January 26, 2021

Jeffrey R. Gaudiosi, Executive Secretary
Public Utilities Regulatory Authority (PURA)
10 Franklin Square
New Britain, CT 06051

Re: Docket No. 17-12-03RE03, *PURA Investigation into Distribution System Planning of the Electric Distribution Companies – Electric Storage*

Dear Mr. Gaudiosi:

The Northeast Clean Energy Council ("NECEC") and the U.S. Energy Storage Association ("ESA") appreciate the opportunity to provide a response to the Notice of Issuance of Straw Electric Storage Program Design and Request for Comments ("Straw Proposal") in the above-referenced docket.

NECEC is a clean energy business, policy, and innovation organization whose mission is to create a world-class clean energy hub in the Northeast, delivering global impact with economic, energy, and environmental solutions. NECEC is the only organization in the Northeast that covers all of the clean energy market segments, representing the business perspectives of investors and clean energy companies across every stage of development. NECEC members span the broad spectrum of the clean energy industry, including energy efficiency, wind, solar, energy storage, microgrids, fuel cells, electric vehicles, and advanced and "smart" technologies. Many of our members are already doing business in Connecticut, and many more are interested in doing so in the near future.

ESA is the national trade association dedicated to energy storage, working toward a more resilient, efficient, sustainable and affordable electricity grid – as is uniquely enabled by energy storage. With more than 200 members, ESA represents a diverse group of companies, including independent power producers, electric utilities, energy service companies, financiers, insurers, law firms, installers, manufacturers, component suppliers, and integrators involved in deploying energy storage systems around the globe. Further, our members work with all types of energy storage technologies and chemistries, including lithium-ion, advanced lead-acid, flow batteries, zinc-air, compressed air, liquid air, and pumped hydro among others.

I. <u>Introduction</u>

NECEC and ESA commend the Public Utilities Regulatory Authority ("PURA" or "the Authority") for its Straw Proposal to create a program ("Program") to provide deployment incentives and performance compensation to energy storage systems ("ESS") for delivering benefits to customers, to the grid, and to the environment. NECEC and ESA are particularly supportive of the 580 megawatt ("MW") 2030 deployment target, the performance payment structure and compensation levels, and the commitment to equity. With appropriate modifications, we believe that this proposal could put Connecticut at the forefront of energy storage by using tested and proven program methods at scale to jumpstart the market. That said, several elements of the proposed Program will create significant barriers to storage deployment and delivering the greatest value and cost reductions to all Connecticut ratepayers. Below we expand upon our support for the Program, and provide recommendations for revisions to the Program design that would ensure robust participation while aligning with Program Objectives.

II. Program Objectives

NECEC and ESA agree with the three objectives identified in the Request for Program Designs,[1] and we appreciate PURA's consideration of the additional objectives to increase resilience, lower barriers to entry for energy storage, and maximize the long-term environmental benefits of storage. These six objectives recognize that storage is able to provide a range of benefits, if properly incentivized.

III. Program Design

a. Program Summary

The Program envisioned in the Straw Proposal would represent a substantial commitment to energy storage in the state of Connecticut. While we provide feedback on specific elements of the proposal below, NECEC and ESA support the overall Program and believe it will deliver meaningful benefits to Connecticut residents, with certain revisions as detailed.

b. Program Length and Size

The overall Program size of 580 MW by 2030 is achievable and cost-effective. A 580 MW deployment goal by 2030 will target some of the most expensive hours of the year that contribute an outsize amount to total grid costs. As provided in our initial response to the Request for Program Designs, an analysis of Connecticut's 2018 summer peak demand indicates that the top two percent of hours June-September account for approximately 580 MW of capacity.[2] Further, the gradual increase in the total procurement over each three-year period will allow developers to ramp up their operations in Connecticut and create a storage sales infrastructure and workforce that will make reaching the higher targets in the later years

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[1] Provide a positive net present value to all ratepayers; provide multiple types of benefits to the electric grid; and foster the sustained, orderly development of a state-based electric energy storage industry.

[2] *See,* RFPD Response, Northeast Clean Energy Council, U.S. Energy Storage Association, dated July 31, 2020, at 9 and 17-18, http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/bb8bbb2e2ebd8d1b852585b60054d775/$FILE/Joint%20ESA%20and%20NECEC%2017-12-03RE03%20RFPD%20Response%207.31.20%20.pdf.

achievable. This ambitious but achievable Program requires the active engagement of storage vendors, customers of all classes, third-party storage owners and operators, and program administrators to achieve its goal. Our recommendations below are provided with the size of this goal in mind.

c. *Program Eligibility*

Non-customer-sited Resources

The Straw Proposal states that front-of-the-meter ("FTM") resources are eligible to participate in the Program. However, the eligibility requirements appear to limit participation to customer-sited configurations, excluding FTM configurations that are not sited at a customer premises. Yet, distribution-connected FTM storage — either stand-alone or paired with renewables — that is not sited at a customer premises represents a significant opportunity for the deployment of cost-effective ESS. Limiting the program to customer premises likewise limits the potential locational value of ESS. Specific applications of energy storage, such as reducing capacity needs at EV fast-charging stations, providing load relief near utility substations, or to accommodate integration of distributed energy resources ("DERs") at specific nodes, may be optimized at sites that are not located on a customer premises.

Additionally, allowing FTM installations that are not located at a customer premises will further increase the participation opportunities for certain customers, including those in underserved and overburdened communities, who may derive greater benefit from off-site ESS. For instance, Community Shared Solar projects that serve low-income customers may desire to pair with energy storage participating in this Program, but would be ineligible to do so under the current eligibility requirements. To maximize the benefits that a diversity of project types would provide to Connecticut ratepayers, including to low-to-moderate income ("LMI") customers, customers in environmental justice or economically distressed communities, and public housing authorities, NECEC and ESA recommend that the eligibility requirements be amended to allow all standalone FTM systems that are connected to the distribution grid to participate. If the Authority is intent that this program only be available to electric customers, ESA and NECEC strongly recommend that PURA pursue a supplemental program to compensate distribution-connected, non-customer-sited FTM ESS.

ISO New England Markets

The Straw Proposal also specifies that resources participating in this Program are not able to register in the ISO New England ("ISO-NE") wholesale energy market and must transfer ownership of capacity rights to the Connecticut Green Bank ("CGB"). Prohibition on energy market participation and capacity rights transfer may be appropriate for a residential solar program, upon which much of the CGB proposal is based. However, energy storage is fundamentally different than solar, and storage owners and operators cannot finance storage projects if they do not have control over them, as would be the case with the CGB having capacity rights. We explain this in greater detail below.

Energy storage is dispatchable and highly flexible in responding to a wide array of grid and customer needs. ESA and NECEC members have invested hundreds of millions of dollars of private capital in the technology necessary to optimize for a wide variety of grid needs, including complex wholesale markets. Limiting storage's ability to provide its flexibility value to the wholesale markets will underutilize the storage resource and ultimately limit the Program's value to ratepayers. Allowing third-party operators and customer owners access to ISO-NE markets will allow the Program to optimize ratepayer benefits, emissions reductions, and customer value and participation, thus contributing to satisfying the Program objectives. The proposed Program wholesale market criteria create a number of difficulties for storage vendors that will significantly inhibit the overall success of the Program and reduce the economic and environmental benefits that will accrue to Connecticut residents. For the reasons below, we urge the Authority to allow participation in the wholesale energy market and for the capacity rights to remain with the ESS owner.

The inability for resources to participate in the wholesale energy markets will leave an important source of ratepayer value on the table. Storage can provide a cost-effective alternative to fossil generators in the energy/ancillary services markets, especially in the emissions-intensive winter months. Prohibiting storage participation in the energy market, and essentially having the storage sit idle for eight months of the year, will deny Connecticut these cost reduction and emissions benefits. While unintended, the prohibition on energy market participation also extends to the ancillary services market. This is because the largest ancillary service, reserves, is co-optimized with the energy market. In other words, if the Program prohibits wholesale energy market participation, storage can't participate in the largest ancillary services market. Without the prohibition on energy market participation, even if the Program obligations prevented an ESS from offering ancillary services during the summer months, the ESS could provide a cost-effective alternative to fossil generators in the emissions-intensive winter months. While a "load reducer" model might be appropriate for a solar program, a storage program can deliver greater benefits from active management of the storage resource, which comes from energy market participation.

The "load reducer" proposal and restricting the owner/operator from participating in the ISO-NE Forward Capacity Market ("FCM") will dampen the environmental and ratepayer benefits of the ESS. Allowing ESS owners the opportunity to participate and clear in the FCM would realize ratepayer and emissions benefits much more quickly than under the "load reducer" model and align more closely with the Program objectives. As stated in the 2018 Avoided Energy Supply Cost Report, "Program savings that are not cleared as capacity resources provide savings much more slowly. A load reduction in 2018 will first affect the ISO New England's Spring 2019 load forecast, which will be used in the February 2020 FCA 14 for 2023/24…While we cannot precisely determine the effect of load reductions on the ISO's complex econometric models and load forecasts, *a reasonable estimate would be that the load forecast would reflect the full effect of the load reduction in Year 10 of the reduction*."[3] Therefore, under the "load reducer" model,

[3] Synapse Energy Economics, Avoided Energy Supply Components in New England: 2018 Report, https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080-Oct-ReRelease.pdf. Pages 103-104.

storage installed in 2022 will not fully displace fossil capacity on a 1:1 basis until 2032, sharply limiting both emissions and ratepayer benefits. And since storage can only participate in the performance payment for 10 years, by the time the full effect of the load reduction is felt, ISO-NE would have to stop counting it as a load reducer. Once the performance payment ends, there is no guarantee that the storage will actually reduce load in those years during the hours that form the basis for the load forecast. So ISO-NE could not adjust its load forecast downward ten years after installment, meaning that any emissions and ratepayer benefits felt during the first ten years would be short-lived. This is just one key difference between storage and solar, as the lengthy useful life of the solar and it's on/off nature would allow ISO-NE to count it as a "load reducer" for at least 20 years.

Further, if ESS acts as a "load reducer" and is only active for four months of the year and not participating in ISO-NE, the ISO-NE control room will not have any visibility into its operation, and would not be able to dispatch the ESS in a system emergency. Such a design greatly underutilizes the reliability benefits that storage can provide.

In contrast, if ESS were to participate and clear in the FCM, it could displace a fossil unit with the commencement of the delivery year for which it clears, and participate as an existing resource in the FCM for years after the Performance Incentive ends. The 2018 Avoided Energy Supply Cost Report estimates this downward pressure, known as Net Zone-on-ROP Capacity DRIPE[4] ($/kW-year), to result in $91/kW-yr in avoided capacity costs 2018-2027 on a levelized basis in Connecticut.[5] While the Minimum Offer Price Rule has prevented storage from clearing to date, given the pending revisions to the ISO-NE Offer Review Trigger Price for storage, we anticipate storage to be able to clear in much greater quantity in the future.

Importantly, transfer of capacity rights to any other entity, including CGB, will imperil the financing of ESS and runs directly counter to the objective of lowering barriers. If an entity other than the storage owner or operator has these capacity rights, there is a risk of the entity clearing the ESS in the FCM, in which case the storage owner must assume they will have to cede full control of the ESS to that entity. When storage clears in the FCM as a Generation resource (front of the meter) or as a Demand Response Capacity Resource (behind the meter), the storage acquires a "must offer" obligation into the co-optimized ISO-NE energy and ancillary services market and the Market Participant (in this case CGB) has to actively bid and manage the storage for every hour of the year. Storage is an active asset that must be managed for charge, discharge, internet connectivity, etc., unlike solar which is fundamentally passive. It would likely be technically and operationally difficult for an entity that does not have full operational control over every ESS installation to successfully aggregate the fleet that

[4] The report defines Capacity DRIPE as the change in state and regional electricity bills due to reductions in electric capacity prices.

[5] Avoided Energy Supply Components in New England: 2018 Report, P. 156. While we recognize that the 2018 Avoided Energy Supply Cost report estimates even higher savings if a resource were not to clear the market, the report also assumes that the resource would be available to reduce load in that year. As noted above, this would not be the case with the Program ending in 2030. Even if the Program were to continue beyond 2030, the longer deferred the savings, the more uncertainty that they actually materialize.

participates in this Program and bid into the Forward Capacity Market. Even for residential storage installations, which may choose not participate in the FCM, transfer of capacity rights will make financing projects more difficult. As discussed, the risk of another entity holding capacity rights and, potentially, accepting a "must offer" obligation will dampen the prospects of resources that do not intend to participate in the FCM and may in fact create a conflict with the active dispatch program.

Storage developers will struggle to finance ESS that carry the risk of ceding full control of the energy storage system to the CGB if capacity rights are transferred. Most notably, when purchasing a storage system, the owner has a warranty for a certain number of cycles per year. But if the CGB controls the ISO-NE participation of the storage, the storage owner cannot assume that the number of cycles per year will be less than those allowed under warranty. Therefore, the storage developer and/or financier cannot have confidence that the storage will have a useful life that allows it to capture the Program revenues that are necessary to develop a project. A storage developer can finance a project if a utility has dispatch rights over storage for a pre-determined and reasonable set of hours each year. The risk and performance requirements are knowable. But when the storage owner no longer has any control over battery dispatch, the developer cannot finance the project.

Beyond the significant financing challenges that transfer of capacity rights would create, the value of capacity rights are more likely to be maximized by third party owners or operators than the CGB. While the Straw Proposal allows CGB to utilize the capacity value if given Authority approval, third party owners and operators are financially motivated to maximize the value of capacity rights and will be able to make investment decisions that deliver the greatest ratepayer impact through capacity market price reductions. Third party owners and operators can be more aggressive in their bidding strategy due to higher risk tolerance for exposure to significant Pay-for-Performance penalties, through the capacity market, expected to reach over $8,500 per megawatt-hour in Forward Capacity Auction 16.[6] An aggressive bidding strategy will be more likely to offset marginal resources in the capacity market, which would lead to increased emissions reductions and cost savings, as inefficient, costly, fossil resources would retire earlier.

NECEC and ESA are aware of no other jurisdictions in New England in which storage incentive programs transfer the capacity rights from the storage owner to another entity. In fact, the Massachusetts Department of Public Utilities ("DPU") found that "allowing a Facility Owner of an ESS paired with a NM (Net Metering) or SMART facility to retain title to the capacity rights associated with the ESS is consistent with the Commonwealth's energy policies and goals of cost-effectively promoting ESS and renewable energy deployment…. in addition, the Department [found] that a Facility Owner holding title to the capacity rights associated with an ESS paired with a NM or SMART facility (in conjunction with the buyout option discussed in

[6] Updates to CONE, Net CONE, and Capacity Performance Payment Rate, FERC Docket ER21-787 at 39, https://www.iso-ne.com/static-assets/documents/2020/12/updates_cone_net_cone_cap_perf_pay.pdf

Section VI) could avoid potential conflicts with current ISO-NE rules regarding registration of paired asset."[7]

Finally, if capacity rights are transferred to the CGB, the ESS owner will not be able to optimize ESS operation for demand charge management, particularly during the summer months if the ESS is obligated to participate in passive dispatch. Demand charge savings are a critical portion of the total revenue stack for many energy storage projects. Storage developers would need to depend entirely on the upfront incentive and performance payments to deliver value to finance the system, which would be increasingly difficult under the declining block incentive program.

In sum, allowing storage owners/operators to participate in all ISO-NE markets will attract the necessary investment to meet the Program's MW goals, and result in greater ratepayer, reliability, and emissions benefits than any other model. If ESS owners/operators are able to monetize their resources in the ISO-NE markets, they will become less dependent on upfront incentives, allowing the Program to move to later capacity blocks and lower upfront incentives.

Passive Dispatch

NECEC and ESA are concerned that the requirement to enroll in Passive Dispatch during the summer months, particularly if combined with the inability to derive value from the energy or capacity markets, will severely limit Program uptake and we urge a reconsideration of these requirements. Specifically, we recommend that the Authority allow for participating ESS to choose between a suite of grid benefits, of which Passive Dispatch may be one option.

The Straw Proposal proposes that all resources participating in the Program are required to receive both the upfront incentive and the performance payments, and thus participation in both passive and active dispatch is mandatory. However, a major value proposition for ESS customers is demand charge management. Because demand charges are not always coincident with system peaks, automatic "set it and forget it" programming for average system peaks would not guarantee that a customer's demand charges are reduced. Without the ability to effectively manage demand charges, customers may not see sufficient value in entering into an agreement for energy storage.

As discussed earlier with respect to the transfer of capacity rights, the Passive Dispatch setting would also prevent the owner or operator of the system from controlling the number of cycles, risking the system warranty and decreasing the useful life of the system. Further, the Passive Dispatch setting would greatly complicate participation in ISO-NE markets and would thus reduce the opportunities to derive ratepayer value from price reductions, as discussed in the section above.

[7] Massachusetts Department of Public Utilities, 17-146-B, at 21, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/10333339

Additionally - and, importantly - having two separate dispatch programs with two separate administrators and possibly utilizing two separate Distributed Energy Managements Systems ("DERMS") would dramatically increase costs, both for participating customers and all ratepayers. This added friction for customers may become prohibitive.

NECEC and ESA appreciate the intent of the Passive Dispatch to ensure that ESS deliver grid benefits in order to be eligible for an upfront incentive. However, Passive Dispatch would not work for many ESS use cases (such as demand charge management), would shorten the useful life of participating ESS, and would represent a barrier to the deployment of ESS through this Program. Other jurisdictions have allowed ESS to demonstrate grid benefits without ceding control of the system and we urge the Authority to adopt multiple options for providing grid benefits in return for accepting the Upfront Incentive to recognize the multitude of ESS use cases. For example:

- Under the Massachusetts SMART program, an Energy Storage System co-located with a Behind-the-meter Solar Tariff Generation Unit may comply with the operational requirements in 225 CMR 20.06(1)(e)e. by demonstrating that the Energy Storage System reduces on-site customer peak demand or increases self-consumption of on-site generated solar energy.[8]
- The California SGIP program has allowed non-residential BTM systems to qualify by either enrolling in a retail demand response program or switching to a time-varying rate.[9]

ESA and NECEC recommend that the Authority further explore options appropriate to Connecticut by which a system may demonstrate grid benefits while retaining operator or owner control over the system.

NECEC and ESA additionally recommend that customers be given the option to forgo the upfront incentive (and thus a requirement to provide the associated grid benefits) but still participate in the performance payment and active dispatch program, and vice versa (i.e., forgo the performance payments and active dispatch requirements but still receive the upfront incentive and participate in the associated grid benefits). This level of flexibility will allow customers and vendors to optimize their level of participation, while still achieving the Program Objectives.

Technical Criteria

Under technical criteria, the Straw Proposal states, "To receive ongoing performance payments, the electric storage system must be actively dispatched by a third-party owner (TPO) or the applicable EDC in accordance with the rules determined by the EDCs and approved by PURA." We recommend that Third-Party Operators, not just owners, be eligible to actively dispatch the storage asset in accordance with the Program rules. While seemingly a minor distinction, some

[8] Guideline on Energy Storage, Section 6)f., https://www.mass.gov/doc/ess-guideline-october-2020/download
[9] SGIP Program Handbook - 2020, at 48, https://www.selfgenca.com/home/resources/

projects may be customer-owned with a Third-Party Operator that manages the battery operation on behalf of the customer.

d. *Compensation Structure*

NECEC and ESA strongly support the proposed Low- and Moderate-Income ("LMI") adder. As we discuss in response to Section III.O, ensuring equitable access and uptake from underserved and overburdened communities is vitally important to ensuring that the transition to a clean energy economy is benefitting *all* residents.

e. *Compensation Level*

Upfront Incentive

The Straw Proposal offers an upfront incentive to both Residential and Commercial and Industrial ("C&I") customers. NECEC and ESA support a declining upfront incentive block structure to defray the initial costs of deploying storage particularly in the early years of deployment, and we offer feedback to improve the upfront incentive. The proposed first block of 2 MW for residential customers would not provide an adequate runway for the initial energy storage market to develop before the incentive value would decline. In order to achieve the 50 MW through 2024 and 290 MW by 2030 there will need to be a robust residential storage market that includes many installers utilizing the program. If the incentive value declines too quickly then it may discourage installer participation, particularly smaller installers. Additionally, continuity during the initial period of the program will be beneficial for all parties as the complications that will undoubtedly arise in implementation are worked through. For C&I customers the first capacity block of 2 MW may be met with one or two projects. Therefore, we recommend increasing the block sizes for each block, with an additional increase at incentive step one to allow for more development and cost efficiencies to arise. We support a more gradual increase in project block sizes for both residential and C&I to reach the 50 MW total, while giving fewer steps[10] to C&I customers to accommodate larger project sizes:

Residential

Incentive Step	Capacity Block
1	5
2	7.5
3	10
4	12.5
5	15

[10] We acknowledge that the incentive level for each block would need to be revised if there were fewer blocks, but do not propose a specific level.

C&I

Incentive Step	Capacity Block
1	10
2	15
3	25

The proposed block structure includes a maximum incentive for all customers regardless of class based upon the value of two 14 kWh Tesla Powerwalls. Considering that C&I systems can be hundreds of times larger than 14 kWh, a much higher incentive cap is needed to incentivize the deployment of C&I systems. For example, NYSERDA limits their retail-level incentives to 15,000 kWh. Whether or not the Authority finds this an appropriate limit for Connecticut, it is clear that a much higher cap is appropriate. We recommend that this topic be explored further in stakeholder technical meetings.

ESA and NECEC seek clarity as to whether the incentive is calculated based off of nameplate or usable battery capacity and recommend that for simplicity, nameplate is used.

<u>Performance Payment</u>

The Straw Proposal provides for a performance payment of $225/kW per summer season.[11] NECEC and ESA generally support the performance payment, with concerns noted below. This model and payment level has been successful in the ConnectedSolutions program, and will continue to be drive cost-effective savings at the expanded deployment levels that will be enabled by this Straw Proposal. As designed, the performance payment call windows appear to overlap with the Connected Solutions program. We recommend that this Program remains available in parallel to the Connected Solutions program for behind-the-meter systems, and available to front-of-the-meter systems.

Our concerns, questions, and recommendations with regards to the Performance Incentive section of the Straw Proposal are:

1. We recognize that the Performance Payment could fluctuate with each three-year cycle for *new* projects based on updated cost-effectiveness analysis, and do not take issue with that. Once a project is *installed,* however, the Straw Proposal is unclear whether the Performance Payment would fluctuate over time for that installed project, or whether it would receive the Performance Payment in place at the time of installation for the duration of the Program.

   The greater the certainty in the Performance Payment level for projects *once they are installed*, the lower the costs of financing and barriers to entry. A ten-year Performance Payment rate lock on a $/kw-yr basis would lead to the lowest barrier to entry, the lowest

[11] The Straw Proposal refers to "summer event", however we believe this is intended to be $225/kW per summer season and operate under that assumption in our response.

financing costs, and the highest potential deployment. As such, we recommend a ten-year rate lock for the Performance Payment for projects once they are installed. So a project installed in 2022 would have the $225/kw-yr Performance Payment for ten years. Again, the Performance Payment may change each three year-cycle for new projects, so a project installed in 2022 could have a different Performance Payment than a project installed in 2025 than a project installed in 2028.

2. The Straw Proposal has significant deployment targets for 2028-2030, with nearly half of the MW expected to be installed in those years. However, the Straw Proposal sends conflicting messages on what happens after 2030. In one section it states “Participating customers may receive performance incentives for the same electric storage system for up to 10 years” but in another section it states “Accordingly, the Authority establishes a nine-year program for electric storage in Connecticut commencing January 1, 2022 and running through at least December 31, 2030.“

   While we believe this to be the Straw Proposal’s intent, NECEC and ESA recommend that any project installed through the end of 2030 be eligible for the Performance Payment for ten years from the date of installation.

3. We recommend that projects installed after the issuance of this straw proposal and prior to a final Decision authorizing the Program should be eligible to earn the Performance Payment, but not the upfront incentive. The Performance Payment is based off the value to all Connecticut consumers of dispatching storage during the peak hours of the summer months. That value isn’t any less just because a project was installed in 2020. Excluding existing projects and not dispatching them during summer months would leave ratepayer benefits on the table.

   Finally, we recommend that any projects installed after the final Decision authorizing the program but prior to 2022 should be eligible for both the upfront incentive and the Performance Payment. If projects have to wait until 2022 to meet the necessary milestones to receive the upfront incentive, it will create an unnecessary waiting game where projects that are ready to be built in 2021 will delay whatever milestones they need to meet until 2022.

f. Ownership Model

NECEC and ESA support the Authority’s proposal to allow for third-party ownership of eligible energy storage systems, subject to continued adherence to the eligibility requirements and dispatch notices. Third-party ownership has proven successful in Connecticut, through the ConnectedSolutions program, and in other jurisdictions, and will allow customers to choose the vendor that is able to optimize the energy storage system to meet their unique needs.

g. Operational Control Model

NECEC and ESA recommend significantly modifying the Straw Proposal's proposed Operational Control Model. We recommend that PURA implement the model already in place for the ConnectedSolutions program. Under ConnectedSolutions, the storage owner/provider receives a dispatch signal from the EDC at the appropriate time, and then the storage owner/provider communicates the signal to, and dispatches, the storage. The storage owner/provider maintains full control over the storage at all times. NECEC and ESA have several members that participate in ConnectedSolutions and find that this Operational Control Model is streamlined and efficient. Since compensation in ConnectedSolutions is dependent on performance, the storage provider/owner has the necessary incentive to induce performance. The same principle would apply here, and there is no reason to alter the successful Operational Control Model already in place for other storage programs. Similar to our concerns with the transfer of capacity rights, ceding operational control, even on a limited basis, would imperil the financeability of storage projects. This may become a concern with certain distribution energy software DERMS providers.

As discussed in the comments on Section III.C., passive dispatch, as proposed, will hinder the effectiveness of the Straw Proposal.

h. Program Administration

PURA intends to conduct annual reviews of the Program in the first two years of each cycle and will conduct a full program review in the last year of each cycle. In conducting the scheduled program review at the end of the first cycle, we encourage the Authority to consider whether a performance payment for winter events is warranted. We expect that the opportunity to realize ratepayer and environmental benefits from active winter dispatch will increase in future years as renewable resources replace retiring fossil resources.

The Straw Proposal states that resources have 270 days from enrolling in both portions of the Program before the upfront incentive expires. NECEC and ESA recommend that resources have 365 days from enrolling in both portions of the Program before the upfront incentive expires. We appreciate the desire to ensure that projects are expeditiously being constructed and subsequently providing benefits, but note that projects may face permitting and interconnection delays that could make it difficult to come online within 270 days. Giving projects 365 days would strike a balance between ensuring that projects are coming online quickly and that vendors are given enough time to navigate the complex permitting, interconnection, and construction landscapes.

NECEC and ESA recommend consolidating program administration with electric distribution companies ("EDCs") in order to minimize administrative redundancies and remove superfluous costs. A program design that requires dual program administrators with multiple dispatch platforms has the potential to increase costs, create customer and market confusion, and duplicate administrative functions. Consolidating certain program administration functions with the EDCs, and at a minimum, the use of the EDC's dispatch platform, is likely to reduce overall program costs. We have consulted with Eversource Energy, who is in general agreement with our position on this topic and consented to our representation of their position. Eversource is filing its own set of written comments which will further amplify this point.

i. Evaluation, Measurement, and Verification ("EM&V")

We do not have comments on this section.

j. Cost Recovery Proposal

We do not have comments on this section.

k. Cost-Benefit Analysis

The cost-benefit analysis in the Straw Proposal is clear that the benefits of deploying storage through this program will far outweigh the costs for ratepayers, as well as for the various other stakeholder perspectives analyzed.

l. Data Privacy and Security Plan

We do not have comments on this section.

m. Technology Eligibility

The intent of the technology eligibility requirements is to be permissive to all commercially available technologies that are able to satisfy the program requirements. However, the technology eligibility requirements do stipulate that resources must have a round-trip efficiency ("RTE") of 80% or greater. NECEC and ESA recommend that this threshold be removed, as it would prevent some technologies that could contribute to system benefits from participating. This threshold is unnecessary given the financial incentive storage vendors will have to ensure the storage assets are configured to most efficiently satisfy the program requirements and deliver customer value. Since the Program would not provide value to resource for charging, only for discharging, there is no need to specify a minimum RTE. Additionally, there are many technical criteria that contribute to the total cost of ownership and resulting benefits of ESS, including cycle life, degradation profile, and depth of discharge. As RTE is one of many technical criteria that does not reflect the full value of the ESS, it should not be used to exclude ESS that could offer system benefits.

n. System Disposal

We do not have comments on this section.

o. Other Program Design Elements

LMI and Medical Hardship Customers

NECEC and ESA support the potential adder for environmental justice (“EJ”) communities, economically-distressed communities, and public housing authorities. Equity is essential in all programs that the state undertakes. We further recommend that the Authority investigate strategies to remove the non-financial barriers to participation in overburdened and underserved communities that will ensure meaningful participation by low-income customers and customers located in EJ communities. An adder is necessary to reach many of these customers, but is not sufficient on its own. The exclusion of FTM systems from this Program would erect a non-financial barrier to participation for underserved customers and we encourage the Authority to remove that barrier by allowing FTM projects to participate and incentivizing them to serve low-income and EJ customers. We, and our members, stand ready to work with the Authority and other stakeholders to ensure that the Program leads to equitable outcomes. We also encourage PURA to review Program participation statistics for low-income and EJ ratepayers during the Program reviews and, if necessary, revise the Program to enhance low-income and EJ participation.

Grid Edge Customers and Critical Facilities

The Straw Proposal would direct the EDCs and the CGB to investigate how to identify grid-edge customers, who experience frequent and prolonged outages, and critical facilities, as well as how to prioritize deployment to these customers. NECEC and ESA support the focus on providing resilience to critical facilities and to grid-edge customers, and the recognition that there is a value for increased resilience. Storage is able to enhance resilience, but it is not a free service and an additional incentive would be necessary for installations configured with resilience as a top priority. The costs associated with operating Critical Facilities during an outage vary based on the type of emergency operations the facility is responsible for, critical load, islanding requirements, and the duration of the outage that is planned for. In the context of climate change and increasingly frequent natural disasters and outages, compensating the dispatch of microgrid and energy storage systems to provide resiliency and maintain critical operations during system outages is a priority that will save lives, improve energy security and maximize the effectiveness of Federal, State, and Local emergency response operations.

Other Northeast states have implemented or considered using EDC outage penalties to fund resilient battery deployment for critical facilities and outage impacted customers. This may be pertinent in in Connecticut.

Increased Emissions Reductions

The focus on reducing emissions from in-state fossil peaking generation is commendable and we support this objective. As discussed in the response to Section III.C., allowing the storage owners to retain the rights to the ISO-NE wholesale markets and to participate in those markets will offset fossil resources and drive emissions reductions in Connecticut and around the region.

To drive deeper, targeted emissions reductions from in-state fossil peaking generation, however, would require access to marginal emissions data from ISO-NE. To date, this information is not publicly available, which complicates any proposal to drive in-state emissions reductions at certain hours. While beyond the scope of this docket, the New England States are undertaking a stakeholder process to surface issues with and solutions for the ISO-NE wholesale markets, which could ultimately lead to better alignment with state emissions policies and allow for program design elements focused more directly on emissions.

IV. Rate Design

Though beyond the scope of this docket, standalone FTM storage resources face significant barriers to entry because these resources are charged the retail delivery rates for charging the storage asset. This leads to substantial demand charges, with no host customer to offset the impact of those charges. We encourage PURA to consider the rate design challenges with deploying standalone FTM storage to ensure FTM participation in the Program. A recent whitepaper jointly developed by the New York Department of Public Service Staff and the New York State Energy Research and Development Authority provides a consideration of the rate design barriers for standalone FTM development and a recommendation for how to alleviate those difficulties.[12]

V. Conclusion

NECEC and ESA commend the Authority for issuing a thoughtful Straw Proposal that, with certain modifications, would create a cost-effective and achievable Program. NECEC and ESA look forward to continuing to engage with the Authority and all stakeholders to further the Straw Proposal.

Respectfully submitted this 26th day of January, 2021.

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[12] Whitepaper on Allocated Cost of Service Methods Used to Develop Standby and Buyback Service Rates, New York Department of Public Service Staff and the New York State Energy Research and Development Authority (November 25, 2020), http://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=256423&MatterSeq=49770