April 5, 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 this Brief in the above referenced docket.

I. Incentive Structure

The combination of an upfront incentive and a performance payment envisioned in the Straw Proposal provides a strong Program foundation which will spur energy storage deployment in the state when coupled with the recommendations made by NECEC, ESA, and energy storage vendors in this proceeding.

States with successful storage markets such as California, New York, and Massachusetts have a combination of an upfront storage deployment incentive and then separate, non-contingent, performance programs. The amount of the deployment incentive is calibrated based on the gap between the cost of the storage and the market opportunities. As revenue availability increases and costs decline, the deployment incentive can decline accordingly. On the other hand, the performance programs are intended to pay for services that a storage installation provides at a level commensurate with the value of the service performed.

While the upfront incentive is designed to facilitate deployment of energy storage, a performance program provides energy storage owners the opportunity, should they choose to do so, to operate the system in ways that benefit all ratepayers and be compensated accordingly. Both elements are necessary to develop a vibrant state-based energy storage industry, but should not be contingent upon each other.

For example, a customer may need the upfront incentive to deploy storage in order to provide resiliency due to frequent power outages. However, once the battery is deployed, daily battery cycling for bill management on a Time of Use (“TOU”) rate may be the most effective use of the battery, particularly if the customer produces their own solar power. This cycling for TOU - and therefore increased solar self-consumption - provides a benefit to all ratepayers and requiring participation in active or passive dispatch programs could be in conflict.
The declining block structure for the upfront incentive is appropriate for a new technology which is expected to realize significant cost reductions over the coming years. However, it is important that the blocks be large enough to be both meaningful with regards to providing predictability for the market and to reflect real cost reductions. This is particularly important during the early stages of a new program so that a broader range of installers will be able to participate. There are implementation costs associated with participation in new programs or the inclusion of a new technology, particularly for businesses seeking to participate in the active dispatch program. Smaller vendors are likely to be discouraged from participation if the initial blocks are fully subscribed too quickly. As such, we urge the Authority to adopt the block size recommendations proposed in the Joint ESA and NECEC comments filed on January 26, 2021 to provide a more gradual increase in capacity between blocks for the residential category and the condensed number of blocks for C&I.

Regarding the incentive levels, we refer the Authority to the extensive analysis and discussion in NECEC’s response to CAE-4. In summary, the starting upfront incentive value of $280/kWh and $225/kW-year performance payment would be appropriate assuming that the energy storage resources are not precluded from participation in wholesale markets, the performance payment is available for 10 years, and there is no passive dispatch requirement.

II. Passive Dispatch

Requiring the passive dispatch of an energy storage system in order to receive the upfront incentive would interfere with the ability to participate in other markets or programs, diminish the value for host customers, and could require an unnecessary and duplicative Distributed Energy Resources Management System (“DERMS”). The drawbacks of requiring passive dispatch for all energy storage systems has been thoroughly discussed throughout this proceeding.¹

The inclusion of energy storage in a project is predicated upon its ability to provide an enhanced value proposition for the host customer. For some host customers that value may solely be back-up power if, e.g., they are medically compromised and require reliable power. However, other customers the value may include demand charge management or increased behind-the-meter consumption of electricity generated by a paired solar system. Requiring passive dispatch would preclude the ability of the system to respond to other price or market signals which could provide greater customer and ratepayer benefits than the passive dispatch. Requiring all energy storage systems to operate according to a predetermined, generic schedule is likely to reduce the value proposition for host customers and therefore may slow the deployment of energy storage. This is especially true as we look at future implementation of FERC Order 2222.

The purpose of the passive dispatch requirement is to ensure that systems receiving an incentive provide some level of ratepayer benefit in return, as originally envisioned in HB 5351 (the concept of which is now expanded upon in SB 952). It is possible that the passive dispatch

¹ For example see Joint ESA and NECEC 17-12-03RE03 Straw Proposal Response, Stem’s responses to CAE-1 and CAE-2, ESA response to CAE-4, and NECEC’s presentation for the February 1, 2021 technical conference.
schedule would provide a lower ratepayer value compared to other potential price signals the energy storage system could respond to.²

We recommend that the program provide multiple operational pathways by which an energy storage system qualifies for the upfront incentive. This would allow the passive dispatch schedule to be one option for developers or customers, while also allowing eligibility through other means including (but not limited to) reducing customer peak demand or increasing self-consumption of on-site generated solar energy, participation in the active dispatch program, enrolling in time-varying rates, or participation in an ISO-NE market. This approach would be more flexible as additional value streams are identified for energy storage resources and would prevent the passive dispatch requirement from being a barrier for deployment. It also mirrors the approach used in the successful Massachusetts SMART program.

The cost-benefit analysis currently treats the active dispatch program value as incremental to the baseline value provided through the passive dispatch. However, given the overlap between passive and dispatch parameters, if passive dispatch was not required, the active dispatch program could reflect the full discharge value of the storage system. Some of that quantified value would likely be reallocated from the passive dispatch to the active dispatch program. Any remaining ratepayer value that might be “lost” due to the removal of the passive dispatch could be made up through participation in the wholesale market, providing peak demand reduction, or through other operational pathways.

Finally, if PURA elects to retain passive dispatch schedule as an option to establish eligibility for the upfront incentive, the passive dispatch program does not require an additional DERMS. The passive dispatch parameters would be set at the time of installation and could be validated as part of the application process. Additionally, the Green Bank could periodically audit systems to ensure they maintain the passive dispatch schedule once operational. Should changes need to be made to the pre-set schedule, those changes can be communicated to developers without the need for a DERMS.

### III. Operational Control Model for Active Dispatch

It is important that the system owner retains direct control of the energy storage asset. The operational control model presented by Eversource is in alignment with the best practices from other states which have implemented bring-your-own-device programs. Under this model the electric distribution company (“EDC”) sends a dispatch signal to either the device manufacturer or a Distributed Energy Resource (“DER”) aggregator, who then dispatch the device in response to the EDC signal and in accordance with the terms of the program the device is dispatched under (i.e., devices may be eligible to participate in multiple programs).

This operational control model is critical in ensuring that the energy storage system can also be optimized to provide host customer benefits and respond to additional price signals. Because

² See Stem response to CAE-2.
the payments through the active dispatch program would only be made based on actual performance, the risk lies with the system owner or aggregator and thus they should be able to make decisions on how to operate the system.

IV. Capacity Rights

The Straw Proposal would require that the capacity rights for the energy storage systems be transferred to the Connecticut Green Bank (“CGB”). This proposal is problematic and should be modified so that system owners retain capacity rights. Simply put, the transfer of capacity rights would imperil project financing, limit the environmental and ratepayer benefits that could be realized through direct participation in the Forward Capacity Market (“FCM”), create significant operational challenges, and place Connecticut out-of-step with the rest of the region.³

Primarily, the transfer of capacity rights would inject operational - and therefore, financing - risk into project development. This would increase project development costs and therefore require a higher upfront incentive amount.

Additionally, for certain market segments, the proposed transfer of capacity rights removes a revenue stream for energy storage projects which then also increases the “gap” that the upfront incentive is intended to address. For some projects, ratepayer value is maximized through direct participation in the wholesale markets rather than treatment as a load reducer and the potential participation in the FCM through the CGB - which is likely not operationally feasible. The treatment as a “load reducer” would also preclude energy storage systems from participating in the largest ancillary services market, reserves. The risk of a party other than the system owner holding the capacity rights and accepting a “must offer” obligation in the FCM could create conflicting operational schedules between the FCM, active dispatch, passive dispatch (if retained), and host customer’s intended usage (i.e. peak demand reduction).

Treatment as a “load reducer” also provides a more limited environmental value than through direct participation in the energy and capacity markets. When resources do not clear as capacity resources, their full impact materializes over a 10-year period which limits their ability to displace fossil fuel resources in ISO-NE.

V. Front-of-the-Meter Storage

Distribution-connected front-of-the-meter (“FTM”) storage that is not sited at a customer premises represents a significant opportunity for the deployment of cost-effective ESS. Providing for the deployment of these resources would maximize the benefits that a diversity of project types would provide to Connecticut customers that may not host energy storage projects at their own premises. Specific applications of energy storage may be optimized at sites that are not located on a customer premises. If the Authority does not include distribution-connected,

³ See Joint ESA and NECEC 17-12-03RE03 Straw Proposal Response, pages 3-7 for a comprehensive discussion of these issues.
non-customer-sited FTM ESS as part of this program, ESA and NECEC recommend a separate a supplemental program to compensate this segment, as contemplated in the proposed SB 952.

Additionally, 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.

VI. Conclusion

NECEC and ESA commend the Authority for its Straw Proposal that, with certain modifications, would create a cost-effective and achievable Program. NECEC and ESA appreciate the substantial time and effort devoted to this proceeding by all docket participants and we look forward to continuing to engage with the Authority and all stakeholders as this Docket moves forwards.

Respectfully submitted this 5th day of April, 2021.

Sincerely,

Sean Burke
Policy Associate
Northeast Clean Energy Council

Julian Boggs
State Policy Director
U.S. Energy Storage Association