

March 14, 2025

Via electronic mail

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RE: Granite Source Power's 83E Round 1 Comments

Introduction

Granite Source Power, LLC ("GSP") appreciates the opportunity to submit these comments in response to the RFP Drafting Parties' ("Parties") February 21, 2025 request for public comments on the upcoming Request for Proposal for the first solicitation for mid-duration energy storage projects under Section 83E. These solicitations will be a critical part of achieving Massachusetts's clean energy mandates, delivering the benefits promised by the Clean Peak Standard, and ensuring that the Commonwealth continues to lead the country in energy storage investment and deployment. GSP offers these comments to improve the viability of the program, particularly for transmission-scale projects.

GSP was incorporated in 2022 to develop utility-scale battery energy storage ("BESS") and solar projects in multiple markets across the United States to improve grid reliability and energy affordability. As of April 1, 2024, GSP has an active pipeline of 15 projects totaling approximately 3.5 GW across six states, including Massachusetts, and five RTOs.

Prior to starting GSP, the company's co-founders and employees had more than six decades of collective experience in the renewable energy industry, during which they developed, sold, and acquired over 12,000 MW of onshore wind, solar, and BESS projects and closed more than \$10 billion of tax equity, cash equity, and debt financing. The team's experience covers the full scope of development activities, from market analysis and site selection through real estate agreements and title work, environmental surveys, local, state, and federal permitting, good neighbor agreements and tax abatements, interconnection, preliminary engineering, offtake structuring, and major equipment selection.

Leveraging our experience developing projects in multiple regions, we provide the following key recommendations, which we elaborate on in response to specific questions posed by the Parties:

1. The Parties should carefully consider the timelines and deadlines associated with ISO-NE's interconnection study process, including ISO-NE's compliance with FERC Order 2023, when setting procurement schedules and maturity requirements to optimize the pool of eligible projects
 - a. Due to the current regulatory uncertainty in the interconnection process and the delays beginning the transitional cluster study, the Parties should require a valid interconnection request as the minimum interconnection maturity requirement for submitting a bid and rely on security deposits to reduce speculative projects
2. In future procurements, the Drafting Parties should include additional products in the solicitations beyond environmental attributes to allow the Drafting Parties to control the delivery of additional benefits from the storage assets and reduce financing costs associated with the volatile and uncertain wholesale and regulatory environment.

Responses:

To expand upon our two high-level recommendations, GSP provides the following responses to the Parties' questions.

1. Procurement Schedule:

- a. The factors the RFP Drafting Parties should consider when designing the schedule for the 83E Round 1 solicitation, including deadlines for bid submission and selection of projects for negotiation. Please include as much specificity in key schedule milestones and timing as well as justification for preferred dates.*

The Parties should carefully consider the timelines and milestones required in interconnection, permitting, and qualification processes when developing the schedule for Round 1 and future rounds of procurements under the 83E solicitations. The final schedule and the minimum maturity requirements for each solicitation will impact the pool of projects that is eligible to participate. Given the statutory deadline included in Section 83E, aligning solicitations with reasonable interconnection milestones is particularly challenging as ISO-NE's interconnection process has been on hold for nearly a year and there are many meaningful energy storage projects waiting to be studied. If there are no changes to the deadlines in Section 83E, it may be impossible for the solicitations to align with key milestone dates in ISO-NE's interconnection process, even once ISO-NE's interconnection schedule is confirmed¹. ISO-NE's interconnection process is currently undergoing significant reform in compliance with FERC Orders 2023 and 2023-A and has been delayed due to a lack of action from FERC on ISO-NE's filed compliance proposal. No one knows when, or if, ISO-NE's compliance proposal will be approved or what provisions will be included. Given that we are already looking at a nearly one-year delay to ISO-NE's originally filed plan and compliance could result in even further delays, the Parties should move forward with minimal interconnection requirements (as we outline further in response to question 4.d), for now, to ensure a robust pool of projects is eligible to participate.

We highlight the disconnect between the section 83E procurement timeline, the interconnection process timeline, and the expected timeline for securing a capacity award for Capacity Commitment Period 2028-2029, in a worksheet that we have attached to this submission.

If there is flexibility in the timing of future procurement dates, we would recommend that the Parties attempt to align procurement dates at logical places in ISO-NE's interconnection process. For example, it is anticipated that the new interconnection process will have several key phases, where additional information regarding an interconnection request becomes known. Projects will receive information at various stages throughout the process and we believe it would be logical to have solicitations occur after a project has received at least preliminary results from a cluster study or any other interconnection study.

¹ In the absence of a FERC order on ISO-NE's compliance filing, ISO-NE plans to present on potential next steps related to the implementation of Order 2023 and 2023-A at the April 17 Transmission Committee meeting per their March 3, 2025 two-month look ahead: https://www.iso-ne.com/static-assets/documents/100021/tc_two_month_look_ahead.pdf

If RFP schedules do not align with ISO-NE's interconnection process and no new study results are published, the Parties would likely see similar, if not identical, projects bid into subsequent solicitation rounds. In order to ensure that the bidding pool is robust, the Parties should seek to expand the pool in every solicitation by including projects which have started to make progress through ISO-NE's interconnection process, even if they have not completed their studies.

4. Eligible Bids:

- a. Project's technology type (e.g., lithium ion, flow batteries, thermal, etc.), and how it meets the defined Section 83E criteria.*

We believe that most bids in the Section 83E solicitation for mid-duration storage will come from lithium-ion projects as these are the most commercially available and cost-effective energy storage technology which meets the criteria defined in Section 83E.

- b. Appropriate minimum and/or maximum bid size, both in terms of MW and Attributes.*

As there are economies of scale with larger projects, the Parties should not impose a maximum project size. Parties should instead let project economics and physical limitations (e.g. interconnection limitations) determine project size which would be reflected in participant's bids and would lead to more cost-effective outcomes.

However, if the Parties were concerned about the risk of relying on a small number of projects or project developers to meet statutory goals, the Parties could consider limiting the ability for a single project or project developer to win more than a fixed percentage (e.g. 50%) of the total procurement target, so long as that did not limit project sizes below at least 200 MW.

- c. Minimum delivery requirements (e.g., a certain number of CPECs delivered that is a function of Qualified Energy Storage Systems ("QESS") capacity); the frequency with which that requirement must be met (e.g., over entire contract, yearly, quarterly); and inclusion of an operational schedule in the bid to support delivery feasibility.*

The Parties should not include minimum delivery requirements for the number of CPECs produced per unit of installed capacity but instead should require bidders to either specify (1) the minimum number of CPECs they guarantee they would deliver per year or (2) the minimum percentage of a theoretical maximum number of credits that they would guarantee they would deliver per year in their bid, with a supporting operational plan and schedule. Imposing a minimum delivery requirement may limit the operational flexibility and business models of developers seeking to participate in this solicitation, potentially eliminating economic and efficient proposals.

If the Parties decide to include a minimum delivery requirement as a criterion for eligibility in this solicitation, it should reflect reasonable assumptions regarding expected forced and unforced outages,



the uncertainty in predicting the Hour of Actual Monthly System Peak, and the potential interactions for responding to conditions in the wholesale markets. Instead of a fixed number of CPECs, the minimum eligibility criterion should be a fixed percentage of the theoretical maximum number of CPECs that could be generated by the project over the course of a year, based on actual system conditions during the operating year and adjusted to reflect outages outside of the project owner's control.

As a general principal, participants in these procurements need to have a clear understanding of their risk exposure (e.g. performance penalties associated with delivery, etc.) and the maximum liability from these contracts in order to make accurate bids. To that end, GSP strongly recommends that the Parties release a draft contract prior to the solicitation and accept feedback from stakeholders on this contract prior to the opening of the bidding window.

d. Appropriate project maturity requirements.

Site Control

Projects should be required to demonstrate site control, consistent with the demonstration for site control to enter ISO-NE's proposed interconnection process, as outlined in section 3.4.1 of the revised OATT Schedule 22 filed with ISO-NE's compliance filing.

Interconnection

Given the uncertainties associated with ISO-NE's interconnection processes as we outlined in our response to Question 1.a and the attached worksheet, the Parties should require that projects only have a valid interconnection request in order to submit a bid in the solicitation. Because of the unprecedented interconnection delay, the potential pool of eligible projects would be small if the Parties implemented more stringent requirements. There is more interest in development in Massachusetts than what has made it through ISO-NE's queue so far, and more stringent requirements could potentially eliminate some of these projects that would otherwise be more cost-effective as few other opportunities exist for contracting.

While we recognize that additional information from the interconnection studies is valuable, given the firm deadlines in Section 83E and the firm timelines that will be established in ISO-NE's interconnection process, it will be impossible to fully reconcile these processes. Underpinning the interconnection process reforms is the desire to only allow projects to enter the queue at a later stage of development, when they are ready to make firm financial commitments. Now, even at early stages in the interconnection process, these projects will have had to make significant initial study deposits and commercial readiness deposits in order to participate. For the transitional cluster study process, ISO-NE is requiring projects to post \$5 million in security to enter the queue. For the subsequent cluster study processes, large generators are required to post \$800,000 in deposits at the time of application and which ramps up as a project continues to progress through the study process, as summarized in the figure below from ISO-NE's compliance filing. These requirements should mitigate overly speculative projects.

	Cluster Study Entry Window			Cluster Study Report	Facilities Study Agreement	Interconnection Agreement
	<i>Initial Application Deposit</i>	<i>Study Deposit</i>	<i>Readiness Deposit</i>	<i>Readiness Deposit</i>	<i>Readiness Deposit</i>	<i>Readiness Deposit</i>
Form of Deposit	Cash: Submitted to ISO	Cash: Submitted to ISO	Cash, Surety Bond, or LOC: Submitted to ISO	Cash, Surety Bond or LOC: Submitted to ISO	Cash, Surety Bond, or LOC: Submitted to ISO	Form of Security Acceptable to Transmission Owner
LGIP	\$50,000	\$250,000	\$500,000	5% Network Upgrade Assignment	10% Network Upgrade Assignment	20% Network Upgrade Estimate
LGIP CETU Designated ¹²⁰	\$50,000	\$250,000	5% Network Upgrade Assignment	N/A	10% Network Upgrade Assignment	20% Network Upgrade Estimate
LGIP CNRIS-Only	\$50,000	\$100,000	\$200,000	5% Network Upgrade Assignment	10% Network Upgrade Assignment	20% Network Upgrade Estimate

Source: https://www.iso-ne.com/static-assets/documents/100011/rev_in_compliance_with_order_2023_and_2023-a.pdf

Recognizing that there will still be concern regarding speculative projects, both from developers and from the Parties, the Parties should require additional security postings from project developers who submit bids into the Section 83E solicitations. These additional security postings should be scaled based on the stage of the interconnection process that a project has completed (i.e. projects with interconnection agreements should have lower security requirements than projects just entering the interconnection queue). These security posting should be fully refundable when an awarded project reaches commercial operation or when a project is not selected for an award.

5. Facilitating the Financing of Projects:

- a. *How the requirement from Section 83E—that this solicitation provide a “cost-effective mechanism for facilitating the financing of beneficial, reliable energy storage systems”—could be applied under this RFP.*
 - i. *Standards the RFP should set to confirm that projects are using this solicitation to facilitate financing.*

Cost-effective financing for most new projects depends on the availability of long-term revenue streams and guarantees. The longer and larger that guarantee, the lower the financing cost of the project. Non-contracted revenue streams will be heavily discounted by investors, particularly as markets continue to evolve (see answer to Question 5.d on risks to revenue streams). Therefore, contracts stemming from these solicitations for new projects by definition facilitate financing. GSP is concerned that any additional requirements for new projects to demonstrate support or financial backing prior to bidding, or after awards, may significantly complicate specific types of development models, potentially deterring otherwise viable projects from participating in these solicitations. Particularly for development models where the project’s developer and the project’s owner/operator are not the same entity and the date upon which the project transitions from one entity to the other varies. Imposing strict requirements regarding the demonstration of financing may force projects into

schedules or arrangements they would have otherwise not made, potentially increasing costs or deterring specific developer models.

- ii. *How those standards could be applied to existing projects to allow their participation in this RFP.*

Existing projects, defined as already having started physical construction, should be significantly discounted in their evaluation criteria in this solicitation, as these projects have achieved financing without this procurement. Construction on a project would not have begun without sufficient financing. Projects that have reached this stage will be built regardless of the Section 83E solicitations as they have likely secured financing under the assumption of other market revenues. These projects are economic based on other value streams and therefore payments through Section 83E would only represent a windfall to the developer and an unnecessary added cost to Massachusetts' ratepayers. Allowing these existing projects to participate will potentially cool interest from new projects and does not achieve the requirements in Section 83E.

- b. *The application of tax credits, for example the Investment Tax Credit and associated guidance, towards the financing of new projects, including whether your project would still be fully financeable if these credits are not available.*

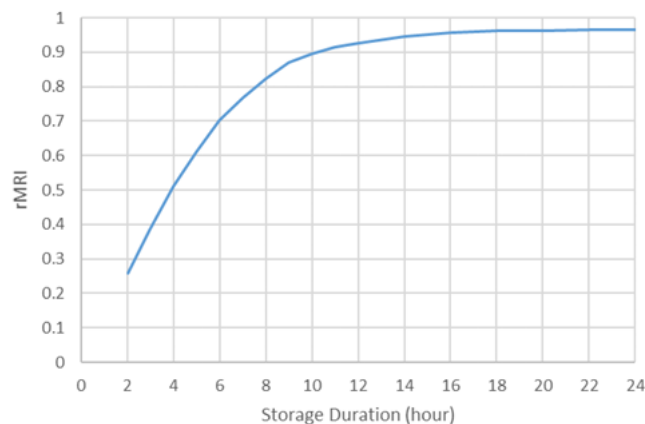
Given the current federal regulatory uncertainty, the Parties should design this procurement to dynamically handle different outcomes regarding the future of the Investment Tax Credit and associated guidance. Ideally, project developers would be able to submit bids with and without their assumptions regarding the Investment Tax Credit, and the Parties could establish clear criteria by which a bid would be adjusted to reflect the final decision on the availability of these tax incentives. This would be similar to how the index adjustment mechanism works for other types of projects. If the Parties also include an index adjustment mechanism, we recommend that projects submit a matrix of prices based on different outcomes and if selected bids would be adjusted by different criteria. The Parties could evaluate projects' price based on weighting prices across this matrix based on the Parties' expectations of the probability of each outcome occurring.

- c. *The approximate percentage of your capital costs met by:*
 - i. *CPECs revenue*
 - ii. *Energy/Energy Arbitrage*
 - iii. *Ancillary Services (Regulation, etc.)*
 - iv. *Forward Capacity Market*

We expect that most of the project's capital costs will be covered by CPEC and Capacity Market revenues, with energy arbitrage and ancillary service revenues making up a smaller portion of a project's value stack.

- d. *The risks associated with each revenue over the life of the project.*

Outside of CPECs, each of the other revenue streams listed above is subject to market fluctuations and market dynamics outside of a project developer's control. The wholesale markets are evolving as the region makes the monumental transition to cleaner energy sources, which has introduced a significant amount of uncertainty and volatility into the market. This is driven by normal economic factors (e.g. as supply and demand balances in this new paradigm) but also by regulatory factors, as ISO-NE makes changes to its wholesale markets to attempt to adjust to these shifts. Some of the reforms that ISO-NE has proposed and is developing will have impacts on the economics for energy storage resources, the magnitude of which is currently unknown. The most impactful reform, measured both by expected magnitude as well as the portion of a project's revenue stack, will likely be ISO-NE's Capacity Auction Reform (CAR) project. The CAR project is expected to fundamentally change the capacity product by modifying (1) the time horizon by which capacity is procured (moving from forward procurements to procurements immediately before the delivery period), (2) the duration of the capacity strip in the primary auction (moving from an annual auction to a seasonal auction), and (3) the capacity accreditation for supply resources participating in the auction (moving to a marginal capacity accreditation technique). In aggregate, we believe that these changes will make capacity market pricing and revenues more volatile, as resources have less time to react to market signals and the amount of capacity that a resource can sell into each auction changes year-over-year. Further, ISO-NE's preliminary modeling in their RCA project indicated that energy storage projects, particularly, mid-duration energy storage projects may see their capacity accreditation values fall significantly due to the proposed changes in capacity accreditation methodology. Recognizing that these values are expected to change with the CAR reforms, the following figure shows the capacity accreditation values for different durations of energy storage based on ISO-NE's Impact Analysis in their Resource Capacity Accreditation project (where the rMRI value would be multiplied by a resource's Qualified Capacity based on a project's duration):



Source: https://www.iso-ne.com/static-assets/documents/100011/a02c_mc_2024_05_07_08_impact_analysis_sensitivity_results_may2024.pdf

This expected volatility is going to make project financing more challenging unless, as we expand upon further in our respond to Question 16.a, the Section 83E solicitations include additional products to help projects firm these other revenue streams.



- e. *How a project's participation in the ISO-NE market affects its bid. Please specifically comment on how any ISO-NE operational obligations will impact the creation of CPECs.*

The generation of CPECs limits the ability of an energy storage asset to optimize their operations in ISO-NE's markets or respond to ISO-NE market signals, because CPEC resources need to adhere to strict charging/discharging windows. For energy storage projects participating in ISO-NE's capacity market, these resources have significant financial incentive but also significant potential risk associated with capacity scarcity conditions. For example, if a capacity scarcity event was to occur after the peak load window and the contracted resource had already depleted its state of charge during the peak load window to maximize its generated CPECs (potentially because it had to contractually), the resource would be exposed to the full performance penalty in the capacity market². The Parties should ensure that projects participating in the capacity market should not be penalized for responding to this ISO-NE market signal as these resources can provide valuable system relief during these stressed system conditions.

6. Commercial Operation Date:

- a. *Any appropriate commercial operation date for Section 83E Round 1.*

For all Section 83E solicitations, the Parties should provide at least 3 years from project award to COD. The Parties should also include an automatic extension to 5 years if the developer has continued to make reasonable progress towards project completion and the option to extend beyond 5 years if the project developer has continued to make reasonable progress towards project completion and there are project delays are outside of the developers' control (e.g. interconnection network upgrades to be completed by the utility are delayed beyond 5 years).

8. Contract Length and Form:

- a. *The contract length, for a period of up to 30 years, that should be considered under Section 83E Round 1 and associated reasoning, including how the contract term will facilitate the financing of the project, how the term aligns with useful life, augmentation schedules, etc.*

The drafting parties should consider 10 years as a minimum for a contract length but should allow project developers to specify in their bid their preferred contract length between 10 and 30 years. This would allow bidders to optimize project terms considering economic factors including availability of financing, project augmentation schedules, and the expected useful life of the equipment. These factors may differ for different developers and development models. By allowing flexibility in bids, the Parties would then be able to see these different options and select the most cost-effective option for meeting the Parties' needs. The Parties' should also consider including "evergreen" provisions in these contracts, which would allow the Parties and the project to mutually agree to extended the

² Starting in the capacity delivery year 2025-2026, the performance payment rate will be \$9,337/MWh per Section III.13.7.2.5 of ISO-NE's Tariff.



contract after the initial term either at prearranged terms or terms which would be renegotiated at the end of the initial contract's term.

- b. Given the degradation of battery performance over time, how contractual provisions for operational security should be constructed to assure optimal/maximum performance for the duration of the contract.*

GSP believes that these contractual provisions can be successfully structured in several ways, including guaranteeing a minimum capacity throughout the contract life which could be demonstrated through a yearly audit and would likely incentivize developers to overbuild and augment when needed.

10. Project Viability and Other Qualitative Factors:

- b. The key elements that should be considered in evaluating project viability, including any minimum requirements for participating in the RFP. Please specifically comment on:*
 - i. Site control*
 - ii. Interconnection studies*
 - iii. Technical and logistical viability*
 - iv. Ability to finance the project*
 - v. Bidder experience*

Please see comments on in response to Question 4.d.

- c. Any other considerations that should be considered when drafting the RFP that would impact project viability.*

If the Drafting Parties are concerned about project viability, they could require bid bonds or security requirements for awarded projects, as we outlined in our response to Question 4.d, so long as those requirements are set in a manner consistent with the size of the project, which would discourage speculative development but accommodate a wide variety of developers of different sizes and business models.

11. Grid Resiliency and Transmission Needs:

- a. How Section 83E Round 1 may be designed to best encourage investments and commitments that maximize grid resiliency and fulfill transmission needs in specific geographic locations. Please be as specific as possible in describing resiliency and transmission needs.*

The Parties should consider non-priced factors in the evaluation of bids which support project locations which benefit grid reliability and resiliency. Transmission owners are the entities responsible for maintaining the transmission system and, therefore, are in the best position to identify where these needs are. The Parties should have conversations with transmission owners to identify



potential needs and then communicate locations which would benefit from storage to potential bidders well ahead of the submission deadline.

New York State has proposed similar geographic non-priced factors in their bulk energy storage procurements³. There, in addition to specific geographic procurement target carveouts, NYSERDA will be considering non-priced factors including electricity system value, which will include an evaluation of the ability of proposed projects to contribute towards system reliability, peaker displacement potential, renewables integration, and curtailment reduction potential. Non-priced evaluation criteria provide the Parties to consider the impact of a project on the greater system which may not be captured easily in price or economic factors.

12. Interconnection Capability Requirement

- a. Please comment on your current interconnection status or plan. What interconnection status, level and maturity should be required by the RFP?*

Please see our response to Question 4.d.

13. Economic Development, Workforce, and Diversity, Equity & Inclusion (DEI):

- a. How Section 83E Round 1 could be designed to best encourage investments and commitments that maximize economic benefits to the Commonwealth, particularly for transitioning fossil fuel communities, support workforce harmony, and advance DEI goals.*

Like grid resiliency and transmission needs, these factors may not easily be captured in project pricing. Therefore, the Parties should consider non-priced evaluation criteria to assess projects for their contributions towards economic development, workforce, and DEI goals. These evaluation criteria should be clearly established and communicated to bidding parties ahead of the solicitation, with an opportunity for feedback from stakeholders on proposed criteria and scoring before they are finalized.

14. Environmental Justice:

- a. How Section 83E Round 1 could be designed to best encourage project design and investments that avoid negative impacts on, and direct positive benefits of the project to, Environmental Justice (“EJ”) communities.*

Like our responses to Questions 11.a and 13.a, environmental justice may not be easily be captured in project pricing. Therefore, the Parties should consider non-priced evaluation criteria to assess projects for their contributions towards environmental justice. Like other evaluation criteria, these should be clearly established and communicated to bidding parties ahead of the solicitation, with an opportunity for feedback from stakeholders on proposed criteria and scoring before they are finalized. It will be

³ <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F099A092-0000-C938-98D5-9D3FB839557F}>



particularly important to solicit feedback directly from environmental justice communities and advocates ahead on these criteria as well, ahead of finalizing the criteria.

16. Future RFPs:

- a. Whether and how the RFP drafting team should consider inclusion of energy services in future 83E RFP Rounds, both in terms of how future RFPs would be similar or different from 83E Round 1's RFP, which is only for environmental attributes.*

The Parties should consider including additional products in future Section 83E RFP Rounds. As we covered in our responses to Questions 5.a.1 and 5.d, wholesale market revenue streams are uncertain and therefore heavily discounted by investors, increasing overall financing costs. By contracting with additional revenue streams, the RFP Contracting Parties can lower the cost of projects, while providing similar value to the system. In fact, contracting for additional energy services gives the Parties greater control over the value that the awarded energy storage projects deliver. As the system evolves, agreements for additional products would give the Parties confidence that these assets will continue to perform in a manner that provides benefits to the system without contractual renegotiation, while reducing the risk and therefore the cost of the project.

Many other regions are considering tolling agreements for mid-duration energy storage devices, which provide full or partial control of the storage asset to the counterparty for a fixed capacity fee. By transferring energy, ancillary, and/or capacity products to the offtaker, tolling agreements allow the counterparty to maximize the assets for their own needs, which in the case of the Parties could lower consumer costs, meet environmental needs, and achieve other policy objectives.

- b. The use of indexing or other adjustment mechanism.*

GSP is interested in the indexed storage credit mechanism proposed in New York and believes that it may be a viable mechanism for cost-effectively facilitating the deployment of energy storage projects in the state. However, the program is still under development, has significant administrative complexity, and has yet to be demonstrated to be successful. Therefore, we recommend that the Parties carefully watch the outcomes from the first Bulk solicitation later this year but strongly consider tolling agreements in the interim, as we covered in our response to Question 16.a.

However, one important part of the New York solicitations through a similar mechanism and which has been included in the Section 83C IV solicitations is the Indexing Adjustment Mechanism, which provides developers a option to submit a bid with a one-time change in price based on economic indices to reflect changes in macroeconomic conditions. As stated in the Indexing Adjustment Mechanism Informational Filing: “The chosen Indexing Adjustment Mechanism is intended to provide a hedge that distributes some of the cost variation risk between developers and customers, i.e., variations (both increases and decreases) in project costs from the proposal submission date until a period when developers have greater certainty that their proposed project will be developed and are in a position to manage these cost risks. The Indexing Adjustment Mechanism is intended to encourage



participation and competition among developers in the RFP, and to deter future default risk.”⁴ Given energy storage projects are exposed to similar macroeconomic factors as projects participating in Section 83C IV, the Parties should include this option in the Section 83E solicitations as well to reduce the risk of project attrition due to factors entirely outside of the control of the project developer.

Conclusion

Once again, GSP appreciates the opportunity to provide this feedback on the Section 83E solicitations and looks forward to continuing this conversation with the Parties.

Sincerely,

Christopher Hickey

Co-Founder

Granite Source Power, LLC

⁴ <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18578719>