# Update on technical assistance

Sean Murphy and Cesca Miller
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# Agenda

- Task overview
- Winter demand flexibility programs and rates in New England
- Suitability of programs and rates to address winter energy shortfalls
- Winter demand response value

# Task overview

| | Sub-task | Status |
|---|---|---|
| **Task 1** | Identify barriers to participation in ISO-NE wholesale markets for retail demand response | Complete |
| | Assess impacts of FERC Order 2222 implementation on barriers | Complete |
| | Describe pathways for retail program access to wholesale markets | Complete |
| **Task 2** | Literature review on winter demand response potential | Complete |
| | Characterize value streams for ISO-NE wholesale demand response | Complete |
| | Review components in AESC study for winter alignment with value of demand response in energy inadequacy events | Complete |
| | Collect data on demand response programs and rates | Complete |
| | Assess suitability of programs and rates to address energy adequacy events | In progress |

# Program and rate screening process
## Winter demand response programs and rates

- 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[1]
  - Third-party program administrators where applicable

- We applied screening criteria to select programs and rates of interest:
  - Programs must have **winter events *and* incentives to flex load** (e.g., curtailing or shifting end uses)
  - Rates must have **a technology requirement *or* dynamic[2] components with winter events**

- Screening process excluded programs and dynamic rates with only summer events.

- **We identified 16 programs and 35 rates** that met our screening criteria.

[1]Per guidance from NECPUC, we included both the largest municipal and co-operative utility in VT
[2]Price of electricity changes depending on grid conditions

# Program and rate categorization
## Winter demand response programs and rates

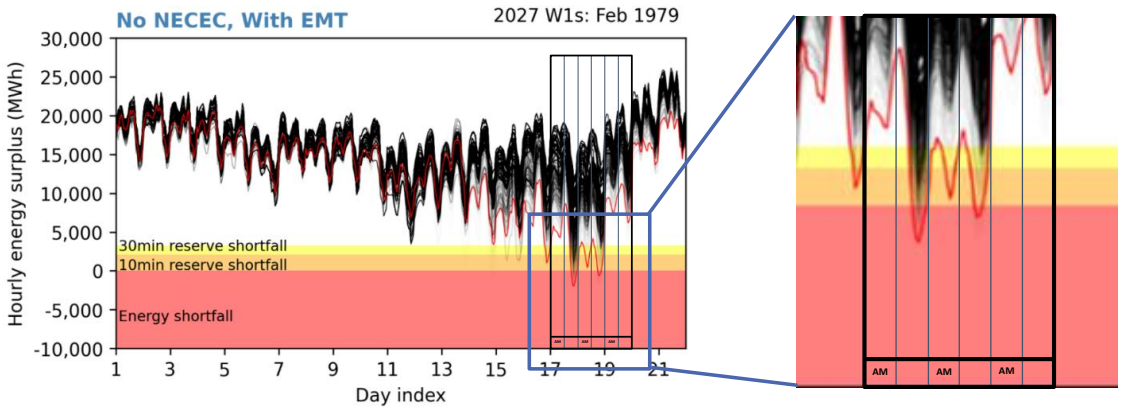
- We categorized the programs by technology and load management strategy and categorized rates by their time-varying component (or lack thereof).

| | Category | Grid impact |
|---|---|---|
| **Programs** | EV charging load shift | -Shifts load out of peak periods into off-peak periods |
| | Battery storage | -Batteries discharge energy during events |
| | Load shed (EV, HVAC, or water heating) | -End uses interrupted or usage is scaled back during events |
| **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 |
| | Dynamic rates | -Variable/critical peak or real-time price or rates that incentivize reduced usage during events by increasing the price of electricity |
| | Discounted flat rates with technology requirement (e.g. space heating) | -Incentives increased usage of end use relative to non-discounted rate |
| | Non-discounted flat rates with technology requirement (e.g. EV charging) | -No impact relative to standard service |

# Defining shortfall event types

## Suitability of demand response to address winter energy shortfalls

- **We identified three types of energy shortfalls** that appeared in ISO-NE's Operational Impact of Extreme Weather Events based on their timing and duration.[1]
  - 1. Evening shortfall only
  - 2. Morning and evening/nighttime shortfall
    - Has energy surplus in afternoon or late night between shortfalls
  - 3. All-day shortfall
- **We assessed how the timing of each program/rate category's grid impacts aligned with each shortfall type.**




Example of an evening shortfall

[1]We limited this assessment on the scenario that generally had the largest shortfalls in both 2027 and 2032. The scenario assumed that New England Clean Energy Connect (NECEC) would be not operational and that the Everett Marine Terminal (EMT) would be operational.

# Existing *program* impacts align partially with evening shortfalls

## Suitability of demand response to address winter energy shortfalls

| | Evening shortfall only | Morning and evening shortfall | | All-day shortfall |
|---|---|---|---|---|
| | | Morning | Evening | |
| **EV charging load shift** | Medium | Low | Medium | Medium (limited coverage) |
| **Battery storage** | Medium | Low | Medium | Medium (limited coverage) |
| **Load shed (EV, HVAC, or water heating)** | Medium | Low | Medium | Medium (limited coverage) |

**Low**: Grid impacts have no overlap with shortfall **Medium**: Grid impacts partially overlap with shortfall **High**: Grid impacts fully overlap with shortfall

- Programs reviewed generally target load during afternoons and evenings but not mornings.
  - EV charging load shift programs could increase morning load.
  - EV charging programs with customized charging schedules may be able to shift load out of mornings and evenings (e.g. Connecticut Electric Vehicle Charging Program Advanced Tier).
- Programs can provide capacity for part of all-day shortfalls.

# Alignment of *rate* grid impacts with energy shortfall timing is variable

## Suitability of demand response to address winter energy shortfalls

| | Evening shortfall only | Morning and evening shortfall | | All-day shortfall |
|---|---|---|---|---|
| | | Morning | Evening | |
| **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 |
| **Discounted flat rates with technology requirement** | Misalignment: may exacerbate shortfall | | | |
| **Non-discounted flat rates with technology requirement** | No grid impacts from demand flexibility | | | |

**Low**: Grid impacts have no overlap with shortfall **Medium**: Grid impacts partially overlap with shortfall **High**: Grid impacts fully overlap with shortfall

- Rates whose impacts have high alignment with shortfalls include:
  - **A TOU rate for thermal storage with long on-peak periods** (6am-12am in Green Mountain Power's Electric Load Management Service Rate).
  - An EV charging rate with **utility-defined charging schedule** and **charging level determined by real-time prices** (Burlington Electric's Electric Vehicle Rate - Flexible Real Time Option)

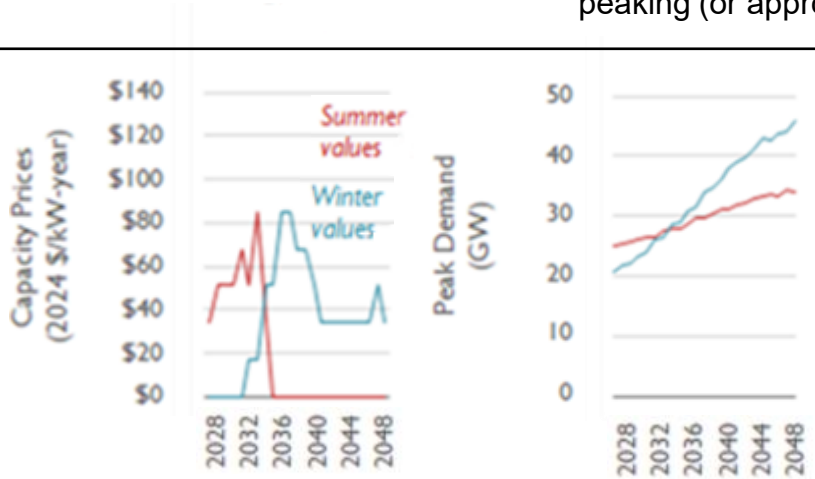
# Avoided Energy Supply Costs in New England
## Winter demand response value

- We reviewed the avoided costs components in the 2024 Avoided Energy Supply Costs (AESC) in New England study:
  - Energy
  - Capacity
  - Demand-reduction induced price effect (DRIPE)
  - Compliance and environmental costs
  - Transmission and distribution (T&D)
  - Reliability
- We determined whether the avoided costs would apply to winter demand response.
- We did not assess the methods used to develop the avoided costs.

# Winter peaks drive avoided winter capacity value

## Winter demand response value

| Avoided cost | Applies to winter demand response value | Key consideration |
|---|---|---|
| **Energy** | Yes | -Value stream may be small due to demand response's focus on demand reductions<br><br>-Seasonal on-/off-peak costing period does not align with demand response events |
| **Capacity** | Yes | -Magnitude depends on whether system is winter-peaking (or approaching winter peak)<br>-AESC does not model constraints to gas supply for electricity generation |
| **DRIPE** | Yes | -Magnitude of capacity DRIPE depends on whether system is winter-peaking (or approaching winter peak) |




Capacity price and peak demand in avoided costs for incremental demand response and storage

Adapted from AESC 2024 page 157

# Non-energy avoided costs apply to winter demand response

## Winter demand response value

| Avoided cost | Applies to winter demand response value | Key consideration |
|---|---|---|
| **Compliance and environmental** | Yes | -Value stream may be small due to demand response's focus on demand reductions as opposed to annual energy savings and avoided costs being in units of $/MWh |
| **Transmission and distribution** | Yes | -Demand reductions must occur during annual system peak that drives transmission investments |
| **Reliability** | Yes | -Assumed hours of generation risk are currently in the summer (per ISO-NE analysis) but could be in the winter<br><br>-Cost of unserved energy is not specific to winter interruptions |

# Demand response revenue streams in ISO-NE wholesale markets during energy shortfalls

## Winter demand response value

- We reviewed ISO-NE market rules to characterize revenue streams for winter demand response during energy shortfalls.

| ISO-NE wholesale market | Winter demand response revenue | Key consideration for winter energy shortfalls |
|---|---|---|
| **Energy** | -Energy savings at market clearing price | -Prices are likely to be high during shortfalls |
| **Reserve** (10-minute spinning and non-spinning and 30-minute reserves) | -Forward and real-time reserve credits | -Demand response can earn real-time reserve credits since reserves would be dispatched to avoid shortfalls |
| **Capacity** | -Monthly capacity payment<br>-Performance payments (during Capacity Scarcity conditions) | -Value could increase during reconfiguration auctions<br><br>-Shortfalls would result in Capacity Scarcity conditions and trigger performance payments |

# Key takeaways

- Energy shortfalls in ISO-NE's study occur in evenings, mornings and evenings, or all-day.
- Existing demand response program impacts partially align with evening shortfalls.
- There is variation in how existing dynamic and TOU rates with technology requirements can address shortfalls in evenings and mornings.
- Discounted rates with technology requirements (e.g. space heating) may exacerbate shortfalls.
- All of the components of the 2024 AESC apply to winter demand response, though value depends on whether system is winter-peaking (or nearly winter-peaking).
- Demand response would earn energy and reserve payments during shortfalls and potentially receive capacity performance payments.

# Next steps

- Assessing how elements of program design other than time-of-day align with energy shortfalls (e.g. event duration).

- Drafting technical memo on findings from Task 1 and 2.

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## Contacts

**Sean Murphy:** smurphy@lbl.gov
**Cesca Miller:** cjmiller@lbl.gov

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