August 2025

Technical assistance to the New England Conference of Public Utilities Commissioners:

Winter demand response value, potential, suitability to address winter energy shortfalls, and participation in ISO-NE wholesale markets

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The New England Conference of Public Utilities Commissioners (NECPUC) is exploring regulatory strategies to mitigate potential winter energy shortfalls in New England described in a recent study by ISO New England (ISO-NE). To inform these strategies, NECPUC requested technical assistance from the Lawrence Berkeley National Laboratory to provide foundational information on demand response programs and wholesale market design. This memo summarizes findings from Berkeley Lab's technical assistance. The memo:

- Describes programs and rates offered by select New England utilities and program administrators that promote winter demand flexibility.
- Assesses how grid impacts of these programs and rates align with the timing of winter energy shortfalls reported in the recent ISO-NE study.
- Documents existing research on winter demand response potential in New England and identifies data and methods that utilities can use in future potential studies.
- Provides an overview of how demand response is valued in ISO-NE wholesale markets and in the 2024 Avoided Energy Supply Components (AESC) in New England study.
- Describes challenges to demand response participating in the ISO-NE wholesale market and identifies actions that state public utility commissions (PUCs) and utilities can take to address those challenges.

Approach

Program and rate collection

We reviewed programs and rates offered by 21 New England utilities and program administrators. For each state, we considered all investor-owned utilities, the largest municipal (or co-operative) utility, and third-party program administrators where applicable (e.g., Efficiency Maine and Efficiency Vermont). Per guidance from NECPUC, we included both the largest municipal and co-operative utility in Vermont. Appendix A provides the full list of New England utilities and program administrators considered.

We applied screening criteria to select programs and rates of interest. We required that programs have incentives to flex load (e.g., curtailing or shifting end uses) in the winter. Such programs may have events in all months of the year or only in winter months. We required that rates have either a technology requirement (e.g., a time-of-use [TOU] rate for buildings with battery storage) or a dynamic component in which the price of electricity changes depending on grid conditions during the winter. Our screening process excluded programs and dynamic rates with only summer events from collection.[1] We then collected data on program characteristics by reviewing utility websites, publicly available reports, program

[1] We maintained a record of programs and rates excluded from collection during the screening process in the collection template.

manuals, and customer agreements and collected data on rate characteristics by reviewing utility tariffs. We also reviewed several programs and rates from outside of New England to serve as comparators.

Alignment of program and rate impacts with winter energy shortfalls

Next, we assessed the suitability of the collected programs and rates to address the winter energy shortfalls described in ISO-NE's Operational Impacts of Extreme Weather Events. These shortfalls are periods in which projected energy demand exceeds projected supply. We performed this assessment by:

- Identifying types of shortfalls based on their timing and duration
- Determining the alignment of program and rate grid impacts with each shortfall type.

ISO-NE estimated energy shortfalls during select 21-day weather events in 2027 and 2032 under scenarios that differed in whether the New England Clean Energy Connect (NECEC) and Everette Marine Terminal (EMT) would be operational during the study period. We focused our assessment on the scenario that generally had the largest worst-case shortfalls (in MWh) in both 2027 and 2032. The scenario assumed that the EMT was operational but that the NECEC was not. While this scenario does not reflect the current trajectory of the New England energy system given that the Massachusetts Department of Public Utilities has approved cost recovery for the NECEC, it does set an upper bound on the shortfalls and is appropriate for our goal of assessing the alignment of program and rate grid impacts with the shortfalls.[2] ISO-NE reported plots of energy surplus and shortfalls across the 21-day events (see Figures 1–4 for examples). Each plot presents energy surplus and shortfalls for a single weather event and scenario across 720 cases that differ in the assumed fuel inventory levels, electricity import levels, fuel prices, and generator forced outages.[3] The red line in each plot represents the case with greatest energy shortfall over the 21-day weather event. ISO-NE reported the probability of shortfalls occurring but did not report the hours in which shortfalls occurred or categorize the shortfalls based on those hours.

We categorized shortfalls based on the hours in which they occurred by analyzing the 21-day surplus and shortfall plots (see Figures 1–4). For each weather event in the selected scenario (four in 2027 and four in 2032), we estimated 12-hour windows in which the worst-case shortfalls (red lines in Figures 1–4) occurred by subdividing each two-day increment in the shortfall figures into four sections. With these windows, we were able to determine the part of the day in which the shortfalls occurred (e.g., morning or evening). Across the events, we observed three types of shortfalls that could occur in a 24-hour period:

- Evening/nighttime shortfall only (Figure 1)
    - Begins ~6pm and ends before or around midnight
- Morning and evening/nighttime shortfall (Figures 2 and 3)
    - Morning shortfall begins ~6am and ends before or around noon
    - Evening/nighttime shortfall begins ~6pm and ends before or around midnight
    - Energy surplus occurs mid-day or in middle of night
- Extended shortfall (Figure 4)
    - Period of at least a 12-hour energy shortfall. This period may straddle more than one calendar day.

Next, we compared the timing of the grid impacts of the collected programs and rates to the timing of each shortfall type. We categorized programs and rates as having low, medium, and high alignment with the shortfall if their grid impacts did not overlap, partially overlapped, or fully overlapped with the shortfall, respectively. This assessment only considered existing programs and rates and not proposed or theoretical program and rates designs not yet offered by New England program administrators and utilities.

[2] The scenario with NECEC and EMT had the same types of events as the scenario without NECEC and with EMT. However, it had fewer shortfalls and, overall, less unmet energy demand across the studied weather events.
[3] See slide 86 of the Operational Impact of Extreme Weather Events report.

We recognize that this visual approach to determining shortfall windows is not exact and that additional data on the shortfalls would help improve the process. In particular, data on the hours in which shortfalls start and end would support more accurate assessments of how program and rate grid impacts align with the shortfalls. PUCs can consider engaging with ISO-NE about the availability of this information.

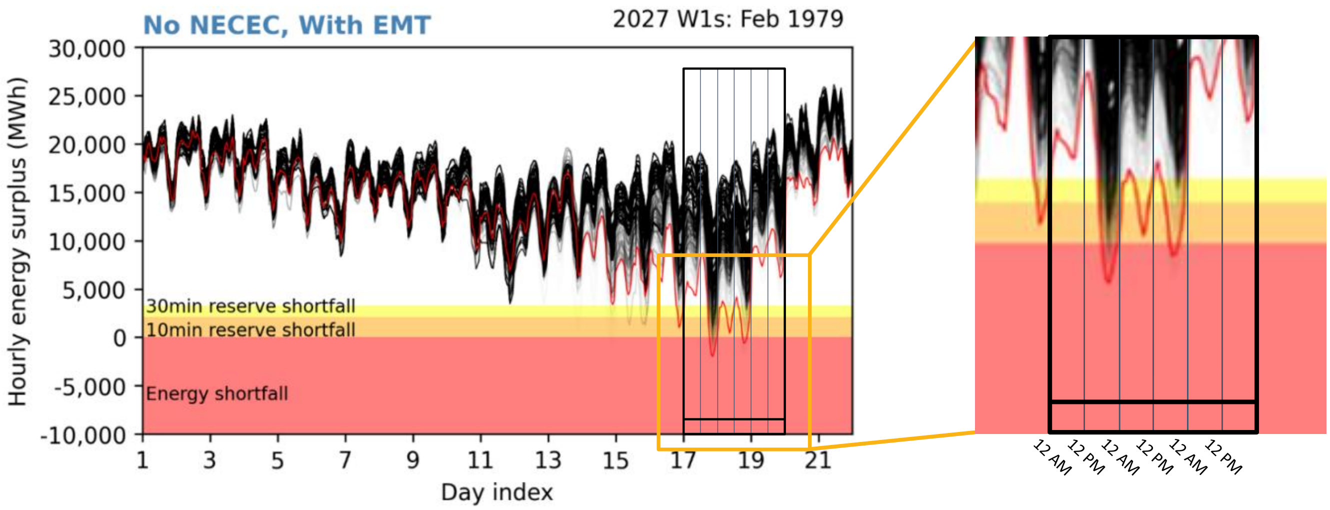

Figure 1. Evening/nighttime shortfall only

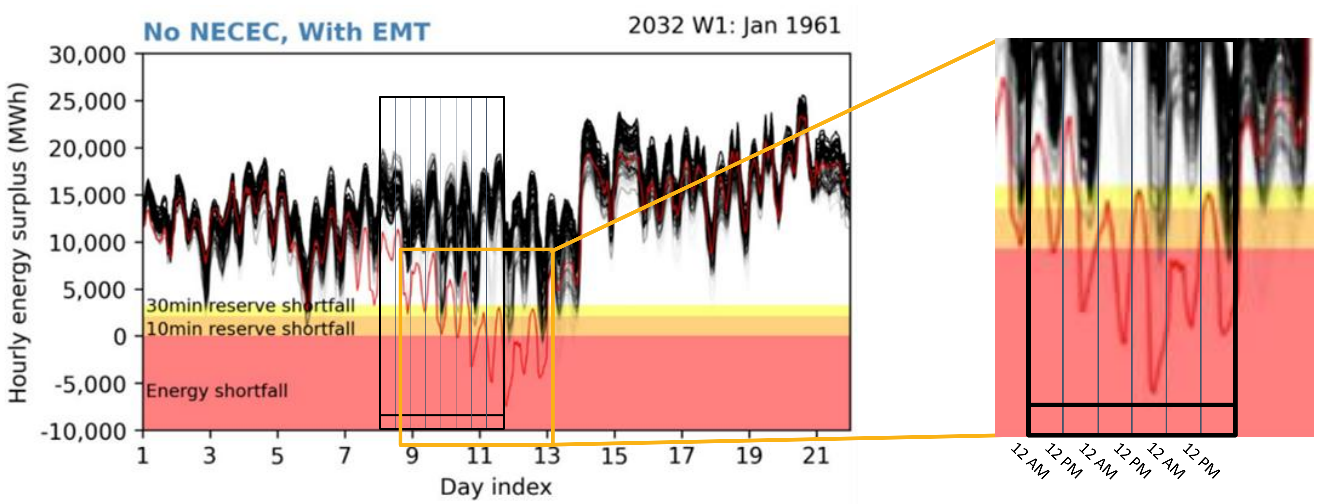

Figure 2. Morning and evening shortfall with surplus in the middle of the night

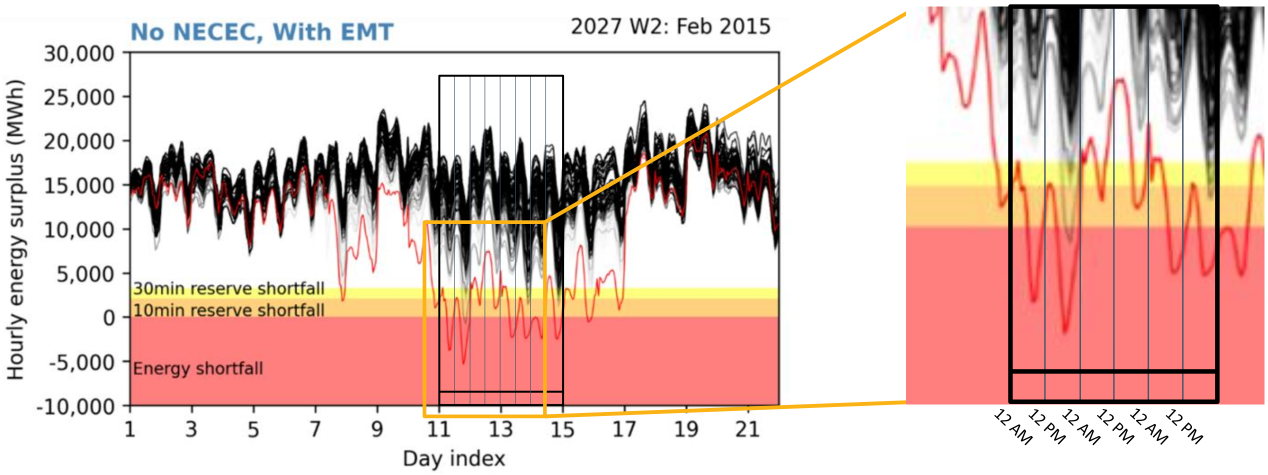

Figure 3. Morning and evening shortfall with surplus in the middle of the day

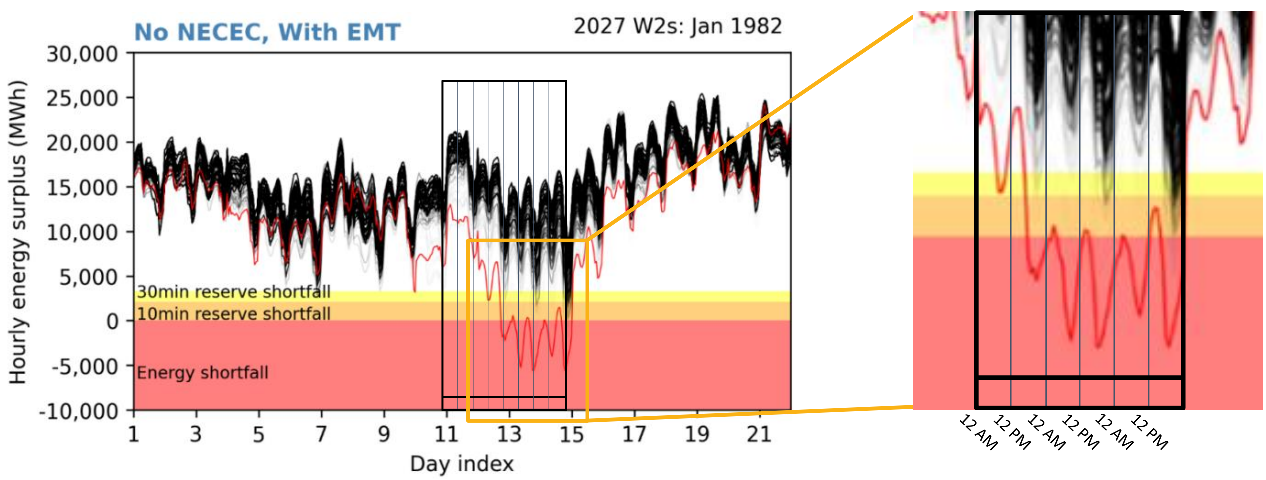

Figure 4. Extended shortfall

Winter demand response value

We assessed two frameworks for valuing winter demand response. First, we reviewed the 2024 AESC study to determine which avoided costs applied to winter demand response. The AESC study quantifies the energy system costs avoided through marginal reductions in energy usage and peak demand. The study calculates all avoided costs relative to counterfactuals that represent the New England energy system if certain investments such as programmatic demand response did not occur.[4] New England program administrators use these avoided costs to determine the economic value of their proposed investments in energy efficiency and demand response programs. Second, we reviewed ISO-NE market rules to identify revenue streams available to winter demand response.

Winter demand response potential

We conducted a literature review of demand response potential studies in New England states through general internet searches and a review of websites that centralized utility studies, such as the one hosted by the Massachusetts Energy Efficiency Advisory Council. We also reviewed demand response potential

[4] For details on the counterfactuals used in the study, see page 91 of the AESC.

studies in two non-New England jurisdictions that have winter-peaking electricity systems: Bonneville Power Administration (BPA) and Portland General Electric (PGE). We selected studies for utilities with winter-peaking systems due to the expected transition to a winter-peaking system in New England.[5] We then documented data and methods that can support future winter demand response potential studies in New England, drawing on examples from the non-New England studies.

Addressing challenges to participation in ISO-NE wholesale markets

We reviewed existing ISO-NE wholesale market rules to identify challenges that demand response may face to participating in the markets. We then reviewed market rules that ISO-NE proposed in response to Federal Energy Regulatory Commission (FERC) Order 2222, which enabled the participation of distributed energy resource aggregations (DERAs) in wholesale electricity markets. We identified key elements of these new rules and their impacts on demand response participation in ISO-NE wholesale markets. We then documented challenges to demand response participation in ISO-NE wholesale markets after implementation of the Order-2222-compliant rules. Finally, we identified actions that PUCs and utilities can take to address those challenges.

Results

Existing winter demand response programs and rates

We identified 14 programs and 35 rates that met our screening criteria (see Table 1). Of the 35 rates, 32 had technology requirements and three were dynamic rates with winter components. Overall, we find limited adoption of winter dynamic rates in New England, with rates identified in two states: Connecticut and Vermont.[6] This adoption reflects the lack of the Advanced Metering Infrastructure (AMI) needed for dynamic rates in several New England states (see Table 6 for details). We identified a rate or program that met our screening criteria in all states but Rhode Island.

Table 2 summarizes categories of the collected programs and rates and describes their grid impacts. Programs that encourage the shifting of electric vehicle (EV) load and battery discharge accounted for 13 of the 14 programs in our collection. We did not find any programs offered by investor-owned utilities that promoted winter demand flexibility in electric space heating.

[5] ISO-NE, 2050 Transmission Study, 2024.
[6] We identified 32 dynamic rates with summer components and 32 programs with incentives to flex load in the summer that did not pass our screening criteria. We retained a list of these programs in the collection templates shared with NECPUC as part of this memo.

Table 1. Count of programs and rates that met screening criteria by state

State	Dynamic rate with winter component	Rate with technology requirement	Rates for collection (unique sum of two preceding columns)	Programs with incentive to flex load in winter
CT	3	2	**5**	**7**
MA	0	5	**5**	**2**
ME	0	10	**10**	**0**
NH	0	8	**8**	**1**
RI	0	0	**0**	**0**
VT	2	5	**7**	**4**
Total	**5**	**30**	**35**	**14**

Table 2. Categorization of programs and rates by grid impact

	Category	Grid impact	Sample size
Programs	EV charging load shift	Shifts load out of peak periods into off-peak periods	n=8
	Battery storage	Batteries discharge energy during events	n=5
	Load shed (EV, HVAC, or water heating)	End uses interrupted or usage is scaled back during events	n=1
Rates	Time-of-use with technology requirement (e.g., battery storage)	Incentivizes decreased usage during peak periods and requires a building have a particular end use	n=15
	Dynamic rates	Variable/critical peak or real-time price or rates that incentivize reduced usage during events by increasing the price of electricity	n=5
	EV charging credits	Incentivizes charging during defined charging windows	n=2
	Flat rates with technology requirement (e.g., space heating)	If rate is not discounted, no impact relative to standard service; if discounted, incentives increase usage of end use relative to non-discounted rate	n=13

Alignment of program and rate impacts with winter energy shortfalls

We find that the duration of the studied shortfalls varies from one to 21 hours and that shortfalls are often clustered on consecutive days. Seven of the eight events had more than one day in a row with a shortfall: four had shortfalls two days in a row, two had shortfalls three days in a row, and one had shortfalls four days in a row. Days with consecutive shortfalls either have shortfalls that span more than one calendar day (e.g., 9pm–1am) or have shortfalls separated by periods of energy surplus (e.g., shortfall 6pm–11pm, energy surplus 11pm–6am, and energy shortfall 6am–12pm).

The maximum peak demand across the 2027 and 2032 events was 21.2 GW and 24.4 GW, respectively, both higher than the gross winter peak demand (20.4 GW and 23.3 GW) and lower than the gross summer peak demand (26.7 GW and 28.1 GW) that ISO-NE reported in its 2025–2034 Forecast Report of Capacity, Energy, Loads, and Transmission. In four of the eight 21-day periods (two in 2027 and two in 2032), shortfalls did not occur on the days with the 21-day peak demand. The absence of shortfalls on these peak days indicates that energy supply and not just demand is a key determinant of energy shortfalls. In contrast, the summer events that many existing demand response programs in New England address are generally demand-driven.

We find that the collected battery, EV charging load shift, and load shed programs generally target evening peaks. However, evening shortfalls generally extend later into the evening than event windows do, which results in partial overlap of the timing of program grid impacts and shortfall (Medium alignment in Table 3). For example, the Reading Municipal Light Department, typically calls its program events between 5pm and 9pm, while the evening shortfalls we observed in ISO-NE's study can extend past 9pm. We also did not find any program categories whose grid impacts align with morning shortfalls (Low alignment in Table 3). To the contrary, the baseline tier of residential EV charging programs offered by Connecticut utilities could potentially increase morning load by incentivizing charging between 9pm and 3pm. The advanced tiers for those EV charging programs, however, offer a customizable charging schedule that could potentially have a high overlap with mornings or evenings. The battery, EV charging load shift, and load shed programs could flex load in morning hours if designed to do so. For example, Georgia Power's TEMPCheck shifts space heating load, and Alliant Energy's Smart Hours program shifts space and water heating and EV charging load outside of 6am–10am during events. **Program administrators can consider establishing morning event windows and extending event windows to increase the overlap of program grid impacts with energy shortfalls.**

No collected program can provide flexibility for the entirety of an extended shortfall. Reported load shed and battery storage program maximum event lengths range from three to six hours, which means that they only can address part of an extended shortfall (Medium alignment in Table 3). EV charging load shift programs generally move load within a day and not outside it, which would likely be needed to handle the longest observed shortfall in the studied events (~21 hours). **Program administrators can consider shifting EV charging load to the day preceding and or following to address a shortfall of this length.**

The ability to shift loads within a given day to mitigate energy shortfalls depends on the magnitude of the energy surplus in non-shortfall hours. For example, shifting loads such as EV charging within a day (e.g., from morning to mid-day) may not avoid a shortfall if the energy surplus that serves the shifted loads is too small or occurs for too short a time. If there is insufficient energy available during the period to which the loads are shifted, then a shortfall could occur. Shifting loads to the preceding and/or following day could mitigate shortfalls in this situation.

The causes of shortfalls also may impact whether load shifting can mitigate energy shortfalls. In shortfalls caused by low fuel inventories, load shifting could just change when a shortfall occurs. For example, if a lack of fuel inventories contributes to a shortfall in the evening, EV charging demand in the morning could lead to the generator exhausting its inventories earlier in the day, potentially leading to a shortfall.[7] Additional data on the causes of shortfalls and the energy supply mix and fuel inventories during shortfalls could inform load shifting strategies. PUCs can consider engaging with ISO-NE on the availability of these data.

Other program design characteristics relevant to winter energy shortfalls include the maximum number of events, modifications to program rules due to grid emergencies, and incentive structure. Programs often

[7] This hypothetical assumes that the availability of other supply resources remains constant throughout the day. It is possible that other resources such as imports are available in the morning to supply the shifted EV load and avoid depleting fuel inventories.

report the maximum number of events (or event hours) that they allow over some time period (e.g., month, year). Demand response events that address winter energy shortfalls could use up a large share of these events, which could affect program operations outside of the shortfalls. In the scenario that we examined, a 21-day weather event could have up to seven shortfalls in four days. Of the programs and rates in our collection with reported data, three battery programs had maximum event counts between five and eight per month and one dynamic rate had a maximum 10 events per month. These programs and the rate could address all or most of the worst-case seven shortfalls in four days without exceeding their maximum event counts (assuming no constraints due to event windows aligning with the shortfalls or uncharged batteries). However, it may be more difficult to have as many events in short succession with programs that affect thermal comfort, such as Wi-Fi thermostat demand response programs. The Georgia Power and Alliant Energy programs, for example, have up to 10 and 15 events per season. **Program administrators can consider the number of possible shortfall events when determining the maximum number of events for a given program.**

Program administrators also may override default program design elements during grid emergencies. For example, Eversource Connecticut requires that enrollees in its managed EV charging program must participate in emergency events, allowing the utility to interrupt charging. Similarly, Georgia Power expands eligible events days to weekdays and holidays in its Wi-Fi thermostat program during grid emergencies. **Such emergency event rules could help programs address winter energy shortfalls and could offset constraints posed by a small maximum event count**.

Program administrators can also consider whether the types of incentives offered to customers encourage event participation. **Performance incentives, which reward energy or demand reductions during events, may encourage participation in events that address shortfalls** more than incentives paid for signing up or remaining in a program.

Table 3. Alignment of collected program grid impacts with shortfalls

	Evening shortfall only (6pm–12am)	Morning and evening shortfall		Extended shortfall
		Morning (6am–12pm)	Evening (6pm–12am)	
EV charging load shift	Medium	Low	Medium	Low
Battery storage	Medium	Low	Medium	Medium (limited coverage)
Load shed (EV, HVAC, or water heating)	Medium	Low	Medium	Medium (limited coverage)

Note: **Low**: Grid impacts have no overlap with shortfall. **Medium**: Grid impacts partially overlap with shortfall. **High**: Grid impacts fully overlap with shortfall. Table contents reflect the range of alignment of individual programs in each category.

We find more variation in how the grid impacts of rates align with shortfalls than those of programs do. **All 17 TOU rates with technology requirements in our collection have higher-priced hours in the afternoon** and evening, and five also have higher-priced hours in the morning. For example, EV rates offered by Unitil and Liberty Utilities in New Hampshire have 3pm–8pm peak periods, which partially overlap with evening shortfalls (Medium alignment in Table 4). An energy storage rate offered by Central Maine Power has two on-peak periods 7am–12pm and 4pm–8pm, which can incentivize energy discharges during morning and evening shortfalls (Medium alignment in Table 4). One thermal storage rate offered by Green Mountain Power has an 18-hour on-peak period that runs 6am–12am, which would fully overlap with both evening and morning shortfalls (High alignment in Table 4). **Utilities can consider creating a morning on-peak period and expanding the length of on-peak periods to better align TOU grid impacts with energy shortfalls**. TOU rates with technology requirements, however, do not provide a price signal to reduce demand in all hours, which limits their ability to mitigate extended shortfalls (Medium alignment in Table 4).

Two variable peak price (VPP) riders in Connecticut, one offered by Eversource and the other by United Illuminating, increase prices between 12pm and 8pm based on ISO-NE wholesale market prices, which partially overlap with evening shortfalls (Medium alignment in Table 4). These prices are not real-time; in Unitil's case, the price is the average day-ahead market price in the on-peak hours. These market-based prices would likely send a stronger incentive to reduce load during an energy shortfall than a TOU rate would. Similarly, a critical peak price rate for EV charging offered by Green Mountain Power that increases the prices of electricity more than five times its base price to ~$0.81 per kWh would also send a stronger signal than a TOU rate. This critical peak price rate also could address shortfalls at any time of the day because it applies when Green Mountain Power calls events, which do not have a specific window defined in the tariff (High alignment in Table 4). **PUCs can consider requiring utilities to incorporate dynamic components into TOU rates to incentive greater demand reductions during energy shortfalls.**

The rate in our collection that has the most flexibility to respond to shortfalls and provides the greatest incentive to reduce demand is Burlington Electric's Electric Vehicle Rate - Flexible Real Time Option**.** In this rate, the utility defines the charging period, and real-time electricity price determines the level of charging. The flexible scheduling in this rate would allow utilities to move charging outside of expected shortfalls, and the real-time prices would reduce charging demand in response to shortfalls, including extended ones that last most of a day (High alignment in Table 4).

Two tiers of a rate offered by Burlington Electric Department provides customers credits for charging EVs in defined windows. In one tier, the window is fixed between 10pm and 12pm, which would incentivize charging during both morning and evening shortfalls (Low alignment in Table 4). In the second tier, the charging occurs in "hours designated by BDE in advance". This utility-defined window could, potentially, incentivize charging outside of shortfall hours, leading to high overlap between its grid impacts and morning or evening shortfalls (High alignment in Table 4).

Several of the rates with technology requirements that we collected had flat rate components. Of these rates, some offered discounted prices relative to standard service. For example, a Versant Power rate for homes with electric resistance heating reduces the price of electricity after 600 kWh of monthly usage. Such rates could exacerbate a shortfall by making increased electricity usage less costly per unit instead of more costly. A rate for customers with electric heating offered by Minnesota Power provides an example of a discounted rate with flexibility: the discounted rate is conditional on allowing the utility to interrupt service when system-wide demand and prices are high. **PUCs can consider requiring interruptible components for discounted flat rates to encourage demand flexibility.**[8] Flat rates with technology requirements and no discount have no grid impact relative to a standard rate.

[8] Interruptible components of tariffs can apply to residential and commercial customers and provide a large share of existing demand flexibility potential in the United States.

Table 4. Alignment of collected program rate impacts with shortfalls

	Evening shortfall only (6pm–12am)	Morning and evening shortfall		Extended shortfall
		Morning (6am–12pm)	Evening (6pm–12am)	
TOU rates with technology requirement	Medium/High	Low/Medium/High	Medium/High	Medium (limited coverage)
Dynamic rates	Medium/High	Low/High	Medium/High	Medium/High
EV charging credits	Low/High	Low/High	Low/High	Low
Discounted flat rates with technology requirement	Misalignment: may exacerbate shortfall			
Non-discounted flat rates with technology requirement	No grid impacts from demand flexibility			

Note: **Low**: Grid impacts have no overlap with shortfall. **Medium**: Grid impacts partially overlap with shortfall. **High**: Grid impacts fully overlap with shortfall. Table contents reflect the range of alignment of individual rates in each category. Low/High and Medium/High refer to multiple rates in the same category with different levels of alignment.

Winter demand response value

Avoided costs

In this section, we describe how the avoided costs in the 2024 AESC apply to winter demand response. The type and value of avoided energy system costs considered in cost-effectiveness screens can affect the level of demand response deployment. If programs are not cost-effective (i.e., the costs of administering the program exceed the avoided costs), then they will not be part of retail demand-side portfolios.

Energy

Energy avoided costs, in $/MWh, measure the reduction in ISO-NE wholesale market costs that result from a MWh reduction in energy usage. These avoided costs are inclusive of ancillary services (i.e., reserves and regulation) as well as embedded environmental costs from the Regional Greenhouse Gas Initiative. Energy avoided costs can contribute to winter demand response value, though **the value stream may be small due to the limited number of hours that demand response reduces load and the avoided costs being in units of $/MWh.**

The seasonal on-/off-peak costing periods that program administrators typically use may also affect the magnitude of energy avoided costs that apply to winter demand response. The AESC uses hourly avoided costs to calculate weighted average *on-peak* and *off-peak* avoided costs for the periods 7am–11pm and 11pm–7am, respectively, from January to May and October to December.[9] Program administrators apply these weighted average avoided costs to energy savings reductions calculated for the same time periods. However, these costing periods may not align with the days and hours in which demand response events are designed to take place. Demand response events are likely to occur on days with higher prices, so valuing demand response with weighted average prices may underrepresent its value. In a supplemental analysis to the 2021 AESC, Synapse Energy Economics shows how selecting a subset of the hourly avoided costs instead of using the weighted average cost periods could illustrate a winter peak. **PUCs can consider requesting that utilities use a subset of the hourly avoided costs in place of the seasonal on-/off-peak weighted average avoided costs to value winter demand response programs.**

The AESC scales avoided energy wholesale energy costs to estimate the avoided retail energy costs that utility customers would experience**.** This scaling accounts for line losses and a wholesale market risk premium.[10] **The wholesale market risk premium factor accounts for the risk of contracted energy procurements exceeding or falling short of demand due to factors such as extreme weather events**. The premium does not explicitly model the price impacts of winter energy shortfalls. However, users of the AESC can define and apply their own risk premium values, including those that reflect the expected price impacts of winter energy shortfalls. Synapse describes a high-level approach to estimating the impacts of winter peak events (not specifically energy shortfalls) on energy and energy demand reduction induced price effects (DRIPE) avoided costs using electricity price, weather, and energy generation data in the supplemental analysis to the 2021 AESC.

Capacity

Capacity avoided costs (in $ per kW-month) represent the change in the ISO-NE Forward Capacity Market (FCM) clearing price due to incremental reductions in peak demand. Seasonal FCM modeling provides winter-specific avoided capacity costs that can contribute to the value of winter demand response, but **the magnitude of avoided winter capacity costs depends on whether the system is winter-peaking** (see Figure 5)**.** The AESC assumes that the seasonal FCM begins annually after May 2028 (the end of the Forward Capacity Auction 18 price period)[11] and forecasts $0 per kW-month winter capacity prices in all counterfactuals through 2032 due to increasing winter reserve margins and the summer market driving the installed capacity requirement.[12] Winter capacity prices do increase when the system is or is nearly winter-peaking.[13]

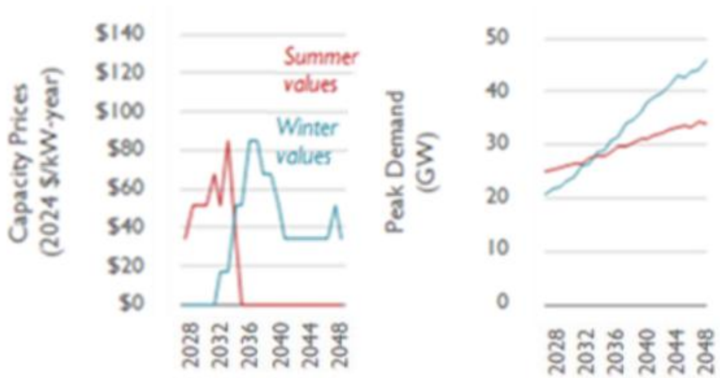

Figure 5. Capacity prices ($/kW-year) and peak demand (GW) in the 2024 AESC.
Note: Images are adapted from page 157 of the AESC.

[9] See 2024 AESC page 354.
[10] See 2024 AESC page 354.
[11] See 2024 AESC page 145.
[12] See the 2024 AESC page 157.
[13] See the 2024 AESC page 143.

The 2024 AESC also notes that the **modeled winter capacity auctions do not consider potential constraints to natural gas supply for electricity generation that may occur during winter energy shortfalls**, such as a generator's ability to import natural gas.[14] These constraints would reduce the natural gas generation capacity accredited in future auctions operated under ISO-NE's proposed Resource Capacity Accreditation. ISO-NE's recent study on winter energy shortfalls considers uncertainties similar to these constraints (e.g., fuel oil and liquified natural gas inventory levels).

DRIPE

The 2024 AESC estimates the decreased market price for:[15,16]

- Electricity generation due to *reduced electricity usage* (energy DRIPE, in $/MWh)
- Electricity generation due to *lower-cost gas combustion that results from reduced electricity usage* (cross-fuel DRIPE, in $/MWh)
- Generation capacity due to *reduced peak demand* (capacity DRIPE, in $/kW-month)

Both energy and cross-fuel DRIPE avoided costs can contribute to winter demand response value. As with avoided energy costs, the value of these DRIPE avoided costs may be small for demand response due to the limited number of hours in which it operates and the avoided costs being in units of $/MWh. These DRIPE values also capture average relationships between demand reductions and wholesale energy prices in winter. For example, electric energy DRIPE avoided costs vary in price by state, month, and on-/off-peak period.[17] The price impacts of individual winter demand response events may differ from this weighted average DRIPE avoided cost. Notably, the value of cross-DRIPE avoided costs are higher in winter to due increases in the gas basis price relative to summer.[18] **As with capacity avoided costs, capacity DRIPE avoided costs contribute to winter demand response value in the years in which winter peak demand approaches or is the annual peak**. These years have non-zero winter capacity prices (see Figure 5).[19]

Compliance and non-embedded environmental costs[20]

Reducing energy usage lowers state procurement obligations under renewable portfolio standards (RPS) and clean energy standards (CES), thereby avoiding any incremental cost of those procurements above typical electricity prices.[21] In the AESC, lower energy usage also reduces the externalities of emissions from fossil-fired electricity generation that are not embedded into the price of electricity.[22,23] These avoided costs can contribute to winter demand response value, but as with energy avoided costs, the value stream may be small due to demand response's focus on demand reductions instead of annual energy savings and the avoided costs being in units of $/MWh. Seasonal CO_2 emissions rates in the AESC do support the

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[14] See the 2024 AESC page 145 and 143.
[15] See the 2024 AESC page 227–8.
[16] The 2024 AESC also estimates DRIPE for gas (page 270) and oil prices (page 283).
[17] See the 2024 AESC page 235.
[18] See the 2024 AESC page 281.
[19] See the 2024 AESC page 157.
[20] This subsection documents how the AESC addresses avoided emissions costs but does not recommend any approach to developing these avoided costs or the social cost of carbon.
[21] See the 2024 AESC page 176.
[22] The cost of emissions reduced through the Regional Greenhouse Gas Initiative are embedded in the price of energy in the 2024 AESC.
[23] See the 2024 AESC page 216.

accurate valuation of winter demand response. The winter rates are higher than summer rates through 2032.[24]

Transmission and Distribution

Lowering annual peak demand can reduce, defer, or avoid the need for incremental investments in transmission capacity. The 2024 AESC estimates the avoided cost of regional transmission in terms of $ per kW-year. The study uses a value of $69 per kW-year based on the ISO-NE 2050 Transmission Study, which assumes transition to a winter-peaking system in the 2030s. **Winter demand response can avoid regional transmission costs if the system is winter-peaking and demand reductions occur in the hours of that peak.** Since annual peaks drive transmission investments, the AESC study suggests that program administrators align transmission avoided cost with demand reductions that occur during the annual system peak.[25] Most counterfactuals in the 2024 AESC include a transition to a winter-peaking system in the 2030s.[26]

Avoided local transmission and distribution system costs apply to winter demand response if equipment is winter-peaking and demand reductions align with those peaks. Utilities, not the AESC, produce these avoided costs.[27] The AESC does document utility methods in the 2024 AESC, but it is not clear from information reported by utilities whether they have identified or anticipate winter-peaking equipment or have applied these avoided costs to any winter peak demand reductions.

Reliability

Reliability avoided costs estimate the economic value (in $/kW-year) of reducing the amount of unserved customer energy through incremental reductions in peak demand.[28] Reducing peak demand can increase installed generation reserves, which reduces the amount of unserved energy. The AESC uses state-specific estimates of the cost of unserved energy from the Interruption Cost Estimate (ICE) Calculator. **Reliability avoided costs apply to winter demand response in years in which there are non-zero winter capacity prices.** However, the cost of unserved energy estimates is not specific to winter service interruptions. The AESC uses historical (2013–2021) annual reliability metrics as ICE Calculator inputs.[29] Using the ICE Calculator, a winter-specific cost of unserved energy may differ from an annual cost due to winter-specific reliability metric values differing from annual values or seasonal differences in the costs of an interruption.

ISO-NE wholesale market revenues[30]

Demand response can earn revenue from the ISO-NE energy, ancillary services, and capacity markets. These revenue streams can affect the level of demand response participating in ISO-NE wholesale markets through the profitability of the aggregators that bid those resources and the compensation of businesses and households that own those resources. A lack of sufficient wholesale market revenue can result in aggregators not bidding resources into the market and/or businesses and households not offering demand

[24] Ibid.
[25] See the 2024 AESC page 203.
[26] See the 2024 AESC page 157.
[27] See the 2024 AESC pages 286–317.
[28] See the 2024 AESC page 319.
[29]See the 2024 AESC pages 320-321.
[30] This section does not consider the potential impacts of changes to a prompt capacity market currently under discussion at ISO-NE. These reforms could change how far out in time the auction procures capacity and replace annual auctions with seasonal auctions.

response resources to aggregators. In this section, we provide an overview of each revenue stream and how they relate to demand response. We do not present a calculation of demand response value in wholesale markets.

Demand response can **earn revenue from demand reductions bid into day-ahead and real-time energy markets.**[31] In the day-ahead energy market, compensation is the product of the locational marginal price (LMP) and the demand reduction, energy generation, or energy withdrawal (e.g., for batteries in a DERA). In the real-time energy market, compensation is the product of the LMP and deviations from day-ahead commitments. ISO-NE has more than 1,000 pricing nodes at which it calculates the LMP.

Demand response can earn revenue from two types of ancillary services: flexible response services and energy imbalance reserves. Flexible response services include 10-minute spinning, 10-minute non-spinning, and 30-minute operating reserves.[32] Demand response typically earns more revenue from 30-minute operating reserves than 10-minute reserves in ISO-NE markets.[33] Energy imbalance reserves provide demand when the day-ahead market does not clear enough energy to meet forecasted energy demand.[34] Market participants cannot offer energy imbalance reserves without also offering flexible response services.[35]

Winter demand response operating through Active Demand Capacity Resources (ADCR) under existing ISO-NE rules and operating through Distributed Energy Capacity Resources (DECRs) under ISO-NE's Order 2222-compliant rules can earn **base and performance-based capacity payments** in ISO-NE's FCM.[36] **Monthly base payments** equal to the product of the cleared capacity and zonal clearing price for the Forward Capacity Auction and annual and monthly reconfiguration auctions. Prices set in the Forward Capacity Auction reflect the capacity needed to meet the Installed Capacity Requirement, which summer peak demand currently determines. Prices set in reconfiguration auctions in winter reflect capacity needs in winter. **ADCRs and DECRs can earn performance payments during Capacity Scarcity Conditions in which reserve requirements are not met.**[37] During these conditions, resources can earn payments based on actual capacity provided in 5-minute intervals,[38] regardless of whether they participated in the FCM or submitted bids that did not clear. The capacity payment rate stipulated by ISO-NE has increased in recent years from $5,455/MWh between June 2024 and May 2025 to $9,337/MWh between June 2025 and May 2026.

Winter demand response potential

We did not find any demand response potential studies in Connecticut, Maine, or Vermont and found summer-only potential estimates in Rhode Island and for multiple Massachusetts program administrators. **We identified two studies with winter demand response potential estimates: a study for Unitil Massachusetts**[39] **and a state-wide study in New Hampshire.**

[31] See Section III.2.1 in existing ISO-NE Market Rule 1 and the same section in the FERC-approved proposed rules.
[32] See ISO-NE Market Rule 1 Section III.2.6.2.
[33] Based on correspondence with ISO-NE.
[34] See ISO-NE Market Rule 1 Section III.2.6.2(b)(ii)(1),
[35] See ISO-NE Market Rule 1 Section III.3.2.1(1)(2)I(iv).
[36] See Forward Capacity Market rules Section III.13.7.1.
[37] See Forward Capacity Market rules Section III.13.7.2.
[38] See Forward Capacity Market rules Section III.13.7.2.3 for details of the calculation.
[39] See Massachusetts potential studies pages 773–892.

The Unitil Massachusetts study estimates the potential for demand response reductions to winter peak demand alongside the potential for demand response reductions to summer peak demand and the potential for annual energy efficiency savings (see Figure 6). The New Hampshire study estimates demand response potential during monthly ISO-NE peaks, with a focus on the annual peak (see Figure 7). **In both studies, the winter peak demand reduction estimates represent the *achievable potential*:** the amount of cost-effective demand response that is possible under likely levels of program participation for a defined set of measures.

The Unitil Massachusetts study estimates winter demand response potential for the period 2022–2024 under three scenarios that differ in the assumed level of program incentives and participation (see Figure 6). The New Hampshire study presents demand response potential in winter months for 2023 and considers scenarios that differ in incentive levels and the demand response technologies deployed. Neither study accounts for the impact of technologies adopted through the utility's energy efficiency programs on their peak demand forecasts.

The demand response measures that the Unitil Massachusetts study includes in its winter potential estimates are commercial and industrial curtailment, battery storage, and direct load control of water heating, electric vehicle charging, and appliances. The New Hampshire study considers battery storage, commercial and industrial curtailment, commercial water heating, and residential pool pumps (see Table 5). **Neither study considers direct load control or smart thermostat control of space heating.**[40] The Unitil Massachusetts study does not report the winter peak demand reductions assumed for each measure, but it did for summer peak demand reductions.[41]

Differences in the scope and methods between the potential studies and the ISO-NE shortfall study make it difficult to relate the winter demand response potential estimates to ISO-NE's projected energy shortfalls. First, the study periods do not overlap; the Unitil Massachusetts study covers the period 2022–2024 and the New Hampshire study provides 2023 winter estimates, but ISO-NE examines shortfalls in 2027 and 2032. We would expect customer and sales growth to increase demand response potential over this period. Second, the studies do not have uniform load forecast assumptions. For example, the Unitil Massachusetts study assumes a constant saturation of electric vehicles over the three-year study period (0.3% of vehicles) and ISO-NE assumes[42] significant increases in EV energy demand in the same years.[43] We would expect that demand response potential for managed electric vehicle charging would be greater with increased adoption of electric vehicles. Third, neither the Unitil Massachusetts nor the New Hampshire study explicitly estimates demand response potential during weather conditions that may cause an energy shortfall. Finally, neither study reports the hours of their winter peaks, so it is unclear as to which type of shortfall (i.e., morning vs. evening) the demand response potential would apply.

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[40] See Massachusetts potential studies page 860.
[41] See Massachusetts potential studies Table 6-7 on page 864.
[42] See Massachusetts potential studies Table 6-4 on page 860.
[43] ISO-NE, 2022 CELT Report, 2022.

DSM Option	2022	2023	2024
Baseline Forecast (MW)	**80.7**	**81.0**	**81.0**
Annual Savings (MW)			
Achievable BAU Potential	0.97	0.97	0.97
Achievable BAU Plus Potential	1.08	1.24	1.50
Achievable Maximum Potential	1.10	1.29	1.61
Energy Savings (% of baseline)			
Achievable BAU Potential	1.2%	1.2%	1.2%
Achievable BAU Plus Potential	1.3%	1.5%	1.9%
Achievable Maximum Potential	1.4%	1.6%	2.0%

Figure 6. Unitil Massachusetts 2022–2024 winter demand response potential summary

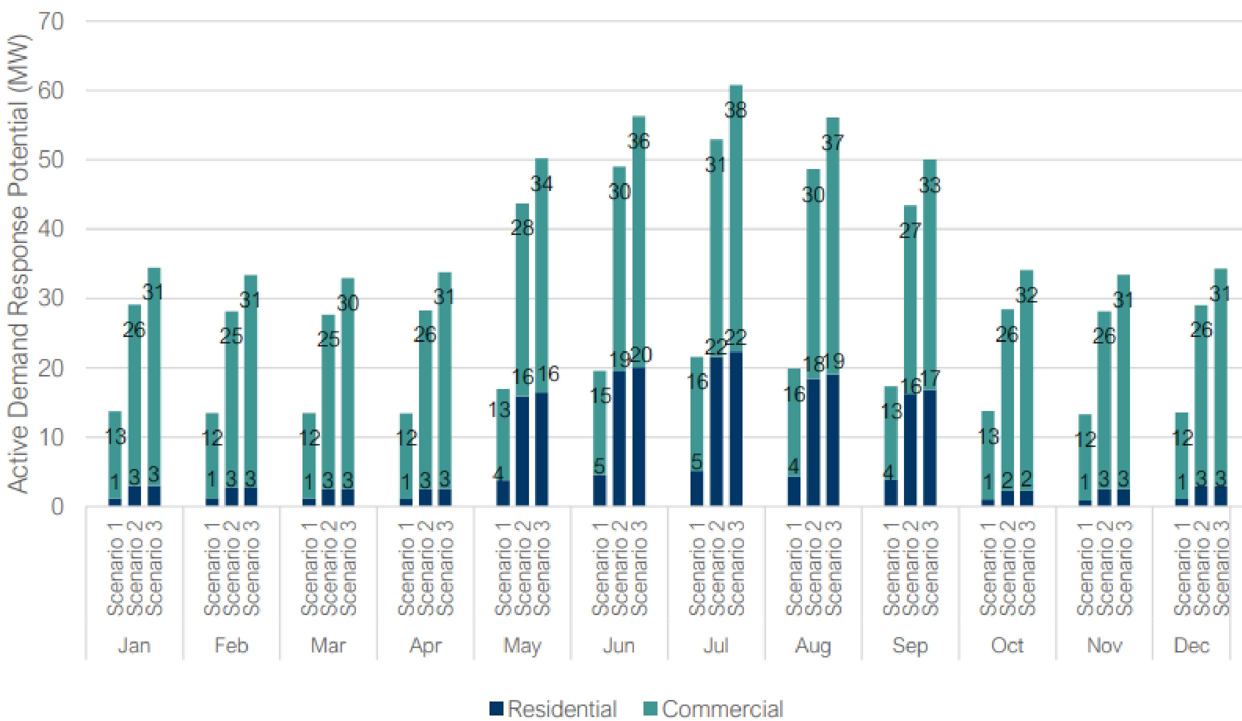

Figure 7. New Hampshire 2023 monthly achievable demand response potential by customer segment

Through our review of potential studies conducted by two winter-peaking utilities in the Pacific Northwest, we identified data and methods that could support future winter demand response potential studies.

Program administrators can report technical, achievable, and economic winter demand response potential. The technical potential sets an upper bound on the peak demand impacts of demand response by assuming that customers adopt all relevant technologies (and/or rates). BPA, for example, estimates technical potential in its service territory both in MW and share of peak demand.[44] The achievable potential, which both the Unitil Massachusetts and New Hampshire study report, is the amount of demand response that is possible under likely levels of program participation for a defined set of measures. The economic potential is the portion of the achievable potential that is cost-effective.

Future studies can estimate demand response potential over long time horizons to account for the adoption of new technologies and support planning for energy shortfalls. PGE, for example, estimates winter demand response potential through 2050 while considering the increased adoption of EV charging, heat pumps, and heat pump water heaters over the same period. Winter demand response potential studies that look five to 10 years out would cover the years in which ISO-NE models energy shortfalls (2027 and 2032). Winter demand response estimates for these years could inform ISO-NE models of the New England power system when it estimates energy shortfalls.

Program administrators can estimate winter demand response potential under a range of scenarios. Scenario-based potential estimates can help illustrate the impact of different grid conditions and adoption levels of technologies that enable demand response. BPA, for example, estimates winter demand response potential under both 1-in-2 and 1-in-10-year weather events. The 1-in-2 events reflect typical winter weather and the 1-in-10 reflect colder winter weather. The Unitil Massachusetts study, as described earlier, considers scenarios for its achievable potential that differ in the level of demand response incentives and participation. Similarly, PGE considers the impact of low, medium, and high levels of adoption for EVs, battery storage, and TOU rates to set bounds on its potential estimates.[45] Future potential studies in New England could consider scenarios that address different weather conditions and/or technology adoption. For example, studies could estimate demand response potential during the weather events in which ISO-NE identified shortfall risks.

Program administrators can base potential estimates on peak demand forecasts that account for expected technology adoption from programmatic and market-based adoption. The adoption of these technologies can change the amount of potential over the time frame of the study. For example, PGE accounts for the market-based adoption of light- and medium-duty EVs, which increases demand response potential.[46] BPA accounts for the impact of its energy efficiency programs on future peak demand, which reduces the demand response potential.[47]

Program administrators can consider a broad set of demand response technologies and time-varying electricity rates in future potential studies. Table 5 presents programs and rates included in the BPA and PGE potential studies and compares them to the programs included in the Unitil Massachusetts and New Hampshire studies. Each utility considers battery storage. However, the BPA and PGE studies also considered space heating demand response and multiple time-varying rate structures. Future winter demand response potential studies also could consider the diversity of program designs we observed in New England. For example, the potential for shifting EV charging load may differ from the potential for shedding EV charging load during peak periods.

[44] See page 45 of the BPA 2018 demand response potential study.
[45] Portland General Electric, PGE DER and Flexible Load Potential – Phase 1, 2021.
[46] Ibid, page 10.
[47] Bonneville Power Administration, Demand Response Potential Assessment 2022–2043, 2021, page 13.

Table 5. Winter demand response strategies used in Unitil, New Hampshire, PGE, and BPA studies

Sector	Measures	Unitil MA	New Hampshire	BPA or PGE[48,49,50,51]
Residential	Space heating – smart thermostats			X
	Space heating – direct load control			X
	Electric resistance water heater – direct load control	X		X
	Electric resistance water heater – grid enabled			X
	Pool pumps		X	
	Smart appliances	X		
	Managed EV charging – direct load control (curtail)	X		X
	Battery storage	X	X	
	Behavioral demand response			X
	Critical peak price rate			X
	Peak time rebate			X
	Time-of-use rate			X
	Electric vehicle charging time-of-use rate			X
Commercial & industrial	Space heating - direct load control			X
	Water heating		X	
	Battery storage	X	X	X
	Thermal storage			X
	Lighting controls			X
	Agricultural irrigation			X
	Critical peak price rate			X
	Real-time price			X
	Curtailment	X		X

48 Ibid.
49 Portland General Electric, PGE DER and Flexible Load Potential – Phase 1, 2021.
50 Bonneville Power Administration, BPA 2018 demand response potential study, 2018.
51 Portland General Electric, Demand Response Market Research, 2016.

Pathways to retail program participation in ISO-NE wholesale markets

Challenges to participation in existing markets

ISO-NE's price-responsive demand model allows demand response resources (DRRs) to bid reductions from demand response assets (DRAs) into and receive dispatch signals from the day-ahead and real-time energy markets, 30-minute operating reserves, and the 10-minute spinning and non-spinning reserve markets. Market participants can map DRRs to active demand capacity resources they can bid into the FCM. DRRs are technology-agnostic, can be aggregations of DRAs in the same Aggregation Zone and must be able to reduce demand by at least 100 kW.[52] Customers who participate in retail programs can become DRAs in a DRR by contracting with an aggregator registered as an ISO-NE Market Participant or by registering themselves as Market Participants, DRRs, and DRAs if they can reduce demand by 100 kW or more.

Retail demand response program participants can face challenges to participation in DRRs due to limitations of the DRR participation model, a lack of data-sharing processes, and market rules on:

- The minimum size of DRAs
- Bounds on the geographic coverage of DRRs
- Requirements for metering and telemetry of DRA load
- Baselines for market performance calculations

Participation models

The DRR model does not leverage all the capabilities of technologies available in retail demand response programs and the marketplace. ISO-NE dispatches DRRs to provide *demand reductions* in energy and reserve markets.[53] Distributed energy resources incentivized by retail programs, such as battery storage, also can *inject and withdraw* energy. Energy storage can participate as a DRA in a DRR but in doing so would only be able to provide demand reductions.[54] The lack of ability to bid injections or withdrawals limits the grid services that customer-sited DERs such as batteries can provide in DRRs and may affect the economic attractiveness of participating in a DRR.

Size and locational requirements

Minimum size requirements for DRAs limit the number of customers eligible to participate.[55] ISO-NE market rules require that a DRA must be able to reduce demand by at least 10 kW, with an exception for an aggregation of customers each with demand reductions <10 kW that represent "a homogeneous population as determined by the ISO."[56] Market rules do not explicitly define "homogeneous population," though ISO-NE shared that such a population could include single-family homes and apartments.[57] Customers with <10-kW demand reductions not in a homogenous population would not be eligible to be DRAs.

Minimum size and locational requirements for DRRs limit the number of potential aggregations. ISO-NE requires that DRRs must be able to reduce demand by at least 100 kW.[58] A recent report by the Energy Systems Integration Group indicates reaching 100 kW may be challenging for some aggregations.

[52] See ISO-NE Market Rule 1 Section III.8.1.2.
[53] See ISO-NE Market Rule 1 Section III.8.4.
[54] See ISO-NE Market Rule 1 Section III.1.10.6.h.
[55] Minimum size requirements provide ISO-NE visibility and locational control of resources, which supports system reliability.
[56]See ISO-NE Market Rule 1 Section III.8.1.1.
[57] Correspondence with ISO-NE.
[58] See ISO-NE Market Rule 1 Section III.8.1.2

ISO-NE also requires that DRAs in an aggregation must be in the same Aggregation Zone (see Figure 8). Utility jurisdictions may include multiple Aggregation Zones, which means that multiple aggregations may be necessary for participants in a single retail program.[59] This potential division of the participants in a retail program across Aggregation Zones may make it more difficult to assemble DRRs that meet the minimum size requirements.

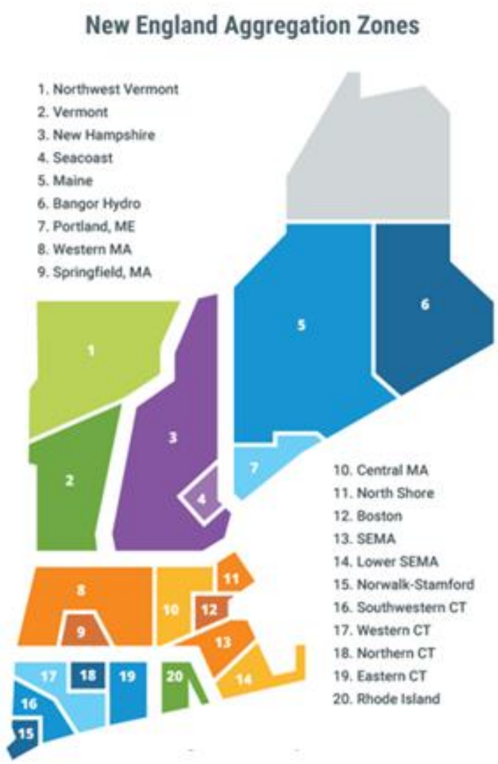

Figure 8. ISO-NE Aggregation Zones
Source: ISO-NE

Metering and telemetry requirements

Some customers may lack, be unwilling to pay, or be unable to afford metering and telemetry infrastructure required for DRAs. ISO-NE operating procedures require that DRAs have 5-minute interval metering, the same interval required for all other market participants. Market rules further detail that DRRs must have 5-minute telemetry data for settlement in the day-ahead and real-time energy markets,[60] 1-minute telemetry for 10-minute spinning and non-spinning reserves,[61] and 5-minute metering for auditing demand reduction capabilities in the FCM.[62] However, the adoption of AMI, which can support metering and telemetry at subhourly intervals, is limited in New England states other than Maine and Vermont as of 2023 (see Table 6). The existing AMI also may not be able to support market participation because meters may not be configured to record energy at 1- and 5-minute intervals, or the network connecting meters to utility systems may not have bandwidth for 1- and 5-minute telemetry. Without utility-owned AMI that can meet ISO-NE metering and telemetry requirements, customers would have to

[59] Ibid.
[60] See ISO-NE Market Rule 1 Section III.3.2.1.1.
[61] See ISO-NE Market Rule 1 Section III.1.7.19.2.3.
[62] See ISO-NE Market Rule 1 Section III.1.5.1.4.

invest in their own metering infrastructure to qualify as DRAs. Customers may not be able to afford this additional metering or may not be willing to pay for it because its cost makes market participation economically unattractive.

Table 6. AMI penetration by New England state

State	Connecticut	Massachusetts	Maine	New Hampshire	Rhode Island	Vermont
AMI as share of all investor-owned utility meters (2023)[63]	18%	2%	99%	11%	0%	97%

Baselines for market performance calculation

Retail program participation can reduce calculated demand response performance in ISO-NE wholesale markets. Unlike generation resources, demand response does not have a physical output of energy that a meter can measure. Instead, demand response performance is often calculated as a reduction in load relative to a baseline that estimates what load would have been absent the demand response. ISO-NE's baseline for DRRs is the average of metered demand during the interval of the dispatch (e.g., 5:25pm–5:45pm) on preceding days, with the number of preceding days depending on whether the event is on a weekday, Saturday, or Sunday/holiday.[64] ISO-NE adjusts the baseline to account for differences between it and metered demand prior to dispatch and excludes days with forced/scheduled curtailment or non-zero dispatch. The excluded days, however, do not include days with retail program events. If a customer participates (i.e., reduces demand) in a retail demand response event that occurs in the window of the baseline calculation, it lowers the baseline relative to what it would have been if the retail event did not occur. A lower baseline decreases the calculated demand reduction (the difference between baseline and metered demand during interval of dispatch) and market revenues derived from that demand reduction. This reduction in calculated performance may disincentivize dual participation in ISO-NE whole markets and retail programs.

Figure 9 illustrates the impact of a reduced baseline on the calculated performance. The distance between the metered demand (blue) during the 5pm–9pm event is greater with the original baseline (orange) and lower with the baseline impacted by retail program participation (green).

[63] Data are from the 2023 Energy Information Administration (EIA) Form 861. The form defines AMI as a meter that can record energy usage in at least hourly intervals and has two-way communication. For details, see the EIA-861 survey form.
[64] See ISO-NE Market Rule 1 Section III.8.2.1-4.

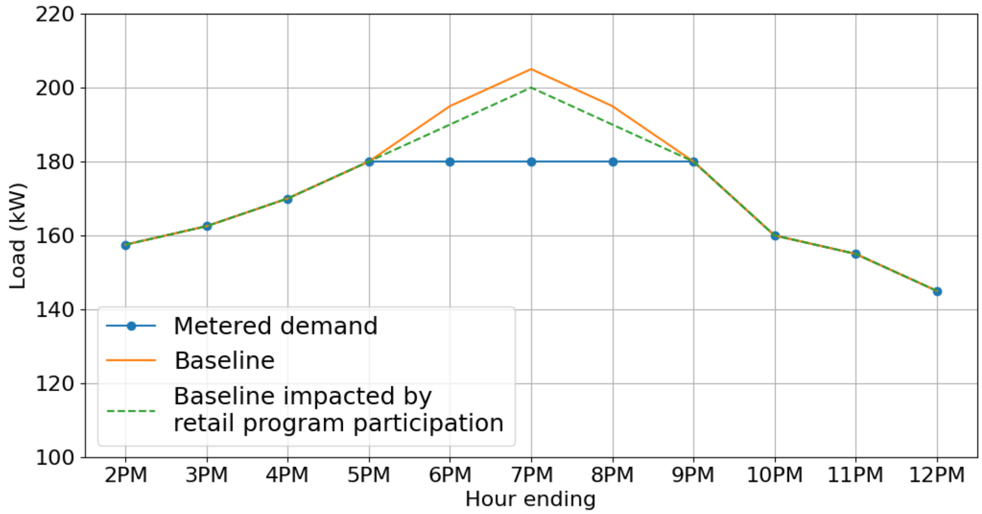

Figure 9. Illustrative demand response load profile

A lack of automated data-sharing processes prevents ISO-NE from accounting for retail demand response program event participation in its baseline calculations. First, ISO-NE does not know that retail program events occur unless they receive data on those events. Retail programs have called events without ISO-NE's awareness,[65] but in summer 2024, utilities and ISO-NE established coordination calls to decide on the dispatch of demand response resources. Second, ISO-NE does not have visibility on retail program participants if they are not market participants (e.g., metering data, location).

FERC 2222 background and ISO-NE compliance filings

In September of 2020, the FERC issued [Order 2222] to enable DERAs to participate in wholesale electricity markets. ISO-NE filed its [first compliance filing] to Order 2222 in 2022 and made subsequent filings in 2023 and 2024 to address sections that FERC rejected.[66] Prior to the filing, committees of the New England Power Pool (NEPOOL) reviewed the proposal.[67] In parallel, ISO-NE hosted stakeholder meetings with New England electric utilities, NECPUC, and distributed energy resource aggregators. ISO-NE is compliant with all FERC Order 2222 directives as of [November 2024] after the FERC issued an order accepting ISO-NE's last set of revisions to its earlier filings. ISO-NE and the California Independent System Operator (CAISO) are currently the only ISOs/regional transmission operators in full compliance.[68] ISO-NE's Order-2222-compliant rules will take effect in energy and reserve markets on November 1, 2026 and the FCM during Forward Capacity Auction 19 in February 2026.[69]

Utility, aggregator, and PUC rules

ISO-NE's Order-2222-compliant market rules **delineated roles for utilities, aggregators, and state PUCs** and expanded the number of participation models applicable to aggregations of DERs.

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[65] Based on comments made in the Retail Demand Response Working Group on December 6, 2024, and January 24, 2025.
[66] See ISO-NE February 2, 2022 compliance filing.
[67] Ibid page 44.
[68] See November 19, 2024, FERC order, Docket No. ER22-983-009.
[69] FERC, FERC Order No. 2222 Explainer: Facilitating Participation in Electricity Markets by Distributed Energy Resources, 2025.

Distribution utilities have the authority to review DERA eligibility and the *incremental* safety and reliability impacts of DERs in DERAs on the distribution system during the DERA registration process.[70] They also have the option to override ISO-NE dispatch of DERAs to prevent safety and/or reliability issues in the distribution system.[71] Through their position as regulators, PUCs have authority over the roles assigned to distribution utilities. They also have authority on the resolution of disputes between aggregators and utilities [72] and rules governing dual participation in retail programs and wholesale markets.[73]

ISO-NE also established rules for ongoing coordination between itself, utilities, and aggregators.[74] Aggregators must abide by utility rules and operate within the limits of the distribution system, and utilities must notify aggregators about distribution system constraints. The rules also require that ISO-NE coordinate with utilities to manage "conflicting operational directives," which can include dispatch instructions and ahead-energy market results.[75]

Participation models and size requirements

ISO-NE expanded the participation models DERAs could leverage by creating new DERA-specific participation models and permitting DERAs to use existing participation models. The two new DERA-specific participation models are the Demand Response Distributed Energy Resource Aggregation (DRDERA) and the Settlement-Only Distributed Energy Resource Aggregation (SODERA) .[76]
In the DRDERA model, demand response can participate alongside DERs that inject and/or withdraw energy, and in the SODERA model, non-dispatchable resources can participate alongside flexible loads in the day-ahead energy market.[77,78] The existing models that ISO-NE permitted DERAs to use are the Binary Storage Facility, Continuous Storage Facility, and Alternative Technology Regulation Resource.[79]

The expansion of participation models that DERAs can use increases the number of customers eligible to have DERs in a DERA. The new participation models, in contrast to DRRs, do not have minimum size requirements for the DERs that comprise a DERA.[80,81] Residential and small commercial customers, including retail program participants, that are not in a "homogenous population" and lack the maximum 10-kW demand reduction required to be a DRA will be eligible to register DERs in DRDERAs and SODERAs.[82] SODERA aggregations also can bypass challenges to market participation posed by metering requirements. These aggregations require *hourly* — not 5-minute — metering data and *do not require telemetry* because they are settlement-only resources.[83,84]

[70] Interconnection confirms the safety of individual DERs. This review assesses whether a DER, due to its participation in a DERA, adversely impacts safety or reliability.
[71] See ISO-NE February 2, 2022 compliance filing Section III.6.8.
[72] See ISO-NE February 2, 2022 compliance filing Section III.6.7(c)(v).
[73] See ISO-NE February 2, 2022 compliance filing Section III.6.7(d)(3).
[74] See ISO-NE February 2, 2022 compliance filing Section III.6.8.
[75] Ibid.
[76] See ISO-NE February 2, 2022 compliance filing Section III.6.1.
[77] See ISO-NE February 2, 2022 compliance filing Section III.6.5.
[78] See ISO-NE February 2, 2022 compliance filing Section III.6.6.
[79] See ISO-NE February 2, 2022 compliance filing Section III.6.1.
[80] See ISO-NE February 2, 2022 compliance filing Section III.6.5.
[81] See ISO-NE February 2, 2022 compliance filing Section III.6.6.
[82] See ISO-NE Market Rule 1 Section III.8.4.
[83] See ISO-NE February 2, 2022 compliance filing Section III.6.6 and page 12.
[84] ISO-NE Operating Procedure No. 18 Section VI(A)(d).

The broader set of participation models also makes more types of aggregations possible. Since DRDERAs can provide a mix of demand reduction, energy injection, and withdrawal, they could include participants from multiple retail programs (e.g., Wi-Fi thermostat and battery storage).[85] Generator and Binary/Continuous Storage models will allow aggregations for the first time and aggregations through the Alternative Regulation Technology Resource will be 100 kW or larger (as opposed to 1 MW or larger under current rules).[86]

Actions to address challenges to retail demand response participation in ISO-NE markets remaining after FERC Order 2222 implementation

After ISO-NE's Order-2222-compliant rules take effect, retail demand response program participants may still face challenges to ISO-NE wholesale market participation due to issues related to DERA development in general and issues specific to dual participation in retail programs and wholesale markets.

General DERA development challenges concern:

- Metering and telemetry requirements
- Size and locational requirements
- Double counting of DER load impacts related to submetering
- Systems and processes for DERA registration
- Aggregator access to customer and grid data
- Dispute resolution between utilities and aggregators
- Utility overrides of ISO-NE dispatch signals

Challenges specific to dual participation relate to:

- Baselines for market performance calculations
- Double compensation and conflicting grid services

General DERA development

Metering and telemetry

Under ISO-NE's Order-2222-compliant market rules, **retail program participants may still lack, be unwilling to pay for, or be unable to afford metering and telemetry infrastructure necessary for ISO-NE wholesale market participation.**

Metering and telemetry requirements for resources that participate in real-time energy and reserve markets do not change under the new market rules. Customers in DERAs that participate in the real-time energy market, such as DRDERAs, will require 5-minute metering and telemetry data, and those that participate in 10-minute spinning and non-spinning reserves will require 1-minute telemetry. [87,88] Customers that participate in SODERAs, in contrast, will only need hourly metering data.[89] The lack of access to AMI, meters that record at 1- and 5-minute intervals, and network bandwidth that may limit customer participation in DRRs also apply to aggregations under the new market rules. For customers that

[85] See ISO-NE February 2, 2022 compliance filing Section III.6.5.
[86] See ISO-NE February 2, 2022 compliance filing Section III.6.1.
[87] See ISO-NE February 2, 2022 compliance filing Sections III.3.2.1.1, III.6.5, and III.1.7.19.2.3.
[88] ISO-NE Operating Procedure No. 18 Section VI(A)(d).
[89] ISO-NE Operating Procedure No. 18 VI(A)(d) and ISO-NE February 2, 2022 compliance filing Section III.6.5.

do not have utility-owned AMI that meet the market requirements, the cost of installing metering to be part of a DERA may not be affordable or economically attractive.

To address the uncertainty in whether existing and planned AMI can support aggregations of customer DERs participating in ISO-NE wholesale markets, **PUCs can request that utilities report whether the AMI can record and provide telemetry at 1- and 5-minute intervals and whether the networks have bandwidth for electricity usage data at those intervals.** If existing or planned AMI does not record at the intervals required for market participation and/or lacks bandwidth to handle that data, utilities can propose investments that enable those capabilities.

PUCs also can consider engaging with aggregators and other stakeholders about the impacts of the metering and telemetry requirements on DERA participation in New England. Additionally, PUCs can monitor the impact of telemetry requirements employed in other jurisdictions**.** For example, CAISO has proposed telemetry requirements that are conditional on DERA size and the grid services provided: Telemetry is not required for a DERA ≤ 10 MW that does not provide ancillary services.[90] CAISO also allows telemetry that is calculated and not measured. In its FERC Order-2222-compliant rules, CAISO permits aggregators to use statistical sampling of metering data when interval metering is not available for some participating customers.[91] Finally, in New York ISO's FERC Order 2222 compliance proposal**,** telemetry can be for aggregations overall, not individual meters associated with participating DERs.[92]

Double counting of DER load impacts related to submetering

Retail program participants may be unwilling to pay for or be unable to afford submetering or parallel metering for behind-the-meter (BTM) DERs. ISO-NE includes requirements on sub/parallel metering for BTM DERs to avoid the double counting of energy services at the meter. ISO-NE states in its compliance filing to the FERC that double counting would occur if it received submetering data on rooftop solar from a customer whose bill was based on the load net of the rooftop solar generation.[93] In this case, the customer could be paid for the submetered generation and benefit from the generation's impacts on a utility bill. To avoid this risk, ISO-NE allows submetering or parallel metering of BTM DERs only if the metering infrastructure can remove the load impacts of DERs at the Retail Delivery Point (i.e., the main meter).[94] In the case of submetered rooftop solar, this approach would yield gross building load at the Retail Delivery Point that is the sum of the submetered generation and net building load.

Without sub/parallel metering, ISO-NE would calculate the performance of a DER in a DERA using net building load. Net building load could obscure DER load impacts, which could lead to inaccurate estimations of the economic value of an aggregation. For example, in a residential building with battery storage, building load could offset battery injections and not be distinguishable from withdrawals. However, submetering and parallel metering can be expensive, which may undermine the economics of DER participation in a DERA.

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[90] See CAISO 179 FERC ¶ 61,197 paragraph 152.
[91] See CAISO 179 FERC ¶ 61,197 paragraph 165.
[92] See New York ISO 179 FERC ¶ 61,198 paragraph 186.
[93] See ISO-NE February 2, 2022 compliance filing page 34.
[94] See ISO-NE February 2, 2022 compliance filing page 35.

Existing AMI and utility data systems also may not have the functionality to remove double counting with submetered BTM DERs. To remove the double counting of DER load impacts, utility data systems would have to separately track gross building load and DER operational load profiles by receiving net load from a building's main meter and the DER load profile from a submeter and adding the DER load profile back to the building's load. Without this functionality, ISO-NE would assess DER impacts based on net building load, which could lead to inaccurate valuation of those DERs in an aggregation.

PUCs may be able to address the costs of submetering and parallel metering BTM DERs by allowing the use of submeters embedded in DERs that meet defined data quality standards. Some DERs can measure their own energy injections and withdrawals. By leveraging this capability, customers may be able to avoid the costs of submetering installed by utilities. The California Public Utilities Commission, for example, has established standards for third-party embedded submetering in EV supply equipment as part of its order requiring the submetering of EVs.

Differences in the accuracy of embedded submetering equipment and the accuracy required by ISO-NE for metering DERAs may affect the viability of embedded submetering as an alternative to standard submetering in the context of DERAs. The field accuracy of embedded submetering allowed by California (+/- 0.5%) falls short of CAISO and ISO-NE requirements (+/- 0.2%).[95] However, ISO-NE currently accepts less accurate metering (+/- 2%) for DRAs if the metering is not used for billing. It is unclear if this exception would apply to DERAs and embedded submetering.[96] **PUCs can consider engaging with ISO-NE on these accuracy requirements** to better understand how they apply to DERAs. PUCs can also engage with DER providers to understand how accuracy may improve over time.

PUCs can determine whether it is possible to remove the double counting of BTM DER load impacts by requesting that utilities report whether existing or planned AMI and data systems can receive communications from BTM DERs (e.g., receive injection/withdrawal data from battery) and separate the impact of BTM DERs from building load.

Size and locational requirements

Minimum size and locational requirements for DERAs limit the number of potential aggregations. ISO-NE's Order-2222-compliant market rules include requirements on the size of DERAs and the location of the DERs that comprise those DERAs. The new market rules require that DERAs be capable of reducing and or injecting power by at least 100 kW or have 100 kW of regulation capability, similar to the requirement in existing rules that DRRs be able to reduce power by 100 kW.[97] The challenge in reaching 100 kW aggregations claimed by the Energy Systems Integration Group applies to DERAs as it does to DRRs. DERs in a DERA, as with DRAs in a DRR, must be in the same Aggregation Zone. Unlike DRAs in a DRR, **DERs in a DERA must also be in the same *metering domain*.**[98] As with DRRs, multiple DERAs may be necessary to cover the participants in a single retail program in utility service territories that include multiple Aggregation Zones. Since metering domains generally align with utility service territories, DERAs largely will not be able to cover multiple utilities.[99] This requirement could limit the viability of aggregations in municipal utility service territories due to their small size.

[95] See ISO-NE Operating Procedure No.18 Section V.B.8 and Appendix C.
[96] Ibid.
[97] See ISO-NE February 2, 2022 compliance filing Section III.6.1 and current Market Rule 1 Section III.8.1.2.
[98] See ISO-NE February 2, 2022 compliance filing Section III.6.2.
[99] See ISO-NE February 2, 2022 compliance filing page 26, footnote 67.

PUCs can address the uncertainty in how size and locational requirements may constrain aggregations by requesting that utilities report the load reduction, injection, and regulation capabilities of retail program participants in the geographic areas demarcated by Aggregation Zones and metering domains. For example, Eversource Massachusetts could see if there are ConnectedSolutions participants with least 100 kW of combined battery storage capacity in each Aggregation Zone that overlaps with its service territory. Such an analysis would not indicate whether an aggregation is economically worthwhile but could identify where aggregations of retail program participations would not be possible due to the size and locational requirements.

PUCs also can consider engaging with ISO-NE on the feasibility of changes to locational requirements for DERAs. ISO-NE indicated that combining the energy injections and or withdrawals from DERs in a DERA that spans multiple metering domains would complicate meter reading and settlement.[100] Discussions with ISO-NE may clarify whether it is possible for their systems to support DERAs that operate across metering domains.

DERA registration

Consistent with the requirements of FERC Order 2222, ISO-NE's new market rules give distribution utilities the authority to determine DERA eligibility and assess their safety and reliability impacts on the distribution system. However, **utilities may not have systems, processes, or criteria for assessing the safety and reliability impacts of DERAs.**[101] A lack of automated systems and processes could slow down reviews. A lack of transparent review criteria could result in anti-competitive behavior by utilities. And a lack of standards could result in inconsistent outcomes across utilities that could increase the complexity of customer recruitment, DERA registration, and dispute resolution from an aggregator's perspective. **To address these issues, PUCs can request that utilities propose frameworks for assessing the safety and reliability impacts of DERAs on the distribution system.** Such frameworks could identify risks posed by DERAs and describe the methods, criteria, and metrics used to assess those risks and determine the need for distribution system upgrades. Coordination of PUCs across New England could support the standardization of safety and reliability review. **Utilities can then propose investments** in systems that automatically assess the incremental safety and reliability impacts of DERs participating in a DERA on the distribution system.

PUCs also can initiate processes to streamline interconnection processes so that customers can more quickly sign up for DERAs (interconnection is required for registration) and **can require that utilities adopt the latest IEEE-1547 standard for DER interconnection** if they have not already adopted it.

Utilities also may not have systems to automatically determine whether DERAs meet eligibility criteria established in ISO-NE's Order-2222-compliant market rules. For example, utilities may not be able to automatically assess DER location relative to Aggregation Zones and metering domains.[102] Additionally, utilities may not have systems that can determine whether a DER is part of another asset that participates in ISO-NE markets, which would prevent double counting of load impacts and double compensation to a

[100] See ISO-NE February 2, 2022 compliance filing page 26, footnote 68.
[101] ISO-NE is coordinating with distribution utilities on the requirements for systems needed to support DERA registration.
[102] See ISO-NE February 2, 2022 compliance filing Section III.6.2.

DER owner.[103] Utilities can propose investments in systems that automatically perform both of these tasks. Similarly**, utilities may not have systems to automatically share data with ISO-NE and aggregators.** A lack of systems to automatically share interconnection data could impede the registration process. **Utilities can propose investments in systems that automatically share interconnection and other registration data with aggregators.**

Aggregator access to customer and grid data

Aggregators may not be able to readily access the data they need for DER enrollment, registration, operation, and settlement. For example, data on DER location, interconnection, and hosting capacity may support enrollment, and metering and grid data could support aggregator decisions on DER operations. Aggregators, through their role as Assigned Meter Reader for DERs in a DERA, will need access to metering data so that they can report it to ISO-NE for settlement of wholesale market transactions.[104,105] However, utilities may not have automated systems that enable third-party access to customer and grid data. A lack of standard data processes across utilities and states could increase effort for aggregators and impede the development of aggregations.

PUCs can address these challenges by requiring that utilities develop systems to enable aggregator access to customer and grid data. In particular, feeder- and node-level hosting capacity data can support localized decisions on DER siting and operations and frequent updates to hosting capacity data can make data more useful to developers. Consolidated Edison, for example, publishes hosting capacity for generation and storage and has an API for accessing the data. Platforms such as the New York Integrated Energy Data Resource and the Energy Data Hub proposed by Unitil, Fitchburg Gas and Electric, and Northern Utilities could provide aggregators access to grid and customer data. The adoption of protocols such as Green Button Connect could enable customers to give aggregators access to metering data. PUCs also can engage with aggregators and utilities to determine specific requirements for sharing metering and telemetry.

Dispute resolution and dispatch overrides

Disputes between utilities and aggregators may arise during the DERA registration process. Absent PUC involvement, the resolution of these disputes defaults to ISO-NE processes.[106] However, ISO-NE does not have review criteria specific to the registration process.[107] **PUCs can address this gap by developing processes for resolving disputes between utilities and aggregators.** Transparent rules could reduce the frequency of disputes and speed up their resolution.

ISO-NE gives utilities authority to override dispatch signals to avoid safety or reliability issues in the distribution system.[108] **However, utilities do not have frameworks for overriding dispatch signals from ISO-NE.** A lack of transparent decision-making could affect aggregators' ability to make informed bids and could increase their exposure to nonperformance penalties from ISO-NE.[109] PUCs can address this gap by requesting that **utilities propose frameworks for overriding ISO-NE's dispatch signals to DERAs.**

[103] See ISO-NE February 2, 2022 compliance filing Section III.6.7.
[104] See ISO-NE January 31, 2024 compliance filing Section III.6.4.
[105] Aggregators may assign a host utility as the Assigned Meter Reader.
[106] See ISO-NE February 2, 2022 compliance filing page 37 and Section III.6.8(e)).
[107] See ISO-NE Tariff Section 1.6.
[108] See ISO-NE February 2, 2022 compliance filing Section III.6.8 for details.
[109] See ISO-NE February 2, 2022 compliance filing Section III.6.8(e)).

Frameworks could describe the situations in which an override may be necessary and could identify the criteria, metrics, and methods utilities use to make override decisions. Transparency into override decision-making could help aggregators avoid overrides and reduce the likelihood of nonperformance penalties from ISO-NE.

Dual participation

Baselines for market performance calculations

Retail demand response program participation can reduce the calculated performance of DRDERAs in ISO-NE wholesale markets. ISO-NE uses the same baseline method for DRDERAs as it does for DRRs.[110] The same issue of retail program participation reducing the baseline calculated for wholesale market performance, therefore, applies to DRDERAs as well (see page 19–20 for details). **PUCs can address this issue by considering engaging with ISO-NE on excluding days with retail program events from DRDERA baselines.** This approach extends ISO-NE's existing practice of excluding days that have reductions in demand that differ from typical usage such as forced/scheduled curtailments and non-zero dispatch. By excluding retail program events from the baseline calculation, ISO-NE could increase the calculated performance of DRDERAs.[111] ISO-NE cannot exclude retail program event days from DRDERA baseline calculations unless it knows when those events occur. **Utilities can address this information gap by sharing data on customer event participation with ISO-NE.**

Double compensation and conflicting grid services

Customers participating in retail programs and ISO-NE wholesale markets could receive overlapping requests that create double compensation risks. For example, ISO-NE and a utility could dispatch a DER to provide the same service (e.g., an energy reduction) at the same time, which could lead to the DER owner being compensated twice. This double compensation may distort wholesale markets and be perceived as unfair to other market and retail program participants. It also creates uncertainty in whether the grid services are attributable to the retail program. For example, if wholesale market revenues are sufficient to encourage a utility customer to respond to an ISO-NE dispatch, then simultaneous participation in a retail program event would constitute free riding.

PUCs can establish rules on dual participation that prevent double compensation. First, utilities could prohibit **"non-identical participation"** in which a retail program participant would not be allowed to participate in a wholesale market that could require a DER to provide the same service as the retail program.[112] For example, a retail program that provides energy services would not be allowed to provide wholesale energy services. Second, utilities could allow a **"switching"** model in which customers participate in a wholesale market and retail program at different times. PUCs could allow customers to choose or establish criteria to determine whether participation should receive compensation from a retail program or wholesale market. For example, a battery could provide wholesale services at any time except during summer peak events called by a utility. This approach is likely easier for retail programs that have few events. Third, utilities could allow **"parallel participation"** and only permit compensation for one of

[110] See ISO-NE February 2, 2022 compliance filing III.6.5 and current Market Rule 1 Section III.8.2.
[111] This expanded set of exclusions would introduce a potential tradeoff. ISO-NE uses data from the 10 most recent eligible days to calculate the baseline. If ISO-NE excluded a day from the baseline calculation because it had a retail event, it would have to include the next most recent eligible day. The less recent the days in the baseline are, the less accurate the baseline may be.
[112] See Forester et al. for additional discussion of the non-identical participation, switching and parallel participation.

the two dispatch responses (retail program or wholesale market). PUCs could set rules on which type of compensation (retail or wholesale) a customer receives under defined cases. This approach requires more coordination between utilities and ISO-NE than nonidentical participation and switching.

ISO-NE and a utility also could make conflicting requests that create an operational risk to the distribution system and or bulk power system. For example, ISO-NE could dispatch a battery to *inject energy* to address a wholesale market need at the same that a utility could dispatch a battery to *withdraw energy* to address a distribution grid need. Since a DER could not respond to both dispatches, operational issues may result from the DER not providing one or both services. Conflicting requests also expose aggregators to nonperformance penalties.[113] In the illustrative example of the battery, if the aggregator responded to the utility dispatch to withdraw energy, it may face penalties from ISO-NE for not injecting energy.

PUCs can prevent conflicting dispatches by identifying the types of conflicting dispatches that may occur and establishing criteria for determining which dispatch a customer should respond to in each case. For example, a dispatch for energy injection to maintain distribution system reliability could take precedent over wholesale energy under certain conditions. PUCs can engage with aggregators, utilities, and ISO-NE to inform this decision framework.

Conclusions

The availability of programs and rates that promote winter demand flexibility varies across New England states. In particular, we find winter dynamic rates in only two states. The collected winter demand flexibility programs generally target evening peaks and partially align with the timing of potential winter energy shortfalls. Program administrators can expand program event windows to better address these shortfalls. The alignment of the grid impacts of rates that promote demand flexibility and the shortfalls is more variable than that of the studied programs. Most New England states and utilities have not developed winter demand response studies. Winter-peaking utilities outside of New England demonstrate approaches to demand response potential studies that New England utilities could follow, including longer study periods and the consideration of a broad set of demand response technologies and rates.

Demand response has multiple revenue streams in ISO-NE wholesale markets and may be able to leverage high-valued performance payments during energy shortfalls. A broad set of avoided costs in the AESC apply to winter demand response, but the magnitude of some avoided costs, including capacity, reliability, and transmission, depend on whether the New England electricity system is or is nearly winter-peaking.

Utility customers may confront challenges to participating in existing ISO-NE wholesale markets, in particular, due to metering and telemetry requirements. The implementation of market rules compliant with FERC Order 2222 expand the type and number of aggregations that are possible in New England, but aggregations under Order 2222 will require the development of new utility systems and processes. Metering and telemetry requirements also affect participation in

[113] See ISO-NE February 2, 2022 compliance filing Section III.6.8(e)).

aggregations after Order-2222-compliant rules take effect. PUCs have opportunities to address many of these issues by developing frameworks that guide utilities and aggregators and by engaging with ISO-NE on market rules and operating procedures.

Appendix A – Utilities in scope of program and rate collection

Table A-1. Utilities and program administrators in scope of program/rate screening and collection

State	Utility/program administrator name	Utility/ administrator type	Has program(s) in collection	Has rate(s) in collection
CT	Eversource	Investor-owned	Y	Y
	United Illuminating Co	Investor-owned	Y	Y
	Wallingford Electric Division	Municipal	N	N
MA	Eversource	Investor-owned	Y	N
	National Grid	Investor-owned	Y	Y
	Unitil	Investor-owned	N	Y
	Reading Municipal Light Department	Municipal	Y	N
ME	Central Maine Power	Investor-owned	N	Y
	Versant Power	Investor-owned	N	Y
	Efficiency Maine	Third party	N	N
	Houlton Water Company	Municipal	N	N
NH	Eversource	Investor-owned	N	N
	Liberty Utilities	Investor-owned	Y	Y
	Unitil	Investor-owned	N	Y
	New Hampshire Electric Co-op	Co-operative	N	N
RI	Rhode Island Energy	Investor-owned	N	N
	Pascoag Utility District	Municipal	N	N
VT	Green Mountain Power	Investor-owned	Y	Y
	Burlington Electric Department	Municipal	N	Y
	Efficiency Vermont	Third party	N	N
	Vermont Electric Cooperative	Co-operative	Y	N

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