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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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Background and motivations

- A recent ISO-NE study identifies the risks of energy shortfalls due to prolonged cold weather in 2027 and 2032
- The New England Conference of Public Utility Commissioners (NECPUC) expressed interest in how retail demand response programs offered by investor-owned utilities and third party program administrators in New England can mitigate these shortfalls
- NECPUC requested technical assistance from Berkeley Lab to better understand:
  - The capability of existing programs and rates in New England to address winter energy shortfalls
  - The potential for and value of demand response in New England
  - How demand response can access ISO-NE wholesale markets

Roadmap

- Winter demand response programs and rates in New England
- Suitability of programs and rates to address winter energy shortfalls
- Winter demand response potential in New England
- Winter demand response value
- Retail demand response program participation in ISO-NE wholesale markets

Winter demand response programs and rates in New England

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] component with winter events**

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

- **We identified 14 programs and 35 rates** that met our screening criteria

- We identified programs and rates in other jurisdictions for comparison

[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)

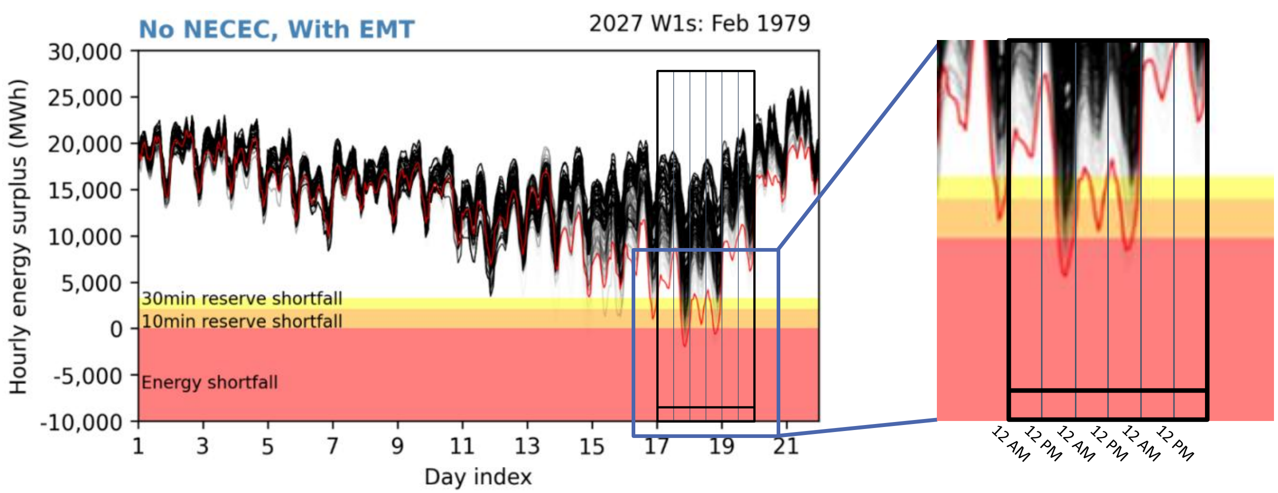
	Category	Grid impact	Sample size
Programs	EV charging load shift	Shifts load out of peak periods into off-peak periods	(n=8)
	Battery storage	Batteries discharge energy during events	(n=5)
	Load shed (EV, HVAC, or water heating)	End uses interrupted or usage is scaled back during events	(n=1)
Rates	Time-of-use with technology requirement (e.g., battery storage)	Incentivizes decreased usage during peak periods and requires a building to 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)
	Discounted flat rates with technology requirement (e.g., space heating)	Incentives increased usage of end use relative to non-discounted rate	(n=2)
	Non-discounted flat rates with technology requirement (e.g., EV charging)	No impact relative to standard service	(n=13)

Suitability of demand response programs and rates to address winter energy shortfalls

Defining shortfall event types

Suitability of demand response programs and rates 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
  - Evening/nighttime shortfall (~6PM to ~12AM)
  - Morning and evening (~6AM-12PM) /nighttime shortfall
    - Has energy surplus in afternoon or late night between shortfalls
  - Extended shortfall (>12 hour shortfall)
- We assessed how the timing of each program/rate category's grid impacts aligned with each shortfall type
- Data from ISO-NE on the hours and duration of shortfalls would improve the accuracy of this categorization



Example of an evening/nighttime shortfall

Alignment of program/rate grid impacts with shortfalls

Suitability of demand response programs and rates to address winter energy shortfalls

- Collected programs generally target evening but *not* morning peaks
  - Program event windows may only partially address evening shortfalls

- None of the collected programs provides flexibility for the entirety of an extended shortfall
  - Reported event windows for load shed and battery programs are 3-6 hours
  - EV charging load shift programs generally move load *within* a day, not *outside* of a day

- The collected rates vary in how well their grid impacts align with the timing of the shortfalls
  - Some partially overlap with evening shortfalls (e.g., EV charging TOU rates in New Hampshire)
  - Some can address morning and evening shortfalls (e.g., a Central Maine Power energy storage rate has both morning and evening on-peak periods)
  - Burlington Electric sets EV charging level based on real-time electricity price, which could reduce demand throughout and extended shortfall

Actions to align program design with shortfalls

Suitability of demand response programs and rates to address winter energy shortfalls

- Increase the overlap of program grid impacts with shortfalls by:
  - Extending winter program event windows later into the evening
  - Establishing morning events
    - E.g., customized EV charging window in Connecticut programs
    - E.g., Georgia Power program has morning events for space heating, water heating, and EV charging
- Shift EV charging loads to days preceding and/or following an extended shortfall
- Account for the number of possible shortfalls when setting caps on event counts
- Require event participation during energy shortfalls (i.e., override opt-out provisions)
- Offer performance incentives that encourage participation in events

Actions to align rate design with shortfalls

Suitability of demand response programs and rates to address winter energy shortfalls

- Create morning on-peak periods for TOU rates with technology requirements
- Extend on-peak periods for TOU rates with technology requirements to cover more of the shortfall (e.g., later into the night)
- Add dynamic components to TOU rates with technology requirements (e.g., variable peak price or critical peak price)
- Incorporate interruptible components into rates
  - Applicable to rates broadly, not just TOU rates

Winter demand response potential in New England

Most New-England states lack winter demand response potential estimates

Winter demand response potential

- We searched for winter demand response potential studies in New England states
- We found **two studies with winter demand response potential estimates** (**Unitil Massachusetts and a New Hampshire-wide study)**
- We reviewed winter demand response potential studies developed for winter-peaking utilities (Bonneville Power Authority and Portland General and Electric) and compared their approaches to those in the New England studies

State	Utility	Has DR potential study	Study includes winter estimates
CT	-	N	N
MA	National Grid	Y	N
MA	Eversource	Y	N
MA	Cape Light	Y	N
MA	**Unitil**	**Y**	**Y**
ME	-	N	N
NH	***Statewide***	**Y**	**Y**
RI	*Statewide*	Y	N
VT	-	N	N

Pacific Northwest potential studies demonstrate methods that New England program administrators can follow

Winter demand response potential

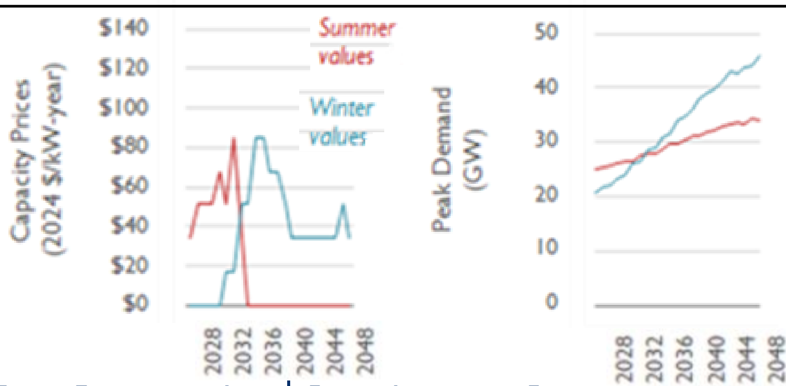
- Program administrators can develop winter demand response potential estimates that:
  - **Address technical, economic, and achievable potential**
    - Unitil and New Hampshire studies include achievable potential
  - **Cover long time horizons** (e.g., 20 years)
    - Unitil study covers 2022-2024 and New Hampshire studies address 2023
  - **Account for expected market-based and programmatic adoption** of technologies that add new loads (e.g., heat pumps)
  - **Explore scenarios** such as different weather conditions (e.g., 1-in-2 vs. 1-in-10 year weather conditions) or levels of technology adoption
  - **Consider broad set of demand response technologies and time-varying electricity rates** (e.g., critical peak price) in future potential studies
    - The Unitil and New Hampshire studies do not consider demand response for electric space heating

Winter demand response value

Winter peaks drive avoided winter capacity value

Winter demand response value

Avoided cost	Applies to winter demand response value	Key consideration for winter energy shortfalls
Energy	Yes	Value stream may be small due to avoided costs being in units of $/MWh and limited number of hours that demand response reduces energy usage Utilities could use a subset of hourly avoided costs in place of seasonal on- and off-peak weighted average avoided costs
Capacity	Yes	Magnitude depends on whether system is winter-peaking (or approaching winter-peaking)
Demand reduction induced price effect (DRIPE)	Yes	Magnitude of capacity DRIPE depends on whether system is winter-peaking (or approaching winter-peaking)



Capacity price and peak demand in AESC

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 for winter energy shortfalls
Compliance and environmental	Yes	Value stream may be small due to avoided costs being in units of $/MWh and limited number of hours that demand response reduces energy usage
Transmission and distribution	Yes	Demand reductions must occur during annual system peak that drives transmission/distribution investments for demand response to receive value
Reliability	Yes	Assumed hours of generation risk are currently in the summer (per ISO-NE analysis) but could be in the winter; value for winter demand response is currently zero

Demand response could have multiple revenue streams in ISO-NE wholesale markets during shortfalls

Winter demand response value

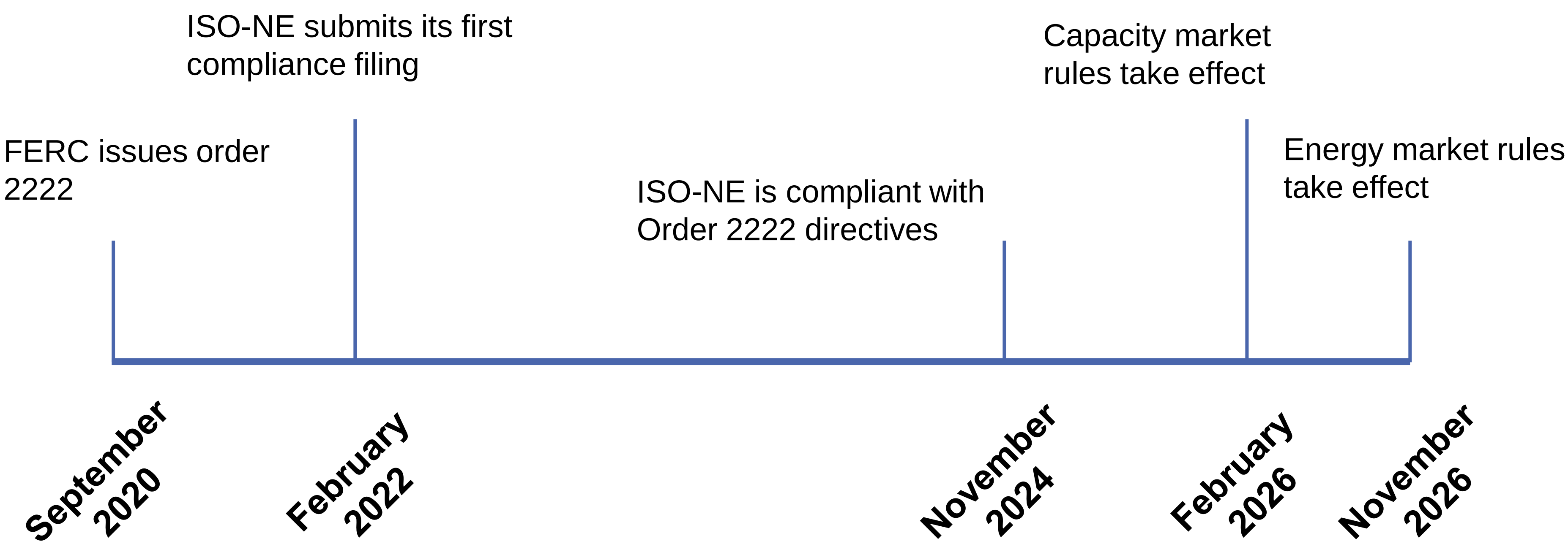
- We reviewed ISO-NE market rules to characterize revenue streams for winter demand response during energy shortfalls

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
Ancillary	Clearing prices for 10-minute spinning, 10-minute non-spinning, and 30-minute operating reserve credits Energy imbalance reserve credit	Prices likely to be high during shortfalls
Capacity	Monthly capacity payment Performance payments (during Capacity Scarcity conditions)	Value could increase during reconfiguration auctions Shortfalls would result in Capacity Scarcity conditions and trigger performance payments

Retail demand response program participation in ISO-NE wholesale markets

FERC Order 2222 background

Retail demand response program participation in ISO-NE wholesale markets



- FERC Order 2222 allows distributed energy resource aggregations (DERAs) to participate in wholesale energy markets
- Relative to existing market rules, ISO-NE's Order 2222-compliant rules make:
  - More customers eligible to have DERs in a DERA (no minimum DER size requirement)
  - More types of aggregations possible (multiple participation models, aggregations can reduce demand as inject/withdraw energy)

Challenges to participation ISO-NE wholesale markets

Retail demand response program participation in ISO-NE wholesale markets

General DERA development

- 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

Dual participation in retail programs

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

Metering and telemetry

Retail demand response program participation in ISO-NE wholesale markets

Challenge

- DERS in most participation models must have **5-minute metering and telemetry**[1,2,3]
  - 1-minute telemetry required for ancillary markets
- Retail program participants may lack, be unwilling to pay for, or be unable to afford such metering and telemetry infrastructure
- Existing AMI networks may not have bandwidth for telemetry

See 2/2/2022 compliance filing: [1]III.3.2.1.1, [2]III.6.5.
See [3]OP-18 VI(A)(d)

Actions to address the challenge

- **PUCs can assess existing AMI capabilities** by requesting that utilities report whether existing and/or planned:
  - AMI can record at 5-minute intervals and provide telemetry at 5- and 1-minute intervals
  - AMI networks and data systems have bandwidth for 5-minute metering and 5- and 1-minute telemetry
- **PUCs can consider engaging with aggregators and other stakeholders on the impacts of metering and telemetry requirements on DERA participation in ISO-NE wholesale markets**

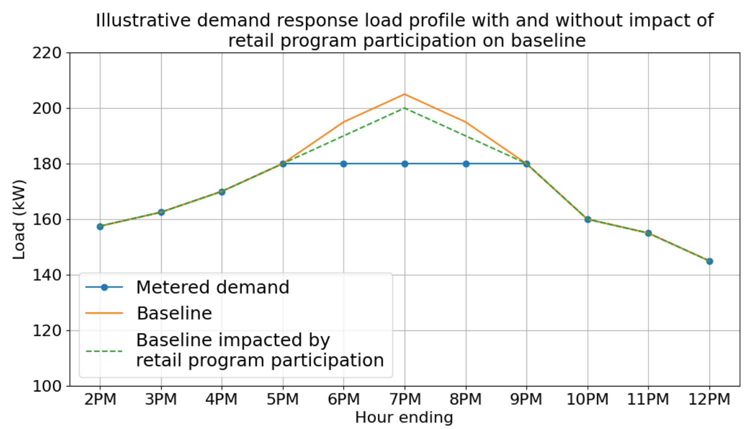
Baselines for market performance calculations
Retail demand response program participation in ISO-NE wholesale markets

Challenge

- **Retail program participation can reduce calculated demand response performance in ISO-NE wholesale markets**
- Performance is calculated against a baseline that may include retail demand response events
  - Retail event participation can lower the baseline, which reduces calculated performance

Actions to address the challenge

- **PUCs can consider engaging with ISO-NE on excluding days with retail program events from baseline**
- **Utilities can share data on customer event participation with ISO-NE**



Double compensation and conflicting grid services

Retail demand response program participation in ISO-NE wholesale markets

Challenge

- ISO-NE and a utility could make overlapping requests that create a **double compensation risk**
- ISO-NE and a utility could make conflicting requests that create an **operational risk** to the distribution system and/or bulk power system

Actions to address the challenge

- **PUCs can establish a framework that prevents double compensation:**
  - **Switching**: Customers participate in wholesale market and retail programs at different times
  - **Parallel participation:** Customer compensated for one of two dispatches
  - **Non-identical participation:** Customer can not participate in a market that requires same service as retail program
- **PUCs can establish a framework that prevents conflicting dispatches by:**
  - Identifying the types of conflicting dispatches that may occur
  - Establishing criteria for determining which dispatch a customer responds to

[1]Framework options are from Forrester et al. 2025

Key takeaways

- Existing winter demand response programs in New England can partially address evening energy shortfalls but not morning shortfalls
- The alignment of demand response rate grid impacts with shortfall timing is variable
- Program administrators can align program grid impacts with shortfalls by addressing event timing and duration (among other strategies)
- Most New England states do not have a winter demand response potential study
  - Non-New England winter-peaking utilities demonstrate methods for future studies
- All of the components of the AESC can apply to winter demand response, but the value of capacity, transmission, distribution, and reliability avoided costs depends on whether system is winter-peaking
- Retail demand response program participants face challenges to participating in ISO-NE wholesale markets due to some market rules and operating procedures
  - PUCs have opportunities to address some challenges and support the development of DERAs

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