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New England Conference of Public Utility Commissioners (NECPUC)
Demand Response and Load Flexibility Working Group
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NRG and CPower Comments on NECPUC’s Draft 2026 Report on the Retail Demand Response and Load Flexibility Working Group

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

NRG Energy Inc., together with CPower, a wholly owned subsidiary of NRG, appreciate the opportunity to provide comments on NECPUC’s draft 2026 report on the Retail Demand Response and Load Flexibility Working Group (“Draft Report”). We commend NECPUC for commissioning this important regional analysis and for producing a report that thoughtfully addresses both peak demand growth and winter energy adequacy challenges facing New England.

NRG is a leading provider of electricity, natural gas, and smart home solutions to eight million customers across North America. The company operates a customer-first platform supported by a diversified supply strategy and the safe, reliable operation of approximately 25 GW of power generation. CPower is a leading Demand Response (DR) and Virtual Power Plant (VPP) Service Provider that monetizes the value of customer-sited energy to intelligently strengthen the grid. CPower became part of NRG in January 2026. Together, CPower and NRG manage more than 8 GW of DR/VPP capacity. The comments below reflect the perspective of our combined organizations, which together serve a broad customer base spanning the residential and commercial and industrial (C&I) sectors.

CPower and NRG support the Working Group’s recommendations and the direction outlined in the Draft Report. Our comments below are organized around four specific findings and recommendations in the report where we believe further elaboration or modification would strengthen the final product.



I. Support for the Transmission Cost Savings Potential of Demand Shifting — with Recommendations for Strengthening the Pathway to Realizing those Savings

The report correctly identifies that "[d]emand shifting by rescheduling load to off-peak hours can avoid costly transmission upgrades," and recognizes flexible load management as an equivalent solution in transmission and distribution planning. We strongly support this finding. As the report acknowledges, the potential magnitude of these savings is enormous: ISO-NE's own 2050 Transmission Study found that a 6 GW reduction in winter peak demand could save approximately \$8 billion in transmission costs.

Today, customers throughout New England have no financial incentive to shift their load to off-peak hours in order to reduce transmission costs. To stimulate demand shifting that avoids costly transmission upgrades, four things must happen:

- **AMI must be deployed to enable hourly metering.** Without granular interval data, it is impossible to know when a customer consumed electricity or to price that consumption based on the time it occurred. We're pleased that AMI deployments in New England are increasing.
- **Customers or their load serving entities (LSEs) must have direct control over, and accountability for, transmission costs.** Under the current framework in most New England states, utilities spread transmission costs evenly across all residential customers on a per-kWh basis regardless of when those customers consume electricity. Rate structures for commercial customers vary, but only a few of these provide incentives to reduce consumption during the hours that drive transmission costs. This means that the vast majority of customers have no incentive to reduce during the hours that actually drive transmission investment. The ISO-NE tariff currently allows capacity costs to be allocated directly to Load Serving Entities (LSEs), including municipal aggregators and retail suppliers. The PJM tariff allows for both capacity costs and transmission costs to be allocated to LSEs. A similar mechanism for transmission costs in ISO-NE would give competitive suppliers and municipal aggregators the motivation to develop the products, tools, and insights that would enable customers to reduce both overall transmission costs and their own bills through shifts in behavior and/or adoption of technology.



- **Utilities must perform load settlement with ISO-NE using AMI interval data.** Even where AMI deployments are happening in Massachusetts, these utilities are currently planning to report customer loads to ISO-NE using estimated load profiles rather than actual metered interval data. This means that a customer who reduces consumption during a peak transmission hour receives no financial benefit from doing so — the savings are averaged across a broad set of customers rather than credited to the individual who reduced. Until utilities report actual interval data to ISO-NE, the financial incentive created by time-varying rates will be muted or nonexistent. Massachusetts has opened D.P.U. 26-44 to address this issue for that state's utilities; we recommend that all New England states investigate whether their utilities have this capability and, if not, open comparable proceedings.
- **Utilities and ISO-NE must be transparent about the hours of the year that are driving the need for new transmission investment.** The report recommends that demand shifting can avoid transmission upgrades, but customers can only act on that incentive if they know which hours matter. ISO-NE's 2050 Transmission Study identifies the magnitude of investment at risk, but customers need to know the specific hours that cause that investment need. Without that granularity, time-varying transmission rates, Non-Transmission Alternatives, and DR/VPP programs will send an imprecise price signal that is less effective at inducing the precise load reductions that would defer or avoid the most expensive projects.

Recommendations for the Final Report:

- 1) The report should acknowledge that realizing the transmission savings potential of demand shifting will require, at minimum: (a) AMI deployment enabling hourly metering; (b) a mechanism for LSEs to have accountability for transmission costs, rather than utilities spreading those costs uniformly; and (c) AMI-based interval settlement between utilities and ISO-NE.
- 2) The report should recommend that all New England state commissions consider investigating whether their distribution utilities currently have the capability to (a) report hourly supplier load to ISO-NE using AMI interval data, (b) calculate individual customer ICAP tags based on actual metered data, and (c) enable competitive suppliers and municipal aggregators to offer time-varying rates settled using that data. For states where this capability



does not exist, the report should recommend that commissions consider opening proceedings similar to MA D.P.U. 26-44 to consider requiring their utilities to develop it, with appropriate timelines and accountability mechanisms. Given the regional scale of the issue, the report should also recommend that NECPUC serve as a forum for sharing progress and best practices across states as they undertake these proceedings.

- 3) The report should recommend that NECPUC collaborate with NESCOE to urge ISO-NE to publicly share the specific hours of the year that are driving the new transmission investment projected in the 2050 Transmission Study, along with the amount of load reduction during certain hours needed to defer or avoid that investment. It should further recommend that transmission owners share the hours driving local reliability projects. This information should be made available to state regulators, program designers, and the public.
- 4) The report should recommend that NECPUC engage with ISO-NE, NESCOE, and state commissions to explore whether an option that assigns transmission charges to the LSE could be made available, giving those entities a direct financial stake in helping customers reduce during transmission-critical hours.

II. Support for Rate Design Options and VPP Standardization – with Recommendations that All New England States Address ISO-NE Load Settlement

We strongly support the report's recommendation to "[c]onsider rate design options to support programs and technologies" and to "[s]tandardize and enable virtual power plants (VPPs) to participate in markets." Time-varying rates and VPP participation are among the most powerful tools available to New England states for reducing peak demand, lowering costs for all ratepayers, and unlocking the benefits of the significant AMI investments currently being made across the region.

However, both of these recommendations share a critical prerequisite that we highlighted in the previous section: utilities must perform load settlement with ISO-NE using actual AMI interval data. Without this capability, the benefits of time-varying rates and VPP participation are severely constrained – and in some cases eliminated entirely.



The report's recommendation that utilities provide "interval usage, TOU and net-metering attributes, program and event flags, and basic billing interoperability" is correct, but the foundation of all of those data flows is a utility back-office capable of ISO-NE interval settlement.

Recommendations for the Final Report:

- 5) *[Same as recommendation 2 above]* As stated above, the report should recommend that all New England state commissions consider investigating whether their distribution utilities currently have the capability to report hourly supplier load to ISO-NE using AMI interval data for settlement. For states where this capability does not exist, the report should recommend that commissions consider opening proceedings to consider requiring their utilities to develop it. Please see Recommendation 2 above for more detail
- 6) The report should make clear that without interval settlement, the rate design and VPP standardization recommendations in this section cannot be fully realized — and that addressing the settlement infrastructure is therefore a prerequisite, not a parallel track, to the other recommended actions.

III. Support for Exploring the Creation of New Winter programs and Scaling Existing Winter DR Portfolios and Managed EV Charging — with a Recommendation for Timely Action

We strongly support the report's recommendation to "[e]xplore the creation of new winter programs" and "[s]cale winter-focused DR portfolios and managed EV charging." Waiting until winter peaks arrive to begin developing programs and customer relationships would leave the region with far fewer cost-effective options precisely when they are most needed.

As the report acknowledges, ISO-NE plans to transition to a seasonal, prompt capacity market beginning with the Capacity Commitment Period starting June 1, 2028. This development fundamentally changes the near-term economics of winter demand response. Under a separate winter capacity auction, a resource that can reduce demand reliably during winter peak events will reduce capacity costs. States and utilities that delay building winter DR capabilities until New England is winter-peaking will miss an opportunity to address affordability.



State commissions and program administrators should immediately begin assessing the winter DR potential of their existing and planned programs in light of the 2028 seasonal market, and should update their cost-effectiveness frameworks accordingly.

Recommendations for the Final Report:

- 7) The report should recommend that state commissions and program administrators consider revisiting their winter DR cost-effectiveness analyses using avoided cost frameworks that account for the value of winter capacity under the forthcoming seasonal market structure, rather than assuming winter capacity value is zero or near-zero.
- 8) The report should recommend that NECPUC and/or states engage with ISO-NE to ensure that the design for state-level programs addresses winter needs and is reflected in future capacity procurements

IV. Support for the Recommendation to Continue Addressing Conflicts between Retail and Wholesale Dispatch of DR resources, with a suggestion for how to facilitate Additional Discussion

As the report acknowledges, dual participation in a retail program and the ISO-NE capacity market can result in significant financial penalties for DR Providers when the needs of each respective program/market conflict with each other. This issue is likely to cause an exodus of demand response from the ISO-NE market if it is left unaddressed.

Recommendation for the Final Report:

- 9) NECPUC, together with NESCOE, should request that ISO-NE add a gap analysis on demand response to its 2027 work plan. This analysis should evaluate the lack of alignment between retail demand response programs and the ISO-NE capacity market and recommend changes to address it.

We thank the Working Group for its diligent effort and for the opportunity to comment on this important report. We look forward to the final report and to continued engagement on these issues at the regional level.



Sincerely,

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