August 29, 2025

New England Conference of Public Utility Commissioners (NECPUC)
Demand Response and Load Flexibility Working Group
info@necpuc.org

Re: CPower and Enel's Comments on Lawrence Berkeley National Lab's August 2025 report for NECPUC

Dear Chairman Phil Bartlett and the NECPUC Demand Response and Load Flexibility Working Group,

CPower and Enel appreciate the opportunity to provide comments on Lawrence Berkeley National Lab's (LBNL's) recent report on the value of demand response (DR) in New England, the potential for DR deployment in the region, and challenges to deploying more DR. CPower agrees with many of the report's conclusions and highlights some of these areas of agreement below. We have questions or points of disagreement on select portions of the report; these are discussed below as well

<u>Comments</u>

1. **The report correctly identifies the conflict between retail programs and the ISO-NE capacity market as one of the major hurdles to participating in the ISO-NE market**

The report notes that, "retail participation can reduce calculated demand response performance in ISO-NE wholesale markets" and "this may disincentivize dual participation in ISO-NE wholesale markets and retail programs".[1] This occurs because demand response performance is measured relative to a baseline and that baseline is reduced when a customer curtails demand for a retail program.

[1] LBNL August 2025 report, page 21 https://www.necpuc.org/wp-content/uploads/2025/07/lbnl_technical_assistance_memo_20250731_final.pdf#page=21

What the report does not capture is that the "baseline reduction effect" and the resulting performance degradation can have serious financial consequences for dual participating customers. These customers provide a valuable service to the ISO-NE system but the increasing risk of an adverse financial impact from dual participation is likely to deter them from providing this service to ISO-NE in the future. This adverse impact was particularly evident on June 24, 2025 when the ISO-NE system experienced a Capacity Scarcity Condition (CSC).

Most retail programs in New England instructed customers to curtail load from 5:00 PM to 8:00 PM on June 24. The ISO-NE system entered scarcity conditions at 5:35 PM and this condition lasted until 8:40 pm.[2] Customers that were curtailing their demand pursuant to a retail program were viewed as non-performing by ISO-NE and therefore incurred penalties at a rate of $9,337/MWh of shortfall relative to their balancing ratio-weighted Capacity Supply Obligation.[3] To put a finer point on this, customers that began curtailing their demand roughly a half an hour before the ISO-NE system went into scarcity conditions were viewed as providing zero value to the system, despite the fact that the scarcity condition likely would have begun earlier and lasted longer without their curtailments.

This counterintuitive result occurred due to the way ISO-NE calculates the adjusted baseline that is used to determine event performance. The adjusted baseline equals the unadjusted baseline plus an adjustment equal to the average MW difference between a customer's demand during the three most recently completed 5-minute intervals prior to event notification and their unadjusted baseline. Because many customers participating in retail programs were already curtailed by 5:35pm, their ISO-NE baseline saw a significant negative adjustment, which caused them to appear as not performing to ISO-NE.

This result is at odds with how other types of resources are treated during Capacity Scarcity Conditions. Generators or importers that self schedule during scarcity conditions receive credit for the energy they provide because that energy helps

[2] Please see Capacity Scarcity Condition Report for June 24, 2025 https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/capacity-scarcity-condition-report

[3] See Section 13.7.2 of the ISO-NE Tariff. In short, capacity resources are penalized during Capacity Scarcity Conditions if the capacity they deliver is less than the product of their Capacity Supply Obligation (CSO) and the Balancing Ratio (BR). The BR is essentially the ratio of load plus reserves to total CSOs on the system. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf#page=206

balance supply and demand. Demand resources that curtail during scarcity conditions because of dispatch from a retail program also help balance supply and demand and yet may receive no credit.

We believe this is an unintended flaw in the ISO-NE tariff because the tariff does provide demand resources on scheduled or forced curtailments credit for providing *Actual Capacity* during a Capacity Scarcity Condition.[4]

The practical effect of this flaw is that some current customers will leave the ISO-NE market and new customers are less likely to join unless steps are taken to resolve this issue. Many customers simply do not have the appetite to absorb the magnitude of penalties levied by ISO-NE on June 24, especially when they performed. This would be a loss for the ISO-NE market and would be a step in the wrong direction as the region anticipates greater reliability challenges in the future. The possibility of an event like the one on June 24 will reduce the availability of DR during all emergency events, even shorter-duration ones like we have seen previously, when DR provided much-needed performance.

ISO-NE has recently expressed openness to revisiting certain Pay for Performance (PFP) provisions in response to a FERC complaint filed by the New England Power Generators Association (NEPGA) and we anticipate that a stakeholder process may be undertaken to discuss such changes .[5] We believe it would be appropriate to discuss the treatment of dual participation resources under PFP as part of any process that arises from NEPGA's complaint.

Please help us communicate to ISO-NE how important it is to resolve the conflict between retail demand response programs and the ISO-NE capacity market and support adding this topic to any future discussions on Pay for Performance reform.

2. **The report discusses the use of DR to avoid energy shortfalls; there may be more targeted ways to utilize DR that attract a greater number of MW and provide greater value in terms of cost reduction and improved reliability.**

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[4] See Section III.13.7.2.2 of the ISO-NE Tariff. "Actual Capacity" is how ISO-NE quantifies the capacity delivered by a resource during a Capacity Scarcity Condition. For an Active Demand Resource, Actual Capacity is equal to the calculated load reduction or reserves provided by the resource. https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf#page=208
[5] See FERC EL25-106

The report identifies three types of shortage conditions that demand response could help mitigate. These conditions are expected to last for several hours, with one category of shortage exceeding 12 hours.[6]

Many demand response customers do not have the appetite to shift or reduce load for such an extended period of time. This does not mean that these resources cannot provide value to the system. To the extent a customer reduces load during any portion of an energy shortfall, it is providing value, particularly if it is reducing the use of resources that are powered by stored fuel.

Rather than requiring all DR customers to provide load reductions during extended time frames, we suggest that any new retail DR programs incorporate tiered performance levels with commensurate incentive rates.

3. **The assumption that winter capacity prices will be zero until the region becomes winter peaking is questionable and likely underestimates the value of winter demand response**

We question whether the report's conclusion that winter capacity prices are likely to be zero until the region is close to or at a winter peaking system should be relied upon in NECPUC's decision making.[7] Real life examples suggest that this conclusion is flawed. The NYISO market – a summer peaking region, for example, holds seasonal capacity auctions and the winter auctions consistently clear well above zero.[8] Notably, the NYISO capacity market does not include a punitive penalty structure like that employed in the ISO-NE market. Given this, one might assume that all else equal ISO-NE prices would clear above NYISO prices. Notably, because of the risk of penalties under the Pay for Performance construct, it is very unlikely that resources would be willing to take on a Capacity Supply Obligation in the ISO-NE market for a zero price.

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[6] LBNL August 2025 report, page 2 https://www.necpuc.org/wp-content/uploads/2025/07/lbnl_technical_assistance_memo_20250731_final.pdf#page=21

[7] The LBNL report references Synapse's 2024 AESC report https://www.synapse-energy.com/sites/default/files/AESC%202024.pdf which concludes that winter capacity prices will be zero until 2032 at the earliest even though a seasonal capacity market is slated to go into place in 2028.

[8] See ICAP auction results on NYISO website https://www.nyiso.com/installed-capacity-market

Another reason why auctions are unlikely to clear at zero even when the system is surplus is that ISO-NE employs a demand curve to clear capacity. A typical sloped demand curve used to clear capacity auctions specifies increasingly lower prices for higher surpluses of capacity. Although the provisions for seasonal capacity auctions have yet to be developed, it is reasonable to assume that ISO-NE will continue to employ demand curves to clear capacity auctions; ISO-NE has suggested exactly this in the materials shared with stakeholders.[9] Notably, the ISO-NE market has cleared surplus capacity in every auction since demand curves and Pay for Performance were instituted in 2018. Those auctions have all cleared at prices well above zero.[10]

Further, while the AESC study referenced in the LBNL report attempts to calculate capacity accreditation values in its seasonal capacity price analysis, it is not clear whether those values will approximate the values that ISO-NE ultimately assigns to resources because those rules are still under development. It is likely that those rules will derate gas-fired generation substantially, which should put upward pressure on winter capacity prices. Moreover, the idea that a winter capacity auction would clear at a zero price seems to be at odds with the concept of increasing winter reliability risk in ISO-NE. Two other RTOs, PJM and SPP, have recently begun incorporating winter risk into how they plan their systems. It is reasonable to presume that ISO-NE will do the same in the new market design that is slated for implementation in June 2028, and thus winter capacity value will almost certainly be non-zero.

Finally, a 2024 study done by the Analysis Group supports this view. In this study, the simulated capacity price for the 2028-29 winter season is $4.29/kW-month. The table below shows the simulated capacity prices that the Analysis Group calculated.[11]

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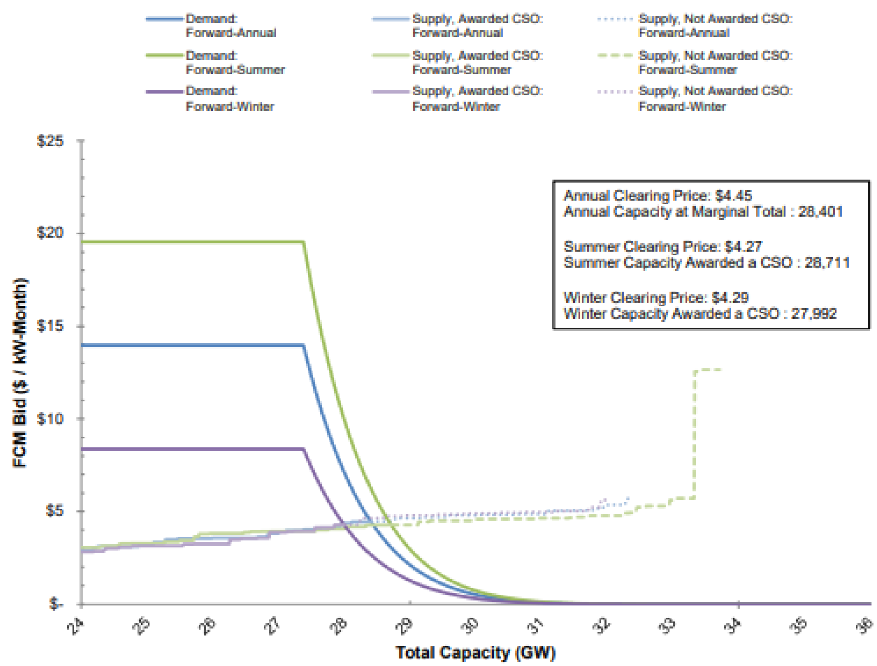
[9] See slide 23 in ISO-NE's July 9-10, 2024 slide deck https://www.iso-ne.com/static-assets/documents/100013/a08_mc_2024_07_09-10_initial_car_scope_considerations.pdf

[10] See auction results here https://www.iso-ne.com/about/key-stats/markets#fcaresults and Summary of capacity requirements by year here https://www.iso-ne.com/static-assets/documents/2016/12/summary_of_historical_icr_values.xlsx

[11] See the Analysis Group January 2024 report, page 103: Capacity Market Alternatives for a Decarbonized Grid: Prompt and Seasonal Markets https://www.iso-ne.com/static-assets/documents/100007/a08b_mc_2024_01_09_11_agi_updated_report.pdf#page=111

Figure 21. Forward-Seasonal Market (Compared to Forward-Annual), 2028-29 CCP



Importantly, failing to assign positive capacity value to the winter misses an important cost savings that DR can provide during the winter months. The ISO-NE capacity market is a roughly billion dollar/year market. As such, there is potential for significant savings with effective incentives in place for demand response.

We suggest that the states work with ISO-NE to understand how to design winter DR programs to maximize avoided winter capacity costs.

4. Dynamic rates alone will not allow the region to realize its demand response potential

The report suggests that dynamic rates will help incent greater demand response.[12] We do not disagree with this contention and do not oppose dynamic rates, but dynamic rates alone will not allow the region to realize its full demand response potential. Ample evidence indicates that predictable, recurrent incentives are most effective in attracting and retaining demand response resources. This is the reason

[12] LBNL August 2025 report, page 9, "PUCs can consider requiring utilities to incorporate dynamic components into TOU rates to incentive greater demand reductions during energy shortfalls" https://www.necpuc.org/wp-content/uploads/2025/07/lbnl_technical_assistance_memo_20250731_final.pdf#page=9

that the Brattle Group found in a study performed for the Australian Energy Market Commission that, "Jurisdictions with capacity markets consistently attract the most demand response participation, and the demand response resources there earn the vast majority of their revenues from capacity".[13] Similarly a joint study prepared by Brattle and LBNL indicates that offering ongoing participation payments is a high impact strategy for increasing virtual power plant enrollment.[14]

Conclusion

We very much appreciate the work done by LBNL to examine demand response opportunities and challenges and commend NECPUC for commissioning this report. In evaluating the report's conclusions and determining next steps, we urge NECPUC to:

- Help the demand response community to convey to ISO-NE how important it is to resolve the conflict between retail programs and the ISO-NE capacity market
- Reconsider the report's assumption that winter capacity prices will be zero until the region is winter-peaking and the resulting conclusion that winter demand reductions will have little capacity cost reducing value until that time.
- Recognize that reaching the region's demand response potential will require more than dynamic pricing; it will require strategically designed recurring and predictable incentives.

Thank you for the opportunity to provide these comments. We look forward to continuing the discussion on how demand response can be better leveraged in New England.

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[13] See the Brattle Group's International Review of Demand Response Mechanisms in Wholesale Markets, pages 4-5 https://www.brattle.com/wp-content/uploads/2021/05/17479_international_review_of_demand_response_mechanisms_in_wholesale_markets.pdf

[14] See Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment, slide 6 https://eta-publications.lbl.gov/sites/default/files/2024-12/30_strategies_to_increase_vpp_enrollment_12-19-2024.pdf

Sincerely,

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