Roadmap. The Roadmap recommends the creation of a new EAM for each utility that incentivizes the improvement of the distribution system load factor, calculated by percentage improvement in load factor. The incentive opportunity available should, according to the Roadmap, be determined based on a share of the overall ratepayer benefits to be provided by the actions.

To mitigate what could become a reverse incentive to increase off-peak load to improve load factors, the Roadmap recommends that the EAM could mandate that a peak-reducing technology be deployed for this solution and off-peak energy usage may not increase more than a defined percent for every percentage of load factor improvement. To effectuate this recommendation, the Roadmap recommends that each IOU propose a load factor EAM in its next rate case filing.

Comments

Most commenters agree with the Roadmap recommendations, although others recommend caution in order to avoid double counting in EAMs. EnergyNest comments that the monetary value of EAMs should be symmetrical regarding valuing peak curtailment against off-peak consumption. Joint Utilities recommend that new EAMs that target specific DER needs be considered, and suggest establishment of an EAM focused on a localized load factor. NY-BEST supports a distribution-system-wide load factor and other EAMs that specifically include energy storage. GridPolicy, Inc., on behalf of Plus Power (Plus Power) Hydrostor supports EAM metrics that encourage the IOUs to invest in energy storage, but expresses concern that the suggested load factor metric may not be the correct measure since DR can also be used to reduce load factor. Joint Utilities recommend that the Commission allow utility ownership opportunities for energy storage.

The City and Department of State Utility Intervention Unit (UIU) state concerns about the potential for duplicate incentives between the load factor EAMs and other incentives. They refer to Con Edison and Central Hudson programs which count incremental installations of storage towards their DER Utilization EAMS. If either proceeds to also establish load factor reduction EAMs, they maintain that it could lead to duplicate incentives to shareholders in excess of the net benefits provided by these resources. UIU also recommends that the Commission deny utility requests to propose EAMs outside of rate cases because EAMs should be considered in light of the total revenue required by an IOU.

Determination

The REV initiative focuses on incentivizing utility behavior to achieve the State's policy goals by allowing additional revenue opportunities to be earned based on predetermined outcomes. Several EAMs have already been established for New York utilities in individual rate cases, although EAMs used to encourage technologies like storage deployment have not been used uniformly. Performance incentives have been a fixture of the Commission's regulatory strategy for years. The goal of EAMs is to encourage achievement of policy objectives while lowering costs to ratepayers. The financial details of EAMs are developed in rate proceedings because the relative weight of each EAM will vary by utility based on its potential value within the service territory, the capabilities of the utility, and the unique financial situation of each utility.[40] During a rate case, proposals for the size of incentives will be evaluated within the larger picture of how the incentives impact the overall financial picture of the utility, and the full picture of earning opportunities available to it.

The Roadmap recommends the creation of a new EAM for each utility that incentivizes the improvement of the distribution system load factor, calculated by percentage improvement in load factor. One of the most important objectives of REV is improving overall system efficiency, since it will reduce the need for bulk power and transmission and distribution investment, and since it incentivizes technologies like energy storage that can charge during off-peak hours and discharge during peak times. Peak reductions will also reduce the marginal rates of CO_2 emissions from the electric grid.

The Commission has authorized, during rate cases, various EAMs intended to incentivize different outcomes, including system efficiency. The Commission agrees with the Roadmap's recommendation to require each utility to propose an EAM in its next rate case filing that addresses system efficiency. However, as Plus Power noted in their comments, the suggested load factor metric may not be the correct measure

[40] Case 14-M-0101, supra, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016) (REV Track Two Order).

since DR can equally be used to reduce load factor. Rather than a metric limited to load factor, we will adopt a system efficiency EAM oriented toward both peak reduction and load factor improvement with due care to avoid unintended consequences such as undesirable load increases that run counter to the objectives of State energy policy. Load factor is an important indicator of system efficiency since it means that total system costs are spread across a larger number of sales units, but it should not be the only metric. Many desirable efficiency measures may have the effect of reducing load factor.

Where one does not already exist, each IOU shall propose in its next rate case a system efficiency target that includes both peak reduction and load factor that are appropriate for its territory. Individual utility targets may be either annual or cumulative, with milestones, taking into account relevant benchmarks including peak reduction potential studies and targets established in other jurisdictions.[41] Peak reduction targets should establish either a specific MW objective for system peak or a percentage reduction from a defined MW amount (e.g., percent reduction below a historical reference year). Both peak reduction and load factor improvement targets should be ambitious in size to encourage a portfolio approach beyond conventional programs. Targets and awards should be established on a graduated basis that encompasses both moderate levels of achievement and superior results. Because targets will be tied to customer savings, positive adjustments will be used, with the size of the adjustment graduated to the extent of achievement. Proposals by each IOU should include:

1) Peak reduction targets;

[41] REV Track Two Order, p. 75.

2) Load factor targets;
3) Weather normalization factors;
4) Description of methods and budgets proposed to achieve targets;
5) Delineation of bulk system peak targets from distribution system or circuit targets, with an explanation of how the program will optimize peak reduction across these systems, and how this delineation affects system peak coincident versus non-coincident reductions;
6) A business case for the defined strategy, grounded in the BCA framework where appropriate;
7) A demonstration of how peak reduction and load factor values, obtained through efforts of the distribution utility, will be monetized to benefit customers of that utility including a comparison of the EAM approach to others, with respect to their efficiency as uses of ratepayer funds; and,
8) A proposed shareholder incentive based on: a portion of estimated customer savings; and a market diversity component ensuring that a reasonable number of market participants are involved in implementation.[42]

B. <u>Investor Owned Utility Ownership</u>

<u>Roadmap Recommendations</u>

Competitive ownership of energy storage, and of DER in general, is core to REV principles, and therefore the existing limitations on utility ownership of energy storage should be maintained if possible, according to the Roadmap. The Roadmap noted, however, that recent proposals by the NYISO to subject

[42] REV Track Two Order, p. 75-76.

energy storage resources in mitigated capacity zones to buyer-side mitigation (BSM) measures could result in inappropriate barriers to entry.[43] Moreover, it observed that this outcome would inappropriately inhibit resources that lack the incentive or ability to exercise market power from accessing the wholesale capacity markets. If this outcome occurs, the Roadmap recommends that the Commission reconsider whether utility ownership of energy storage could be a necessary option.

Comments

ACE NY, AEMA, Borrego, GI Energy, Independent Power Producers of New York, Inc. (IPPNY), NPS, NY-BEST, Sunrun and Enel Group support Staff's recommendations on competitive procurement and third-party ownership of energy storage. Hydrostor recommends the reevaluation of the rules governing utility ownership of energy storage, claiming IOUs understand long-term needs of their customers and suggests IOUs should be eligible to own energy storage. Joint Utilities comment that utility ownership of energy storage should be explored, and that targeted utility investments in energy storage can be constructed to benefit the system and customers. O'Connell Electric disagrees with allowing utility ownership of energy storage if markets fail. SEIA suggests that should the market fail, an exploration of whether regulatory barriers need to be removed should be initiated. GI Energy commented that delivery tariff treatment for utility owned FTM energy storage is not equal to 3rd party-owned FTM energy storage delivery tariff treatment.

[43] See NYISO Presentation: Capacity Market Rules for Energy Storage Resources (May 23, 2018) available at: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2018-05-23/Initial percent20ESR percent20Capacitypercent20Model.pdf.

Determination

Utility ownership of storage technologies has garnered significant Commission interest because of the technology's ability to be integrated into electric grid architecture, to be used for reliability, and to enable the optimal deployment of other distributed resources. The Commission elaborated on this issue in the Order Adopting Regulatory Policy Framework and Implementation Plan (REV Framework Order), noting that for energy storage resources "that are on the utility's system and will be used to support and enhance reliable system operations," utility ownership and operation is permissible.[44] The Commission noted that the application of energy storage technology by the utility should be permitted without the need for a market power analysis. With respect to energy storage resources at the customer location, the Commission made clear that utility ownership should not be necessary.

In the REV Framework Order, the Commission also delineated the circumstances in which utility ownership would be considered, including where: (1) procurement of DER has been solicited to meet a system need, and a utility has demonstrated that competitive alternatives proposed by non-utility parties are clearly inadequate or more costly than a traditional utility infrastructure alternative; (2) a project consists of energy storage integrated into distribution system architecture; (3) a project will enable low or moderate income residential customers to benefit from DERs where markets are not likely to satisfy the need; or (4) a project is being sponsored for demonstration

[44] Case 14-M-0101, supra, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015)(REV Framework Order), p. 69.

purposes.[45] The Commission sees no compelling reason to modify utility ownership of energy storage system rules at this time.

Most commenters are also in agreement that no changes should be made to the Commission's policy on utility ownership, although others like the Enel Group recommend stronger prohibitions against utility ownership and the Joint Utilities and Hydrostor recommend a loosening of the restrictions. As part of their Distributed System Implementation Plan (DSIP) filings and rate plans, utilities are required to develop information on optimal locations and levels of energy storage, either on the system or behind the customer's meter. These REV planning activities will support a greater understanding of how energy storage that is used strategically on the electric grid can support greater penetration of intermittent renewable resources without compromising system reliability.

The IOU's demonstration projects in which the Commission authorized specific utility ownership of energy storage projects, provides helpful guidance to both utilities and others in how best to use these resources under various use cases. For BTM energy storage, the Commission finds no compelling reason to modify its stated preference for third-parties to develop these projects. Even in the case of electric grid-connected energy storage, utility ownership will be limited to compensating for failures in the marketplace and other specifically delineated situations. As was suggested in the Roadmap, if the NYISO market participation rules inappropriately apply BSM to energy storage resources, as presently contemplated, the Commission's current framework would likely allow the utility to support energy storage deployments that enhance the system value in a manner that provides benefits in

[45] REV Framework Order, p. 70.

excess of costs. If required, that support, under the market failure reasoning, may include utility ownership of energy storage resources.

C. Facilitating NWA Projects on Utility-Owned Land

Roadmap Recommendations

According to the Roadmap, developers need more information on potential interconnection costs and the availability of utilizing utility-owned land for NWAs prior to bidding. Identifying suitable utility land and infrastructure can reduce NWA costs and implementation time, according to the Roadmap. Inventorying and valuing these resources will accelerate the process and may enable better solutions, according to the Roadmap. It was therefore suggested that IOUs should be directed to inventory and estimate the fair-market value of unused utility land near NWA-eligible areas, considering the IOU's opportunity cost of the property and future planning needs. In addition, it proposed that IOUs should calculate the expected range of interconnection costs for non-binding planning purposes for DER situated on utility land near any proposed NWA. Similarly, it asserted that utilities should provide guidance on local situations that may have a substantial impact on interconnection costs and can reasonably be anticipated. Alternatively, utilities could indicate that interconnection costs will be borne by them and considered in calculating the BCA for the project, which would eliminate the need for developers to estimate these costs.

Comments

GI Energy, NY-BEST, GlidePath Development, LLC (GlidePath), and Hydrostor support the Roadmap recommendations. GlidePath further suggests that the Commission adopt a form lease for utilities to use when making land available for NWAs. Hydrostor suggests increasing utility transparency regarding what substation would address current and forecasted needs. SEIA comments that using NWA solicitations to procure energy storage can pose significant limitations on developers, forcing them to respond to market signals from utilities that are not known ahead of time. Joint Utilities comment that they support exploring alternative business models for Non-Wires Solutions (NWS), are open to the use of utility-owned land for NWSs, and note that any interconnection estimate would be too broad without project details. They also oppose having ratepayers pay interconnection costs because it would favor energy storage over other technologies.

Determination

The Commission adopts the Roadmap’s recommendations to more effectively facilitate NWA projects on IOU property. Ratepayers have paid for any suitable, unused, and undedicated land in a utility service territory, so such assets should be tabulated, inventoried, and utilized to the extent practicable. Therefore, the Commission directs the electric IOUs to inventory suitable, unused, and undedicated utility land by July 1, 2019, and establish a mechanism for the standardized valuation of unused utility land that would be included in utility BCA handbooks.

In addition, NWAs should include estimates of the fair-market value of suitable, unused, and undedicated utility land near NWA-eligible areas, and estimates of interconnection costs to the greatest extent possible, or indicate that such costs will be borne by the utility and included as a cost in the BCA calculation. Utilities are in the best position to undertake such an evaluation, and will allow bidders to make more accurate NWA proposals by, among other things, reducing the risk premiums applied to bids due to uncertain future costs. At this time, the Commission will not require a standardized lease agreement for utility-owned land as GlidePath suggests, but such leases and the fair-market value of the land shall be reviewed by Staff in any proposed NWA.

D. Optionality in the IOU Benefit-Cost Analysis Roadmap Recommendations

According to the Roadmap, the Commission's BCA framework relies upon deterministic net present value (NPV) calculations.[46] Projects that appear to be higher cost on a deterministic basis may be the lower-cost option when risk and uncertainty of future conditions are accounted for. As a result, many projects that could benefit both utilities and ratepayers may not be selected because they cannot pass existing deterministic BCA tests. By contrast, real option analysis incorporates uncertainty by calculating the value of optionality under a variety of circumstances and considers the additional information available after an investment has been made. According to the Roadmap, real option analysis does not replace NPV, but rather augments NPV in situations where: 1) the NPV is close to zero; 2) an investment is flexible (i.e., multi-use, modular, or mobile); or 3) information about the future is uncertain.

The Roadmap recommends that utilities should begin development of a standardized framework for identifying when and where optionality should be considered in the context of utility capital investment or NWA procurements – for example, under conditions of high uncertainty or for certain technologies like energy storage that have clear multi-use, modular or mobile applications. It also mentions that IOUs should engage with relevant stakeholders to begin development of a methodology to

[46] Case 14-M-0101, supra, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016).

include in BCA handbooks that details how optionality valuation should be performed and provide examples.

The Roadmap further recommends that utilities should examine potential NWA contracting mechanisms (i.e., options) that capture the value of flexibility while ensuring the necessary revenue and cash flow for third party financing. Likewise, it posits that mechanisms for utilities and vendors sharing an interest in value created beyond the NWA term (i.e., potential bulk market revenues) should be pursued and could be structured as a terminal value or option for utility purchase at the end of the NWA term. In addition, consideration of salvage value or terminal value of assets with remaining useful economic life should be examined. According to the Roadmap, this should include consideration of how the mechanics would work as a commercial matter, how a terminal value could be realized (e.g., does the developer sell to the utility at a pre-agreed price), and how ratepayers would capture such values.

Comments

ESA, GI Energy and Plus Power generally agree with Staff and NYSERDA’s Roadmap recommendations. NY-BEST agrees with the Roadmap’s recommendations, but believes that more direction is required to appropriately capture the value of optionality in the BCA. The City supports a more nuanced stakeholder process to develop components of the BCA. The UIU is concerned that the peak load and distribution savings anticipated from AMI installed was not included in the BCA calculations in the Roadmap, and seeks confirmation from the Commission that the analysis accounted for these AMI installations. Joint Utilities assert that there are reasons issue-specific modifications to the BCA framework should not be made in isolation without consideration of how changes impact other technologies and other aspects of the framework, although they can see merit in considering the Roadmap’s recommendations.

Determination

As the Roadmap explains, energy storage systems are characterized by their flexibility in terms of modularity, potential multi-use applications, and in some cases mobility. This flexibility is known as optionality in capital planning, and, given the uncertainties in energy price and demand forecasts and the changing needs of the electric system, the Commission recognizes its great value to IOUs. Because additional work is needed regarding optionality, the Commission declines to act at this time. Instead, the Commission will continue to review the utility DSIP filings and their related BCA Handbooks, and direct appropriate action in the DSIP proceeding. The Commission is accepting comments regarding the DSIP filings and BCA Handbooks through December 19, 2018.[47]

IV. Direct Procurement

A. IOU Procurement Through NWAs

Roadmap Recommendations

The Roadmap recommends that utilities expand the scope of NWA opportunities to include the consideration of expanded DER portfolios that will reduce their customers’ total bills. Specifically, for each NWA identified, Staff and NYSERDA recommend that the IOUs examine the potential to procure additional MW of energy storage that would be operated specifically to decrease the system peak load of the utility’s full-service customers or the NYISO zone, thereby cost-effectively reducing customers’ total bills. The Roadmap also recommends that IOU request-for-proposals (RFPs) for NWAs should specifically cite the intent for resources to provide services

[47] Case 16-M-0411, In the Matter of Distributed System Implementation Plans, Notice Regarding Submission of Comments (issued August 30, 2018).

to NYISO markets when the energy storage asset is not needed for distribution system and system peak relief.

Additionally, the Roadmap mentions that when examining the location of an NWA, the utility should identify whether an existing peaking power plant or unit resides in that location interconnected at the appropriate voltage level to allow the NWA solution to also meet peaker needs, including local reliability for contingency purposes. Doing so may offer the opportunity to leverage the existing footprint of the peaker plant or unit and interconnection point more cost-effectively, according to the Roadmap.

The Roadmap also recommends that NYSERDA work with the IOUs to determine how a market acceleration bridging mechanism can be integrated into NWAs to enable these expanded NWA services to be deployed more quickly, so that a minimum of 100 MW of energy storage is deployed to meet expanded NWA services. A fixed capacity payment was suggested as part of the consideration in this approach for the term of the NWA, with a fixed value for the capacity based on a discount of forecasted zonal capacity prices so that ratepayers receive a benefit from what otherwise is expected to be the cost for that capacity. In this manner, developers would receive bankable contracted revenues in return for performance, and ratepayers would receive any upside potential should capacity prices rise higher than forecasted, according to the Roadmap.

Comments

ESA, NY-BEST, and GI Energy generally support the recommendations regarding NWAs. AEMA comments that the current NWA procurement process could benefit from increases in transparency and reporting, and recommends that the Commission not create a program that is too prescriptive. ESA also cautions against making participation in the NWA solicitation contingent on approval to participate in the NYISO market, and urges the Commission to provide flexibility by facilitating multiple opportunities for storage assets to secure payments for values provided. GlidePath recommends that the Commission closely monitor all NWA solicitations to ensure IOUs are not limiting the viability of independently-owned projects. KCE encourages the State to continue to define the value attributes that are needed and for the utilities to contract for just those value attributes. LIPA believes that a potential alternative to direct utility procurements would be for NYSERDA to centrally procure. NYPA suggests the contract term should be for at least seven years, if not 10-20 years, for an NWA, and that a "prequalification" process be developed in advance of a specific solicitation.

The City suggests that NWA opportunities should be limited to solutions that could be operationally effective as traditional infrastructure solutions but with lower costs. In its reply comments, Enel Group recommends that the NWA RFP detail the cost of traditional solutions and supports focus on hosting capacity. NY-BEST makes several suggestions, namely that: the NWA contract terms should be at least for seven years, if not 10-20 years, and align with the amortization period of the avoided costs; each utility should be required to publish a transparent calculation of the benefits and the costs, and a spreadsheet that developers can use to see how their project's services agreement compares; and, utilities incorporate hosting capacity increase into NWA opportunities by combining utilities' hosting capacity analyses with utilities' MCOS analyses to establish both the amount of energy storage and the value of energy storage to incentivize development of energy storage at its most valuable points on the grid. Sunrun notes that NWA offerings should adhere to three main principles, which include a response to clearly articulate the specific needs, conforming with a structure, and consideration of real-world market contexts.

Joint Utilities note the purpose of NWA solicitations is not to guarantee the financeability of projects but rather to assure that distribution system needs are addressed. Ideally, according to the Joint Utilities, the term of the compensation should correspond to the term of the services needed and rendered. They further maintain that any compensation provided to DER must be linked to the value of the anticipated infrastructure deferral and not the DER’s measured life. According to the IOUs, if energy storage or any other form of DER is determined to be part of a cost-effective solution to meet a system need, but the project cannot be financed, the Commission should consider utility ownership.

Determination

Procurements using competitive mechanisms are a cornerstone of Commission policy, and the Roadmap’s recommendations on direct procurement align with this policy. Accordingly, the Commission will incorporate competitive procurement mechanisms as part of energy storage procurements.[48] Storage is an area in which utilities have the continued potential to work with innovative third parties to develop alternative solutions to achieve the NWA and procurement

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[48] As noted above, the Legislature has passed further amendments to PSL §74 that were sent to the Governor for his review on December 11, 2018 (i.e., Bill No. A11099/S8602-A). The Commission recognizes that these amendments would require a competitive procurement process for qualified energy storage resources and incorporates that approach here as an appropriate method to ensure the resulting rates are reasonable.

objectives required by this order at lower ratepayer expense and at a faster pace. Doing so can also create additional value and the opportunity for shared savings. This order seeks to encourage and reward utility achievement of such opportunities.

Under REV, utility NWAs have proven to be a successful mechanism to competitively procure DER solutions that can meet utility needs more cost effectively than traditional solutions. The NWA process to date has proven to be an effective mechanism to reveal the opportunities that exist for DERs to provide the reliability needs of utilities as a cost-effective alternative to traditional infrastructure. The Roadmap recommendations to expand the scope of NWAs to go beyond just the infrastructure deferral and include cost-effective opportunities to reduce customers' total bills, is therefore adopted. In addition, the Commission directs the utilities to continue identifying all potential revenue streams from DER participating in NWA opportunities, including the distribution and wholesale market values and services.

While an expanded NWA scope is expected to open opportunities for storage deployment to meet state goals, they may be limited by the operational needs and constraints of the specific NWA area. Therefore, the Commission finds that an additional utility scale storage procurement is necessary to provide the flexibility for such bulk-level storage applications to provide maximum benefits to ratepayers. The Commission directs electric IOUs to hold competitive procurements for storage resource services. This requirement will give utility grid operators and system planners real world experience using storage to meet system needs at scale.

Such procurements shall take the form of responses to utility Request for Proposals (RFPs) from storage developers to build new storage resources that will be under contract with the utility for operation and dispatch rights. Each IOU shall issue an initial RFP in 2019, and subsequent annual procurements as necessary, to competitively procure dispatch rights for bulk-level energy storage systems sited within their service territory to provide a combination of the following, based on local needs: (1) local reliability services; (2) local load relief; (3) local environmental benefits derived by reducing use of peaking units for contingency purposes; and, (4) wholesale services (e.g. capacity, spinning reserves, frequency regulation). The energy storage asset may be sited anywhere in the utility's transmission and distribution system. Specific locations of higher system value shall be indicated in the RFP. For example, differentiated local reliability or load relief values could be based upon the interconnection level. Similarly, local environmental benefits could be based upon siting at an existing peaking unit plant with corresponding operational requirements.

The RFPs shall request bids for contracts for up to seven years, during which the utility will have full dispatch rights to the asset. This approach provides a fixed revenue stream to the developer and provides the utilities experience operating as a Distribution System Platform (DSP) provider with direct experience dispatching storage to maximize benefits to the distribution system and wholesale market. The Commission expects that proposals may include revenue sharing mechanisms in exchange for a reduced contract payment, or some other approach to the sharing of risks and rewards. The storage asset shall remain the property of the developer. After the contract term, the utility and developer may negotiate a new contract, the utility could continue to perform dispatch services for a fee, the developer could sell directly into the wholesale market, or another reasonable path forward may be identified.

Each utility is required to procure a minimum amount of storage to be operational by December 31, 2022, with Con Edison required to procure at least 300 MW and each of the other electric IOUs required to procure at least 10 MW each, provided that bids do not exceed a utility-specific defined ceiling.[49] The utilities shall amortize and recover the contract costs over the term of the contract. These costs shall be recovered from all delivery customers in the same manner that NWA program costs are recovered at each utility. The IOUs shall account for their actual wholesale revenues earned from the asset as a benefit for ratepayers in recovering contract costs. To provide an incentive for the utilities to maximize the wholesale revenues of the storage asset, when revenues exceed contract costs on an annual basis, the Commission authorizes revenue sharing of 30 percent to utility shareholders and 70 percent to ratepayers.

NYSERDA shall design the bulk system component of its market acceleration incentive to work in coordination with the utility competitive procurements directed by this order. This market acceleration bridge incentive may compensate for such things as the benefit of accelerating declining storage costs, CO_2 savings (peak/off-peak arbitrage), and local emissions benefits.

Within 60 days of this order, each electric IOU shall submit a compliance filing containing implementation details of the bulk-level procurement and the cost recovery accounting procedures. These compliance filings shall be informed by discussions with Staff, NYSERDA and the Joint Utilities, and it

[49] Due to the competitive nature of these RFPs, the utility-specific ceiling shall not be publicly released.

shall be filed with the Secretary to the Commission for DPS Staff review. Any necessary tariff modifications to allow for the contract cost recovery described above, shall be filed on not less than 30 days' notice, to become effective on a temporary basis on June 1, 2019.

B. NWA Term Extension

Roadmap Recommendations

According to the Roadmap, energy storage systems typically have an expected lifetime of at least 10 years, and other components of the energy storage NWA proposal may have even longer expected lifetimes. This can often exceed the term of some NWAs, introducing significant revenue uncertainty after the NWA period has ended and making it difficult for any form of capital solution to be deployed by a third-party to meet the NWA need. The Roadmap recommends that NWA contracts should include clearly-defined conditions for the extension of an NWA's term when a proposed NWA DER asset has a life expectancy greater than the original NWA term. The Roadmap suggests that the RFP should either include specific conditions or request respondents to provide terms by which this would be handled. Developers should be explicitly allowed to maintain the interconnection after the term of an NWA that ceases to provide contracted distribution services and should be allowed to continue to use that asset to provide other non-NWA services.

Comments

AEMA, GI Energy and Hydrostor agree with the Roadmap's recommendations, and Hydrostor further supports extending contracts to a minimum of 30 years. NYPA suggests expanding the NWA project scope by allowing the resource to access wholesale market revenues, and recommends that the Commission initiate a stakeholder process to develop protocols on coordinated dispatch of energy storage services and identify specific data needed to define NWA needs and how to access that data.

Determination

The Roadmap recommendations are reasonable and are therefore adopted. NWA contracts shall include clearly-defined conditions for the extension of an NWA's term, and developers shall be explicitly allowed to maintain the interconnection after the term of an NWA and allowed to continue to use that asset to provide other non-NWA services. NWA solicitations shall include estimated interconnection costs, or indicate that interconnection upgrade costs will be borne by the utility and included as a cost in the BCA calculation. The IOUs shall incorporate all of the Roadmap's recommendations on this issue into future NWA RFPs.

C. Large Scale Renewable Procurement

Roadmap Recommendations

The Roadmap asserts that the manner in which energy storage is bid and participates under the CES program is an area that Staff should continue to investigate based on procurement results. It also suggests that co-locating energy storage with a renewable generator is not currently practical due to NYISO market rules. If a developer includes a renewable generator with co-located storage to improve dispatchability, it would lose its favorable NYISO treatment as an Intermittent Generator, as discussed below under the Wholesale Market Actions section.

Comments

Most parties including Fuel Cell and Hydrogen Energy Association (FCHEA), GI Energy, Glidepath, Hydrostor, and the Enel Group support the pairing of energy storage with large-scale renewables procurements. Glidepath argues that developers should be able to bid in new or existing storage and not require that storage only be bid in jointly with new proposed resources.

Hydrostor and Enel Group also state that standalone energy storage should be eligible to receive additional benefits, with Hydrostor supporting Renewable Energy Credit (REC) eligibility for their output and Enel Group favoring creation of a Clean Power Certificate (CPC) for generation created during peak periods.

NY-BEST states that the six-point adder for storage is insufficient due to its non-monetizable character, and adds that higher compensation for "clean hours" generation as done by Arizona Public Service, would provide greater compensation and result in greater storage installations. NY-BEST goes on to call for more in-depth evaluation of energy storage to analyze benefits related to avoidance of curtailment, GHG emissions, local criteria pollutants, and transmission.

Determination

Presently, the criteria under RES procurements gives additional consideration (up to six additional points) to bids committing to develop energy storage with the eligible renewable energy generating facility. Developers can either co-locate the energy storage with the renewable generator or deploy it elsewhere on the electric grid where it is most valuable, and bids may be submitted as a single paired package, both with and without energy storage.

New York's RES encourages energy storage development in conjunction with intermittent renewable generation. The aim is to promote the addition of flexible energy storage assets in the bulk system as the State increases the amount of intermittent resources. The flexibility of energy storage is expected to allow for both greater renewable energy penetration in the electric grid and provide operational flexibility to make generators and the electric grid run more efficiently. One of the key structural components of participation by energy storage in RES procurements is adequate, long-term compensation for the resources. For example, some storage assets such as certain compressed air systems have 30 years of operability and need similar revenue streams to become viable.

The Commission instructs NYSERDA, in consultation with Staff, to continue evaluating whether refinements to the RES procurements should be required, so as to optimize operational flexibility of energy storage that improves system benefits. NYSERDA shall report back to Staff. Further discussion of this issue is addressed in the Clean Peak Actions and Wholesale Market Actions discussions below.

D. New York State "Leading by Example"

Roadmap Recommendations

The Roadmap recommends that the State continue its leadership as an early adopter of sustainable energy solutions by requiring that Office of General Services (OGS), State Education Department, Department of Corrections, and the State University of New York (SUNY) modify, by the end of 2018, any existing RFPs for energy efficiency and renewable energy to explicitly include energy storage as a standalone or paired solution to meet their efficiency, sustainability and resiliency goals. Any new RFPs should also include this explicit requirement.

In addition, NYPA is already working with a variety of customers to pursue energy storage projects, and the Roadmap recommends that NYPA continue in its role as a leader in early adoption of sustainable energy solutions, including energy storage, and should work with key State partners to ensure that this opportunity is maximized. Specifically, NYPA should work with customers, including State and municipal facilities across New York, as well as its own utility asset sites, to accelerate the adoption of energy storage, according to the Roadmap.

Comments

NY-BEST supports a coordinated effort among NYPA, OGS, and SUNY to deploy energy storage, and states how the agencies represent an untapped market for storage and can be a proving ground for developing rules and strategies for integrating storage with distribution utilities and NYISO markets. While NYPA is a willing partner in this effort, it warns that its public-sector customers cannot support additional incentives without reasonable payback timeframes. NPS suggests that storage could provide additional electric grid resiliency and also raises the potential for added incentives for microgrids which incorporate storage to provide a community relief element.

Climate Change Mitigation Technologies LLC (CCMT) identifies a specific location for storage, the No. 7 Flushing Line in which wayside storage could be implemented, with the eventual goal of full storage deployment within the MTA-NYC subway system. O'Connell Electric recommends that public-sector partners utilize purchased power agreements and performance contracts in securing energy storage, while it recognizes that the private sector can take advantage of tax credits and accelerated depreciation in deploying energy storage. Greenlots notes that there is an opportunity for energy storage to more adequately address storage-integrated electric vehicle (EV) charging, and that it expects to see a future trend of co-locating EV charging infrastructure at already-existing storage sites.

Determination

Achieving the expected deployment levels of storage in New York will require the efforts of many entities, including State agencies and affiliates. The Commission urges these entities to continue their work to achieve these goals. The State and municipal agencies and authorities consume large quantities of the electric used in the State. In New York City, for example, city buildings including City University of New York (CUNY) campuses consume 8 percent of the total electricity used. Executive Order 166 calls upon State agencies to demonstrate their contributions to the State's greenhouse gas reduction goals of 40 percent by 2030 and 80 percent by 2050. Building upon this Executive Order, in May 2018 Governor Cuomo called upon all agencies to develop energy sustainability master plans, benchmark and disclose building energy performance, and advance zero energy new construction.

State agencies and authorities can serve as early adopters in deploying new DER solutions, championing new business models and procurement approaches, and enabling greater scale by deploying solutions across a portfolio of buildings. The Commission acknowledges the work already underway by the state and local agencies and authorities including SUNY, NYPA, and LIPA. As described in the Roadmap, DPS Staff and NYSERDA identified significant opportunities to use energy storage and other DER solutions to reduce the electric impact of state and municipal buildings on the electric system, time shift renewable generation to periods when it is most valuable, and achieve greater resiliency during electric grid outages.

Several of the actions ordered by the Commission will help to advance the project economics for these use cases, including by providing more granular time and location differentiation for electric delivery costs and exported electricity's value. The Commission directs NYSERDA to continue to work with State agencies to help inform their procurement decisions in furtherance of Executive Order 166 and their own energy or environmental policies.

V. Market Acceleration Bridge Incentive

Roadmap Recommendations

In order to accelerate cost declines and increase the confidence and experience of customers and of system operators by speeding deploying and utilizing energy storage assets today, the Roadmap recommends an investment in the form of bridge incentive funding. A bridge incentive is a proven approach, successfully applied in NY-Sun, that provides revenue certainty to the market for a defined duration and level of deployment. Such an approach provides that funding at levels of "missing money" to enable markets to work in the near term, and tapers this level of missing money predictably and transparently so as costs decline and values improve, to arrive at a point of cost reduction and economic deployment where incentives are no longer needed or appropriate. As in the case of NY-Sun, the incentive levels can be differentiated, by market sector and use case. It is a mechanism that constitutes a cost-contained and market aligned investment that achieves accelerated cost reduction and market readiness, and is justified by the level of energy and economic benefits so achieved.

The Roadmap proposed that NYSERDA work with the IOUs and LIPA to develop an energy storage market acceleration bridge incentive using funds already approved by the Commission. This first stage would begin with a NYSERDA-initiated storage adder within NY Sun for paired Photovoltaic (PV)-plus-Storage. The Roadmap further recommended that this initial stage be timely followed by a program for unpaired storage systems, and that NYSERDA, IOUs, and LIPA engage with stakeholders during the formal public comment period to establish the framework for how such bridge incentives would be deployed. The amount estimated and recommended in the Roadmap to be appropriate for such an incentive scheme was $350 million. The Roadmap further estimated that such an incentive program could support a minimum of 500 MW of customer-sited and distribution/bulk sited storage by 2021–2022, achieving deployment of over one-third of the 1,500 MW target for 2025 and establishing critical foundations for a self-sustaining market

Finally, the Roadmap recommends expanding the existing NYSERDA value stacking solicitation (PON 3541), which can fund use cases that are not monetizable or possible today, in order to expand bulk system projects that could be monetizable in the future under the NYISO's DER Roadmap.

Comments

Almost all parties support a market bridge incentive, with various caveats. Borrego supports the incentive based on storage capacity and prefers the incentive be split into two incentives, one for standalone systems and one with PV paired with solar. ETS voices support for the multifamily and commercial programs, and stresses the need for return on investment (ROI) standards. ESA comments that incentive participants not be precluded from other programs. Glidepath stresses the need for incentives to provide market certainty, while Hydrostor would like them to fund storage-specific RECs. IR stresses the need for a cost-effectiveness test and project timelines.

The Joint Utilities recommend that incentives be targeted to the distribution and bulk systems with criteria established for transparent quantifiable customer benefits. RCE states that most funding should be for standalone projects because there are other incentives for paired projects. Plus Power and IR recommend that replacement of dirty downstate peaker plants be prioritized. LIPA stresses the need for storage in the most valuable locations using a central procurement model. NRDC states that funding should be aimed chiefly at the bulk system while maximizing emissions reductions because there are no incentives for bulk resources to be sited in a manner that reduces emissions. NY-BEST recommends a declining incentive structure similar to the NY-SUN program, and stresses the need for a reasonable application process with required timelines to commence operation depending on system size and application.

While NYCEJA supports the bridge incentives, it notes that the current prioritization of market opportunities for storage risks precluding 40 percent of New York residents who are in the low-to-moderate income level. NYCEJA refers to its comments submitted in the E Value VDER subgroup comments, and stresses that a portion of the proposed $350 million be directed for pilot projects to address market barriers in environmental justice communities. NYPA stresses that the bridge incentive should be available to all utility customers including NYPA customers because electric grid-tied storage benefits all customers. O'Connell Electric states that the ROI for proposed projects within similar customer classes be equal regardless of physical location, and that a lesser incentive would be required for areas with high capacity charges. SEIA stresses the need to implement the program quickly to take advantage of the federal Investment Tax Credit (ITC) before its expiration at the end of 2019.

Stem focuses on the need to learn from California's Self Generation Incentive Program (SGIP) and adopt the successful portions of it while avoiding the negative aspects of it, including its operational requirements to provide electric grid and societal benefits which result in a "messy hybrid" situation. Sunrun and NYC support the bridge incentive as an adder to existing solar incentives, while Sustainable Westchester (SW) recommends basing the incentive on storage discharge capacity. Enel stresses the need to require financial assurances and milestone reporting from project developers to reduce speculative behavior.

Multiple Intervenors opposes the bridge incentives and recommends that any uncommitted funds being considered for the incentive be returned to customers or used to reduce future Clean Energy Fund (CEF) collections. It also stresses the need to ensure that existing policies, rates, and tariffs do not impede energy storage. Greenlots notes that "smart" or managed one-way charging has the same potential value as non-export charging, and that the incentives and value streams should recognize this fact.

Regarding specific incentive levels, recommendations include: Borrego – standalone at $370/kWh; EnergyNest - $150/kWh; KCE - declining incentive between 2019 and 2022 on a $/kW basis; NY-BEST – range of $250 - $350/kWh based on system size; and Stem and IR – begin at greater than $350/kWh which is California SGIP's initial rate with declining amounts in future years. O'Connell Electric stresses the need for incentives on a geographical location/utility rate structure basis.

Determination

The Commission finds that a bridging mechanism to a scalable and self-sustaining market can result in significant beneficial impacts and cost savings to New York's electric customers, especially with respect to the near-term deployment policy supporting 1,500 MW of installed qualifying energy storage systems by 2025. As described in the Roadmap, a bridge incentive could accelerate the cost decline curve by almost two years and save approximately $200 million from the projected cost of deploying 1,500 MW of energy storage by 2025, and more than $400 million from the projected cost of deploying 3,000 MW by 2030. For these reasons, the Commission authorizes an Energy

Storage Market Acceleration Bridge Incentive to by administered by NYSERDA.

This incentive will accelerate qualified energy storage system deployments, cost reduction, value improvement, and the market, consistent with REV principles. Based on the project analytics presented in the Roadmap, party comments, and the PV-plus-Storage incentive already being administered by NYSERDA through the CEF, the Commission authorizes NYSERDA to use previously collected, uncommitted ratepayer funds to fund the Energy Storage Market Acceleration bridge incentives not to exceed $310 million, plus associated administration and program evaluation fees.[50] The Commission notes that NYSERDA is already implementing an Energy Storage Chapter under the Clean Energy Fund Investment Plan for the initial stage addressing PV-plus-Storage that can begin funding these paired projects with already approved CEF funds.[51] This timing recognizes the pending step down of the ITC, which provides favorable tax treatment for certain renewable technologies including such paired PV-plus-Solar systems. This Investment Plan aims to deploy $40 million over three years. The Commission expects that this level of funding, combined with NYSERDA incentive initiatives on Long Island, will result in the deployment of at least 500 MW of storage by 2022.

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[50] These uncommitted funds were collected through the Renewable Portfolio Standard (RPS) to achieve the goal of at least 25 percent of the electricity used in New York State being provided by renewable resources. The Commission's stated purpose for RPS funds, to provide incentives to increase the percentage of electricity used by retail customers in the state that is derived from renewable resources, is advanced by this Energy Storage Market Acceleration Bridge Incentive.

[51] Matter 16-00681, <u>In the Matter of the Clean Energy Fund Investment Plan</u>, Clean Energy Fund Investment Plan: Energy Storage Chapter (filed September 6, 2018).

Within 60 days of the issuance of this order, NYSERDA shall file an implementation plan that sets forth the program goals and implementation strategies that will deploy the Energy Storage Market Acceleration Bridge Incentive funds. This plan shall accelerate energy storage deployment at the electric IOU customer sites, as well as sited in each IOUs distribution and bulk systems, including when paired with on-site generation. This market acceleration bridge incentive may compensate for such things as: storage cost decline acceleration benefits; CO_2 savings (peak/off-peak arbitrage); local emissions benefits; hosting capacity improvements; reduced renewable curtailment; and/or, system resilience. The Commission expects NYSERDA to reduce the market acceleration incentive over time to align with and encourage energy storage cost declines. In doing so, the implementation plan should seek to maximize the effectiveness of the incentive dollars by prioritizing market segments that have the fastest rate of cost decline, thereby more quickly enabling future storage deployment without incentives.

NYSERDA shall work with Staff and the electric IOUs in developing and deploying bridge incentives to ensure coordination and provide clear and consistent market signals. Additional coordination with other existing storage development initiatives and procurements, such as those being carried out by NYPA, should leverage all available resources to meet the Commission's energy storage goals in the most cost-effective manner. The implementation plan shall be developed in consultation with Staff and include, at a minimum, the following items:

1) Budget details, including the allocation of funds between customer sited, distribution, and bulk use cases;

2) Performance metrics, which will be used to evaluate the program;
3) Identification and prioritization of use cases with the best economics and ability to achieve scale;
4) Incentive details, including incentive levels, adjustment of these incentive levels, and timing, of a scheme designed to accelerate deployment and improve market readiness to enable a self-sustaining market beyond the incentive period;
5) Ongoing planning and coordination details, that will:
   (a) identify and address deployment barriers;
   (b) communicate with market participants including industry, customers, and the financing community; and,
   (c) identify and maximize opportunities to use energy storage to cost effectively address electric system needs; and,
6) Efforts to assist the low-to-moderate income residential community.

In keeping with the Commission's long-held acknowledgement of the value of flexibility when coupled with transparency and accountability,[52] NYSERDA, with Staff's guidance, may reallocate funds within these authorized amounts between customer, distribution, and bulk system use cases based on market learning, adoption, and cost variations in order to ensure that the maximum efficient amount of energy storage is

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[52] Case 03-E-0188, Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard, Order Regarding Renewable Portfolio Standard (issued September 24, 2004), p. 7. See also Case 03-E-0188, supra, Order Approving Implementation Plan, Adopting Clarifications, and Modifying Environmental Disclosure Program (issued April 14, 2005), p. 31.

deployed as market conditions and deployment factors change over time. NYSERDA shall also develop a program manual based upon the approved implementation plan that sets forth specific program provisions and requirements. This manual may be updated as needed, after consultation with Staff.

DPS Staff and NYSERDA shall work with LIPA to facilitate an equivalent set of energy storage market acceleration bridge incentive mechanisms on Long Island. These incentive mechanisms should be consistent with the principles established in this order.

VI. Address Soft Costs

A. Continue to Reduce Soft Costs

Roadmap Recommendations

The Roadmap estimates that the State can drive down soft costs by up to $50 per kWh for a distribution/bulk sited system, and up to $150 per kWh for a customer sited system by 2025 compared to 2017-2018 costs. These costs can comprise up to 20 percent or more of the total installed cost of an energy storage system. Specifically, soft costs related to permitting, customer acquisition, and interconnection could be reduced 50 percent to 75 percent below 2017-2018 levels by 2025. These achievements would be enabled by the industry at scale, as well as by strategic actions. In addition, over this timeframe, hardware costs may decline 50 percent or more, and engineering and construction costs may decline by 40 percent or more as installations become more easily replicable, according to the Roadmap.

In addition to expanding this technical assistance to permitting agencies across the State during 2018, the Roadmap recommends that NYSERDA engage local communities, such as on Long Island, that are likely to see large amounts of energy storage deployments. Additionally, NYSERDA should add energy storage to the PV Payment In Lieu of Taxes (PILOT) calculator so that local communities can begin preparing for the financial impact these systems could contribute to their tax base without overestimating fiscal benefits.[53]

The Roadmap recommends that LIPA, NYPA, and the IOUs work collaboratively with DPS and NYSERDA to provide anonymized customer-related load data to facilitate targeting of best fit customer profiles for energy storage or other distributed energy solutions to reduce peak load impact on the local electric system in a manner consistent with the data requirements outlined in 2018 DSIP Staff Guidance and in Section 4.5.4 of the Roadmap.[54]

The Roadmap recognizes that NY-BEST has been engaged by NYSERDA to develop and provide educational content and outreach to vendors on energy storage use cases, tariffs, and regulations. This includes maximizing customer economics through standby rates, facilitating participation in DR programs, participating in wholesale markets as opportunities evolve, and reducing interconnection costs. The Roadmap recommends that NYSERDA target developers already working in New York, as well as those not yet operating here, to make them aware of opportunities and business cases for energy storage. This will expand customer choice by increasing the number of developers working in New York and add additional competition to discipline pricing.

As noted in the Roadmap, the New York State Standardized Interconnection Requirements (SIR) were recently

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[53] See PILOT Calculator, available at: https://www.nyserda.ny.gov/-/media/Files/Programs/NYSun/PILOT-Calculator.xlsm.

[54] Case 16-M-0411, supra, DPS Whitepaper Guidance for 2018 DSIP Updates (filed May 29, 2018).

amended to include standalone energy storage, raise the maximum threshold to 5 MW, and apply this threshold for paired solar and storage based on the amount of power that the combined system is intended to inject.[55] In order to prevent the potential interconnection bottlenecks that could likely occur in the future as energy storage reaches scale, the Roadmap recommends that the DPS Interconnection Policy and Technical Working Groups (ITWG and IPWG), be required to incorporate standalone and paired energy storage with onsite renewables into their scope. In particular, it is recommended that these working groups should develop a prioritized list of critical issues that must be resolved within the next three years to allow energy storage (standalone or paired) to reach commercial scale. This priority list and the timeline by which resolution would be recommended to DPS Staff would be developed by the first quarter of 2019.

Because certain energy storage technologies may require various types of end-of-life actions that could involve repurposing the equipment, recycling the materials, and/or remediation/reclamation, the Roadmap recommends that NYSERDA and stakeholders continue to establish these end-of-life actions and processes.

The Roadmap envisions that, by the first quarter of 2019, NYSERDA, in coordination with the ITWG and IPWG, would develop a schedule for soliciting bids to research and examine through field demonstrations inverter-based solutions that can adequately limit reverse power flow to avoid the need for additional relays for systems below an established threshold (e.g., 1 MW). Results would be available so that

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[55] Case 18-E-0018, In the Matter of Proposed Amendments to the Standardized Interconnection Requirements for Small Distributed Generators, Order Modifying Standardized Interconnection Requirements (issued April 19, 2018).

recommendations may be considered before the end of 2019. Hosting capacity would be examined from a perspective that considers the dispatchability and control that energy storage can provide to an otherwise-intermittent resource. The Joint Utilities, through the ITWG and IPWG, would work collaboratively with stakeholders to identify possible alternative approaches for increasing hosting capacity. While two interconnection applications – one for energy storage and one for on-site power – may not yet prove a hindrance, the Roadmap seeks to avoid these types of operational inefficiencies. There is a strong desire for integrated capital planning and this should be reflected throughout the manner in which DERs are considered, according to the Roadmap.

Comments

All commenters agreed on the need to reduce soft costs, and refer to different aspects of these costs to support their comments. Borrego and JU agree with the Roadmap's recommendation that the IPWG and ITWG identify and address the most critical issues to be resolved to permit storage to reach commercialization. ETS refers to the need to refine and improve the permitting process, which will encourage further installations, particularly in New York City. Glidepath suggests NYSERDA provide guidance to local officials pertaining to SEQRA that would result in minimizing the need for costly environmental studies, particularly for systems which would not impact the environment. The Enel Group focuses on the difficulty of interconnection and the need for the utilities to have engineering staff available to review and process storage interconnection projects. NY-BEST mentions the lack of knowledge about New York markets by many parties, and recommends appropriate training to address it. O'Connell Electric believes that marketing and customer acquisition do not factor into soft costs, and that the market will develop naturally if incentives are established correctly.

Determination

As the Roadmap indicates, soft costs associated with customer acquisition, siting and permitting, interconnection, and financing are largely driven by factors that can be directly impacted by State action. The Roadmap notes that in 2016, NYSERDA began a multi-year effort under the CEF to begin addressing soft costs, including permitting, customer acquisition, and vendor education on tariffs and market design.

To ensure that these cost declines are achieved, NYSERDA is in the process of examining its existing CEF investment plan to increase the technical assistance resources available in reducing these soft costs, and reallocating already approved funds within this investment plan as deemed necessary.[56] Requested changes to this investment plan may be submitted to Staff at any time. NYSERDAs soft-cost reduction effort shall include assistance in the following areas:

- Energy Storage Siting: NYSERDA shall expand technical assistance available to municipalities to assist permitting agencies across New York in making informed decisions when considering energy storage installations. Model procedures and permitting guides shall be developed while codes and standards continue to evolve. NYSERDA, with assistance as requested from the utilities, shall also proactively engage local communities that are likely to see large amounts of energy storage deployed.

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[56] Matter 16-00681, In the Matter of the Clean Energy Fund Investment Plan, Clean Energy Fund Investment Plan: Energy Storage Chapter (filed September 6, 2018).

- Reducing the cost of site identification and customer acquisition: Critical to siting energy storage is identifying locations in the electric system that can benefit most from its installation. This includes distribution and transmission locations and customer sites. While advanced metering is steadily being deployed to increase the availability of this data, it will take five to ten years before all of the State's non-residential customers have interval data available. Significant progress has already been made in some locations, including by Con Edison in New York City where over 500,000 customers now have advanced meters. This infrastructure shall continue to be prioritized within individual utility rate cases. NYSERDA and the IOUs are ordered to collaborate, as further described in the data section of this order, to develop the necessary data platform and resources that enables a level of data granularity sufficient for developers and customers to deploy energy storage and DERs in locations that can best meet electric system and customer needs. This shall incorporate methods to provide frequent updates to this data and protect customer privacy as previously ordered by the Commission. LIPA and NYPA are requested to work collaboratively with DPS and NYSERDA in this development.
- Clearly explain storage solutions, economics, and market rules: As retail and wholesale rate designs and market rules continue to evolve, it is imperative that developers have the most streamlined access to understanding implications on their business models and product offerings. Similarly, State ratepayers need straightforward tools that can clearly explain energy

storage and other DER solutions, benefits, and economics. In addition to resources provided by NYSERDA, each of the IOUs is directed to identify an ombudsperson who will respond to technical questions on rate design and work with DPS and NYSERDA to address deficiencies or inconsistencies identified in tariffs or IOU tariff implementation that might adversely impact project economics and deployment.

- Interconnection: The most recent version of the SIR includes energy storage system interconnection rules, either stand-alone or paired with on-site renewable generation, up to 5 MW. Additionally, the ITWG and IPWG have continued to work collaboratively with the Joint Utilities, project developers, and other stakeholders to consider energy storage concerns in the context of the interconnection process. The Roadmap recommendations regarding the interconnection process are currently being carried out in the IPWG and ITWG, and the Commission encourages Staff and stakeholders to continue these efforts.
- Increasing confidence in deployed systems and project economics: NYSERDA shall continue to update the DER Portal, which lists all deployed energy storage systems in the State, to make it searchable by use case and type of installation and to include minimum non-proprietary performance information on deployed systems.[57] NYSERDA, including the NYGB, shall collaborate with other financial parties and developers to ensure that financial and performance metrics from case studies are

[57] See NYSERDA DER Integrated Data System, available at: https://der.nyserda.ny.gov/.

collected, validated, and available for review. To make the DER Portal as comprehensive as possible, the IOUs are ordered to provide NYSERDA with non-proprietary performance and financial data on any energy storage projects providing distribution relief, such as NWAs. LIPA and NYPA are also encouraged to provide this information.

- End-of-life considerations: Certain storage technologies may require various types of end-of-life actions which could involve repurposing the equipment, recycling, and/or remediation/reclamation. NYSERDA shall work with the utilities, market participants, local communities, and appropriate State agencies to ensure that appropriate decommissioning and end-of-life actions and processes are developed.
- Accountability and transparency to the market. NYSERDA will engage regularly with stakeholders and market actors to ensure that these forms of assistance are properly prioritized and developed. NYSERDA will also annually report to the market on progress achieved, and on the priorities and goals going forward.

B. Reducing the Cost of Capital

Roadmap Recommendations

NYSERDA should continue to collaborate with NYGB, other financial parties, and developers to ensure that necessary financial and performance metrics from deployed projects are collected, validated, and available for review on the NYSERDA DER Portal, according to the Roadmap. Further, it suggests that NYSERDA should facilitate discussions with Energy Improvement Corporation (EIC) and New York City Energy Efficiency Corporation (NYCEEC) to bring clarity to the developer and customer community around Commercial PACE financing opportunities, with projects being financed by C-PACE by early 2019.

Staff and NYSERDA note that the NYGB has issued a Request for Information (RFI) in conjunction with NYSERDA to further engage and increase active dialogue with energy storage developers and other market participants regarding specific ways in which NYGB can be helpful in financing energy storage projects in New York. The NYGB also plans to issue an RFP to support solar plus storage deployments in conjunction with NYSERDA implementing the Roadmap's recommendation for a PV and storage bridge incentive.

As noted in the Roadmap, NYPA is in the unique position to design, manage, own, and/or provide project finance for energy storage projects deployed at customer sites paired with NYPA generation assets and in the bulk power system. This ability to manage and finance all aspects of a project, according to the Roadmap, should also result in lower costs, especially as it relates to customer acquisition through NYPA's ability to bundle needs into a single RFP. NYPA can also enter energy services contracts that bundle the cost of the energy storage asset into the delivery component of a customer's bill or through a shared savings model. The Roadmap recommends that NYPA work with customers to prioritize competitive procurements that it can issue on behalf of its customers to procure cost-effective energy storage or paired projects. Staff and NYSERDA contend that NYPA should conduct these procurements immediately so that projects can begin construction in 2019 and 2020.

Comments

Most commenters are supportive of reducing capital costs. GI Energy supports a regulatory framework in which energy storage can receive revenue from the NYISO markets while allowing developers to also sell dispatch rights to the local utility. IR adds that establishing PACE financing in localities can provide capital for storage projects and improve energy management in commercial buildings. Multiple Intervenors does not support customer-funded incentives for energy storage, and warns that such incentives could end up favoring the technology.

Determination

As the Roadmap explains, energy storage systems today are largely financed through one of three mechanisms: customer financing, third party capital, or utility financing, with the majority being third-party financed (and largely higher-cost) equity financing. The greater the tenor, amount, and predictability of the earnings streams, the lower the cost of capital. Traditional power generators are able to finance greater portions of project costs because such deals are of large size, which may be syndicated out to investors and subsequently traded in secondary markets, and the market risk associated with wholesale electric and ancillary service prices is well established and considered in project finance modeling. This is not yet the case for energy storage, which lacks scale, precedent, operating history, and standardization.

The Commission aims to reduce the cost of capital for energy storage by reducing uncertainty associated with revenue or benefits, while striking a balance in order to minimize ratepayer exposure to unacceptable and imprudent risk. This includes improvements to the bankability of the VDER Value Stack for exports of renewable energy, changes to retail delivery charges, load relief contracts, NWAs, and wholesale market changes that are recommended.

The early stage of the storage industry’s maturity, combined with the uncertainty in the evolving wholesale market requirements, results in challenges to financing these capital-intensive assets. The utility procurements discussed above can achieve economies of scale and the long-term contract certainty results in lowering the cost of capital as wholesale market rules evolve.

The Commission directs Staff to work with NYSERDA to facilitate discussions with EIC and NYCEEC to bring clarity to the developer and customer community around Commercial PACE financing opportunities. NYPA should continue to pursue procurements on behalf of its customers, as described further in the Lead by Example section.

C. Workforce Development

Roadmap Recommendations

According to the Roadmap, a pipeline of skilled workers is essential to ensure that energy storage employment reaches 30,000 jobs by 2030, from almost 4,000 employed today. The recommendation contained in the Roadmap is that NYSERDA work with the New York Department of Labor, Empire State Development Corporation, and training partners including the SUNY, CUNY, and labor unions. Through an industry partnership approach, these entities should: inventory specific worker skills that will be required by businesses throughout the energy storage supply chain; map required skills to existing training and the existing labor pool to identify gaps and shortages; work with these stakeholders to develop a blueprint that will ensure a talent pipeline of workers with the necessary skills; identify gaps in training infrastructure and capacity in areas such as curriculum, trained trainers, training equipment, job placement initiatives, on-the-job training, internships, apprenticeships, career pathway training, certifications, etc.; and, support disadvantaged workers including youth (18-24), displaced and dislocated workers, women, minorities and veterans.

Comments

All commenting parties agreed on the importance of quality workforce development efforts. While Hydrostor supports the effort to create a labor force of 30,000 in storage related work, it notes that the long-term strategy is not included in the Roadmap. Hydrostor also references how A-CAES systems require full-time employee opportunities that lead to long-term jobs that are not available for other storage mediums such lithium-ion batteries. NYCEJA seeks a multi-sector industry partnership to address supply-chain and workforce needs in the storage industry. Included in the workforce requirements should be requirements for minority and women-owned business enterprises. NYCEJA also comments that populations residing in environmental justice communities including women, formerly incarcerated New York residents, veterans, native Americans, low income individuals, individuals with disabilities, unemployed workers in fossil-based industries, and youth participating in work-training programs are provided the opportunity to reach employment in energy storage efforts.

Determination

No Commission action with respect to workforce development is necessary at this time. By Spring 2019, NYSERDA shall facilitate an industry partnership to develop an inventory of workforce development needs and a blueprint for addressing potential skilled talent shortages. Staff and NYSERDA shall bring forth recommendations that result from this stakeholder effort, if any, for Commission consideration by Fall 2019.

D. Data Access

Roadmap Recommendations

The Roadmap echoes the 2018 DSIP Staff Guidance,[58] suggesting the utilities should increase and improve the customer and distribution system data provided to DER developers and operators.

The Roadmap continued that the following datasets should be made available within 12 months following the order: detailed monthly capacity and production data – actual and forecasted up to 5 years – for existing peaker units with low capacity utilization; and hourly load data – actual and forecasted – for substations that connect the distribution system with the bulk electric system (transmission nodes). The data will inform DER development and operation decisions that can help the utility peak-shave at the right times and locations, thereby lowering the utilities' ICAP tags and creating opportunities for energy storage deployments.

Within six months following the order, all of the utilities would expedite their plans to implement "Green Button Connect My Data" or its equivalent, and should provide synthesized load profiles for customers who are not yet equipped with interval meters. All utilities should expedite their AMI deployments and identify how they are prioritizing the deployment and to what extent "high value customers"[59] are being prioritized. Moreover, the IOUs, NYPA and LIPA should provide NYSERDA with non-proprietary performance and financial data on any energy storage projects providing distribution relief such as NWAs.

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[58] Case 16-M-0411, supra, DPS Staff Whitepaper: Guidance for 2018 DSIP Updates.

[59] According to the Roadmap, examples of high value customers are those with high demand, are under Con Edison's Rider Q or VDER tariff, or who have installed DER or drive electric vehicles.

NYSERDA and DPS should lead coordination efforts with the Joint Utilities, and LIPA to develop and issue a solicitation for a third-party to develop, implement, and maintain a searchable data platform containing both customer and system data useful to developers for planning and developing energy storage and other types of DER. The following schedule is recommended: (1) within six months of the order, determine which entity is leading and issuing the solicitation, refine the specific features and data fields that will be included on the platform, resolve policy decisions including customer privacy, and determine the process for identifying customers, with their consent, to DER providers; DER providers shall also be consulted to maximize the usefulness of the platform; (2) in months 7-12, issue the solicitation, review proposals, and select a vendor; and (3) by month 18, a beta version of the platform should be established with testing underway so that it is available for use by developers by summer 2021. If prioritization of customer types is necessary in initially populating the platform, then demand metered customer data shall be prioritized over mass-market customers.

Comments

The parties generally agree on the importance of access to quality data. Borrego supports increased data transparency and specifically seeks hourly substation load data from utilities with increased granularity over time. IR recommends collaboration between the utilities and NYSERDA to develop a searchable database containing aggregated customer load data. The Enel Group questions how collecting anonymized data on customers can assist in connecting DER providers and customers, particularly without customer assent. NPS stresses the importance of developer access to distribution and customer data, including granular data at the distribution feeder and substation level. NYPA supports the prioritization of AMI deployment and suggests that all public facilities be included in the definition of high value customers. The City also comments on the need for improved access to data in successfully siting energy storage, and highlights the need for development of a searchable data platform containing customer-related data to assist DER developers.

The UIU stresses the need to evaluate any recommendations pertaining to access to customer data in the context of all DERs, not just energy storage. Furthermore, UIU states that use of a third-party platform raises two issues – how to educate consumers on the platform along with the comfort of opting in, and the scope of customer data that should be included in the platform. The Joint Utilities recognizes the importance of providing quality data and assert that it is already providing this function through: MCOS studies; DRV and LSRV through the VDER proceeding; posting NWS information on utility websites; DER hosting capacity maps; and granular forecasted 8,760-hour data at utility substations. It goes on to state that the Customer Data Working Group is the forum in which to discuss customer data sharing and related standards and not this proceeding. LIPA adds that there is a need for a separate vetting of data protection and confidentiality requirements.

Discussion

The electric IOUs have made significant progress in their efforts to provide needed data to DER developers, as shown in each of their 2018 DSIP Update filings.[60] Nevertheless, developers and other stakeholders need more and better access to customer and distribution system data. For example, while the

[60] Individual utility DSIPs are filed in Case 16-M-0411, In the Matter of Distributed System Implementation Plans.

utilities identify potential DER deployment opportunities and related data through NWAs and their procurements, they do not provide developers with the data needed for independent analyses and long-term planning. The Order Adopting Accelerated Energy Efficiency Targets, which the Commission addressed contemporaneously at Session December 13, 2018, articulates key principles related to the strategic use of energy data and initiates a number of data access actions.[61] Energy storage projects, energy efficiency initiatives, and DER deployments will all be more successful with more useful and accessible data. The Order Adopting Accelerated Energy Efficiency Targets data directives satisfy a number of the Roadmap's recommendations, including those regarding Green Button Connect deployment.

The Commission also directs Staff and NYSERDA to lead coordination efforts with the electric IOUs, LIPA, NYPA, and other stakeholders to develop a Pilot DER Data Platform for a third-party to develop and implement. In developing this pilot platform, the possibility of using the NYPA New York Energy Manager or other available platforms shall be explored. The Pilot DER Data Platform shall contain both anonymized customer and system data useful to developers for planning and developing energy storage and other types of DER. This coordination effort to develop the Pilot DER Data Platform shall also determine the extent of system data that is already available to developers, and identify additional data needs. The Pilot DER Data Platform will allow DER developers to query the anonymized data to identify potential candidates for energy storage and other DER. The Commission anticipates this modern electric function, in which the IOU performs the service of obtaining customer consent

[61] Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative.

prior to sharing customer-specific data with a DER developer, may provide a DSP market revenue stream. The electric IOUs are authorized and directed to work with NYSERDA to conduct this Pilot DER Data Platform with qualified partners, and shall enter into strict data security agreements with the third party entity that compiles the information.

The Commission expects that this Pilot DER Data Platform will comply with the appropriate cyber security protections, such as potential Data Security Agreements, and directs Staff to engage with ongoing efforts to strengthen cyber security protections.[62] The Commission shall require a report by Staff on or before July 1, 2019 on the progress and schedule of implementing the Pilot DER Data Platform with the goal of it being operational by December 31, 2019.

To develop the Pilot DER Data Platform, the electric IOUs shall provide the following customer-related data: load profile attributes (average load, average peak, peak times, load factor), current tariff/program enrollment, North American Industry Classification System code, building size, NYISO zone, substation, circuit, installed DER by type, electric vehicle charging information, and hosting capacity. The Commission expects the Pilot DER Data Platform will provide crucial information regarding which entity is best suited to host a potential statewide platform, algorithms needed to produce the most useful information, the parameters of allowed queries, protection of data, availability of certain data, utility protocols, cost recovery, and access fees. Staff shall ensure that the Pilot DER Data Platform complements any efforts

[62] Case 18-M-0376, Proceeding on Motion of the Commission Regarding Cyber Security Protocols and Protections in the Energy Market Place, Order Instituting Proceeding (issued June 14, 2018).

directed in the Order Adopting Accelerated Energy Efficiency Targets.[63]

VII. CLEAN PEAK ACTIONS

Roadmap Recommendations

The Roadmap asserts that stakeholders, including the Joint Utilities, the NYISO, DPS, DEC, and NYSERDA, should work together to develop a methodology for analyzing peaker operational and emission profiles on a unit-by-unit basis to determine which units are potential candidates for repowering or replacement. As proposed, the study results produced by applying the methodology would be presented to the Commission by July 1, 2019. This analysis would also include a series of reliability and operational assessment studies looking at the equivalent level of "clean resources" that could provide the same level of reliability as the existing peaker units. Hybridization and repowering with energy storage, as well as replacement with stand-alone energy storage, should be explicitly examined, according to the Roadmap.

The Roadmap further recommends that IOUs directly impacted by the DEC NO_x regulations under development should develop a "Peaking Unit Contingency Plan" by July 1, 2019, to address the potential retirement of generation facilities similar to that which was required by the Commission in the Indian Point contingency planning matter.[64] Other mechanisms to enable cleaner generation to meet periods of peak electric demand should continue to be examined, including flexible

[63] Case 18-M-0084, supra.

[64] Case 12-E-0503, Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans, Order Instituting Proceeding and Soliciting Indian Point Contingency Plan (issued November 30, 2012).

capacity benefits that reduce greenhouse gas emissions and increase renewable generation.

Comments

Stakeholders generally support the Roadmap recommendations and highlight different areas of interest. AEMA is supportive and encourages further storage exploration to firm up renewable resources and system reliability. Energy Nest argues that the State should encourage generating facilities to reduce peaks during the hottest and coldest days, and notes that Waste-to-Energy facilities should be able to participate. ESA looks to obtain emission profiles of the electric grid to enable market-based signals to permit charging in low emission periods. FCHEA looks for greater opportunities for clean generation to meet peak electric demand, while Fluence supports the creation of Peaking Unit Contingency Plans with the utilities defining what services are needed and at what times. Glidepath calls for additional studies to gauge the potential effect that storage would have on peaking resources. Hydrostor believes that A-CAES can replace Group 1, 2, and 3 peaking units.

IPPNY and the Joint Utilities support a stakeholder process to determine which units can be hybridized. The Joint Utilities add that analysis should focus on certain load pockets that have sustained peak load periods, and on the availability of space to site DER. IR proposes encouraging energy storage that can best time shift renewables in place of peaking unit generation. KCE supports open competition for battery storage solutions, and has identified peaking plants with the highest CO_2 and criterial pollutant emissions and notes that those with short peaks lead to higher GHG emissions. NPS states that it supports consistent valuation of environmental benefits in relation to utilizing energy storage, but warns that market barriers must be eliminated first. NRDC supports continuation of the E3 analysis presented in the Roadmap, and identification of potential improvements to the alternative solicitation process.

NY-BEST states that the Commission should use its leverage to replace aging peakers, and urges DEC to place limits on NO_x emissions. It goes on to support creation of a Clean Reliability Credit similar to the RES program. NYPA supports the Peaking Unit Contingency Plan but with the caveat that customer confidential data be protected. O'Connell Electric states that once there is a new alternative rate structure where there is a sufficient price differential between peak and off-peak times, then energy storage can naturally develop. Plus Power supports a downstate clean peak incentive for bulk-connected energy storage and the creation of a storage REC. Stem and IR supports a "Clean Peak Credit" mechanism to be layered into different energy storage markets. Sunrun supports a clean peak program similar to Massachusetts, and believes BTM energy storage should be considered as well.

The City warns that if regulatory changes are made to peaking units in New York City, it may have a significant impact on in-city generation, reliability, and cost to consumers. To avoid these potential problems, it calls for coordination between the DEC and Commission to recognize the impacts that peaking rulemakings may have in these areas. The Enel Group would like to see direct storage procurement mechanisms established.

Determination

Today's electric grid relies on reserves of mostly idle generation capacity to meet changes in consumption patterns and intermittency in renewable energy production. As the Roadmap detailed, there are over 3,000 MW of conventional generation units in Zone J and Zone K (i.e., New York City and

Long Island, respectively) that have low utilization (generating electricity less than 5 percent of the year), are approaching an average of 50 years of age, and are generally used for meeting periods of high electric demand or for reliability purposes. These units primarily provide peaker services, which include capacity to meet NYISO locational and system capacity requirements and other more local (i.e., utility-level) reliability-based services such as contingency reserves.

Many of these downstate peaker generators are dual-fuel and may be required to temporarily burn oil or kerosene during winter periods due to reliability rules or fuel constraint concerns, or to relieve demand on the natural gas system. Many peaking units have high operating costs and run less than four hours per start, making them potential candidates for "hybridization",[65] repowering, and/or replacement.

A number of prior recommendations are each designed to help facilitate a shift toward meeting peak demands with clean energy, including: differentiating the E Value in the Value Stack, utilizing NWA solutions that also reduce peak system loads, calibrating the proposed market acceleration bridge incentive to maximize CO_2 reduction, and continuing to encourage energy storage pairing with renewables in RES procurements.

Similar to the need for Indian Point Reliability Contingency Plans to plan for the Indian Point Energy Center nuclear generator retirements,[66] there is a present need for

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[65] Hybridization involves installing storage at an existing conventional site that can either be charged from the on-site generating unit or enhance the operations of the existing conventional units.

[66] Case 12-E-0503, supra, Order Instituting Proceeding and Soliciting Indian Point Contingency Plan (issued November 30, 2012).

reliability contingency plans in the event of downstate peaking power plant generating units' retirement. While the impacted utilities and the Commission await the DEC final rules, potential impacts may be studied based on the publicly available pre-proposal stakeholder draft of Part 222 and plans will be developed.[67] The Commission expects this Peaking Unit Contingency Plan will have broad implications, and will consider and report on portfolios of alternatives that could be deployed in the event that the peaking units are no longer available. Peaking Unit Contingency Plans should not be technology specific. Therefore, the Commission will institute a proceeding where the Peaking Unit Contingency Plan will be filed, to examine the broad reliability impacts of the proposed DEC regulations in the near future.

Qualified energy storage systems may play a role in securing the reliability of the grid in the affected utility service territories, while advancing the state's energy storage deployment goals. The Roadmap's recommendation to analyze peaker operational and emission profiles on a unit-by-unit basis to determine which units are potential candidates for repowering or replacement is adopted.

Staff shall consult with the NYISO, NYSERDA, DEC, LIPA, and Con Edison to develop a methodology to be used in the study, and shall file the study results produced by applying the methodology with the Commission by July 1, 2019. The study shall include determining how many MWs of peaking units could be replaced or repowered economically with energy storage at varying durations without threatening reliability.

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[67] See Draft Express Terms of 6 NYCRR Part 222, Distributed Generation Sources (May 16, 2018), available at: http://www.dec.ny.gov/docs/air_pdf/replacepart222.pdf.

This study should also include a series of reliability and operational assessment studies looking at the equivalent level of clean resources that could provide the same level of reliability as the existing peaker units. Hybridization and repowering with storage, as well as replacement with stand-alone storage. should be explicitly examined. In addition, the analysis should include quantifying the benefits of peaker replacement such as avoided fuel, O&M, capacity, emission costs (monetized and unmonetized) over the life cycle of the facility, versus alternative clean energy portfolio costs that include various energy storage configurations.

VIII. Wholesale Market Actions

A. Bulk System Focus

Roadmap Recommendations

Significant barriers exist for the widespread use of energy storage for services which benefit the bulk electric system, according to the Roadmap. With few exceptions, the NYISO market is structured for large resources that can run regularly and for long periods, are interconnected to the transmission system, and participate only in the wholesale market. Certain types of energy storage such as batteries are highly responsive and accurately dispatchable for short-term electric grid functions, according to the Roadmap. One option specified therein is for the NYISO to pursue benefits from this characteristic as a fast-ramping product since energy storage resources can provide accurate and reliable ramping service better than any existing alternative and, even when paired with existing fossil fuel plants, can improve overall system efficiency and utilization.

As proposed, the NYISO and Staff should work to modify transmission planning processes to incorporate consideration of energy storage in addressing transmission needs and public policy objectives. New York's transmission planning process and the manner of cost recovery and compensation limits the consideration of energy storage as an alternative solution to transmission needs, according to the Roadmap.

As the Roadmap points out, the NYISO requires intermittent wind and solar generators in the bulk electric system to provide the NYISO with the ability to curtail output. Wind and solar developers avoid adding energy storage to their projects because under current NYISO rules the project generation type changes to "dispatchable" and voids the project eligibility for intermittent generator exemptions, according to the Roadmap.

Accordingly, the Roadmap recommends that the NYISO and the utilities should develop and implement cost-effective dispatch and telemetry solutions for distribution-connected resources which provide dispatchable services to the bulk electric system. A working group, comprising the NYISO, DPS, NYSERDA, the Joint Utilities, DER developers, operators, and vendors, and other industry stakeholders should specify and test a cost-effective and scalable manner of telemetry and dispatch interoperation for distribution-connected resources. In particular, this working group should specify standard telemetry, metering, and dispatch requirements for aggregations of smaller resources.

The Roadmap also recommends a number of reforms to better enable the unique characteristics of energy storage to meet capacity requirements, including:

- Establish a manner to value and enable participation of shorter duration (one to four hours) storage resources.
- Evaluate procuring a portfolio of both long (unlimited) and short duration (one to four hours) capacity resources.

- Consider short duration capacity resources for meeting energy needs during system peak.
- Allow energy storage resources to be aggregated zonally.
- Determine whether fast-responding resources like energy storage can be more valuable than other resources.
- Energy storage participation as capacity should only be assessed penalties under limited circumstances.
- Ensure that any energy storage assets that provide capacity are able to participate in other NYISO markets.
- Exempt energy storage from buyer-side mitigation rules.[68]

Comments

AEMA states that shorter duration storage resources should be able to aggregate zonally, which would enable the resources to reach full capacity value. Borrego stresses the need to facilitate wholesale market participation by those resources that are not available year-round. EnergyNest supports the renewable definition found in New York Energy Law section 1-103 because of its flexibility in resources allowed. ESA supports Staff's view that storage should be considered as a regulated transmission solution and recognizes that it must be evaluated as an alternative to traditional transmission. ETA agrees with Staff's recommendations and warns that the rules embedded in that proposal should not be applied arbitrarily. FCHEA states that the process of adding storage to intermittent renewable generators is not practical because of NYISO rules.

Glidepath and GI Energy support the continued NYISO stakeholder process, and Glidepath further encourages NYSERDA to

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[68] See NYISO Presentation: Capacity Market Rules for Energy Storage Resources (May 23, 2018), available at: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_icapwg/meeting_materials/2018-05-23/Initial percent20ESR percent20Capacity percent20Model.pdf.

provide revenue to early-mover storage projects. NPS supports a 20-year contract commitment, with a minimum of ten years, for energy storage incentives. NY-BEST places a priority on adopting capacity market rule changes that provide flexibility in duration requirements. NYPA stresses the need to enable shorter duration energy resources to participate in the wholesale markets. Plus Power disagrees with the Roadmap that energy storage systems under 20 MWs should be exempted from BSM, but agrees that if the NYISO finds that fossil peaker plants are exempt from BSM, so should the energy storage facilities designed to replace them. It also supports shorter duration energy storage capacity product. The City supports Staff's recommendations that energy storage and DER be exempt from existing NYISO rules. The Enel Group states that four-hour energy storage resources should have similar capacity value as other generation.

IPPNY argues against the Roadmap's proposal that energy storage be exempt from BSM rules, stating that ICAP prices would be greatly reduced and that other, unsubsidized resources would be harmed if energy storage were to receive out-of-market payments.

Determination

Ongoing discussions have been occurring with Staff, NYSERDA, the NYISO, and other stakeholders to reform the wholesale markets to allow energy storage the opportunity for greater participation and to be compensated fairly. Much of the activities are ongoing at the Staff level, and therefore the Commission has little need to act here. Nevertheless, the Commission reaffirms that Staff and NYSERDA shall continue to be active in all of the applicable NYISO working groups going forward, and work to have the recommendations from the Roadmap adopted.

The Commission urges the NYISO to exempt energy storage from its BSM rules. Exposing new energy storage resources, which have little or no ability or incentive to manipulate capacity prices, to BSM exposes these resources to the potential of not receiving capacity revenues depending upon how the mitigation tests are applied. Exposing energy storage resources of any size to the potential of mitigation will lead to increased consumer costs and decreased system efficiency. At a minimum, the NYISO should propose an exemption from BSM for energy storage resources under a certain size threshold (e.g., 20 MW), as resources of this size will clearly not have the ability to artificially suppress capacity prices. It is also recommended that energy storage resources deployed on the distribution system and primarily performing a distribution service or operating under a distribution tariff, be exempted from BSM should they also qualify to be a bulk market capacity resource.

The Commission urges the NYISO to accelerate its proposed rules for aggregation of energy storage resources. The second phase of Energy Storage Integration process described in the NYISO's Draft Master Plan will be the Renewable and Energy Storage Aggregation Model.[69] This phase is planned to have the Market Design component completed in 2020 and deployment by 2023. The Commission encourages this timeline to be accelerated, or for the NYISO to develop pilot approaches that can be implemented during the pendency of final market design

[69] 2018 MASTER PLAN: WHOLESALE MARKETS FOR THE GRID OF THE FUTURE, A Report by the New York Independent System Operator (June 2018). Available at: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg/meeting_materials/2018-05-15/Master percent20Plan percent20Draft.pdf.

rule changes. The Commission directs Staff and NYSERDA to engage the NYISO accordingly.

B. Dual Market Participation

Roadmap Recommendations

Energy storage in the distribution system should be allowed to provide separate and distinct services to both the utility and the NYISO, according to the Roadmap. Additionally, distributed energy storage operating under a distribution tariff, without obligation to the utility, should be allowed to provide bulk market services. Staff recommends that dual participation be prioritized so that a dual market participation model accompanies the NYISO's tariff filings in 2018 to comply with FERC Order 841. The NYISO should develop rules and procedures for resources that are available less than year-round, and should accommodate both scheduled and unscheduled unavailability in a manner consistent with existing unavailability rules applied to other generators, according to the Roadmap. DPS, NYISO, and transmission owners should engage stakeholders on an appropriate construct to allow energy storage on the distribution system to participate in bulk markets with appropriate implementation of commodity costs and retail delivery tariffs.

The Roadmap also recommended that the Commission should adopt principles for dual participation of energy storage, as well as other DER. The principles were intended to identify the different modes and ways in which energy storage and other DERs can provide value to the electric system as whole. Staff recommends the following:

- Resources interconnected in the customer segment may provide services in any segment.
- Resources interconnected in the distribution segment may provide services in all segments except the customer

segment, with the possible exception of community energy resources.

- Resources interconnected in the bulk segment may provide services in all segments except the customer or distribution segments.
- Resources interconnected in any grid segment may directly or indirectly provide bulk system services like transmission and wholesale market services.
- If one of the services provided by a DER is a reliability service, then that service must have priority. A resource interconnected in the customer segment must give first priority to customer reliability, second priority to distribution system reliability, and third priority to bulk system reliability. A resource interconnected in the distribution segment must give first priority to distribution system reliability, and second priority to bulk system reliability.
- Priority means that a single DER must not enter into two or more reliability service obligation(s) such that the performance of one obligation renders the resource unable to perform the other obligation(s). New agreements for such obligations, including contracts and tariffs, must specify terms to ensure resource availability, which may include financial penalties.
- If using different portions of capacity to perform services, DER providers must clearly demonstrate, when contracting for services, the total capacity of the resource with a guarantee and means to verify that a certain, distinct capacity is dedicated and available to the capacity-differentiated reliability services.
- For each service, the program rules, contract, or tariff relevant to the segment in which the service is provided

must specify enforcement of these rules, including any penalties for non-performance.

- In response to a utility request for offer, the DER provider is required to list any additional services it currently provides outside of the solicitation. In the event that a DER is enlisted to provide additional services at a later date, the DER provider is required to provide an updated list of all services provided by that resource to the entities that receive service from that resource. The intent of this principle is to provide transparency in the DER market.
- For each service provided, the DER must comply with availability and performance requirements specified in the DER provider’s contract with the service recipient.
- In paying DERs for performance of services, compensation and credit may only be permitted for those services that are incremental or distinct. DER services provided must be measurable, and the same service only counted and compensated once to avoid double compensation.

Comments

Most commenters support the Roadmap’s recommendation. ESA further recommends that the Commission consider convening a stakeholder group to develop together a set of specific principles for dual participation. GI Energy believes that the idea of dual participation should not be an issue for bulk energy storage development, and that bulk energy storage should not be treated differently simply because they are connected to the distribution system. IPI agrees that market participation rules should be redesigned to accommodate storage resources that may be unavailable for periods of time, but nevertheless have useful part-time services to provide. IR believes energy storage resources are highly flexible and may provide wholesale or retail services depending on market need. In its reply comments, ACE NY supports the Roadmap's recommendation to work with stakeholders to develop rules to facilitate participation of energy storage not available year-round.

Joint Utilities argue that accessing wholesale market revenue streams is critical to unlocking the full value of energy storage, and note that dual participation can minimize subsidies from utility customers that would otherwise be necessary to fill the gap between energy storage costs and distribution and customer benefits. Joint Utilities also note that they are committed to continuing work with stakeholders to address these issues. NPS urges Staff to further explore and prioritize a distribution energy storage capacity market, while NYPA comments that a dual participation model must ensure that resources are not being compensated for the same service twice. Stem supports dual participation but contends that New York is not ready to formally adopt dual participation principles. In Stem's opinion, the principles that were adopted by the CPUC in early 2018 have failed to be actionable and should not be used as a foundation for a dual participation framework.

The Enel Group recommends adopting the following principles: energy storage should be eligible to provide any wholesale service for which it is not already being compensated for at retail; energy storage that is participating in a retail tariff or procurement that does not include wholesale revenue streams should have no restrictions on wholesale market participation; and energy storage that is dispatched in real-time by a utility for a local reliability or peak shaving program can self-schedule in the NYISO market.

Determination

The Commission recognizes that adopting overly prescriptive frameworks may deter market participation models not currently envisioned, and declines to adopt all the principles for energy storage and DER dual participation recommended in the Roadmap. The following principles as to what guidelines can best unlock value to the electric system and for New Yorkers, reflect the Commission's expectations and are adopted:

- A resource that is technically capable of providing services in any market segment (bulk, distribution, or customer-level) shall not be unreasonably restricted or prohibited from doing so.
- If one of the services provided by a DER is a reliability service, then that service must have priority. A resource interconnected in the customer segment must give first priority to customer reliability, second priority to distribution system reliability, and third priority to bulk system reliability. A resource interconnected in the distribution segment must give first priority to distribution system reliability, and second priority to bulk system reliability.
- For each service, the program rules, contract, or tariff relevant to the segment in which the service is provided must specify enforcement of these rules, including any penalties for non-performance.
- In paying a resource for performing one or more services, compensation and credit shall be provided for each service that provides a recipient with a separate and distinct value. DER services provided must be measurable, and the same service only counted and compensated once to avoid double compensation.

As energy storage deployment increases and the market matures, these principles may be adapted or expanded. The Commission expects that the utilities' Market Design and

Integration Report will inform these principles and more efficiently enable dual participation. The Commission directs Staff and NYSERDA to continue to engage with the NYISO stakeholder working groups as participation models are developed through the NYISO's DER Roadmap effort.

C. Distribution and Wholesale Market Coordination Roadmap Recommendations

According to the Roadmap, energy storage deployed in the electric distribution system can perform multiple functions that benefit the distribution system while also supporting bulk electric system needs. The 2018 DSIP Staff Guidance described the need for a supplemental filing to identity, describe, and explain the Joint Utilities' planned market organization and functions as well as the policies, processes, and resources needed to support them.[70] The Market Design and Integration Report will describe the utilities' shared plan for designing, implementing, and managing DSP market functions that will enable DER participation in both the distribution and bulk system markets. To inform each electric IOUs Market Design and Integration Report, a working group should be established comprising appropriate contributors from the Joint Utilities, the NYISO, DPS, and NYSERDA to develop a schedule to accomplish the following tasks:

- Determine the information and capabilities that the NYISO needs for planning, dispatching, measuring, and compensating each type of wholesale service that a resource can provide;
- Determine the information and capabilities that the utilities need for planning, dispatching, measuring, and

[70] Case 16-M-0411, supra, DSP Staff Whitepaper: Guidance for 2018 DSIP Updates (filed May 29, 2018).

compensating each type of service that a resource can provide to the electric distribution system;

- Determine the needs and priorities, both technical and economic, for coordinating DER operations from the perspectives of the NYISO, the utilities, and the DER operators;
- Identify and evaluate alternative approaches for integrating and optimizing the use of DER for both bulk and distribution services;
- Identify and evaluate alternative approaches for determining and allocating the economic costs and benefits of bulk system effects attributable to DER;
- Consider different combinations of roles and responsibilities for the NYISO, the utilities, and DER operators;
- Examine the advantages/disadvantages of the utility having sole responsibility for monitoring, dispatching, billing, and compensating DER;
- Determine how FERC Order 841 affects the use of DER for bulk system services; Establish DER metering, telemetry, and dispatch policies to ensure efficient optimization and coordination of energy storage services for both the bulk and distribution systems;
- Identify and develop approaches for fast-tracking energy storage applications in which use of the resource for both distribution and bulk system services does not require operational coordination;
- Ensure that the existing compensation framework fully and fairly compensates energy storage resources for multiple value streams benefitting the bulk and distribution systems but prevents double payments for single services; and

- Determine the detailed functionalities, and corresponding operational and management systems, needed to implement the market-coupling framework.

Comments

GI Energy and Glidepath support the Roadmap recommendations, and state that the NYISO should clarify that projects connected to the distribution system but participating in the NYISO market will not be charged distribution facilities fees. FCHEA supports the need to more effectively utilize energy storage connected to the distribution system. IR supports the proposal to develop clear control, coordination, and dispatch requirements to enable greater use of DERs, and believes that aggregations of DERs, including energy storage, will help manage system and network loads ensuring that services are provided when they are needed most. Joint Utilities comment that most parties support the Clean Peak proposal, and add that NY-BEST stated there is sufficient information on peaking plants for the Commission to act to replace some of the units with energy and DER. Also, Joint Utilities state that the Commission should reject NY-BEST’s Clean Reliability Program.

Determination

It is envisioned that, as part of the DSIP process, the Joint Utilities are responsible for preparing and filing a Market Design and Integration Report describing the utilities’ shared plan for designing, implementing, and managing DSP market functions that will enable DER participation in both the distribution and bulk system markets. While Commission action regarding the Market Design and Integration Report will occur in the DSIP proceeding, by this order the Commission directs Staff and NYSERDA, with appropriate contributors from the electric IOUs and NYISO, to convene and prepare a work plan and schedule for a Market Design and Integration Working Group by March 1, 2019 that identifies and organizes the requirements to:

- Determine the information and capabilities that the NYISO needs for planning, dispatching, measuring, and compensating each type of wholesale service that a resource can provide;
- Determine the information and capabilities that the utilities need for planning, dispatching, measuring, and compensating each type of service that a resource can provide to the electric distribution system;
- Determine the needs and priorities, both technical and economic, for coordinating DER operations from the perspectives of the NYISO, the utilities, and the DER operators;
- Identify and evaluate alternative approaches for integrating and optimizing the use of DER for both bulk and distribution services;
- Identify and evaluate alternative approaches for determining and allocating the economic costs and benefits of bulk system effects attributable to DER;
- Consider different combinations of roles and responsibilities for the NYISO, the utilities, and DER operators;
- Examine the advantages/disadvantages of the utility having sole responsibility for monitoring, dispatching, billing, and compensating DER;
- Determine how FERC Order 841 affects the use of DER for bulk system services;
- Establish DER metering, telemetry, and dispatch policies to ensure efficient optimization and coordination of energy

storage services for both the bulk and distribution systems;

- Identify and develop approaches for fast-tracking energy storage applications in which use of the resource for both distribution and bulk system services does not require operational coordination;
- Ensure that the existing compensation framework fully and fairly compensates energy storage resources for multiple value streams benefitting the bulk and distribution systems but prevents double payments for single services; and
- Determine the detailed functionalities, and corresponding operational and management systems, needed to implement the market-coupling framework.

The Market Design and Integration Working Group work plan shall be filed in the DSIP proceeding, where future Commission action regarding the Joint Utilities' Market Design and Integration Report will be contemplated.

IX. Accountability

Roadmap Recommendations

The Roadmap recommends that the Commission establish accountability over those responsible for achieving the 2025 and 2030 energy storage targets, including NYSERDA, the IOUs, and LIPA. It also suggests that Staff should provide the Commission annually with a "State of Storage" report that presents progress toward achieving the energy storage targets, zonal locations of installations, projects in the queue, solutions deployed and the ranges of use cases, as well as impediments and proposed solutions to these impediments that may slow deployment. This should also include corrective paths for reallocating bridge incentive funds and other measures as needed to ensure that these targets are reached.

Comments

AEMA agrees with Staff's recommendation to establish mechanisms for accountability and tracking progress toward energy storage targets. AEMA suggests a report be established on energy storage progress, including the availability of incentive funds. NYSSGC also supports the development of a report on goals and accomplishments to ensure complete transparency. GI Energy supports the Roadmap's recommendations.

Determination

The Commission adopts the Roadmap's recommendation to establish clear accountability processes for each entity responsible for deploying energy storage. Consistent reporting of each energy storage project, whether standalone or paired with renewable or on-site generation, shall adhere to the national energy storage metrics set forth below and be reported to NYSERDA by each responsible entity, to be included in a statewide list of deployed energy storage projects.[71] Each energy storage project shall report:

- General Description of System: Storage technology type deployed.
- General Description of System: Storage technology type deployed.
- The contractor with primary responsibility for the installation
- Interconnection approval date
- Rated Power and Capacity in kW and kWh respectively

[71] Measuring and Expressing the Performance of Energy Storage Systems – Update on and Overview of Revision 2 to the PNNL/SNL Protocol, Pacific Northwest National Laboratory and Sandia National Laboratories for the U.S. Department of Energy, June 30, 2016.

- Location and primary use case(s) for the energy storage system
- Facility type where the energy storage system is installed

In addition to these energy storage project-specific reporting requirements, Staff shall also provide an annual report in compliance with PSL §74(2)(i). In preparing this annual report to be provided to the Governor, the Temporary President of the Senate, and the Speaker of the Assembly, Staff shall consult with NYSERDA, LIPA, and the NYISO. Staff's annual report shall detail the achievements and effectiveness of the energy storage deployment policy and specifically report the status of and recommended adjustments to: the utility procurement process; wholesale market design changes; utility rate design actions; data platform development; retail and wholesale market coordination; and any other relevant issues. data platform development; and retail and wholesale market coordination. The following items shall also be included in the annual report:

- Average total installed cost of energy storage systems
- Major progress during the year in reducing soft costs
- Total MWs deployed
- Impediments and proposed solutions to these impediments that may slow deployment
- Adjustments to market acceleration incentive deployment

X. Implementation Issues

By this order, the Commission adopts an energy storage deployment policy to realize 1,500 MW of installed qualified energy storage systems by 2025, and a goal of up to 3,000 MW of installed qualified energy storage systems by 2030. In order to swiftly implement the important initiatives adopted here, this order establishes specific requirements and timelines regarding various directives. A number of additional implementation measures will be necessary to fully administer the energy storage deployment policy, but do not have a specific date certain; these are listed below.

The Commission expects that the remaining implementation matters will be transparently addressed in a planned and deliberate manner to ensure that stakeholders and other market participants receive timely guidance on matters that affect them. The incremental nature of this energy storage deployment policy allows the Commission to make necessary adjustments where appropriate. The annual "State of Storage" report that Staff will submit for Commission review will highlight program areas that should be revisited or addressed. Additionally, the Commission will conduct a triennial review of the progress towards achieving the energy storage deployment goal and the effectiveness of the energy storage deployment policy in meeting this state goal. These review opportunities will allow the Commission to take corrective action and to address new matters as they arise.

Retail Rate Actions and Utility Programs

- Staff Whitepaper on Standby Service
  Commission action on the Staff whitepaper regarding Standby and Buyback Service Rate Design is expected expeditiously, following public notice and comment.
- Staff Whitepaper on Avoided Distribution Costs
  Staff shall file a whitepaper within the first quarter of 2019.
- Staff Whitepaper on E Value
  Staff shall file a whitepaper within the first half of 2019.

- DLM Competitive Procurements
  Utilities shall file their proposed annual competitive procurement process for DLM resources in next year's annual DLM report.

Utility Roles and Business Models

- System Efficiency EAM
  Where one does not already exist, each utility shall propose in its next rate case a system efficiency target that includes both peak reduction and load factor reductions that are appropriate for its territory.
- Unused Land Inventory and Valuation
  By the first quarter of 2019, each utility shall inventory unused utility land and establish a mechanism for the standardized valuation of unused utility land that would be included in utility BCA handbooks and NWAs.
- NWA Interconnection Costs
  Each utility shall estimate interconnection costs in future NWA areas to the greatest extent possible, or indicate that such costs will be borne by the utility and included as a cost in the BCA calculation.
- Optionality
  Staff shall issue a whitepaper for future Commission consideration with recommendations related to this topic by the end of 2019; Staff shall host a technical conference with relevant stakeholders to inform the development of the whitepaper.

Direct Procurement

- Expanded NWAs
  Electric IOUs shall expand the scope of future NWAs to go beyond just infrastructure deferral and include cost effective opportunities to reduce customers' total bills.

- Competitive Procurements

  Each electric IOU shall issue a Request for Proposals in 2019 to competitively procure dispatch rights for bulk-level energy storage systems sited within their service territory.

- NWA Extensions

  For all future NWAs, utilities shall include clearly-defined conditions to extend a NWA asset term. Developers should explicitly be allowed to maintain the interconnection after the term of an NWA, and should be allowed to continue to use that asset to provide other non-NWA services.

- Renewable Energy Standard Procurements

  NYSERDA, in consultation with Staff, shall continue evaluating whether refinements to Load Serving Entities' Renewable Energy Standard procurements are appropriate, to reflect the improved system benefits afforded by the operational flexibility of energy storage.

- State Agencies Procurements

  NYSERDA shall continue to work with State agencies to help inform their procurement decisions in furtherance of Executive Order 166 and their own energy or environmental policies.

Market Acceleration Incentive

- Bridge Incentives

  NYSERDA shall work with Staff and the electric IOUS in deploying market acceleration incentives. NYSERDA is ordered to develop an implementation plan in consultation with Staff, and file such plan within 60 days of this order. NYSERDA shall also develop a program manual based upon the implementation plan that sets forth specific program provisions and requirements.

- Long Island Incentives

  DPS and NYSERDA shall work with LIPA to facilitate an equivalent set of market acceleration bridge incentive mechanisms on Long Island.

Address Soft Costs

- Technical Assistance

  NYSERDA shall amend its current CEF Investment Plan Energy Storage Chapter, to increase the technical assistance resources available in reducing soft costs, and reallocating already approved funds within this investment plan as deemed necessary; NYSERDA shall work with the utilities, market participants, local communities, and appropriate state agencies to ensure that appropriate decommissioning and end-of-life actions and processes are developed.

- Property Assessed Clean Energy (PACE) Financing

  Staff shall work with NYSERDA to facilitate discussions with the Energy Improvement Corporation and New York City Energy Efficiency Corporation to bring clarity to the developer and customer community around Commercial PACE financing opportunities.

- Workforce Development

  NYSERDA should facilitate an industry partnership to work with State and local partners, industry, and other stakeholders to develop an inventory of needs by spring 2019, and a blueprint for addressing potential skilled talent shortages for consideration by fall 2019.

Data Access

- Data

  NYSERDA and DPS shall lead coordination efforts with NYPA, LIPA, and the electric IOUs to establish a Pilot DER Data Platform to test a consumer data platform, and to determine the system data needed for the energy storage industry.

Clean Peak Actions

- Peaker Replacement Study
  Staff shall consult with the NYISO, NYSERDA, DEC, LIPA and Con Edison to develop a methodology to be used in analyzing operational and emission profiles of peaking generators on a unit-by-unit basis to determine which units are potential candidates for repowering or replacement. Staff shall file the study results produced by applying the methodology with the Commission by July 1, 2019.

Wholesale Market Actions

- Bulk Reforms
  Staff and NYSERDA shall continue to be active in all of the applicable NYISO working groups, and advocate for wholesale market participation rules that complement the state energy storage deployment policy.
- Dual Market Participation
  By March 1, 2019, Staff and NYSERDA shall convene a working group to inform the electric IOUs Market Design and Integration Report, which will be further contemplated in the DSIP proceeding.

Accountability

- Annual Report
  Staff shall file an annual report detailing basic industry metrics for each energy storage project installed in New York. Staff's annual report shall also provide the status of and recommended adjustments to: the utility procurement process; wholesale market design changes; rate design actions; data platform development; and, retail and wholesale coordination.

- Triennial Report
  Beginning in 2020 and each third year thereafter, the Commission will conduct a review of the progress towards achieving the energy storage deployment goals and the effectiveness of the energy storage deployment policies and actions in meeting those goals.

CONCLUSION

In compliance with the Commission's statutory obligations under PSL §74, by this order we establish a statewide energy storage goal of up to 3,000 MW by 2030. To support this goal, the energy storage deployment policy described in this order will realize 1,500 MW of installed qualified energy storage systems by 2025. The Commission expects Staff to continue to consult with NYSERDA, LIPA, and the NYISO in executing the deployment policy and drafting annual reports.

The Commission orders:

1. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation are directed to maintain consistent reporting of each energy storage project, whether standalone or paired, that shall adhere to the national energy storage metrics set forth in the body of this order.

2. By February 11, 2019, Central Hudson Gas & Electric Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall file an implementation plan detailing a

competitive direct procurement process and the cost recovery accounting procedures to deploy 10 MW of qualified energy storage systems.

3. Tariff amendments necessary to effectuate cost recovery of the contract costs directed by Ordering Clause No. 2 shall be filed on not less than 30 days' notice, to become effective on a temporary basis on June 1, 2019.

4. By February 11, 2019, Consolidated Edison Company of New York, Inc. shall file an implementation plan detailing a competitive direct procurement process to deploy 300 MW of qualified energy storage systems.

5. Tariff amendments necessary to effectuate cost recovery of the contract costs directed by Ordering Clause No. 4 shall become effective on not less than one day's notice, to take effect on or before April 12, 2019.

6. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall propose a system efficiency target that includes both peak reduction and load factor in the next major rate filing.

7. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall compile an inventory of suitable, unused and undedicated utility land that may be used for Non-Wires Alternatives by July 1, 2019, and establish a mechanism for the standardized valuation of unused utility land that would be included in utility BCA handbooks.

8. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation shall calculate Non-Wires Alternatives interconnection upgrade costs to the greatest extent possible and include such costs in Requests for Proposals, or include utility-borne interconnection costs in the benefit cost analysis calculation.

9. The New York State Energy Research and Development Authority shall file an Energy Storage Market Acceleration Bridge Incentive implementation plan and program manual as discussed in the body of this order by February 11, 2019.

10. The Department of Public Service Staff, in consultation with the New York State Energy Research and Development Authority, with other appropriate stakeholders, shall convene and prepare a work plan for a Market Design and Integration Working Group by March 1, 2019. The work plan shall be filed in case 16-M-0411.

11. The Department of Public Service Staff, in consultation with the New York State Energy Research and Development Authority, the Long Island Power Authority, the New York Independent System Operator, the Department of Environmental Conservation, and Consolidated Edison Company of New York, Inc. shall develop and file a unit-by-unit operational and emission profile study and methodology to determine which units are potential candidates for repowering or replacement as described in the body of this order by July 1, 2019.

12. Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and

Rochester Gas and Electric Corporation are directed to work with the New York State Energy Research and Development Authority and an appropriate third-party to develop the Pilot Distributed Energy Resource Data Platform as described in the body of this order. The Department of Public Service Staff shall submit a report on or before July 1, 2019 detailing the progress and schedule of implementing the Pilot Distributed Energy Resource Data Platform with the goal of it being operational by December 31, 2019.

13. The Department of Public Service Staff, in consultation with the New York State Energy Research and Development Authority, the Long Island Power Authority, and the New York Independent System Operator, shall draft an annual report on the achievements and effectiveness of the energy storage deployment policy as required by Public Service Law §74(2)(i). The first such report shall be filed by April 1, 2020 for calendar year 2019, and by April 1 of each subsequent year thereafter. The Department of Public Service Staff shall provide the Public Service Commission with an annual informational briefing, based on the annual report.

14. The Department of Public Service Staff shall issue a whitepaper that reflects the progress made in the VDER Value Stack Working Group evaluating the Roadmap's recommendations and the stakeholder input submitted in this proceeding regarding the E Value by July 1, 2019.

15. The requirements of Public Service Law §66(12)(b) and 16 NYCRR §720-8.1, related to newspaper publication of the tariff amendments described by ordering clauses 3 and 5, are waived.

16. In the Secretary's sole discretion, the deadlines set forth in this order may be extended. Any request for an extension must be in writing, must include a justification for

the extension, and must be filed at least one day prior to the affected deadline.

17. This proceeding shall be continued.

By the Commission,

(SIGNED) KATHLEEN H. BURGESS
Secretary

COMMENT SUMMARIES

Party Commenters

Alliance for Clean Energy New York, Inc. (ACE NY)
Borrego Solar Systems, Inc. (Borrego)
Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas & Electric Corporation (Joint Utilities)
City of New York (The City)
Enel Green Power North America (The Enel Group)
Energy Technology Savings, Inc. (ETS)
Fluence Energy, LLC (Fluence)
GlidePath Development, LLC (GlidePath)
Institute for Policy Integrity at NYU School of Law (IPI)
Joint Comments of Azure Mountain Power, Bloom Energy, the City of New York, Environmental Defense Fund, the Institute for Policy Integrity at New York University School of Law, Natural Resources Defense Council, New York City Environmental Justice Alliance, and WattTime (Joint IPI)
Joint Comments of the Independent Energy Efficiency Program, Inc., Municipal Electric Utilities Association, and the New York Municipal Power Agency (Municipal Utilities)
Key Capture Energy (KCE)
Long Island Power Authority (LIPA)
Multiple Intervenors
National Fuel Gas
National Fuel Cell Research Center (NFCRC)
National Resources Defense Council (NRDC)
New York Battery and Energy Storage Technology Consortium (NY-BEST)
New York City Environmental Justice Alliance (NYCEJA)
New York Power Authority (NYPA)
New York State Smart Grid Consortium (NYSSGC)
NextEra Energy Transmission New York, Inc. (NEETNY)
Northern Power Systems (NPS)
Solar Energy Industries Association (SEIA)
Sunrun, Inc. (Sunrun)
New York Department of State Utility Intervention Unit (UIU)

Public Commenters

Advanced Energy Management Alliance (AEMA)
Climate Change Mitigation Technologies LLC (CCMT)
EnergyNest AS (EnergyNest)

Energy Storage Association (ESA)
Fuel Cell and Hydrogen Energy Association (FCHEA)
GI Energy
Greenlots
GridPolicy, Inc., on behalf of Plus Power (Plus Power)
Hydrostor, Inc. (Hydrostor)
Independent Power Producers of New York, Inc. (IPPNY)
Ingersoll Rand (IR)
Metropolitan Transit Authority (MTA)
O'Connell Electric Company, Inc. (O'Connell Electric)
Safari Energy, LLC (Safari)
Simpliphi Power (Simpliphi)
Stem, Inc. (Stem)
Sustainable Westchester (SW)

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I. RETAIL RATE ACTIONS AND UTILITY PROGRAMS

A. Delivery Service Rate Design

Borrego states that the current rate structures are a barrier to deployment of energy storage, and requests that the IOUs propose optional rate structures for energy storage systems or revise existing tariffs within three months.

ETS agrees that rates should be more granular by time and location in order to best capture the actual benefits supplied by the storage resource, and notes that the rates should be opt-in for now so that the results can be studied to ensure that all potential downsides will be discovered.

GI Energy commented that Standby and Buyback Service rates may be appropriate for BTM DER but applying these rates to utility-directed energy storage will likely suppress energy storage development. It requests that utility-directed energy storage not be subject to the same cost recovery metrics imposed on conventional Standby and Buyback Service customers. Utility-directed energy storage should not be treated any differently than other generating resources, which do not pay transmission service charges.

IPI recommends that Staff focus on developing cost-reflective rate designs that vary with time and location to provide incentives for deployment of energy storage systems.

IR proposes that utilities apply optional, more granular daily as used demand charges as a pilot tariff for demand-metered customers, and supports the implementation of Rider Q-like pilot tariffs for demand metered customers statewide.

Joint Utilities comment that it is inappropriate to modify retail rate designs within a proceeding which is focused on a single resource type, and suggest a comprehensive review of all mechanisms and programs to ensure that compensation is commensurate with the overall customer benefits. Demand charges for commercial customers are the appropriate method for recovering fixed costs, and it is premature to expand a pilot program on a statewide basis before seeing the results of the current pilot.

NY-BEST comments that current rate designs discourage deployment of energy storage, and urges the Commission to: change delivery rate design to an hourly, location-based model on an opt-in basis; establish robust enrollment limits that are aligned with the Roadmap deployment goals for energy storage; consider the recommendations included in the Regulatory Assistance Project's paper on rate design; apply demand charges only to load put on the grid for charging coincident with local peak load times and not penalize the DER for delivering power at a higher level when it is supporting the grid by generating; and not apply contract demand charges to exported energy that is participating in a distribution system relief program.

NYPA supports the Roadmap's recommendation that compensation should accurately represent the value energy storage brings to energy consumers, the energy markets, and the grid. A predictable and transparent compensation scheme that recognizes the full range of retail services energy storage can provide will support wider deployments.

NYSSGC commented on: the need to improve customer retail delivery rates; the necessity of customer incentives being available for not only energy storage but also for competing energy efficiency or load management technology options; the importance of identifying the appropriate technology for individual customer's unique load profile; and prioritizing policy actions that encourage deployment of distribution and bulk system energy storage systems which can effectively address coincident peak and other electrical system needs, as opposed to BTM systems that tend to benefit fewer customers.

O'Connell Electric supports implementation of predictable and consistent optional rate structures for all utilities and service classifications, recommending the addition of an on-peak/off-peak structure and an on-peak/off-peak plus prime-peak hours option.

Safari comments that utility tariffs do not appear to align with the Roadmap, and asserts that Consolidated Edison's tariff precludes customers on daily demand rates from receiving VDER benefits and prevents projects from being economically feasible.

The City supports developing proper market designs and rate structures, and recommends: designing delivery rates in a way that sends accurate price signals to the market and properly accounts for and maximizes the environmental and societal benefits of implementing energy storage; careful review of rate design elements intended to compensate for self-generation to ensure they do not serve as barriers to DER adoption; clarification of when the expanded technology standby rate components would apply; and eliminating the application of a contract demand charge to dispatchable energy storage.

Sunrun supports the Staff's proposals to offer new rate design options for both residential and non-residential energy storage customers on an opt-in basis and with bill-impact protection rules to protect customers.

The Enel Group commented that the Commission should approve transitioning the delivery rate design by 2021 from block periods to an hourly, location-based model, on an opt-in basis for customers, and with a robust participation cap.

Reply Comments

GI Energy provides further explanation regarding the issue of undefined delivery service rates for FTM energy storage, and states that the related transmission and distribution billing for these resources represents the potentially greatest operating expense. It seeks clarity from the IOUs to avoid the inconsistency in treatment of these resources and eliminate the protracted deliberations in determining delivery service charges. It relays its frustration that for grid upgrade purposes, IOUs can rate their non-BTM resources as "grid assets", subject to no delivery charges, while also treating these assets as retail accounts with the concomitant delivery charges incurred.

Joint Utilities reiterated that it is inappropriate to modify retail rate designs within a proceeding focused on a single resource type, and that rate design and tariff issues are being considered by VDER Working Groups.

NY-BEST disagrees with the Joint Utilities that expanding Consolidated Edison's Rider Q Standby pilot tariff is "premature".

B. Rates for Storage Charging and Discharging

Borrego urges Staff to consider a delivery rate design for FTM standalone energy storage that accurately reflects the costs and benefits of serving these resources, and asserts that energy storage should not be penalized for exporting electricity during times of peak system load through supply-based or transmission and distribution-based demand charges.

EnergyNest commented that the economic benefits to the energy storage operator of charging at LBMP rates will be substantially reduced if the project is made to absorb grid fees associated with the interconnection. The level of these grid fees should be minimal or non-existent.

ETS believes that the key to enabling the implementation of energy storage resources is the ability to charge off-peak and discharge on-peak, as well as balancing DER regardless of time of use. If the rules and pricing are not properly addressed, there may be a roadblock that would impede the State from achieving its energy storage goals.

GI Energy commented that FTM energy storage should not be disadvantaged in favor of bulk power generation by having to pay standby rates or buyback demand charges when selling either to the local utility or to the NYISO.

LIPA has proposed rate structure changes to facilitate BTM energy storage, and looks forward to participating in such discussions with stakeholders on this topic.

NPS recommends the charging and discharging rules and rates should be defined in very specific daily/monthly/seasonal timeframes in the standalone energy storage approach, so that a set of rules can begin to formalize and the market can begin to understand investment in energy storage.

The Enel Group commented that contract demand should be based on the amount of charging, and DER should not be penalized for delivering power at a higher level when it is supporting the grid by generating. Metering and billing costs should be covered in fixed charges, and the interconnection costs should only cover the service transformer and drop connecting to the building. The variable daily demand charge should reflect the coincident peak charges for both the bulk and distribution system which have temporal, locational, and seasonal variations, and the kW variable contract demand charges should be a function of the maximum kW that a battery consumes from the grid. For distribution-connected resources, the cost of energy to charge an energy storage system should be based on the LBMP that is established by the NYISO along, with a fixed adder that covers the cost for delivery across the distribution system.

C. VDER Value Stack

Borrego agrees that standalone energy storage should be eligible for the Value Stack tariff, and supports call-signal-based DRV mechanism but suggests refining it by: narrowly tailoring call signals’ duration to meet the distribution need;

requiring a minimum of five call signals per year; providing bonus payments to production in response to call signals over 15 hour cumulative total; having the DRV value spread over ≤15 signals called in a calendar year; and having DRV be fixed for the life of the tariff.

GI Energy recommends additional VDER components to reflect the unique nature of energy storage, and that the Value Stack be described and visually depicted by compensation components and all applicable delivery bill cost components. GI Energy also requests that the mechanics of payment and billing for FTM energy storage use cases under the proposed VDER Expansion Order be clearly explained, and that the utility call signal go out at least an hour prior to the 5 A.M. NYISO Day-Ahead Market bid close. Gi Energy also requests that consideration of expanded VDER eligibility within the Value Stack and Rate Design Working Groups include defining and harmonizing delivery ratemaking to FTM energy storage, and not restricting consideration to only BTM resources.

Hydrostor recommends expanding the VDER tariff to projects deployed at all system levels, including the bulk system, and encourages NYSERDA to review the VDER tariff to ensure it maximizes the scheduling coordinator's operational flexibility.

IPI supports the expansion of the Value Stack to include standalone energy storage, and asserts that all energy storage should receive compensation for the range of services they can provide to each level of the grid.

IR supports the recommendation to expand the VDER Value Stack to standalone energy storage resources, and the proposal to use contracting as a mechanism for lower financing costs including extending the DRV lock to seven years and utility-secured load management contracts for up to five years.

Joint Utilities agree that reflecting a shaped E-Value would provide improved price signals, and assert that it would be premature to adopt the technology-specific recommendations from the Roadmap at this time since this issue is being addressed by the VDER Value Stack Working Group. Additionally, the Joint Utilities recommend existing DLM call signals be employed to effectively address DRV rate lock extensions and call signals for top utility system hours, and suggest the Commission consider the Joint Utilities comments submitted in August on this topic.

KCE encourages the inclusion of stand-alone energy storage as part of the VDER process, and recommends: clarifying that energy storage will receive the nodal and not the zonal price for both charging and discharging as a VDER project; defining a capacity value for energy storage to ensure the projects can become profitable sooner; 4 hours as the amount for full credit and allow partial credit for lower duration projects; awarding two streams of environmental credits (overall GHG emission reduction and localized emissions based on NOx/SOx for those projects in environmental justice areas); a 7-year DRV lock-in; and that each utility should define a separate tranche of high value locations for energy storage to aid developers in selecting locations.

NY-BEST agrees that changes to the DRV and LSRV components of the Value Stack are needed, and that the Value Stack should be expanded to include stand-alone energy storage. The DRV rate lock should be 7 years, and perhaps longer; there should be an advanced call-signal for the top utility system hours; the unused LSRV avoided cost value should be added back into the DRV value until a more comprehensive solution can be implemented; and that limitations should be removed on the ability of DERs to participate fully in the Value Stack, demand response or Non-Wires Alternatives (NWA) programs.

NYCEJA requests that Staff conduct a robust, iterative, and fully transparent review, in partnership with stakeholders, of the comments submitted by the Aligned Parties in the VDER Value Stack Working Group, and address their applicability to energy storage across relevant issue areas and identify opportunities for their integration and implementation.

NYPA supports: expanding VDER eligibility to standalone energy storage and regenerative braking coupled with energy storage and expanding the DRV rate lock-in from three to seven years; allowing the utilities sufficient time to streamline and gain more experience in the NWA solicitation and selection processes before considering phasing out LSRV; allowing sufficient time for extensive record development, deliberation and stakeholder feedback to help design a mechanism that accurately captures the Value of E for avoided marginal emissions; accounting for local emissions' value and any positive or negative impacts of DERs on environmental justice communities; and identifying and monetizing the full range of retail services energy storage is capable of providing.

O'Connell Electric commented that they do not support adding energy storage to VDER until the tariff is completely revamped, as it is already complicated, unpredictable, and unfair.

SEIA supports the recommendation that energy storage should be an eligible resource for the VDER tariff. The amortization period of the avoided cost that informs the MCOS value should match the period over which a DER is eligible to receive compensation, and that the 25-year period proposed in the VDER whitepaper with no reduction in value every two years is a reasonable placeholder.

Stem supports the key recommendations regarding standalone energy storage eligibility, the DRV, and LSRV, but notes that the Roadmap does not address the potential "missing money" with regards to the capacity value of energy discharged from BTM energy storage to serve host load. Stem recommends that any further analysis or reports done with respect to the VDER Value Stack and energy storage should include treatment of the capacity value of non-exporting energy storage discharge.

The City commented that the Commission should continue to refine the VDER Value Stack and take actions to ensure that clean energy projects, including energy storage, are properly valued and compensated for all the benefits they provide.

Reply Comments

ACE NY agrees that: energy storage should be an eligible resource for the VDER tariff, both when installed alone and when paired with a renewable energy generator; dispatchable technologies, such as energy storage, being capable of hitting a smaller target window of grid injections, should be encouraged to do so to reduce emissions when the grid is expected to emit the most pollution; local pollutants, such as NOx and SOx, should be included in E-Value calculations; and the time-varying E-Value should be made available on an opt-in basis to all standalone and paired energy storage, including energy storage installed before the date that such variable E-Value is adopted.

D. Carbon Reduction Benefits and Shaping the E Value

AEMA recommends that the E Value be time- and season-sensitive to ensure that the incentives for energy storage are fully captured and made available for financing and deploying energy storage where it is most needed.

Borrego supports the Roadmap's proposed creation of a 4-8-hour window for a statewide "peak E" Value that varies seasonally to recognize the higher carbon emissions that occur during peak times, but recommends the time-varying E Value should be made available on an opt-in basis to all standalone and paired energy storage, including energy storage installed before the date that such variable E Value is adopted

EnergyNest suggests that thermal energy storage systems integrated with renewable thermal power generators or BTM of an industrial processing facility utilizing waste heat for power generation, be granted an "E+" Value, where the "+" is an adder representing the environmental value of time-optimization renewable thermal fuel for power and the value of repurposing what would otherwise have been wasted thermal energy because there is no Marginal Emissions Rate for charging. Additionally, it recommends a 5-hour peak window not be a requirement, and instead allow assets to discharge into the peak window as they are able and willing.

ETS advises shorter and seasonably flexible participation windows to pilot new rate designs and enable optimal market participation signals.

GI Energy commented in support of the proposal to shape the E Value so that it more appropriately reflects the amount of carbon being displaced during on-peak and off-peak periods, and believes that Staff should continue to identify the value of other avoided pollutants and add those costs to the Value of E. Ultimately, NYISO should reflect the value of carbon in its dispatch and thus negate the need for a carbon offset in VDER.

Hydrostor supports the data-driven approach to quantifying carbon emission reductions described in the Roadmap, but notes the importance of considering this data across the full technology lifecycle, including manufacturing and disposal, and suggests that valuation of carbon reduction should account for the ability of long-duration energy storage such as Advanced Compressed Air Energy Storage (A-CAES) to replace fossil generation.

IPI recommends that the Commission should clarify that the E Value is not limited to carbon, and start working towards incorporating local pollutants.

Joint IPI recommends: evaluating the net emissions of energy storage based on granular marginal emission rates; applying marginal emission rates to update the E Value with higher temporal and locational granularity for application to dispatchable energy resources; calculate marginal emission rates that are developed for other states; providing a real-time signal that enables and rewards energy storage operators for dispatching based on current grid emissions; and expanding the current scope of the E Value to include the public health benefits of reducing local pollutants, particularly in environmental justice communities who are disproportionately burdened by polluting power plants.

Metropolitan Transportation Authority (MTA) supports receipt of full carbon benefits for displacing carbon during peak E hours from resources which can demonstrate capability to charge entirely from renewable resources, such as in paired configurations. It states that regenerative braking meets these criteria because it provides electricity as needed without any emissions.

NRDC recommends that Staff develop a framework to assess the E Value for energy storage using granular data, which could be used to choose among projects competing in a solicitation, and to inform a performance incentive for those projects. Staff should use hourly MER data, at high spatial granularity, to link the E Value to an accurate depiction of emissions impacts, as well as develop sub-hourly MER data to provide a more accurate assessment of environmental value.

NY-BEST comments that stand-alone energy storage should not be excluded from receiving the E Value, the value of which should be based on marginal carbon emissions. Staff should be improving the E Value calculation to compensate for the environmental benefits associated with avoided local criteria pollutants, as well as avoided emissions in environmental justice areas that are currently disproportionately affected by the environmental impacts of fossil-fueled generators.

Stem commented that: accounting for carbon reduction from peak load shifting is unrelated to whether the energy storage is charged from co-located renewable energy generation; the calculation of carbon benefits should be the same since the carbon benefit depends on the marginal generators in either case; and Staff should adopt an overall framework that values the carbon reduction achieved in the shifting of energy independent of the E Value as constructed today.

The City supports the development of a more granular E Value that accounts for differences in emissions between energy from energy storage and grid power, supports the development of an environmental justice Value Stack adder, and recommends the Commission consider a resilience adder that compensates energy storage used in critical community facilities.

The Enel Group supports Staff's recommended method for determining the E Value from energy storage that charges from the grid, and recommends using the three-meter solution suggested in the current VDER rate.

E. Dynamic Load Management Program Improvement

AEMA supports Staff's recommendations for making longer-term rule and price certainty in the utility DLM programs, and asserts that the revenue certainty created for reliable DER resources, not limited to energy storage, would give developers and aggregators a stronger business case to implement automation or other technologies.

EnergyNest agrees with the DLM terms being lengthened to at least five years and including sub-metering at the energy storage system-level, but requests that the definition of energy storage system be broad enough to accommodate the meaningful contributions of high-grade heat-based thermal energy storage.

Joint Utilities comment that the Roadmap changes are unnecessary because: (1) the current DLM approach is working; (2) the proposed DLM modifications would create a multi-year lock untethered to a specific grid need; (3) the recommendation could create confusion, create artificial arbitrage opportunities, and produce suboptimal outcomes; and (4) the premium service proposal based on performance is unnecessary as the current DLM programs already expect consistent and high performance levels from participants. Instead, they recommend: participation in DLM programs be fixed at three- to five-year terms with resources acquired via competitive procurements that include performance penalties; the development of a "premium" DLM resource category; and DLM participation by energy storage on a sub-metered basis. DLM programs should be technology-agnostic since the overall goal is to reduce the total load of a facility and note that the Roadmap's provision to limit specific resources from obtaining certain benefits from the proposed DLM modifications represents a violation of this principle.

MTA supports measuring energy storage DLM participation by sub-metering battery output directly at the storage system, which it states will increase accuracy in comparing load during DLM events with historic customer load baselines. It seeks longer agreements with higher compensation to support this DLM participation.

NY-BEST supports the recommendations in the Roadmap for improving DLM Programs, including the recommendation to establish an option for multi-year participation where terms of participation remain unchanged for a longer period. NY-BEST recommends that Staff and the Commission exercise caution against making major changes to the existing program structures so as not to disrupt programs that are functioning well, and that Staff should engage with Stakeholders before utilities file changes to DLM programs.

NYPA supports the Roadmap recommendations to implement multi-year DLM program participation agreements and a premium for resources with a high-performance factor during DLM events.

Sunrun comments that NWAs are limited to location specific needs and do not provide enough market opportunity to support wide scale deployment of energy storage. Sunrun encourages the adoption of a tariff-based demand response procurement approach for BTM solar and storage, and suggests that the program be designed and implemented to include a residential component that explicitly allows residential DER customer participation, including those on netmetering tariffs.

The Enel Group supports the recommendations, especially the multi-year DLM program participation agreement where terms of participation remain unchanged for a period, but cautions against making major changes to the existing program. The Enel Group's only exception is that the premium auto-DLM resource category needs further exploration.

Reply Comments

Enel, **NY-BEST**, and **NYPA** are supportive of the Roadmap's recommendation to extend the term of DLM programs, while developing a premium DLM resource category.

Joint Utilities reiterated their objections to the proposed changes.

NY-BEST notes that the current DLM program structure results in a bias toward short-term, low-capital investment solutions because of the short-term horizon of the revenue stream.

Locking the rates for 3-5 years would provide a hedge to all ratepayers, while stimulating more participation in cost-effective programs. Staff should engage with stakeholders before utilities file changes to DLM programs to ensure that the changes are fully explored and avoid unintended consequences.

II. UTILITY ROLES

A. Earnings Adjustment Mechanisms

EnergyNest comments that the monetary value of EAMs to increase utilization rates should be symmetrical in regards to valuing peak reduction and off-peak consumption.

Joint Utilities recommend that new EAMs be considered, and suggests the establishment of an EAM focused on load factor. The Joint Utilities do not support the development of a system-wide load factor EAM, but do see a role for a more focused location-based EAM. The Joint Utilities support the ability of individual utilities to propose and develop EAMs that target the use of DER to address local needs such as improved utilization of specific equipment, and assert that the Commission should consider allowing each utility to propose additional utility programs and utility ownership opportunities for energy storage.

NY-BEST agrees that energy storage is uniquely qualified to improve load factor, and recommends a distribution system load factor. NY-BEST urges the Commission to explicitly include energy storage in the EAM since it would align utility actions with the delivery of system value to ratepayers.

Plus Power supports the concept of explicitly incorporating EAM metrics to encourage the IOUs to invest in energy storage, either through ownership of assets that provide transmission or distribution services, or contracts with energy storage assets. Plus Power expresses concern that the suggested load factor metric may not be the correct measure since demand response can equally be used to reduce load factor.

The City recommends that: EAMs and utility shareholder incentives must be directly linked to incremental achievements, rather than business-as-usual performance; prior to any new EAMs being implemented, an analysis should be conducted to collect baseline information, benchmark each utility’s current system-wide load factor, and set appropriate targets above those baselines; and a new EAM should be designed in such a manner that fosters development of energy storage, rather than through broad targets and metrics that can be achieved through alternative means like load shifting or other forms of DER.

Reply Comments

UIU states concern that providing an EAM for improvement to load factor could result in duplicative incentives being distributed due to other programs also providing incentives for improved load factor. It states further that EAMs should only be considered in the context of a rate case where the total revenue requirement and proposed rate of return are known.

B. IOU Business Model

AEMA supports the Staff's promotion of competitive procurement and third-party ownership of energy storage while maintaining the existing limitations on utility generation ownership. AEMA recommends the Commission direct such procurements to be awarded through a transparent, competitive process open to third-parties and with third-party ownership. AEMA comments that it is concerned about the potential implications of the NYISO's proposal to subject energy storage to BSM.

Borrego strongly supports the Roadmap's reaffirmation that third-party ownership of energy storage, including capacity, is core to New York's REV principles.

GI Energy commented its support of the Roadmap recommendations, although they emphasized that delivery tariff treatment for utility owned FTM energy storage is not equal to 3rd party-owned FTM energy storage delivery tariff treatment.

GlidePath strongly agrees with Staff and existing Commission decisions regarding utility ownership of energy storage.

Hydrostor recommends a reevaluation of the rules governing utility ownership of energy storage, asserting that IOU's understand the long-term needs of their customers and are well positioned to procure long-term infrastructure to meet these needs through competitive processes. IOUs should also be able to take advantage of incentives for energy storage, which should be geared toward newer technologies to ensure that sector is able to innovate where appropriate for the application.

IPPNY agrees with maintaining the existing limitations on utility ownership, and recommends that energy storage projects should be developed and owned only by independent providers selected through a competitive process.

Joint Utilities comment that targeted utility investments in energy storage can be structured to broadly benefit the system and customers.

NPS supports the REV principles of competitive ownership of energy storage in DER markets.

NY-BEST supports existing limitations on utility ownership.

O'Connell Electric noted its disagreement with the Commission's ruling on allowing IOU ownership if the markets fail.

SEIA strongly supports the current limitations on IOU control of energy storage, and asserts that if markets fail to deploy energy storage Staff should seek to understand whether additional regulatory barriers should be removed to encourage greater deployments by third parties.

Sunrun supports the Roadmap's recommendation to maintain existing limitations on utility ownership of energy storage, and urges the Commission to continue to work with the NYISO to develop market rules that will allow third-party-owned energy storage to participate in wholesale capacity markets.

The Enel Group strongly supports maintaining the existing limitations on utility ownership, even in instances where there is the de-facto absence of competitive markets.

<u>Reply Comments</u>

ACE NY noted its support for third-party ownership of energy storage and maintaining limitations on utility ownership.

Joint Utilities comment that the Roadmap recognizes that the Commission permits utility ownership for energy storage integrated into the distribution system in cases of market failure and in other situations, and assert that arguments to further restrict utility ownership are counter to the Commission's prior decisions.

C. Facilitating NWA Projects on Utility-Owned Land

GI Energy supports the Roadmap recommendations.

GlidePath agrees that siting independently-owned NWA projects on utility-owned land could provide benefits to ratepayers, encourages the Commission to adopt a form lease for utilities to use when making utility-owned land available for NWA projects, and encourages the Commission to closely monitor any utility purporting to make its land available to NWA developers to ensure that the utility is offering its land on market terms.

Hydrostor supports this recommendation and agrees that it would lead to improved competition in NWAs, and recommends increasing utility transparency regarding what substations would address current and forecasted needs.

Joint Utilities comment that they are open to exploring alternative business models for NWS, including the use of utility land for third-party projects. They recognize the uncertainty that developers face in estimating interconnection costs, but note that without specific project details such as technology type and size, any estimate would be too broad to meaningfully reduce risk in project economics. The Joint Utilities assert that the proposal that all utility customers pay interconnection costs for energy storage resources represents an approach that favors energy storage over other DER and violates REV.

NY-BEST supports Staff's recommendations regarding facilitating access to utility-owned land for NWAs.

SEIA comments that using NWA solicitations to procure energy storage can pose significant limitations on developers who are then forced to respond to market signals from utilities, often without the required lead time to bring projects to a nearly implementable stage. The VDER tariff should be a heavily relied-on tool for furthering energy storage development.

D. Optionality in the IOU Benefit-Cost Analysis

ESA strongly supports Staff's recommendation that the BCA consider how to incorporate the basic aspects of optionality into that analysis and suggests further stakeholder processes.

GI Energy supports the Roadmap recommendations.

Joint Utilities assert that there are sound policy reasons why issue-specific modifications to the BCA Framework should not be made in isolation without consideration of how such changes impact other technologies and other policies.

NY-BEST agrees that utilities should be directed to incorporate the value of optionality into the BCA, although it believes that more direction is required from the Commission to ensure that this value is appropriately captured in the BCA.

Plus Power agrees that placing a value on optionality is important, and requests that optionality not just be limited to NWA applications.

The City supports a more nuanced stakeholder process to develop components to the BCA, which will have a significant impact on project economics.

Reply Comments

Joint Utilities comment that they could see merit in considering all of the suggestions.

NY-BEST supports building the value of Optionality into the utility DSIPs, NWAs and BCA framework, and suggests that incorporating optionality in the BCA framework should not be implemented as a "one-off" and should be considered holistically consistent with the process used in updating the BCA Handbooks every two years. NY-BEST recommends stakeholder input be gathered in an expeditious manner.

UIU states concern that the Roadmap BCA did not adequately include the costs of Con Edison's AMI deployment, which would result in overstatement of benefits.

III. DIRECT PROCUREMENT

A. IOU Procurement Through NWAs

AEMA commented that the current NWA procurement process could benefit from increased transparency and reporting.

ESA generally supports the recommendations regarding NWAs, particularly in considering the value of different applications. ESA recommends that the PSC not create a program that is too prescriptive or relies on wholesale market rules that are not yet in place, and cautions against making participation in an NWA solicitation contingent upon receiving approval for participation in the NYISO market.

GI Energy supports the Roadmap recommendations.

GlidePath recommends the Commission closely monitor all NWA solicitations to ensure IOUs are not unnecessarily limiting the viability of an independently-owned project. They recommend that all NWA project developers should be required to post material amounts of development security, with such security tied to key development and construction milestones to ensure that developers remain committed to contacts once they are executed and to prevent speculation.

Joint Utilities comment that they are open to pursuing an NWA expansion when it produces both a positive BCA on an incremental basis and does not delay or otherwise disrupt the localized load relief being pursued through the NWA.

KCE encourages the state to continue to define the value attributes that are needed by the utilities and for them to contract for just those value attributes, allowing for the owner of the project to optimize the rest of the revenues in the wholesale markets.

LIPA believes that a potential alternative to direct utility procurement would be for NYSERDA to centrally procure energy storage resources in a manner similar to its approach to procuring offshore wind. This likely would expedite the acquisition of energy storage, provide a basis for equitable cost sharing, and ensure a consistent and manageable deployment schedule.

NY-BEST believes that NWAs can be a successful mechanism to competitively procure DER solutions. NY-BEST suggests that contract terms should be at least seven years, if not 10-20 years, and align with the amortization period of the avoided costs. Each utility should be required to publish transparent calculations of the benefits and costs, and a spreadsheet that developers can use to see how their project’s services agreement compares. NY-BEST strongly supports the Roadmap recommendation to establish an NWA “+” program and create replicable transparent mechanisms for utilities to contract for the “plus” part of the NWA. NY-BEST recommends that utilities incorporate hosting capacity increases into NWA opportunities by combining utilities’ hosting capacity analyses with utilities’ MCOS analyses to establish both the amount of energy storage and the value of energy storage to incentivize development of energy storage at it most valuable points on the grid.

Sunrun comments that successful NWA offerings adhere to three main principles: Clearly articulate the specific needs of the project; be structured to effectively deploy energy storage capacity; and consider real-world market contexts to enable successful deployment matched to grid needs.

The City commented that NWA opportunities should continue to be limited to those solutions that could be as operationally effective as traditional infrastructure solutions, and with lower costs than the traditional solutions.

The Enel Group commends the work done by utilities in recent years to develop and improve the NWA process, and recommends that the NWA RFP detail the cost of the traditional solution and support the Roadmap's focus on hosting capacity.

Reply Comments

Joint Utilities argue that the VDER tariff is a blunt tool that undercompensates energy storage when it produces quantifiable distribution benefits at specific substations or feeders, and overcompensates energy storage elsewhere. The Joint Utilities do not support the NWA+ proposal if it means proposals deviating from the intended primary purpose of an NWS. While the Joint Utilities agree with the City that the major focus of NWS solicitations should be seeking alternatives to traditional infrastructure solutions, there may be situations where an expanded NWS is a beneficial option because it produces a better BCA than the pre-expansion NWS, and does not impact the timing or effectiveness of the NWS solution. In such situations, the expanded NWS delivers the greatest net benefits to customers.

The Joint Utilities note that their standard NWS practice is to provide potential bidders a full suite of data for bids. Each NWS solicitation is unique but they all include detailed information related to the specific system constraint and the location and types of resources that might be employed to relieve the constraint. Developers are free to propose other options and NWS procurements can result in solutions that do not precisely match the impact of the traditional solution.

The purpose of NWA solicitations is not to guarantee the financeability of projects, but rather to assure that distribution system needs are addressed. Ideally, the term of the compensation should correspond to the term of the services needed and rendered. While the Joint Utilities believe that there may be ways of making the amount of compensation more certain, any compensation provided to DER must be linked to the value of the anticipated infrastructure deferral and not the

DER’s measure life. If energy storage or any other form of DER is determined to be part of a cost-effective solution to meet a system need but the project cannot be financed, the Commission should consider utility ownership.

NY-BEST stresses that if the BCA, after any incentives, is positive, then the project should move forward. Any incentives would be justified outside of the BCA and therefore should be considered as a “cost reduction” in the BCA analysis. The NWA+ program is needed to ensure that the benefits and services that a given energy storage device is capable of providing are fully utilized and compensated.

NYPA notes that mandatory procurement requirements for public entities make it difficult for public sector customers to meet otherwise reasonable NWA deadlines. NYPA recommends that the Commission develop a “prequalification” process allowing a developer to identify a technical energy storage solution, obtain general approval from the utility, and secure the required equipment and contracting resources – all in advance of a specific solicitation.

B. NWA Term Extension

AEMA agrees with Staff’s recommendations, including the NWA+ model and allowing for term extensions when projects have a longer expected lifetime than the proposed NWA term.

GI Energy supports the Roadmap recommendations.

Hydrostor strongly supports the Roadmap’s recommendation to increase NWA contract terms, which should likewise be matched to specific resource lifespans. NWA contract terms should be extended to a minimum of 30 years, and additional term lengths should be available to technologies which can demonstrate their ability to operate beyond 30 years.

NYPA supports expanding the NWA project scope by allowing the NWA resource to access revenue opportunities in the wholesale energy markets when the resource is not needed for distribution system relief. NYPA suggests the Commission initiate a stakeholder process to develop protocols on coordinated dispatch of energy storage services for the bulk power system and distribution grid. NYPA recommends the Commission identify the specific data needed to define NWA needs, and develop a process for market participants to access it.

C. Large Scale Renewables Procurement

EnergyNest comments that NYSERDA should include waste-incineration power generating facilities as eligible for renewables procurement.

FCHEA noted its agreement with the Roadmap recommendation for continuing to encourage energy storage pairing with large scale renewables, particularly when such a pairing provides cross-sector opportunities and non-wires solutions.

GI Energy supports the Roadmap recommendations.

GlidePath comments that NYSERDA should facilitate the coupling of specific, intermittent generation projects bidding into its procurement programs with new or existing energy storage projects, rather than only allowing developers to jointly bid project combinations. Co-locating energy storage with an intermittent generator or tying a specific energy storage project to a specific intermittent generation project is likely to result in overly complicated contractual structures, underutilized energy storage assets, and reduced ratepayer value. Additionally, having developers collaborate to jointly bid paired projects may have anticompetitive implications for the market with a negative impact for ratepayers. As an alternative, NYSERDA should independently procure certain amounts of energy storage with each renewables procurement, with such procurement potentially structured as a capacity payment.

Hydrostor agrees that the LSR program design should encourage co-location of energy storage with renewable generation, and recommends standalone energy storage be made eligible for RECs or another program be developed to recognize the benefits of emissions free dispatchable technology.

LIPA recommends that coordination with the affected utility on siting energy storage will help to ensure that consideration of energy storage options is reasonable and appropriate in terms of location, use case, amount, cost, and system impact.

NY-BEST notes that the six-point adder for energy storage is insufficient to result in a meaningful increase in renewables paired with energy storage, as these points are not monetizable. NYSERDA could establish a "clean hours" similar to what Arizona Public Service did for a recent RFP to establish higher compensation levels for resources that can line up well with these hours. NYSERDA could also provide a real valuation for energy storage within the renewables procurement, and should analyze the specific additional benefits provided by pairing renewables with energy storage and create appropriate valuation mechanisms. Such an evaluation should consider benefits such as avoided curtailment, avoided GHG emissions, avoided local criteria pollutants, and avoided transmission.

The Enel Group recommends procuring resources, including renewables paired with energy storage, renewables, standalone energy storage, and demand reducing technologies and services, that can deliver clean energy during peak periods using a Clean Power Certificate equaling 1 MWh of environmental attributes. NYSERDA should enter into multi-year contracts and procure CPCs through annual solicitations. All load-serving entities should be obligated to procure certificates.

D. New York State "Leading by Example"

CCMT has identified a location on the No. 7 Flushing line where a Wayside energy storage system (WESS) can be installed and made operational within a short period of time. A WESS demonstration on the No. 7 Flushing line would be a first step toward deploying WESS throughout the MTA-New York City subway system with a potential energy and demand savings of $84 million or more annually. A full-scale deployment of WESS is estimated to cut CO2 emissions by 168,000 metric tons annually. NOx reductions are approximately 181 metric tons annually, and SOx reductions are 111 metric tons annually. If the Green Bank or other financial institutions will provide project financing for the capital cost of WESS systems that can be repaid by a lease payments made by the MTA, then the MTA will not be required to expend capital budget funds and will be able to take ownership of the WESS system at the end of the lease term. NYGB may also be able to provide revolving funds or warehousing, credit support, and other financing techniques to support the rapid deployment of WESS in the subway.

GI Energy commented that the Roadmap represents a rare chance to define a coherent energy storage service classification amongst utilities for the distribution and bulk system use cases. NYISO responded to FERC Order 841, which required a set of comprehensive, coherent rules for integrating energy storage into the wholesale markets, by creating a new energy storage asset class. The Roadmap could extend NYISO's work to the Joint Utilities to create a coherent set of definitions for FTM energy storage use cases across New York.

Greenlots notes that there is an opportunity for the Roadmap to more adequately address storage-integrated EV charging, and that it expects to see a future trend of co-locating EV charging infrastructure at already-existing storage sites.

NPS notes that resiliency seems to be an area the Roadmap could further explore, or define. Perhaps, an added incentive under the formulation of the bridge incentive could be warranted for microgrids that provide a community relief element.

NY-BEST agrees with the recommendations of the Roadmap regarding leveraging NYPA, OGS, and SUNY to deploy energy storage projects. The State and municipal facilities owned, managed, and accessible by these entities represent a significant untapped market for energy storage that can provide important proving grounds for energy storage and opportunities for developing rules and strategies for integrating with distribution utilities and NYISO markets.

NYPA supports the Roadmap’s recommendation that the State continue its role as an early adopter of sustainable energy solutions. Current energy storage pricing and incentive structures for energy storage severely limit the number of projects that can be done without subsidy, and public-sector customers do not have the ability to take on investments without a reasonable payback.

O’Connell Electric supports governmental entities entering into PPAs and performance contracts where the private sector can monetize the tax credits and depreciation to truly help government buildings lower expenses. It should be a public open bidding or RFP process for selecting developers who can provide these contracts to any governmental entities. This will help keep collusion to a minimum.

IV. MARKET ACCELERATION INCENTIVE

Borrego supports the Roadmap’s market acceleration incentive, and urges its swift implementation to take advantage of the ITC. An upfront $/kWh incentive based on the capacity of the energy storage facility would provide revenue certainty that will reduce financing costs of energy storage. Borrego also supports the Roadmap’s proposed bifurcation of the incentive into one program for standalone systems and one for energy storage paired with solar PV. For standalone storage, we support a bridge incentive of $370/kWh issued in kWh blocks that decline by 10%.

EnergyNest recommends that NYSERDA administer a cash rebate program, similar to NY-SUN, on a $/kWh basis. Eligibility requirements governing the incentive should be translatable to kWh-thermal as well as kWh-electrical. To jumpstart the market, we recommend starting with $150/kWh-electrical. For thermal, this will translate to between $35-$50/kWh-thermal.

ESA supports the bridge incentive and recommends that receipt of the bridge incentive does not preclude participation in other programs. For the customer-sited market segment, Staff rightfully identified the need for a storage adder in the NY Sun Program as well as a separate declining block bridge incentive on a dollar per watt-hour basis for storage. Incentive amounts should be developed through gap analysis, and be based on the duration of the system rather than installed watt. Customer classes and applications that face greater hurdles, such as residential should be the focus. Program rules should require enough "skin in the game" to ensure that only serious projects are awarded funds. Incentive program design should focus on installing similar quantities of storage on an annual basis. ESA supports Staff's recommendation to direct a portion of the market acceleration incentive to distribution-connected energy storage systems through NWAs. Finally, ESA supports a REC-type program for energy storage assets on the bulk system.

ETS is supportive of bridge incentives, particularly in the multifamily and commercial sectors, where capital projects must meet certain ROI standards and where the cost of such systems is often the driving factor.

Fluence strongly supports a bridge incentive to be equally split among customer sited, distribution system and bulk system. It also recommends that a different procurement mechanism be used for resources eligible to participate in NYISO markets to avoid issues with buyer side mitigation.

GI Energy supports the Roadmap recommendations.

GlidePath states that market incentives must provide enough revenue certainty to allow a given project to obtain financing. Incentives that are not appropriately matched to a project's economic life and to existing market structures are unlikely to incentivize sustainable development. Market incentives for distribution and bulk-sited projects are well-suited to be modeled after the REC programs. The market-based incentive payment should be indexed or tied to a combination of ancillary services pricing, capacity pricing, and energy costs, so the project owner would receive market payments and NYSERDA would provide the balance. Because credits would be tied to actual market prices, ratepayers would be protected against over-payment.

Hydrostor supports the establishment of a bridge incentive program to fund storage-specific RECs and new technology incentives in NWA procurements, and recommends that the incentive be increased over time.

IR supports market acceleration incentives, but cost effectiveness tests and project timelines should be required. IR proposes that all energy storage projects receive the same incentive amounts, regardless of project cost, and that incentives should take project deployment lead times into consideration because, while most current programs require one-year implementation, large scale new construction and building renovation projects can take two years to complete.

JU argues that incentives should be targeted to the distribution and/or bulk systems because they are more cost effective than customer-funded projects, which typically benefit only the customer. This principle should also apply to the Roadmap's proposal to use $350 million of customer funds, and it should be used strategically to maximize the cost-effective deployment of storage technology and maximizing its contribution toward meeting the State's storage goals. The criteria for prioritization should be based on quantifiable customer benefits and incentives should be transparent with a clear ending date. The JU also recommends that any funded programs be evaluated by a BCA to ensure positive net customer benefits.

KCE encourages NYSERDA to focus funds on grid-tied projects in 2019, since initial projects have the highest soft costs but deploy new technologies which eventually help to lower soft costs. It recommends that the incentive be the delta between the expected wholesale market prices and what it required for project financing. The incentive should not be aligned to a specific use case, but rather to the $/kw-year necessary to bridge the gap between a profitable project and a marginal one. The incentive contracts should have a duration of 7-10 years to create guaranteed revenues. Any project that achieves COD after January 1, 2019, should be eligible for bridge incentives. Incentives should be distributed primarily within the initial years of the program, and decrease thereafter and that the rate of the awarded incentives should follow the decreasing cost trends of technology and deployment of the energy storage systems as they grow increasingly more competitive.

KCE recommends the incentive be a $/kW basis in 2019 and that in 2020 it should switch to a $/kWh basis to encourage longer duration batteries. KCE proposes the following schedule for the incentive: 2019 projects – 100% $/kw-year per kW of new installed capacity for ten years; 2020 projects – 100% of $/kw-year per kWh of new installed capacity for ten years; and 2021-2022 projects – 50% of $/kw-year per kWh of new installed capacity for ten years. The majority of the incentives should be reserved for standalone projects, as there are other incentives designed for combined renewables plus storage. For instance, paired solar and storage allows for the storage portion to receive the 30% ITC and storage paired with onshore wind, offshore wind, and solar are all eligible for NYSERDA's renewables RFP.

Analyzing the projects on an emissions reduction basis will: capture additional benefits from the storage systems; give a non-biased method for distributing the incentive; and encompass a broader range of emissions than just carbon.

LIPA recommends that incentives be conditioned on locating storage projects in the most valuable locations. By using a competitive, central procurement for storage, NYSERDA could assure that the most optimal projects are selected.

Multiple Intervenors opposes the incentive, and recommends that uncommitted funds should be returned to customers or utilized to reduce future CEF collections. If the incentive is created, such funding should be the maximum subsidy provided to energy storage. The Commission should refrain from expending customer funds and focus on ensuring that existing policies, rates and tariffs do not artificially impede energy storage.

MTA supports the incentive and stresses that installing regenerative braking throughout MTA properties will require significant up-front financing which is difficult to obtain without stable, long-term incentive structures. It seeks Commission clarification that the MTA will be eligible for the incentive if adopted.

NPS supports the incentive and recommends a declining incentive over time. It further notes the need for sufficient time frames to allow market mechanisms to develop. A longer contract life would result in reduced upfront incentives. NPS urges the Commission to explore zonal differences in incentives and scaling similar to NY-Sun. NPS also comments that an incentive capacity and value of each zone based on different capacity sizing is warranted.

NRDC supports the incentives, especially for bulk energy storage, noting that the incentives should be designed to maximize emissions reductions. Several recent studies have shown that cost-optimized storage operation can potentially cause emission increases. Bulk resources do not currently have an incentive to be located and operated in a manner that maximizes environmental benefits, and is not eligible for VDER. The incentive could include a combination of an upfront payment and an environmental performance payment. Bulk, standalone storage provides certain benefits that may not be realized by customer-sited and distribution system storage. NRDC goes on to state that bulk standalone storage allows for transmission and distribution deferral, reduction of the use of highly polluting urban peaker power plants, electricity congestion reduction, and is uniquely suited for areas like New York City where large solar arrays and wind farms are not as easy to site and it is more difficult to develop paired systems.

NRDC also supports incentives for storage paired with renewables and for distributed storage, including a new NY-Sun incentive for paired PV plus storage. Distributed storage can ultimately be incentivized by the VDER process if Staff continues to refine and improve that framework.

NY-BEST supports a bridge incentive, and believes that funding should be available for projects in all market segments with the expectation that established line-of-sight cost declines enable projects to be deployed within the next three to five years. NY-BEST believes that allocation of these funds should be based on economic analysis, such as the use case analysis framework and should be used to fill the gap of uncommitted funding left after leveraging existing available revenue streams and taking into account higher soft costs in the near term. If the Commission wishes to incorporate additional policy considerations, such as incentivizing longer duration systems or locating systems in particular areas, it recommends that this be done through adders or additional programs rather than incorporating these requirements into the base incentive.

NY-BEST recommends that the storage bridge incentive be provided in a similar manner to NY-SUN, with incentives available statewide and in declining blocks over time in a technology-neutral manner. It recommends that in setting the incentive levels, Staff and the Commission review the project economics at the utility territory and regional levels, and based upon that analysis establish incentive levels at either the statewide, regional or utility territory level. Incentive levels should be in the range of $0.25 to $0.35 per Watt hour (Wh) for small systems less than one MW. Using this range as a guide, it presents a potential declining bridge incentive that begins with an initial value of $0.35/Wh of installed energy capacity for the first tranche of MWh, with declining incentive amounts for each subsequent MWh block of projects. It encourages the Commission and NYSERDA to study the economics of larger energy storage projects (greater than 1MW) to determine if a reduced incentive may be appropriate.

NY-BEST also recommends that reasonable application requirements be established to ensure that serious projects are awarded funding, and encourages the Commission to make projects constructed after January 1, 2019 eligible for the incentive. NY-BEST recommends projects must receive permission to operate within 18 months of receiving confirmation of their incentive, with 6-month extensions possible. For projects undergoing NYISO interconnection where a class year process is used, it may be appropriate to allow for up to 36 months in some cases for permission to operate before revoking incentives.

For larger scale systems, NY-BEST suggests funding to provide projects with a revenue stream that enables them to participate in the NYISO markets. This requires structuring the incentive to ensure the incentive revenues are included in the buyer side mitigation test. See also comments in the Clean Peak Actions section below.

NYCEJA states that prioritizing projects based on existing projections of cost and market opportunities risks leaving behind the 40% of New Yorkers who are low-to-moderate income. NYCEJA explains that low-income communities and communities of color are often not perceived to be “bankable” by regulators and the financial sector due to ongoing legacies of classism and economic racism. It goes on to recommend that a portion of the $350 million be devoted to piloting innovative projects that can help address prevailing barriers to market participation while facilitating innovative and creative opportunities for project participation that result in wide ranging benefits for underserved market segments. NYCEJA refers to the Aligned Parties and E/EJ Value Subgroup comments submitted as part of VDER Phase Two. These recommendations identify environmental justice and low-income characteristics that possibly cannot be monetized as part of the VDER value stack, but should be valued through parallel incentives and allocation of resources for pilot projects.

NYPA supports the bridge incentive, and notes that in most areas of the State the costs to install and operate energy storage exceeds currently available market revenues because in part the services it provides to the system have not been fully monetized. NYPA states that the bridge incentive is not a subsidy or a grant, but rather is rough compensation for those unmonetized values. NYPA explains that the bridge incentive should be available to all utility customers, including NYPA customers, because grid connected storage provides benefits to the electric system and the entire body of ratepayers, and RGGI funds are paid by NYPA customers as well. Finally, NYPA's supply customers provide public services so projects supported through the bridge incentive would be to the public benefit.

O'Connell Electric states that the bridge incentive should have the ROI value be as equal as possible for similar customers, regardless of the actual physical location throughout the State. It explains that a lesser incentive is needed in areas that already have very high rates. The areas that require higher initial incentives are those areas that have lower kw rate structures. O'Connell states that it observed this unequal disbursement of incentives funding with solar incentives where most of the incentives were spent in the downstate region where the end user (e.g., homeowners and business owners) did not need as much of an incentive to have a very attractive ROI.

State business owners who employ residents must receive a higher incentive than FTM or IOU projects. Large scale FTM and IOU projects have a substantial advantage due to the economies of scale and should not need as high of an incentive to reach a fair ROI. It encourages the Commission to assist and promote the incentive to the business community to continue employing residents rather than having those employers relocate to another state. O'Connell states that it would like to see decreased incentive for projects that are owned, engineered, and or installed by out of state companies or residents which would promote the growth of New York State firms.

O'Connell also recommends that the incentive be based on the type and the life expectancy of the system. It supports a larger incentive for a technology with a 20 year life and a reduced incentive with a 10 year life span. It concludes this section by stating that thermal storage should be also factored into the bridge incentive for a fair and equal compensation across all technologies.

Plus Power disagrees that projects with the best economics should be prioritized, and instead requests the Commission to allocate one third of the planned incentives to bulk-scale energy storage and to place the emphasis on where there is the greatest immediate public health and environmental need. Plus Power cites the need to replace aging, expensive and dirty downstate peaker plants and asserts New York will not be able to retire these NOx and SO2 emitting facilities, or meet the clean air goals, without installing large scale projects. Plus Power comments that the clean peak bridge incentive for bulk energy storage should specifically target the downstate generation fleet and suggests it be called the "Downstate Clean Peak Bridge Incentive." Plus Power comments that since the primary intent of the incentive is to deliver a clean peak, it suggests that it be structured in terms of capacity instead of energy.

SEIA supports the incentive, and states that it should be finalized quickly to allow developers access to the ITC. It further supports the development of a NY-Sun adder for pairing storage with solar across all market segments using Clean Energy Fund resources. Furthermore, it strongly recommends coordination with LIPA to establish a similar incentive structure.

Stem supports the bridge incentive and argues that the proposed incentive should encourage storage to provide other grid benefits as a condition of receiving the incentive. It explains that the incentive should not constrain projects to administratively-set operational requirements or specific program and market participation. Stem maintains that the incentivized installations should not be locked into a pre-determined set of grid benefits.

Stem refers to California's SGIP that it states has been the only meaningful incentive program in the country for the customer-sited energy storage segment. New York should adopt the successful elements and avoid the pitfalls and mistakes that have hampered SGIP. Stem further posits that California's most significant, fundamental error was adding operational requirements for incentivized energy storage systems to force those installations to provide grid or societal benefits. In this way, SGIP was changed from a technology deployment incentive program to a messy hybrid of deployment incentive and policy objective program. Stem states that because this was done legislatively, the program has suffered years of legislative and regulatory battles, with a variety of detrimental unintended consequences.

As an example, Stem relates that the authorizing statute states that all technologies must reduce GHG emissions in order to be eligible for the incentive and that California policymakers have interpreted this as requiring each energy storage installation to itself reduce emissions on an annual basis. However, because retail rates in California are not aligned with marginal emissions rates and energy storage systems lack any kind of marginal emissions signal, regulators created what Stem refers to a "misguided requirement" as a proxy for the statutory goal.

Stem states that SGIP also demonstrates the flaws in the idea of minimum cycling requirements for energy storage. At different times the program has required larger installations to cycle either 260 or 130 full cycle equivalents in a year based on the premise that each installation should be executing a minimum amount of grid beneficial activity. However, Stem states that there is no connection between a generic cycle and a grid benefit and therefore there is no rationale for why more cycles produces more benefits. Furthermore, Stem states that program designers have no way to gauge how many cycles is economically optimal for energy storage applications. In Stem's opinion, this has caused energy storage system to cycle needlessly, at times when it's least costly, with the impact of "burning out" the batteries for no purpose and in many cases increasing GHG emissions even further. Stem states that since New York is starting with a clean slate with respect to an incentive, the program can pursue the primary objective of driving down costs by accelerating the learning curve on deployment of energy storage.

Furthermore Stem states that requirements such as participation in a specific demand response program could undermine the BICOS analysis that will presumably be used to size the incentive. Stem strongly supports the BICOS methodology for estimating the economic "gap" faced by energy storage systems today. That analysis is premised on the energy storage operator having full flexibility to pursue the value streams that are currently available. Any of the operational requirements ideas that have been suggested around the country, such as grid services participation, charging from renewables, etc., represents a constraint that could hurt the economics of the system.

Stem expects that Staff will conduct design workshops or other stakeholder meetings to gather best practices for design of the incentive and is committed to bringing the company's considerable experience to these discussions. To seed those discussions, Stem offers the following initial design concepts:

• *Upfront declining block incentive*: The incentive budget should be divided into blocks where the incentive amount declines as each pre-determined amount of capacity or budget is reserved. The incentive should be paid upfront to enable least cost financing.

• *Initial incentive level:* The closest benchmark for the necessary incentive level is $0.35/Wh, which is the current SGIP incentive. New York should start higher than this level because the state has not achieved the soft cost reductions California has to date. Stem states that it is one of the only companies to successfully interconnect advanced batteries at customer locations in New York and can attest that soft costs in New York are substantially higher than in California. Further, in New York City specifically, the prevalence of secondary networks makes interconnection costs significantly higher than in California, where the majority of interconnections are not done on secondary networks.

• *Declining by duration:* Because the incremental costs of installing additional hours of duration to an energy storage system are reduced as the installation scales up, the incentive amount per Watt hour should also decrease. SGIP provides a useful example here, where installations receive the full incentive for the first 2 hours of duration at max power discharge, 50% for hours 3 and 4, 25% for hours 5 and 6, and zero beyond hour 6.

• *Vendor Eligibility:* Vendor eligibility requirements should be limited to a meaningful security deposit provided at the time that an incentive is reserved. Other developer viability criteria have proven to be difficult to design given the desire not to unfairly prohibit new entrants to the market.

• *Vendor Concentration:* To avoid dominance by a few vendors, programs such as SGIP have tried a variety of caps either by technology vendor or by developer. These have caused a range of undesirable outcomes, stalling markets or preventing least cost solutions. Stem feels the best practice here is to implement what it refers to as a "concentration trigger" that pauses a developer's participation once that developer reaches a threshold of reserved incentive. Once sufficient time has been allowed for other developers to catch up, the pause can be released.

Sunrun supports the bridge incentive and an adder in the NY-SUN Program. Sunrun recommends this funding be provided directly to storage program participants through an upfront $/kW incentive as an adder to the solar incentive to be paid in conjunction with the rest of the NY-Sun program. To provide the market acceleration benefits intended, Sunrun recommends structuring the program according to the following principles: Avoid non-value and operational requirements; Allow and encourage participating customers to access other revenue streams for their storage systems; Take into account that additional revenue streams for the provision of wholesale market services may not be realized in the near-term; Make the Bridge Incentive available across the state; and Ensure that projects are funded and operational in a timely fashion.

SW recommends offering incentives based on storage discharge capacity in kWh as capacity-based incentives because: (1) measurement & verification costs in the case of performance based incentives would be incurred by the program and reduce the funds and slow the release of funds, thus make the incentives less attractive to investors; (2) an adder to the previous NY-Sun program tied to a minimal demand reduction apparently did not attract many because of the high threshold (250 kW) imposed – therefore SW recommends no threshold; (3) there may be use cases that could involve participation in demand management, demand response, as well as in wholesale markets; and (4) pairing NY-Sun with storage.

The City suggests that bridge incentive funding should be prioritized for storage projects based on the value proposition the projects provide to customers, and recommends that the proposal for creation of a NY-Sun adder to include solar plus storage be subject to the existing MW Block incentive framework to ensure that incentives are equitably distributed.

The Enel Group supports NY-BEST's proposed design for the incentive, and recommends the following points for the design: The incentive should be available to any customer-sited, distribution-connected, and bulk-level storage device; in order to qualify to receive an incentive the applicant would need to demonstrate site control, potential to finance, record of accomplishment, and be in the interconnection queue; the Commission should explore requiring financial assurance for those who receive incentives until their project becomes commercial to eliminate speculative behavior and it should establish milestones that those who receive incentives would need to meet to retain their incentive before commercialization, while recognizing that interconnection challenges can delay projects; and the milestones should ensure that projects that are not progressing or have no chance of becoming commercial are not holding an incentive more deserving of another party.

While Enel cautions against any onerous operational requirements, it states that incentive recipients for customer-sited resources must demonstrate that they are using the battery either for demand charge management, participation in a utility program or tariff, or the NYISO market, and that the same would be true for a distribution-connected resource (including VDER or an NWA), except for demand charge management. Recipients for bulk-level resources could demonstrate compliance through participation in the NYISO wholesale market or a utility contract that reduces the amount of capacity to procure.

Reply Comments

ACE NY agrees with numerous stakeholders, including NRDC, Borrego, and SEIA, that the market bridge incentive should be instituted as quickly as possible to maximize benefits from the ITC sunsetting at the end of 2019. ACE NY supports an incentive structure that is frontloaded and agrees with commenters that projects constructed after January 1, 2019 should qualify for the bridge incentive. Furthermore, ACE NY supports SEIA's recommendation of a NY-Sun adder and agrees with Borrego's assessment that the benefits provided by the NY-Sun MW Block Program could be replicated in the energy storage market.

IR supports technology neutral bridge incentives that are paid at COD, and recommends a cash rebate program similar to NY-SUN on a $/kWh basis with $150/kWh incentive rate. IR agrees that incentives should be paid at COD rather than over the lifetime of the project. Its experience is that project owners may discount longer term incentive payments.

STEM suggests an upfront declining block incentive with an initial incentive over $0.35/Wh that declines by duration (e.g., full incentive for the first 2 hours of duration at max power discharge, 50% for hours 3 and 4, 25% for hours 5 and 6, and zero beyond hour 6).

Plus Power suggests that one third of the bridge incentives be allocated to bulk-scale energy storage, and that the incentive should be technology neutral and based on system need. It also recommends that the Commission lead stakeholder workshops or other proceedings to develop incentives that solve system needs at least cost, regardless of the technology with incentives specific to service territories.

Joint Utilities support the position taken by Multiple Intervenors and others that the potential cost impacts of the incentive must be evaluated in a comprehensive manner that considers all other utility activities and Commission policy initiatives. The Joint Utilities believe that the Commission should prioritize the use of funds to those energy storage projects that are most cost-effective, thereby maximizing progress towards meeting the State's storage goals. JU states that several parties made specific recommendations regarding a prescriptive disposition of funds across the three energy storage use cases, and that these positions should be rejected because they: (1) reflect an arbitrary result without any supporting technical analysis; (2) would channel money to the customer-sited projects that in many cases will only benefit participants while increasing costs to non-participants; and (3) do not give the Commission the flexibility to allocate funds to the projects that produce the greatest benefits. Considerations related to low-income customers and those in environmental justice areas could be considered by the Commission when determining the allocation of funds among similar projects.

NYPA stated that only customers who pay the System Benefits Charge are eligible to participate in NYSERDA and Commission-approved public benefit programs. Therefore, NYPA should be allowed to participate in the allocation of funds proportionate to its customers' contribution to the $350 million fund.

KCE states that the market bridge incentive must eliminate revenue uncertainty and funding currently nonmonetizable value streams. KCE agrees with NRDC that the funds should be distributed partially upfront. KCE agrees with time-varying E-values, and emphasizes both the inclusion of NOx and SOx calculations as well as modeling the storage systems on a sub-hourly basis. KCE agrees with NY-BEST that projects constructed after January 1, 2019 qualify for the incentive. KCE agrees with Borrego on the retroactive E-Value for all energy storage systems. KCE disagrees with the approach several parties have taken for the allocation of market bridge incentives, and believes that market bridge incentives should be neutral to location and use case and should be the same across the entire state, as the projects that are most beneficial to the electric grid (thus corresponding to highest wholesale prices) will be the ones that developers prioritize. KCE agrees with the suggestion to specifically incentivize standalone storage, and with the ideas proposed by Sunrun that market bridge incentives should factor in that NYISO market participation pathways and revenue earning opportunities.

Municipal Utilities note that grid-scale and distribution level projects should be prioritized when a BCA supports their installation. Utilities are in the best position to evaluate where storage is most beneficial on their systems, and are currently studying the feasibility of a number of storage installations across several member systems in partnership with local communities. Municipal Utilities agree with New York State Smart Grid Consortium and other commenters that storage should not be preselected as the optimal solution in all situations, and that all solutions should be evaluated on a technology neutral basis.

NY-BEST recommends policy actions in all three market segments: Customer-sited; distribution system; and bulk system. It disagree with parties who argue that the State's investment, and regulatory focus should be primarily on larger scale and front-of-the-meter storage applications. NY-BEST believes that State actions in the customer-sited market segment are needed too since they can create benefits for all ratepayers (e.g. reduced peak load, reduced capacity costs, energy costs, system T&D, reduced emissions, etc.). Customer-sited energy storage that is connected to the distribution system can be used to provide the same services as FTM storage. The Joint Utilities general assertion that customer-sited storage is less valuable than distribution-sited is also further contradicted by Roadmap modeling performed by E3 and others that analyzed a number of use cases for energy storage. Storage should be encouraged, not required, to provide other grid benefits as a condition of receiving the incentive. NY-BEST agrees with Stem et.al., that the incentive should be structured in a manner that allows storage owners to deploy the systems as needed to maximize revenues associated with market participation and should avoid creating restrictive operational requirements.

NY-BEST concludes that if the Commission wishes to incorporate into the bridge incentive additional policy considerations such as locating systems in particular constrained areas, as suggested by the JU, or incorporate operational constraints to reward environmental performance, as suggested by other parties, it recommends that these additional objectives be addressed through utility programs such as demand response, NWAs, or through program adders, tariff and/or rate design.

NYC submits that limiting the sourcing of incentive funding only to the CEF may have the unintended consequence of foreclosing storage project development opportunities that have the potential to bring value to all customers. As stated by NYPA, its customers provide public services so projects supported through the bridge incentive would be to the public benefit. Opening up incentive funding to all customers to be sourced from RGGI funding, or some other pool of funding that is also accessible to NYPA customers, is equitable and consistent with the Recommendations set forth in the Roadmap.

Sunrun disagrees with the Joint Utilities that customer-sited storage systems should not be prioritized. The Joint Utilities comments do not account for the benefits that residential solar plus storage can provide to the grid, and ignore reasons stated in the Roadmap.

V. ADDRESS SOFT COSTS INCLUDING BARRIERS IN DATA AND FINANCE

A. Continue to Reduce Soft Costs

Borrego supports Staff's recommendation that the IPWG and ITWG develop a prioritized list of critical issues that must be resolved to allow energy storage to reach commercial scale. However, we recommend these problems be addressed within the next six to twelve months, rather than three years.

ETS agrees with the importance of reducing soft costs for energy storage systems. The permitting process must continue to be refined and improved in order to allow the installation of such systems to go forward. As the process is enhanced, additional suppliers of storage will recommend energy storage systems to their customers, and customers will have comfort in knowing that many systems have now been installed without major delays or extra costs. This is particularly important in NYC, where the indoor restrictions cause some to decide against installing the systems. In some cases, the systems can be installed outdoors, but there can be major cost increases associated with building protective shelters for the battery systems. In many cases, finding space outdoors for the systems is near impossible in NYC as well.

GlidePath suggests that NYSERDA provide guidance to county, town, and other local agencies on development of storage projects within their jurisdictions, including guidance on SEQRA that would minimize the need for time consuming and costly Environmental Impact Statements when a project is unlikely to have significant impacts. NYSERDA should also provide resources for developers to use when communicating with agencies, non-governmental organizations, and the public about their projects and the benefits that such often complex projects bring to the state's electric system.

Joint Utilities will continue to work collaboratively as storage develops while also recognizing that some of this work will be within the context of actual projects. The IPWG and ITWG are the appropriate forums to address interconnection issues as their efforts to streamline the interconnection process have already been incorporated into the SIR technical requirements to support the interconnection of both standalone and paired storage.

O'Connell Electric does not agree with marketing and customer acquisition factoring into soft cost. A contractor, developer, or manufacturer could grossly overspend on marketing campaigns to acquire customers and inaccurately drive up the percentage of soft cost. If the bridging incentives are set up correctly and the rate structures are modified, the market will naturally develop.

The Enel Group strongly supports the Roadmap's emphasis on reducing soft costs, and notes that its most pressing concern with soft costs surround interconnection. If issues around interconnection are not properly resolved in an expeditious manner, the rest becomes moot. As applications for DER interconnections increase, it is important that utilities continue to have adequate engineering resources to process those applications in a timely manner. It will also be important for there to be as much transparency as possible regarding applications.

NY-BEST notes that their most pressing concern with soft costs relate to siting and interconnection, and recommends that the interconnection working groups prioritizes energy storage interconnection this fall. NY-BEST has identified a knowledge deficit among companies about the intricacies of New York markets, and recommends continued focus on industry outreach and education. NY-BEST believes there is a need for increased cooperation between the utilities and energy storage project developers. There is a large variation among the State's utilities in their acceptance of energy storage as a valuable resource.

B. Reducing the Cost of Capital

GI Energy believes that a regulatory framework that supports the sale of energy, capacity and ancillary services into the NYISO wholesale markets while also providing the opportunity to sell dispatch rights to the local utility would reduce risks and the cost of capital for energy storage.

IR supports PACE financing because it is a key mechanism that can provide low cost capital that can be used to achieve the overall energy improvement of commercial buildings.

Multiple Intervenors is supportive of efforts to identify and address market barriers to the greater utilization of energy storage technology. The Commission should at the same time refrain from tilting the playing field in favor of energy storage through the use of customer-funded subsidies. It should, at a minimum, evaluate all such actions in the context of the numerous other initiatives similarly dependent upon customer funds. Multiple Intervenors does not support the creation of new, customer-funded subsidies of the technology, and questions whether they truly are needed. Customers are being called upon to support numerous utility investments related to REV. Customers may be required to pay higher wholesale electricity prices due to a carbon pricing initiative. Multiple Intervenors is very concerned that, if discretionary costs continue to be imposed on customers, the aggregate price and rate impacts of the Commission's collective initiatives will cause energy-intensive businesses to increasingly shift production, capital and jobs to other regions.

C. Workforce Development

GI Energy supports the Roadmap recommendations.

Hydrostor supports the Governor's directive to increase energy storage sector employment to 30,000 jobs by 2030. Hydrostor notes that long-term operational employment is not captured by the Roadmap. In addition to the hundreds of high-value engineering and construction jobs created during the multi-year construction window, A-CAES systems require a dedicated, full-time operations and maintenance staff. The ongoing employment opportunities generated by A-CAES projects mean that communities will see economic benefits for the entire 30 plus years of the project. This long-term benefit supports the development and expansion of local service industries. Other technologies which operate autonomously such as lithium-ion do not create comparable lasting benefits and have limited economic impacts during their construction given the short construction window.

NYCEJA supports Staff recommendations for a multi-sector industry partnership to address wide-ranging supply chain and workforce needs, and recommends that opportunities to support disadvantaged workers must be made a priority. All direct procurements of energy storage must have minimum requirements for project-related expenditures to be allocated to local and Minority and Women-Owned Business Enterprises, with higher favorability given to project proposals that exceed these minimal requirements. NYSERDA and DPS should partner with labor organizations and the Governor's Working Group to develop workforce development goals, workforce programming, and energy storage procurements targeting the following populations, particularly residing in environmental justice communities: Women; Formerly Incarcerated New Yorkers; Veterans; Native Americans; Low-income individuals; Individuals with disabilities; Current and/or unemployed workers in fossil fuel based industries, such as power plant workers; and Youth participating in work preparedness training programs that include energy-related technical training, such as technical high school programs, etc.

NYSERDA and DPS should convene a series of vendor forums and job fairs targeting these firms and recruitment of the priority populations listed above, with particular focus on environmental justice communities. These forums and fairs should be carried out in partnership with labor organizations, workforce development specialists, academic institutions, chambers of commerce, and community-based environmental justice organizations. These forums will bring together industry participants and experts to support local and MWBE firms poised to broaden their operations to participate in research, design, production, and supply opportunities in energy storage. Forums should include industry training and guidance on emerging markets, regulatory considerations, relevant incentives, bidding processes, and structure sustained opportunities for ongoing collaboration on business incubation and workforce development, thereby providing pathways and reducing barriers to energy storage participation among local and MWBE firms.

D. Data Access

Borrego supports increased data transparency generally, and the Roadmap's recommendation, specifically, to require utilities to provide developers with hourly load data for substations, with increasing granularity over time.

The Enel Group supports increased focus on access to data, although it is unclear how anonymized data will help connect DER providers and customers absent the customer volunteering to share their contact information. To ensure anonymized data is useful, Enel recommends that customers can opt-in to sharing their contact information with qualified DER providers who have appropriate data protections in place and who have demonstrated a clear ability to develop new storage projects. REV Connect or Con Ed portals may serve as an appropriate platform for facilitating this matchmaking.

GI Energy commented that they will address this topic in comments to the DSIP proceeding.

IR supports the recommendation that utilities and NYSERDA collaborate to develop a searchable database containing aggregated customer-related load and usage data, because it will reduce costs to identify and acquire customers that can benefit from energy storage technologies. IR suggests that bill design standards be developed to help reduce soft costs further. While not addressed in the Roadmap, it is consistent with the intent reflected in making customer data more readily available. Bill design and rate transparency are critical to help customers understand, interpret and respond to the price signals inherent in electric rates. Poorly designed electric bills can be confusing to customers if demand charges and time of use rates are not specifically outlined.

Joint Utilities comment that they already provide developers large amounts of system data to assist in the development of their proposals, including: (1) the results of marginal cost of service studies that are used to present distribution values, (2) DRV and LSRV in the VDER proceeding, (3) posted NWS information that is available on the utilities' websites as a result of distribution planning analysis, (4) DER hosting capacity maps that also serve as access points to more granular system data information such as DER connected to a circuit or DER in queue, and (5) granular, forecasted 8,760 hour data at utility distribution substations. The Joint Utilities view customer privacy as a priority and the Commission's long-standing policy regarding customer consent shapes the sharing of such customer data. The Commission has established that any deviations from a policy prohibiting the disclosure of customer data without the customer's permission require the Commission's careful review of the specific circumstance that apply to each instance of data disclosure.

The Customer Data Working Group provides the Joint Utilities with a forum to support the development of statewide customer data sharing standards, coordinate implementation efforts, and solicit stakeholder feedback on the evolution of statewide standards. Review and development of customer data and privacy rules in the context of individual technology proceedings and roadmaps will lead to different rules for similar providers, causing confusion for DER developers and other third parties and creating duplicative implementation requirements for utilities. The Joint Utilities do not believe that this proceeding is the appropriate forum to decide the mechanism and associated privacy standards for a customer data database. Rather this important and far-reaching topic should be reviewed in a proceeding that will consider all of the aforementioned proceedings and the needs of all types of DER and service providers, weighed against customers' rights to protect their own specific data.

LIPA comments that there will be a need for a vetting process, including data protection and confidentiality requirements, before developers can receive sensitive customer or utility system data.

NPS supports the guidance in the Roadmap regarding developer access to distribution and customer data, and supports detailed information related to capacity, pricing, renewable penetration, voltage, and the like.

NYPA supports the Roadmap's recommendation that all utilities expedite their AMI deployments, and identify how they are prioritizing AMI deployment and to what extent "high value customers" are being prioritized. NYPA suggests that, to the extent that they are not already considered a high value customer, all public facilities be included in the definition of high value customers and receive priority for AMI deployment. The Commission should require utilities to work with the New York Energy Manager to provide access to AMI data installed at NYPA customer sites.

The City commented that improved access to data is needed to provide greater transparency and assist in siting energy storage in areas with the most value to customers. The City supports the recommendation that utilities be required to provide developers and operators with more granular substation load data. The City also supports the development of a searchable data platform containing customer-related data that can assist DER developers with identifying potential candidates for energy storage and other DERs, subject to appropriate mechanisms to maintain protection for customer data.

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Joint Utilities believe that much if not all of the data requested by the parties is already available and suggest a technical session to review the scope of the available data. They also note that while the Roadmap states that developers need certain information to independently identify and evaluate system needs, this statement is incompatible with the Commission's decision in the REV Track One Order that utilities are best positioned to identify and develop solutions for distributions needs, and that utilities should serve as the DSP providers. In that role, the Joint Utilities already provide developers large amounts of system data to assist in the creation of developer proposals and projects while also using that data internally to plan for and maintain an electric distribution system that provides safe and reliable service.

UIU states that engaging a third party to develop, implement and maintain the searchable data platform containing customer data may not be necessary given the various customer data tools under development. Furthermore, it opines that customer data access should be evaluated within the context of all DERs, not just storage resources.

VI. “CLEAN PEAK” ACTIONS

AEMA supports the recommendations and encourages further exploration of storage to help firm up renewable resources and maintain system reliability and local capacity needs in place of peaker plants that are nearing retirement. AEMA urges owners of peaking units in New York City and Long Island work together with NYISO, PSC, NYSERDA, and DEC to fully coordinate on the process of identifying which units are potential candidates for hybridization, repowering and/or replacement.

EnergyNest recommends the definition of energy sources eligible for the Clean Peak should be consistent with the renewable definition in New York Energy Law §1-103. EnergyNest argues that the State should encourage facilities to take measures and investments that will reduce energy peaks during the hottest and coldest days of the year. EnergyNest points out that the Roadmap does not include renewable baseload facilities like waste-to-energy (WTE)from participating. EnergyNest believes WTE facilities would be a perfect candidate for energy storage because they generate energy at very low demand times which could be released during peak times.

ESA agrees with Staff, although it encourages consideration of the emissions profile of the grid to the extent possible, which will develop market-based signals to charge in low emissions periods, ensuring the intended greenhouse gas and SOx and NOx emissions benefits of shifting clean energy from off peak to on peak are realized. ESA strongly believes that there is a role for standalone energy storage in Clean Peak programs.

FCHEA encourages the exploration of other mechanisms to enable cleaner generation to meet periods of peak electric demand, including flexible capacity benefits that reduce greenhouse gas emissions and increase renewable generation. FCHEA recommendations that hydrogen energy systems would allow the desired flexibility, and can provide accurate and reliable ramping service better than any existing alternative.

Fluence recommends having the DEC quickly implement the pending regulations that limit the NOx emissions of generators, likely resulting in the retirement of some of the peaking resources. Fluence believes the NYISO should enact long-term price signals to ensure those resources are replaced with new cleaner resources. Fluence believes that providing at least some long-term revenue certainty is critical to building energy storage projects in New York, and supports the Roadmap's recommendations to analyze peaker operational and emission profiles on a unit-by-unit basis. Fluence strongly supports the creation of Peaking Unit Contingency Plans and the utilities should define what services they need and when and why they need them.

Fluence supports the Clean Reliability Program and Clean Reliability Credit laid out in NY-BEST's comments. Fluence recommends a few modifications to their proposal, such as only resources eligible to participate in NYISO's capacity market or provide capacity to Load Serving Entities are eligible to receive the credit. Fluence adds that this avoids double payment for resources already receiving compensation for their capacity contributions and ensures the resources are eligible to replace the retiring fossil plants through the existing capacity procurement mechanism.

Fluence comments that the portion of the incentive dedicated to bulk helps provide a portion of the initial funding for the Clean Reliability Credit to smooth and mitigate any near-term rate impacts and jumpstart the program. In addition, Fluence states that if customer and distribution sited storage provides a meaningful number of the Clean Reliability Credits a portion of the Market Acceleration Incentive which is dedicated to supporting these projects should be used as part of the jumpstart funding. Fluence suggests that NYSERDA should consider front loading the payments into the early years to reduce the financing costs of the project, while also having claw back provisions if they are not online for the length of their guarantee.

GI Energy supports the Roadmap recommendations.

GlidePath agrees that additional study needs to be completed on energy storage's effect on peaking resources. GlidePath suggests that the study should include analysis of the likely remaining life of each unit. In addition, the study should include discussions with the owners to determine their commitment to operate and the costs of maintaining the facility. Any study should also include the analysis of new construction hybrid plants using current technologies, with such combinations of gas generation with batteries being a more cost-effective approach than a stand-alone storage system.

Hydrostor supports the flexible capacity credit mechanism proposed by the Roadmap to incentivize cleaner peaking generation. Hydrostor sees A-CAES as well-positioned to replace the Group 1 and 2 peaking units and replace the Group 3 peaking units. Hydrostor believes that sending a market single which highlights the value of this capability will result in significant energy storage deployments.

IPPNY supports the Roadmap's recommendation that a stakeholder process be conducted to determine which units are potential candidates for hybridization, repowering and/or replacement. IPPNY suggests future storage procurements be awarded through a competitive process, allowing for transparency and the most efficient and least cost outcome.

IR agrees with Staff's proposal that the Value Stack include an E Value to reflect time and day marginal carbon emissions, and encourages energy storage technologies that can best time shift renewables and reduce the need for peaking.

Joint Utilities recommend a multi stakeholder process to evaluate this issue, but note there will likely be limitations on sharing transmission data that contains critical energy infrastructure and/or market-sensitive data. The methodology of these solutions should focus on the feasibility of meeting bulk and distribution system needs of the geographic area served by the peakers to determine the optimal deployment of storage and other clean energy as part of a complete solution. The analysis should consider certain load pockets that exhibit sustained peak load periods, availability of space to site DER and other solutions and all viable solutions including energy efficiency, other DER, transmission, and new, more efficient combustion turbines.

KCE has identified peaking plants with the highest O_2/NOx/SOx/sulfur emissions and points out that some of them have many short peaks – which typically lead to higher GHG emissions. KCE believes there is no value to the market to subsidize owners of fossil fuel plants. A process should be created to open competition for solutions with battery storage and other technologies. NYSERDA should identify the highest local GHG emitting facilities in high population areas and offer Market Bridge Incentives to get batteries in the areas identified, and place specific environmental values for CO_2, NOx, SOx, and sulfur emissions for any battery that is within 2 miles of these systems.

LIPA suggests there are significant ramifications of the recommendations regarding peaker units, depending on implementation timing, methodology, and restrictions.

Development and shaping of the VDER E Value should involve utility participation, study, and agreement among the affected entities. LIPA argues that the Reliability and Operational Assessment Studies, as well as the Peaking Unit Contingency Plan, should factor in other major state policy initiatives (such as developing 2,400 MW of offshore wind) that will likely stress and impact the interconnecting downstate electric systems.

NPS supports the Commission's continuing efforts to solicit stakeholder input on additional approaches to valuing flexible resources including storage. NPS agrees that fair and consistent valuation of environmental benefits will support the development of storage markets and the idea of clean peak but only and once market barriers are eliminated.

NRDC comments that Staff should move forward with targeted reliability analyses to expedite the transition from retiring power plants. NRDC supports the Peaking Unit Contingency Plans as a way for the State to smooth this transition process and save customers money by cutting down the time an uncompetitive plant may be supported. NRDC recommends that Staff expand upon the E3 analysis presented in the Roadmap to identify where Contingency Plans are likely to be most needed and explore improvements to the alternatives solicitation process to expedite it.

NY-BEST believes the Commission should leverage its authority to accelerate the replacement of some of the peaker units with energy storage and other clean energy resources. NY-BEST urges the DEC to implement pending regulations to place limits on NOx emissions from these peaking generating units. NY-BEST contends that New York does not have a capacity market that supports a new entrant due to the lack of a long-term price signal, and believes the NYISO should implement a capacity market that provides the forward price signal and multi-year revenue certainty. NY-BEST proposes the creation a Clean Reliability Program and associated Clean Reliability Credit, like the CES RES program, but with a focus on providing clean capacity resources. Further, NY-BEST recommends the procurement in impacted zones of non-carbon emitting energy storage and open to all eligible resources, with contracts ranging from 10 to 15 years starting with 300MWs in 2019 (online date by 2022) and funded through utilities. NY-BEST supports NYSERDA and the Commission exploring long-term bilateral contracts.

NYPA supports the recommendation to produce a Peaking Unit Contingency Plan, so long as it is developed in a manner that safeguards confidential, market sensitive information. NYPA supports the inclusion of other stakeholders, including other transmission owners, to comment during the Plan's development.

O'Connell Electric If there are new alternative rate structures where the delta is great enough between on peak and off peak then you will naturally develop storage.

Plus Power agrees that there should be a short-term incentive that represents the environmental value of clean peak, and recommends development of a Downstate Clean Peak Storage Incentive for Bulk-Connected Energy Storage, and suggests defining a "Downstate Clean Peak Storage REC". Plus Power requests the Commission to clarify that the objective of the Energy Storage Deployment Program is designed primarily to encourage new energy storage projects, not the retrofit or expansion of existing pumped hydro. Further, Plus Power recommends allocating one-third of the State's proposed $350 million budget to the procurement of downstate clean peak RECs, and increase the total budget allocated. Plus Power recommends authorizing NYSERDA to perform a downstate clean peak storage REC competitive solicitation, similar to the RES solicitation, for 2019 (projects to be online 2021/2022).

Stem suggests that policies that seek to use energy storage to reduce GHG emissions should be based on carbon reduction achieved in time shifting the energy only, and recommends that New York implement a "Clean Peak Credit" mechanism that can then be layered into the different markets energy storage can access without interfering with existing market mechanisms, programs or incentives.

Sunrun supports the development of a Clean Peak Program through a stakeholder process, and believes BTM solar + storage should be considered too. Sunrun supports a Clean Peak Credit program similar to that recently approved by the Massachusetts Legislature, and should be stackable and not conflict with other programs or rates. Sunrun supports a contract term of at least 10-years for credits and it should be calibrated to maximize carbon and other emission reductions during peak periods. Sunrun recommends a Clean Peak Program should have a carveout for BTM assets, and believes stakeholders should consider emissions baselines to be the aggregate percent of peak hours annually, rather than the percent on a single peak day.

The City cautions that regulatory changes that affect the operation of peaking units in New York City may have a significant impact on in-city generation, electric reliability, costs to consumers, and air emissions. The City also recommends that a stakeholder process to assess alternative approaches to solving a reliability need should be started after any resources are identified as short-term reliability solutions. Coordination is important between Staff and DEC so that the full impacts of the DEC's proposed peaking unit rulemaking can be realized in advance of implementation. Any Peaking Unit Contingency Plans requirement should allow for full participation by interested stakeholders.

The Enel Group supports the Clean Peak goals; however, more direct procurement mechanisms are necessary. Enel supports the recommendations for the series of Reliability and Operational Assessment Studies and explicitly reviewing storage as an alternative for existing high-polluting and costly peaking units that may close due to pending DEC regulations. Enel also supports the utilities developing a Peaking Unit Contingency Plan. Enel strongly endorses the proposal from NY-BEST for a Clean Reliability Program and Clean Reliability Credit with a competitive procurement. Enel suggests the program funding should come from separate funding other than the $350 million bridge incentive. Enel comments that if BSM rules unfairly prevent the development of storage resources, it supports exploring long-term bilateral contracts, although it prefers that storage owners/developers participate directly in wholesale markets. Enel stresses only third parties should continue to own the storage, and not utilities.

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IR supports a VDER E Value to reflect the time and day marginal carbon emissions.

Stem agrees that the CPC is a novel idea but may be too complex to implement in the near term. Stem believes that the value of time shift is very important and would hope for it to be addressed through an E Value in the near term.

Municipal Utilities believe a Clean Reliability Credit-like mechanism is premature, and it is imperative to allow markets to provide sufficient revenue streams for efficient and cost-effective storage deployment before ratepayers are subject to yet another funding obligation. The cumulative costs and impacts on the bulk system of these programs should be considered holistically.

VII. WHOLESALE MARKET ACTIONS

A. Bulk System Focus

AEMA agrees with Staff's recommended NYISO reforms in the capacity market rules, and argues that resources capable of shorter duration response should be able to aggregate zonally to provide a larger resource to obtain full capacity value. AEMA also strongly agrees with Staff's position opposing the NYISO proposal for subjecting energy storage and DER generally to BSM measures.

Borrego supports the Roadmap's call for State policymakers to work with the NYISO to enable energy storage to participate in the wholesale markets. Borrego also supports the Roadmap's recommendation that the NYISO develop rules and procedures to facilitate participation for energy storage that are not available year-round. Borrego agrees that energy storage should be exempt from any buyer side-mitigation rules enacted by the NYISO because there is no evidence that energy storage can manipulate wholesale market prices.

EnergyNest believes that resources must have multiple hours of storage to be eligible for the program, and that if this is most meaningful to NYISO then the program should compensate for the additional hours of capacity. Additionally, for the minimum capacity of exemption from BSM, EnergyNest agrees that 20 MW-electric is a good potential level to start with. EnergyNest supports the renewable definition found in New York Energy Law §1-103 because it will allow for the most flexible and effective program. Further, EnergyNest requests the Commission recognize the value of recovering waste-heat from industrial processes.

ESA agrees with Staff that storage should be considered as a potential regulated transmission solution to any identified public policy transmission needs, and urges transparency regarding how storage will be evaluated as an alternative to traditional transmission investment. ESA notes that the lack of a sufficient longer-term revenue certainty would be a significant barrier to deployment to storage. ESA believes that an incentive for bulk-scale energy storage, realized through a Clean Resiliency Credit, as proposed by NY BEST, is an innovative and straightforward way to ensure these systems come online despite the lack of price signals and revenue certainty. ESA echoes and supports NY BEST's proposal that the value of that credit could be based on the avoided cost of replacing older, inefficient peaking capacity. ESA notes that the definition of eligible resources is critical to ensure a robust market. ESA agrees with Staff's set of recommendations aimed at aligning NYISO rules related to energy storage with the State's policy objectives. Additionally, ESA supports the Roadmap recommendation to call on the NYISO to exempt energy storage from BSM rules. Alternatively, ESA supports efforts to find other mechanisms to enable energy storage to access the revenues associated with the NYISO ICAP market.

ETS agrees with Staff's BSM recommendations. ETS suggests that if such rules are arbitrarily applied to multifamily or commercial energy storage systems, the systems will have no economic value to customers, and will not be installed.

FCHEA states that adding storage to an intermittent renewable generator behind the same point of common coupling is exceedingly impractical due to NYISO rules that require intermittent wind generators to provide the NYISO the ability to curtail output, and has proposed the same requirement for solar.

GlidePath strongly encourages the continued engagement by Staff in the NYISO stakeholder process. GlidePath believes that the focus should be on the development of sustainable NYISO markets that allow owners of storage projects to derive enough value from the wholesale markets while the programs implemented by NYSERDA should focus on supplementing the revenue of early-mover storage projects during this market development and transition period.

GI Energy supports the Roadmap recommendations.

Hydrostor states that the Roadmap recommends adjusting capacity market rules to allow for smaller and shorter duration resources. Hydrostor recommends this four-hour minimum duration be increased or maintained, arguing that if shorter duration resources are able to bid into capacity markets and are considered equivalent to long-duration resources, New York may experience similar grid challenges to those already facing other regions.

IPPNY recommends the Commission reject the Roadmap's proposal that energy storage be exempt from the BSM Rules, and comments that ICAP prices would be severely depressed and otherwise economic, unsubsidized resources would be harmed if energy storage receiving out-of-market payments were exempt from the BSM rules. Further, IPPNY believes this would prevent the market from sending accurate price signals to new, economic entrants. Nowhere did FERC say that energy storage should be exempt from BSM Rules or that energy storage participation should come at the expense of just and reasonable price formation. IPPNY argues that energy storage resources are not energy limited resources, as they are capable of withdrawing or injecting into the grid at any time, independent of the traditional factors that have defined energy limited resources. IPPNY urges DPS Staff to work through the NYISO stakeholder process to develop capacity market participation rules that value the unique reliability attributes of energy storage. IPPNY adds that the Commission may also consider supporting in the next Demand Curve Reset process a Net CONE that is determined using an energy storage as the proxy peaking unit technology.

Joint Utilities believe exempting storage from BSM would increase the opportunity for downstate economic storage investments to obtain revenues in the capacity market.

NEETNY agrees that storage should be considered as a potential regulated transmission solution to any identified public policy transmission needs. NEETNY believes that it is important for stakeholders to know how storage will be evaluated as a transmission asset compared to other non-storage transmission solutions.

NPS believes that energy storage should have a twenty-year market, but at minimum ten-year commitment. NPS comments that if the contracts are of ten years for market participation, a set of market rules should be created to secure the rights to the interconnection point for another ten years as this will create another value, or assurance, that the project can be financed. NPS states that with the contract duration still not defined, the interconnection of such resource should have the right to interconnection for a period of defined time and the creation of market rules to extend such, once a contract ends. NPS suggests that an energy storage that underperforms in relation to any market defined set of procedures or rules should be negatively penalized, and the energy storage owner will have to make the required upgrades to keep its system satisfactory at the expense of the investment otherwise the energy storage may be subject to non-performance and lose its interconnection status.

NY-BEST concurs with the Roadmap recommendations for wholesale markets and note the following priorities: enable storage resources to participate in the bulk and retail markets; adopt capacity market rule changes that are more flexible in duration requirements, including establishing an appropriate mechanism to value and enable participation of shorter duration (e.g., less than 4-hour) storage resources that can be available during summer and winter capability periods and examine the relative system value that varying durations can provide; identify and examine mechanisms to ensure that energy storage resources supported by clean reliability credits or market acceleration bridge incentives can access NYISO capacity market revenues; establish rules and requirements for aggregation that are appropriate for smaller resources, including behind-the-meter energy storage; develop a model for short-duration storage to provide all products it is technically capable of delivering, notably ancillary services; allow storage to co-locate with wind or solar as one asset given the significant increases in generation cost reductions from the NYSIO process and ongoing operation and compliance perspective; and incorporate energy storage as a bulk transmission resource in NYISO planning.

NYPA supports efforts designed to enable shorter duration energy storage resources to participate in the capacity markets. NYPA notes that the development of innovative participation models through DER aggregation or partial participation are viable paths to pursue to enable shorter duration resources to contribute to meeting system requirements for resource adequacy. NYPA adds that participation models for shorter duration energy storage resources could be done via-third party aggregators or by the NYISO through a partial participation model, where the NYISO would be aggregating or stacking shorter duration resources to meet the current duration requirements and the shorter duration resource would receive a pro-rata or reduced payment based on its contribution to reliability. Further, NYPA states that any aggregation participation model should limit aggregations from crossing system constraints that could result in increased constraints or other undesirable system operating conditions and limit capacity aggregations to be within the applicable capacity zones. NYPA cautions against modifying the existing capacity market duration requirement that is designed to meet system needs and assure resource adequacy.

NYPA states that energy storage resources are competing against slower and, therefore, lower quality resources that can meet current product requirements but cannot provide the faster service that the ISO/RTO relies upon. Moreover, NYPA adds that setting compensation levels based on the capabilities of less capable resources, which have lower associated costs, can be expected to drive prices to levels below the costs required to attract new and maintain existing more capable resources, which have correspondingly greater costs, to the detriment of both system reliability and efficiency.

NYPA states that BSM rules should not be applied to energy storage or DER. NYPA argues that energy storage resources are relatively expensive on a per-MW basis to meet the capacity market duration requirements compared to other resources, and participation in the capacity market is not a primary driver of energy storage deployment and would not be the resource chosen if one's intent were to depress market prices. NYPA supports creating a participation model for short-duration energy storage to provide both reserve and frequency regulation with NYISO-provided state-of-charge management. However, NYPA believes that state-of-charge management and NYISO control should be optional for larger resources providing other market services like energy and capacity. NYPA supports the Roadmap's recommendation to pursue a fast-ramping service product, and recommends that further consideration be given to whether there is a higher value to resources that can provide an extended ramp capability via an individual resource or aggregation. NYPA supports the establishment of a working group and further exploration of alternatives to address the cost of telemetry as a barrier.

Plus Power agrees that energy storage must be exempted from BSM and also supports the development of a shorter duration capacity product. Plus Power recommends the Commission work with NYISO to fast-track the full implementation of FERC Order 841, with a focus on issues such as participation of energy storage in capacity markets and de-rating. Additionally, Plus Power requests that newer energy storage technologies are not being discriminated against and are treated equitably with older technologies, such as pumped hydro. Plus Power disagrees with the suggested compromise of exempting energy storage systems under 20 MW. Plus Power comments that if the ongoing reliability study being performed by GE concludes, for example, that the State will need a 6-hour minimum run time to participate in markets, then the Commission should ensure that NYISO revises the storage tariff to match that. Plus Power comments that if the NYISO has found that current, or proposed, fossil replacement downstate peak power plants are exempt from BSM, then energy storage facilities designed to replace downstate peakers should be similarly exempt, regardless of size.

The City submits that what the NYISO has indicated will be included in its forthcoming FERC compliance filing does not go far enough. The City states that the NYISO indicated that its

December compliance filing will not include market rules that permit dual participation in both the wholesale and retail markets. The City supports the Roadmap recommendation that dual participation issues be addressed at the NYISO in short order. The City is concerned that the current requirement that energy storage have a minimum runtime duration of 4 hours will limit the viability of energy storage in the wholesale markets. The City agrees with Staff's recommendation that the NYISO accelerate its examination of whether energy storage could provide greater value to the grid with a modified minimum runtime requirement. The City supports Staff's recommendation that energy storage and DER be wholly exempt from existing NYISO BSM rules.

The Enel Group shares Staff's concerns on several critical NYISO design principles, and urges the NYISO to reconsider its approach toward ignoring flexibility in the capacity market. Enel believes that four-hour storage resources should have the same capacity value as any other resources. Enel argues that NYISO appears to use duration as the key determinant for capacity value, ignoring flexibility. However, Enel notes that with a grid moving to 50% renewable energy, and the need for fast ramping resources, it is inefficient to have a capacity market that values resources with long start-up times over resources that can start nearly instantaneously. Enel argues NYISO should not count revenues received from retail programs and/or tariffs toward the minimum offer floor of DERs and energy storage. Enel recommends that NYISO create an option for new resources in the NYISO capacity market to have a price lock for upwards of seven years.

B. Dual Market Participation

ESA strongly supports Staff's effort to prioritize and clarify development of rules on dual market participation, and believes it is imperative that the Commission and NYISO work together to facilitate DER participation in the wholesale market as well as in distribution system services. ESA recommends that the Commission consider convening a stakeholder group to develop together a set of specific principles for dual participation that are tailored to the circumstances in the State of New York.

GI Energy believes that the idea of dual participation should not be an issue for FTM energy storage development, and that if the NYISO receives 100% of the energy and capacity of a FTM energy storage and the utility receives priority dispatch rights, then there should be no conflict between value received by each entity nor complexity of operation. GI Energy notes that today there are several examples in the Con Ed service territory where Con Ed has priority dispatch rights to alter the dispatch of bulk power generating units participating in the NYISO market to resolve constraints on non-NYISO controlled facilities. GI Energy argues that FTM energy storage should not be treated differently simply because they are connected to the distribution system.

IPI expresses concern that barriers to energy storage participation in certain markets leads both to an under-utilization of existing storage systems and to an under-investment in new storage systems. IPI agrees that market participation rules should be redesigned to accommodate storage resources that may be unavailable for periods of time, but nevertheless have useful part-time services to provide.

IR supports the recommendation that NYISO should enable energy storage resources to participate and earn revenue from multiple parts of the energy value chain. IR believes energy storage resources are highly flexible and may provide wholesale or retail services depending on market need. IR states that the NYISO should be encouraged to lift restrictions on dual participation of energy storage resources.

Joint Utilities argue that accessing wholesale market revenue streams is critical to unlocking the full value of storage, and note that dual participation can minimize subsidies from utility customers that would otherwise be necessary to fill the gap between storage costs and distribution and customer benefits. Joint Utilities are committed to continuing work with stakeholders to address these issues.

NPS comments that dual participation as among the most critical issues to solve, and urges Staff to further explore and prioritize a distribution energy storage capacity market, with a declining level of capacity available in each of those zones or utilities – perhaps utility specific capacity that can be contracted directly while allowing the energy storage to participate in ancillary markets with the NYISO. NPS adds that this allows the utility the opportunity to approach the energy storage market with precise planning while maintaining the larger capacity needs with the NYISO. NPS believes that a market could begin to assimilate, be expanded, and in ways mirror the DR markets. NPS supports the expansion to include energy storage in a specific manner with a defined set of rules and patterns that energy storage are capable of achieving in their current market state. NPS argues that the distribution operator may have more visibility into their network and be able to plan for the longer term through such a program. NPS sees that the solar and storage markets seem to be most addressable today based on a thriving understanding of the value to time shift solar and the tangible evidence of the market growth. NPS notes that school and universities may have energy consumption that actually may decrease or doesn't dramatically increase during summer due to the scheduling of school which could offer storage another example of a dual participation opportunity.

NYPA agrees that dual participation model must ensure that resources are not being compensated for the same service twice.

Stem supports dual participation but contends that New York is not ready to formally adopt dual participation principles. In Stem's opinion, the principles that were adopted by the California Commission in early 2018 have failed to be actionable and should not be used as a foundation for a dual participation framework. Stem argues that Staff and NYSERDA should initiate a working group akin to the California effort, but with strong facilitation and full stakeholder buy-in to establish dual participation principles.

The Enel Group recommends adopting the following principles: DER/energy storage should be eligible to provide any wholesale service for which it is not already being compensated for at retail; DER/energy storage that is participating in a retail tariff/procurement that does not include wholesale revenue streams should have no restrictions on wholesale market participation; and DER/energy storage that is dispatched in real-time by a utility for a local reliability/peak shaving program can self-schedule in the NYISO market.

C. <u>Distribution and Wholesale Market Coordination</u>

FCHEA asserts that hydrogen is a versatile energy carrier that can be transported and stored in very large quantities (terawatt hours if geological storage is used) and over long durations (up to months and years) with no self-discharge. FCHEA adds that this stored energy could then be used as a high-value transportation fuel for fuel cell vehicles or run through a fuel cell to provide electricity in emergencies and during peak demand. FCHEA explains that devices for converting electrical energy to hydrogen and later returning the energy to the grid using electrolyzers and fuel cell systems have grid-beneficial attributes, including abilities to provide load following, power quality, ancillary services, and siting flexibility. FCHEA adds that both the production and conversion of hydrogen under these circumstances is completely free of criteria pollutant and greenhouse gas emissions. FCHEA argues that this paradigm also allows siting of the electricity consuming (hydrogen production) facilities in locations that are disparate from the electricity production (hydrogen consuming) facilities. FCHEA notes that electric-utility procurement valuation methodologies do not account for the potential cost optimization of economic dispatch to either fuel or power.

GI Energy supports the Roadmap recommendations.

GlidePath disagrees with the statement that "most [energy storage resources] are likely to be smaller, often well below 1MW". GlidePath states that the NYISO should also clarify that projects connected to the distribution system but participating in the NYISO market would not be charged distribution facilities charges (e.g., wires or demand charges) and would transact energy (buy and sell while charging or discharging) in the wholesale market and not at the retail level.

IR supports the proposal to develop clear control, coordination and dispatch requirements to enable greater use of DERs in meeting customer, distribution and wholesale needs. IR believes that aggregations of DERs, including energy storage, will help manage system and network loads ensuring that services are provided when they are needed most.

Reply Comments

ACE NY supports the Roadmap's call, and multiple stakeholder reiterations, for NYSERDA and other State policymakers to work with the NYISO to develop rules and procedures to facilitate participation for energy storage that are not available year-round. ACE NY also agrees with NEETNY that it is important for NYISO to clarify the role that energy storage will play in the public policy transmission need process and that storage should be considered as a potential regulated transmission solution. Furthermore, ACE NY agrees with Borrego Solar that energy storage should be exempt from any buyer side-mitigation rules enacted by the NYISO.

Joint Utilities comment that most parties support the Clean Peak proposal carefully moving forward with analyses similar to those outlined in the Roadmap. Joint Utilities point out that NY-BEST stated that there is sufficient information on the reliability and operational characteristics of peaking plants for the Commission to take actions that accelerate the replacement of some units with storage and other forms of clean

DER. The Joint Utilities believe the Commission should reject NY-BEST's "Clean Reliability Program" with "Clean Reliability Credits" proposal on three grounds: (1) as NRDC notes, Clean Peak should utilize existing NYISO approaches for addressing potential plant closures as it is the NYISO's responsibility, not the Commission's, to make determinations regarding the impact of retirements on system reliability; (2) NY-BEST's assertion that sufficient information exists to make such a determination is not true because, as the Roadmap concludes, a detailed analysis is required to study this topic; and (3) it is premature to consider the creation of any type of credits until an analysis is completed and NYISO confirms the results.

VIII. ACCOUNTABILITY

AEMA agrees with the Staff's recommendation that the Commission establish mechanisms for accountability and for tracking progress towards the storage targets. AEMA applauds the content areas of the proposed report, especially the outlining of corrective paths for reallocating bridge incentive funds and other measures if the funds are not effectively being deployed, to drive down implementation costs. AEMA suggests that a report on the State of Storage be published semiannually. AEMA also recommends that a report on the availability of incentive funds be published quarterly or, alternatively, that a website be developed on which this information can be viewed on a frequently-updated basis to give storage developers insight into how much funding remains available as they scope out and develop their projects.

GI Energy supports the Roadmap recommendations.

NYSSGC believes it is essential that the referenced State of Storage report be publicly available on a specified schedule to ensure complete transparency. Further, NYSSGC adds that the goals and milestones included in this annual report should be prioritized to highlight progress towards achieving the truly essential actions that need to be accomplished each year to achieve the ultimate goals and vision of the Energy Storage initiative.

IX. OTHER

AEMA suggests that Staff should continue to work with the utilities and the NYISO, and accelerate efforts where possible, to make sure that the supporting retail tariffs and wholesale market rules are in place to allow energy storage to be effectively deployed with certainty around participation models and revenue opportunities.

Hydrostor notes that there are known limitations of Li-ion technology which impact the technology's deployment potential and ratepayer value such as performance degradation and lifespan, long-duration capability, and grid service delivery. Hydrostor adds that lithium-ion's inability to deliver the required grid services (long-duration, rotational inertia, etc.) and its inherently limited lifespan, the dominance of lithium-ion in future deployments would diminish ratepayer value. Hydrostor states that insufficiency of current solutions deployed in New York and the need for technology diversity requires the deployment of newer technology-approaches like A-CAES. However, Hydrostor says it is unlikely such technology can be feasibly deployed under the current framework alone because new technologies often require special treatment to enable their financing and deployment that cannot be delivered through the merchant electricity market alone.

Joint Utilities agree that energy storage has the potential to play a key role in New York's clean energy future, particularly if storage technology costs are substantially reduced and use cases evolve and mature. Joint Utilities add that the energy storage market is still in its early development stages and it is not yet clear how the market will evolve over the coming years as existing technologies mature, costs decline, wholesale market rules are adapted for DERs, permitting requirements are developed/clarified, and new storage technologies become available. Joint Utilities support an approach that encourages the development of storage policies and programs that provide all customers with grid benefits while maintaining flexibility to adjust course to take advantage of greater savings opportunities as the storage market matures. Recognizing that there is uncertainty in the economics of storage applications that will drive adoption rates, the Joint

KCE supports defining the 1500 MWs by 2025 and 2795 MWs by 2030 as a target floor and not a target ceiling. KCE suggests that NYSERDA should commit to re-evaluating the optimal energy storage power and energy by zone every two years to accommodate a rapidly changing electric grid. KCE explains that incentivizing projects that can get in the ground in 2019, regardless of battery duration; projects can always start with a short duration (30 minutes) and scale up to a long duration (6 hours) as battery cell prices continue to decrease and the wholesale market begins to value longer duration storage. KCE argues that there should not be a mandate by zone or resource type, but rather be a mandate for the entire state.

National Fuel Gas does not support the confining framework of REV, particularly in focusing on limited subset of technologies in the past year such as offshore wind and EVs. It notes its concern about this approach closing out potentially innovative energy-related opportunities, particularly those related to natural gas. It recommends its "power-to-gas" concept in which surplus renewable electric power is used to create methane using electrolysis and "methanation" which could in turn be injected into the natural gas pipeline system. The advantage of this technology is that it can be used to store and transport energy without the physical limitations of where the generation occurs which is typically where battery storage is confined to.

NFCRC comments focus on recommendations for technology diversity and appropriate resource valuation and rate structures that are key to a successful long-term energy storage implementation plan for New York. NFCRC adds that the goals outlined in the Roadmap cannot be achieved with a single energy storage technology, and advocates the need for storage technologies of durations in excess of six hours. NFCRC states that Lithium ion technology is not likely to alone be suitable for addressing this need due to a fixed power-to-energy capacity ratio that is also typically greater than one (i.e., a 10 MW Li-ion battery typically can deliver less than 10 MWh of energy). NFCRC notes that the limited supply is already leading to increased lithium and cobalt commodity prices, and NFCRC research suggests that the storage requirements of renewable utility grid networks will far outstrip global lithium and cobalt reserves if it were to all be served by Li-ion batteries. NFCRC suggests that the customer-sited use cases in the Roadmap should include diverse energy storage technologies as well.

Dependence on a single storage solution creates risk of supply shortages of necessary materials and also creates a risk for the lack of deployable and cost-effective solutions to meet storage functions that are not easily provided by Li-ion technology. The required flexible resources to meet grid capacity constraints can be accomplished by installation of energy conversion devices that are fueled (e.g., fuel cells fueled by gaseous fuel), but cannot be provided by Li-ion battery energy storage that could have a limited state of charge at any given moment in time.

Hydrogen is a relatively versatile energy carrier that can be transported and stored in very large quantities (terawatt hours with geological storage) and over long durations (up to months and years) with no self-discharge. Devices like electrolyzers and fuel cell systems that convert electrical energy to hydrogen and later return the energy to the grid, have benefits and services listed in the Roadmap including abilities to provide load following, power quality, ancillary services, and siting flexibility. In addition, both the production and conversion of hydrogen under these circumstances is completely free of criteria pollutant and greenhouse gas emissions.

The NFCRC believes that New York should target no less than 75 MW to the immediate deployment of MW scale projects of innovative, long-duration storage technologies. This deployment would enable DPS, NYSERDA and the utilities to evaluate the usefulness of such long-duration technologies in a period of time that just precedes their significant need for these technologies. The Commission should also allocate no less than 5% of the total mandate to storage technologies that can offer specific and desirable technological features that are different than Li-ion batteries. These features could include energy storage technologies that can: (1) transmit and distribute energy without any additional investments in electric transmission and distribution infrastructure; (2) consume electricity in locations disparate from electricity production; (3) store energy for seasons without self-discharge; and (4) produce fuels that can be used in various transportation and industrial applications. Energy storage technologies with these features are being evaluated in other power markets.

There is also a critically important need to identify the manner by which clean power generation and energy storage are dispatched on the utility grid network. For the most part, clean power generation is today dispatched as a base-load resource due to the financial incentives that promote the 24 hours/day 7 days/week (24/7) continuous operation of the equipment to garner the best rate of return on investment. However, if rate structures were developed to provide a financial incentive for clean power generators to operate dynamically, producing more power during some times of the day and less during others, then the inherent capabilities of clean power generators to operate dynamically would be exercised by those participants fulfilling the storage mandate.

NPS encourages Staff to begin to formulate a customer centric informational page that may include marketing tutorials that allows customers and developers to understand what all these changes mean. If developers can’t explain these new methods, how can customers understand this with confidence. Perhaps NYPA, or other government side agency can provide a real world scenario with a school, a government site, or other, that simply

shows the simplicity of how this works, or should work.
There may be sophisticated customers that are early adopters but with the government side to support the market changes, since they are the ones who have created them, this will provide the market with translatable information that alleviates confusion and may provide a way for the market to gain confidence in what this means to their energy consumption and how to utilize these policies and new ideas.

NYSSGC recommends that the Commission first identify the highest priority goals of the Roadmap, and when they need to be achieved to ensure the achievement of the ultimate goals and vision. NYSSGC has been working with several New York utilities and their California counterparts on an U.S. Department of Energy ARPA-E funded project to develop a highly specialized and interactive software tool capable of simulating the operation of emerging DSPs at the physical, information, and market levels. The software offers electricity industry analysts, engineers, economists, and policy makers a "design studio environment" in which various propositions of roles, market rules, rates, processes, and services can be studied to achieve a robust DSP design.

The software provides a number of urgently needed, but currently unavailable, simulation capabilities including:
a) Decentralized energy scheduling able to model active, DER-rich subsystems, including energy storage.
b) Explicit modeling of DER services transacted in the market.
c) Locational and time-vector pricing of active/reactive power, ancillary, and security services.
d) Explicit modeling, analytics, and valuation of DER services, DSP rules and business models.
e) Simulation of the DSP interactions with up-stream ISO, same level DSPs, and downstream (microgrid, building, and home) prosumer subsystems.

O'Connell Electric commented that the Roadmap seems to be geared toward the downstate regions with little to no direction for the rest of the state and assert it is a disservice to a few energy storage market segments; primarily BTM commercial and the potential aggregated BTM residential and commercial market in the rest of the state.

SimpliPhi Power believes that it is important for the benefit of storage providers, customers and first responders to include prominently in the 9540A test results, reports and summaries, the results at each level of the tests, including cell, module and system, not just an overall summary at the installation level. This will support the most informed decisions and the safest choice in materials at every level of an energy storage solution, from chemistry, engineering, and manufacturing. By contrast, summaries focused only at the installation level would obscure these critical factors in the construction of an energy storage solution and thereby inadvertently promote fundamental risks that are merely mitigated at the installation level by set-back requirements, cooling and fire suppression systems.

Stem notes that aggregated customer-sited BTM energy storage can provide all the services that have traditionally been procured from FTM systems installed in either the distribution or bulk transmission grid. For simplicity, regulatory commissions around the country have categorized energy storage installations into their interconnection domains (customer, distribution, bulk/transmission) and designed storage targets and goals around those domains. However, few have been clear that the services from energy storage can be procured from installations in any domain, provided that it is technically feasible. Thus, while it may be useful to separate storage targets into different domains, the policies and programs need to allow storage in any domain to fairly compete to provide services.

Plus Power notes that additional benefits from transmission deferral and reliability are not included in the cost-benefit analysis for energy storage. While ESA recognizes that there may be some uncertainty about the timing and prospects for additional transmission build out in the future, it contends that the cost-benefit analysis provided in the Roadmap likely underestimates the overall value of energy storage to customers as a result of omitting transmission deferral and avoidance from the modeling exercise. The Roadmap acknowledges that this use case could potentially yield high value. Transmission deferral is an important value in the stack of values to consider for energy storage.

Plus Power disagrees with the assumptions incorporated into the cost declines of long duration energy storage in Appendix K. The Acelerex presentation includes pumped hydro in the list of long duration technologies that are projected to decline in cost by 11% annually until 2021 and then by 3% until 2029. Plus Power comments that it recognizes the state benefits from approximately 1,400 MW of installed pumped hydro. However, given the limitations on siting new pumped hydro and the environmental challenges, Plus Power asserts it is unrealistic to assume that pumped hydro costs will decline, and if anything, they will increase. Plus Power requests that any future studies regarding the value of storage include realistic cost estimates for pumped hydro.

Hydrostor believes A-CAES could be an important storage technology pathway well-suited to New York’s bulk system needs going forward. A-CAES is a scalable (50-500+ MW), fuel-free/emissions-free, and long-duration (4-24+ hours) energy storage solution that is uniquely suited to the replacement of fossil generation at scale and supporting grid reliability through its synchronous generators and similar operating characteristics as conventional gas turbines. Unlike other long-duration energy storage technologies, such as pumped storage hydro and traditional compressed air energy storage, A-CAES can be flexibly sited where the grid requires it (i.e. it does not require pre-existing topology/caverns or salt formations). It is also a resource with 30+ years of operability and long-duration capability, unlike the to-date more commonly deployed lithium-ion batteries. Of further note, A-CAES is immediately available and based entirely on proven and bankable technologies, including standard mechanical equipment from Tier 1 OEM suppliers with decades of service history.

IR notes that thermal energy storage (TES) is a proven technology with more than 120 MWh deployed in New York City alone. TES is a cost effective, safe and durable technology that can be an integral part of achieving Governor Cuomo’s goal of deploying 1.5 GW of energy storage by 2025. TES provides C&I customers with the ability to materially time shift their energy usage during hot summer months. It relies on chillers that make ice typically at night (charging) which is then used to provide air conditioning service during the day (discharging). This process enables building owners to use off-peak energy during peak times.

TES is also highly durable and efficient. Calmac thermal energy storage tanks have a useful life up to 30 years with little maintenance cost and achieve round trip efficiencies approaching 97%. Moreover, it can provide cooling service for at least eight hours at a time, and almost all of its components can be recycled at the end of its useful life. Overall, TES lasts 2 to 4 times longer than batteries at a fraction of the cost. The deployment of TES can also help New York achieve policy goals around renewable energy and emissions. Because it typically charges at night, TES is well suited to “storing” wind energy for daytime use, which in turn reduces the need for and emissions from thermal generation. TES charges at night and accordingly provides an immediate offtake for emissions-free wind energy production that can be used during daytime. This enables emission-free energy to be utilized during the day and reduces the need for peaking fossil fuel plants. IR encourages state policymakers to consider thermal energy storage because of safety concerns. As mentioned in the Roadmap, the fire risks associated with some technologies have prevented widespread installation, particularly in New York City.

APPENDIX B

State Environmental Quality Review Act

FINDINGS STATEMENT
December 13, 2018

Pursuant to Article 8 (State Environmental Quality Review Act (SEQRA)) of the Environmental Conservation Law and 6 New York Codes, Rules and Regulations (NYCRR) Part 617, the New York State Public Service Commission (Commission), as Lead Agency, makes the following findings.

Name of Action: In the Matter of Energy Storage Deployment Program (18-E-0130); Order Establishing Energy Storage Goal and Deployment Policy
SEQRA Classification: Unlisted Action
Location: New York State
Date Final Generic Environmental Impact Statement (GEIS) Filed: September 12, 2018
Final GEIS Available at: http://www.dps.ny.gov

I. PURPOSE AND DESCRIPTION OF THE ACTION

Public Service Law (PSL) §74 directs the Public Service Commission (Commission) to establish a 2030 goal for the installation of qualified energy storage systems and a deployment policy to support the statewide goal.

On June 21, 2018, the New York State Department of Public Service (DPS) and the New York State Energy Research and Development Authority (NYSERDA) filed the "New York State Energy Storage Roadmap and Staff Recommendations" (the Roadmap). The Roadmap outlines the market-supported policy, regulatory, and programmatic actions necessary to achieve the State's near-term energy storage goals and recommendations for the Commission to consider when designing the energy storage deployment policy per PSL §74. Broadly, the recommendations are separated into seven categories: (1) retail rate actions and utility load management programs; (2) investor-owned utility roles and business models; (3) direct procurement; (4) market acceleration bridge incentives; (5) cross-cutting actions to reduce barriers; (6) "clean peak" actions; and, (7) wholesale market actions. The Roadmap specifically supports the State's initiative to deploy 1,500 megawatt (MW) of energy storage by 2025 and a up to 3,600 MW by 2030 pursuant to PSL §74.

The Roadmap is focused on recommendations to design and establish a framework and incentive structure that will drive new investment and activities in the energy storage market. The extent to which each type of qualified energy storage technology will be used (or activated) in response to the Roadmap is uncertain. Given these circumstances, and consistent with SEQRA regulations found at 6 New York Codes, Rules and Regulations (NYCRR) §617.10(a), the GEIS is broader and more general than a site or project-specific environmental impact statement (EIS), and identifies potential areas where environmental impacts may be caused by the construction, operation, and disposal of energy storage facilities. By the Order Establishing Energy Storage Goal and Deployment Policy issued December 13, 2018, the Commission adopted several Roadmap recommendations and established the statewide deployment policy and an aspirational 2030 goal.

II. FACTS AND CONCLUSIONS RELIED UPON

A. Public Need and Benefits

If successfully implemented, the statewide deployment policy should result in positive environmental impacts due to reductions in peak load demand during critical periods, increases in the overall efficiency of the grid, and/or displacement (or accelerated displacement) of fossil fuel-based generation (e.g. by allowing greater integration of renewable energy resources). Such outcomes will lead to an array of public benefits, including economic, health and environmental benefits. Specifically, these benefits may include:

- **Public health**
  Improvement in public health from avoided emissions of criteria air pollutants, such as nitrogen oxides (NOx), sulfur oxides (SOx) and particulate matter (PM2.5). To the extent that these avoided air emissions occur from the displacement of peaker plants located in Potential Environmental Justice Areas (PEJAs), the associated benefits may accrue to these vulnerable communities.
- **Climate change mitigation and adaptation**
  Mitigation of the impacts of climate change from approximately 2 million metric tons of avoided greenhouse gas (GHG) emissions. Climate change is expected to increase air temperatures, in turn intensifying water cycles through increased evaporation and precipitation. Greater energy storage deployment can reduce the State's reliance on fossil fuel energy, aiding in the prevention of flooding, and extreme heat event impacts.
- **Ecosystem services**
  Relative to the business as usual scenario, greater energy storage deployment increases the use of renewable energy resources. In turn, the land and water use impacts associated with greater investment in fossil fuel sources or expansion of the State's transmission and distribution system are avoided.
- **Economic development**
  Energy storage deployment range of 1,500 MW to 3,633 MW would result in an approximate annual job growth in energy storage research and development, development,

manufacturing, installation and other support services between 1,100 and 2,700 jobs per year respectively, by 2030.

B. Potential Impacts

Overall findings suggest that adverse direct environmental impacts of the actions recommended by the Roadmap are minimal. The GEIS considers three types of energy storage technologies: batteries, thermal storage and flywheels. Risks exist across all three technology types, most notably: risk of soil and groundwater contamination due to improper disposal of battery-related waste, and public safety risks from the operation of batteries and flywheels. A summary of the environmental impacts across the three technology types follows.

Land Use and Space Requirements

The energy storage technologies considered in the GEIS (i.e., battery storage; thermal storage; and flywheels) have a relatively small land use footprint and it generally increases as the size of a project increases. The development of utility-scale energy storage facilities may have site-specific impacts on land use.

Water Resources

Surface water resources may be potentially affected by the construction of an energy storage facility through storm water runoff if site-soils are disturbed during construction. The potential degree of environmental impact would depend on the size of the impacted area and the site’s proximity to protected waters, among other site-specific factors. Impacts of battery energy storage on water resources may occur at the battery’s end-of-life. If lithium-ion batteries are handled improperly, lithium – which is highly flammable when it contacts water – could flow into surface water or leach into groundwater and cause combustion.

Public Health

Public health impacts directly attributable to battery storage include fire and toxicity risks. The potential for the battery to melt, leak, combust, or explode exists, generally as a result of damage due to inadequate cooling, ventilation, unsafe activity, or seismic activity. Notably, documented incidences of utility-scale battery fires are rare, as of 2016, only two renewable energy generation plus energy storage facilities had reported a fire. Many types of battery storage technologies contain toxic and hazardous chemicals that can cause damage when exposed to humans. When exposure occurs it is generally because the battery has been damaged or tampered with, therefore the risk can be reduced following instructions from the manufacturer. There is also a potential safety risk associated with flywheel technologies. If the flywheel is overcharged (i.e., loaded with more energy than its components can handle), this can result in an "explosive-like" event. To minimize this risk, security walls (or housing) are often used and systems are mounted carefully. In addition, care must be taken in design and installation to ensure that the tensile strength (i.e., strength of the rotor material) is operated within a suitable safety margin to keep the stress of the rotor below the strength of the rotor material.

Climate Change and Air Quality

When evaluating the environmental impacts of a statewide deployment policy, such impacts are influenced by the efficiency of the technology and the original source of electricity. By design, a storage device outputs less energy than the charging input. The overall emissions impacts to the grid are highly case-dependent. The energy loss between the electricity generator and an energy storage system increases with the distance between the two. Physically remote electricity generators have to account for the transmission losses by producing more electricity. As such, energy storage devices may result in increased electricity demand from the existing grid, which may result in greater emissions when considered on a standalone basis (e.g., not taking into account displacement of other forms of energy generation). When energy storage technologies complement cleaner generation – as envisioned under the existing Reforming the Energy Vision (REV) framework – such technologies can contribute to lower levels of both local (i.e., criteria pollutants) and global (i.e., greenhouse gases) emissions. One of the goals of the Roadmap is specifically aimed at avoiding carbon dioxide (CO2) emissions over the lifetime of storage assets, particularly as the amounts of renewable generation on the grid increase and curtailment becomes a more significant occurrence. On a large scale, the use of storage as part of a broader strategy to increase the responsiveness of demand will facilitate greater development of low-carbon energy generation. Where system efficiency is measured in terms of average heat rate, storage that complements low-carbon off-peak generation will reduce total carbon output.

Waste Management

Substantive environmental impacts due to battery-based energy storage could occur during the end-of life disposal phase. Lithium combined with water creates a flammable compound. If lithium-ion batteries are disposed of in typical landfills without end-of-life battery processing they pose an environmental and human-health hazard. Proper end-of-life battery processing neutralizes the solvents in the battery to minimize environmental impacts prior to disposal. Recycling lithium-ion batteries may also limit negative environmental impacts, although several barriers exist including lack of (1) cost-effectiveness, (2) facilities, and (3) regulatory oversight. For example, in 2016, mined lithium was less expensive than recycled lithium. Compared to a typical lead-acid battery, lithium-ion batteries' more heterogeneous chemistry requires labor-intensive or chemical reagent-intensive processes, which are rarely cost effective. Recycling lead-acid batteries is heavily regulated which has resulted in well-established recycling processes. As most utility-scale lithium-ion batteries have not yet reached their end of life, there are relatively few companies within the U.S. that recycle lithium-ion batteries, and no facilities with the capacity to recycle utility-scale lithium-ion batteries. Batteries may reach their end-of-life prior to the development of established battery recycling facilities, potentially resulting in environmental impacts.

Transportation

The majority of lithium-ion batteries are manufactured in East Asia. The closest utility-scale lithium-ion battery manufacturer to New York is in Canada. Transportation will play a significant role in enabling the State to obtain battery storage systems. This may lead to a minor increase in greenhouse gas emissions and traffic congestion on major roads. At the battery's end-of-life – due to lack of processing and recycling facilities in the State – lithium-ion batteries currently must be transported out of the State which may also lead to a minimal increase in greenhouse gas emissions and traffic congestion on major roads.

Community Character

The installation of energy storage systems is not likely to impact the community character of an area. During the construction phase movement of heavy machinery may create noise pollution, which could potentially have a short-term impact on community character. The operational phase of energy storage technologies is generally quiet; for example, batteries create minimal noise but some noise pollution from the cooling units that prevent the batteries from overheating could potentially have an impact on community character if not mitigated. The efficiency of the cooling units can be increased (and therefore the noise impacts decreased) by focusing them directly on the battery racks as opposed to cooling the entire battery casing. This method of cooling can also use up to 70 percent less power for the cooling units. For thermal storage, compared to a traditional chiller operation, thermal energy storage minimizes daytime noise pollution. Thermal energy storage systems avoid "chiller vibration" and similar noise associated with traditional systems. While flywheel storage systems generate operational noise, the noise levels are relatively low, compared to conventional technologies (e.g., cooling fans).

Socioeconomic

Socioeconomic impacts of energy storage are generally similar across technologies with some exceptions for thermal energy storage which does not supply electricity to the grid. The cost of producing and supplying renewable energy such as wind and solar may be reduced through battery or flywheel energy storage. For example, a cost model of the Maui Electric Company system found that employing battery storage systems is effective at lessening wind curtailment as well as the annual cost of power production. The study found that replacing the diesel-fired power generation with wind generation provided some savings, but energy storage systems accounted for the majority of the savings due to increased operational efficiencies of the conventional units, such as the spinning reserve. Batteries and flywheels can also recycle energy to the grid (receive excess energy and redistribute it to the grid when needed), leading to reductions in energy costs. Thermal energy storage systems do not supply electricity to the grid, but similar to other types of energy storage they reduce demand during peak hours. As a result of this reduction in peak demand, individuals’ energy costs are often reduced. Utility charges are reduced from the overall reduction in usage during peak hours, but also from avoidance of demand charges. These demand charges are extra fees associated with usage during peak hours, and can be substantial (up to an 80 percent surcharge). In some cases, utilities run demand response programs, in which customers are compensated (or their bill is reduced) if they reduce their peak consumption. Thermal energy storage systems also decrease utility charges as they generate the stored energy when prices are low (i.e., at night). A study found that in the European Union, jobs directly or indirectly linked to the production of battery storage systems and their value chains are expected to be created in response to the growing demand for lithium-ion batteries. This is also expected to increase the market share of lithium-ion batteries.

Cumulative Impacts

The statewide deployment policy is anticipated to engender overall positive environmental and social impacts, primarily by improving grid resiliency, reducing the State’s CO2 emissions, and promoting jobs growth. Certain cumulative negative impacts (e.g., potentially hazardous waste generation from battery storage facilities), however, may constrain the overall positive impacts of the deployment policy. As discussed further in Chapter 6 of the GEIS, a number of regulations, policies, and best practices serve as measures that will mitigate adverse impacts that may arise from activities undertaken in response to the deployment policy. A summary of mitigation efforts is also provided in the following section. Finally, cumulative site-specific impacts of the Roadmap are not known at this time and are beyond the scope of the GEIS. The GEIS provides a generic description of the potential environmental impacts of the Roadmap on land and water resources, agriculture, cultural and aesthetic resources, and other individually relevant impacts. Appropriate federal, state, and local permitting and environmental review processes will identify, evaluate, and mitigate potential site-specific impacts.

Mitigation of Potential Adverse Impacts

Consistent with SEQRA requirements, the GEIS describes the variety of measures available to minimize or avoid, to the maximum extent practicable (incorporating all practicable mitigation measures), potentially adverse environmental impacts that may result from energy storage activities that may be implemented under the Roadmap. The GEIS discusses 1) key federal and state regulations that may apply to energy storage activities during construction, operation, and closure of a specific project, and 2) provides an overview of site-specific project design and planning which serves as a primary mitigation measure for many site-specific issues. Measures to mitigate (i.e., minimize or avoid) the potentially adverse environmental impacts that may result from greater deployment of energy storage, include:

- Federal, state and local regulations, notably Resource Conservation and Recovery Act (RCRA) regulations and New York Department of Environmental Conservation (NYSDEC) Part 364;
- Site-specific permitting regimes, such as the SEQRA process, NYSDEC Commissioner Policy 29 on Environmental Justice and Permitting (CP-29), and Article 10 and Article VII of the New York Public Service Law; and

- Use of best management practices during site-specific design, planning, and siting efforts.

Exhibit 6-1 of the GEIS provides an overall summary of potentially applicable regulations. These regulations cover cultural or societal, water, air, and land resources, as well as waste management regulations.

Alternatives Considered

The primary alternative is the No Action scenario, wherein the energy storage deployment program does not exist; and therefore there is no associated energy storage deployment target. Under the No Action alternative, the State still expects to achieve its Clean Energy Standard (CES) mandate that 50 percent of all electricity consumed in New York State be supplied by renewable resources by 2030 (the 50 by 30 goal) by employing a variety of resources, including energy storage, although the amount of installed storage capacity is expected to be lower during the period of analysis without the Roadmap. Under the No Action alternative, there could be more, fewer, and different potential impacts on the environment, depending on the other types of resources that ultimately would be used under the No Action alternative to achieve the “50 by 30” goal.

Unavoidable Adverse Impacts

There are no unavoidable adverse impacts that could not be avoided, minimized, or mitigated through applicable federal and state laws, regulations, and review processes.

Irreversible and Irretrievable Commitment of Resources

The statewide deployment policy will not, in itself, result in irreversible or irretrievable commitment of resources because no particular energy storage project, project site, or regulatory modification will be approved or endorsed by approval of the policy and MW goal. The construction of new energy storage projects in the future in response to the Commission

Order addressing Roadmap recommendations may raise such concerns, but these will be identified in site-specific environmental analyses and avoided or minimized in accordance with SEQRA and other applicable laws and regulations.

Growth-Inducing Aspects and Socioeconomic Impacts

By establishing a statewide deployment mandate and directing greater resources to the energy storage market, the statewide deployment policy is expected to increase the number of energy storage jobs in the State than otherwise would exist based on current conditions in the energy storage market (e.g., continuing declines in the cost of storage and increasing demand due to greater deployment of renewable energy and smart grid technologies). The cumulative incremental employment impacts associated with the deployment of 2,795 MW of energy storage capacity through 2030 in the State is approximately 7,100 and 17,200 jobs in research, engineering, and manufacturing, or industry support.

While the statewide deployment policy does not result in the approval of any specific projects, one of the Roadmap's proposed actions is intended to investigate the opportunity to replace peaker plants, primarily located in the heavily populated downstate region, with energy storage facilities. These downstate peaker plants are only activated during extreme weather events, but produce twice the carbon emissions per unit of energy generated compared to fossil-fuel plants of similar capacity – emitting sulfur oxides (SOx), nitrous oxides (NOx), and particulate matter (PM), and contributing to ground-level ozone which causes asthma and other health impacts. Potential replacement of the peaker plants with energy storage is expected to reduce both the overall and site-specific environmental impacts associated with fossil fuel-based energy generation.

Effects on Energy Consumption

As discussed in prior chapters, penetration and adoption of energy storage could affect the electrical system at the generation, transmission, and distribution levels. In particular, expansion of energy storage may facilitate the deployment of renewable generation resources and relieve system pressures during periods of peak demand. These potential changes to the structure of the electrical system are not expected to directly affect the amount of electricity used or the amount of energy conserved in the State; rather, energy storage is expected to change how this demand is met. To the extent energy storage does not change net retail prices in a material way, the Roadmap is not expected to indirectly affect the amount of energy consumed or conserved in the State.

III. CONCLUSIONS

Based on the discussion set forth in the Final GEIS, the Commission makes the findings stated above regarding the potential environmental impacts, as well as benefits, of the Energy Storage Deployment Policy, and certifies that:

1. The requirements of the State Environmental Quality Review Act, as implemented by 6 NYCRR 617, have been met; and
2. Consistent with social, economic, and other essential considerations from among the reasonable alternatives available, the actions being undertaken yield overall positive environmental impacts and avoids or minimizes adverse environmental impacts to the maximum extent practicable.