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Public Comment

As the Council considers Rhode Island Energy's proposed 2027-2029 System Reliability Procurement (SRP) investment plan, NRG and CPower respectfully request that you consider the comments below, which were submitted to Rhode Island Energy during the stakeholder process. As RIE recognizes, the electric system is undergoing significant change. Growing electrification, rising demand, and evolving wholesale market structures are all reshaping the value of demand-side resources.

More specifically, electrification-driven load growth will require significant

transmission buildout, increasing costs for ratepayers unless steps are taken to contain those investments. In addition, ISO-NE will transition to a seasonal capacity market in 2028, meaning that summer and winter peak load reductions will be needed to achieve the same capacity cost savings produced by summer only peak load reductions today. Finally, ISO-NE will also change the way that it assigns capacity value to resources in 2028. This last change is expected to reduce wholesale demand response revenue by approximately two thirds. This marked decrease in value combined with ongoing Pay for Performance (PFP) penalty risk will result in attrition of demand response from the ISO-NE market.

In this environment, expanding and strengthening demand management programs is more important than ever to support reliability and manage ratepayer costs. To that end, we offer the recommendations below.

1. ConnectedSolutions should be expanded to include a winter component

The Draft Proposal approaches winter demand response as a longer-term need associated with the expected shift to a winter-peaking region and therefore proposes an assessment-focused strategy rather than near-term change.

While increasing winter peaks are certainly an important consideration, the Draft Proposal overlooks a more near-term development that necessitates planning for winter demand response now: ISO-NE's planned transition to a seasonal capacity market.

a. Adding a winter component to ConnectedSolutions is necessary to preserve capacity savings for ratepayers.

ISO-NE’s annual forward capacity market will transition to a prompt, seasonal

market with the 2028/29 delivery period. Under this plan, ISO-NE will conduct summer and winter capacity auctions and will allocate the costs coming out of these auctions based on the respective seasonal peaks from the prior year. Seasonal capacity requirements will be developed based on forecast seasonal peak loads.

In contrast, today resource planning and cost allocation are based only on summer peak loads. For this reason, ConnectedSolutions has focused on reducing summer peaks. That focus aligns with today's market structure, where reducing summer peak demand is the primary way to mitigate capacity costs. In the future, however, managing both summer and winter peaks will be necessary to contain capacity costs.

The capacity market costs consumers more than $1 billion annually. Although ISO-NE expects overall capacity costs to remain relatively unchanged with the transition to seasonal auctions, it projects that roughly 40% of those costs will be driven by winter capacity requirements, making winter demand response essential to maintaining today's level of capacity savings.

Adding winter peak load reduction offerings to ConnectedSolutions would reduce the capacity costs that are borne by Rhode Island ratepayers in two ways:

i. Lower regional capacity procurement needs

ISO NE determines how much capacity to procure based on load forecasts that are heavily informed by historical peak demand. Reducing winter peak loads today will lower future winter peak load forecasts, thereby reducing the amount of capacity ISO NE must procure for the region. Because ISO-NE uses a multi year set of historical loads to forecast future loads, these benefits persist for many

years.

ii. Decrease capacity cost allocation to Rhode Island.

Capacity costs are allocated to zones based on each zone's contribution to system peak demand in the prior year. Under the proposed seasonal framework, allocation will be based on contributions to both the summer and winter system peaks. Rhode Island would therefore realize additional savings by reducing its relative contribution to winter peak demand.

b. Winter peak load reductions would also produce savings in energy and ancillary costs and decrease carbon emissions.

Periods of extreme cold this past winter drove some of the highest wholesale energy costs New England has seen since the inception of Standard Market Design ("SMD"), while also leading to a substantial increase in the use of oil fired generation. In January 2026 alone, wholesale energy market costs totaled approximately $2.7 billion, exceeding the previous record of roughly $2.2 billion set in 2014. In total, looking at energy costs from December through February, this past winter was the highest cost winter in the last 10 years, coming in at just over $6 billion, exceeding the previous record from 2013/14 of just over $5 billion. A program that systematically reduces winter peak loads could make a real dent in these costs and reduce the use of the most carbon intensive generation to meet demand.

2. The avoided cost study underway now should reflect the move to a seasonal capacity market.

We understand that the 2028-2030 avoided cost study is now underway. It is

critical that the study reflect ISO-NE's planned transition to a seasonal capacity market. Failing to account for this change would undervalue winter peak load reductions and result in avoided cost estimates that are misaligned with the needs of the future electric system.

3. NRG/CPower supports RIE's Daily Dispatch Performance Factor proposal provided performance factors are calculated at the customer level and implementation is no sooner than summer 2028

NRG and CPower appreciate the open and transparent process RIE undertook to develop the performance factor proposal and solicit feedback. That collaborative approach has resulted in a proposal that we can support. More specifically, the following items are key to our support: 1) calculating the performance factor at the customer level rather than the portfolio level, 2) implementation in 2028, and 3) allowing for mid-season adjustments to enrollment values.

Calculation of the performance factor on a customer-by-customer basis ensures that Curtailment Service Providers (CSPs) can compensate customers based on their individual performance. This feedback loop will help improve customer performance and reliability while ensuring that strong performers are not penalized for poor performance elsewhere in the portfolio.

It is important that the performance factor proposal not be implemented before 2028
given that a final determination on the Draft Proposal may not be issued until mid-2027. This timeline will provide CSPs with sufficient time to update contractual arrangements, make any necessary modifications to their systems, and educate customers on the new Performance Factor methodology.

Finally, we understand that RIE plans to allow mid-season adjustments to enrollment values when a customer's capabilities change during the season. This flexibility is important because it helps ensure that customers are not unfairly penalized when unforeseen circumstances, such as a prolonged equipment outages, reduce their ability to perform.

4. During the 2027-2029 period, RIE should evaluate how demand response can be used to mitigate future transmission costs.

The increase in winter demand from electrification of heating and transportation will necessitate substantial transmission buildout which will increase transmission costs significantly in the coming years.

a. Future transmission costs can be contained with dedicated demand response initiatives

ISO-NE's 2050 Transmission Study found that each additional gigawatt of peak demand growth adds $750 million in regional transmission costs, doubling to $1.5 billion per gigawatt once peak demand exceeds 51 GW — the equivalent of $750,000 to $1.5 million for every megawatt of avoided peak demand. The chart below illustrates this.

Chart taken from ISO-NE 2050 Transmission Study, Final Report

The region can and should take action to contain these costs by designing programs aimed at reducing "transmission peaks". This will require coordination with ISO-NE to understand better when and where demand reductions can produce the most significant savings in transmission costs.

Expanding ConnectedSolutions to include a winter component (Recommendation #1) will allow the region to gain valuable implementation experience and give customers time to engage with winter demand flexibility programs. The lessons learned will help inform the development of future winter demand management programs aimed at reducing the need for transmission investments.

5. The Incentive Rate for C&I Targeted Dispatch should be increased to bring it in line with rates in neighboring states

The Draft Proposal recommends maintaining the C&I Targeted Dispatch incentive rate at $35/kW. However, this incentive is approximately 22% lower than what is offered in neighboring states. In Massachusetts, Eversource and National Grid provide $45/kW for Targeted Dispatch participation, and Eversource offers the same $45/kW incentive in Connecticut. These higher incentive levels were adopted in 2025 to reflect the increasing costs customers incur to deliver reliable load reductions during dispatch events. Rhode Island Energy should align its incentive with neighboring states by increasing the Targeted Dispatch rate to $45/kW. A more competitive incentive would support enrollment growth and help ensure a more robust demand response program.

6. Changes are needed to create a viable pathway for behind-the-meter storage in Rhode Island

CPower submitted testimony on battery participation in ConnectedSolutions during deliberations on the 2024-2026 Plan. In that testimony, CPower noted that the $1 million cap/year incentive cap would effectively limit battery size, as most battery projects are not economic without incentives that support their full capacity value.

CPower also raised concerns about the lack of long-term revenue certainty. At the time, a five-year rate guarantee could support the economics of some C&I battery projects. Since then, however, changes in market conditions have further weakened the economic outlook for storage. While battery projects now require even greater long-term certainty to be viable, the Draft Proposal retains the current structure which provides a rate guarantee only through the end of the triennial plan period.

These challenges are compounded by RIE's proposal to reduce the Daily Dispatch incentive rate from $275/kW to $200/kW. Taken together, the incentive cap, limited rate certainty, and lower incentive payments make C&I battery development in Rhode Island economically unviable in most cases.

Thank you for considering these comments. We look forward to working with RIE to ensure that Rhode Island maintains robust demand flexibility offerings that continue to deliver reliability and cost savings for ratepayers.

Sent from Energy Efficiency Council

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