Challenges to retail demand response program participation in ISO-New England wholesale markets

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2025.04.18

This work was funded by the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy, under Contract No. DE-AC02-05CH11231.

Roadmap

- Background and motivations
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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) is interested 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:
  - Identify challenges that participants in retail demand response programs face to participation in ISO-NE wholesale markets.
  - Assess the impacts of FERC Order 2222 implementation on those challenges.
  - Describe actions that state public utility commissions (PUCs) and utilities can take to address remaining challenges.

Demand response in existing ISO-NE markets

Demand response in existing ISO-NE wholesale markets

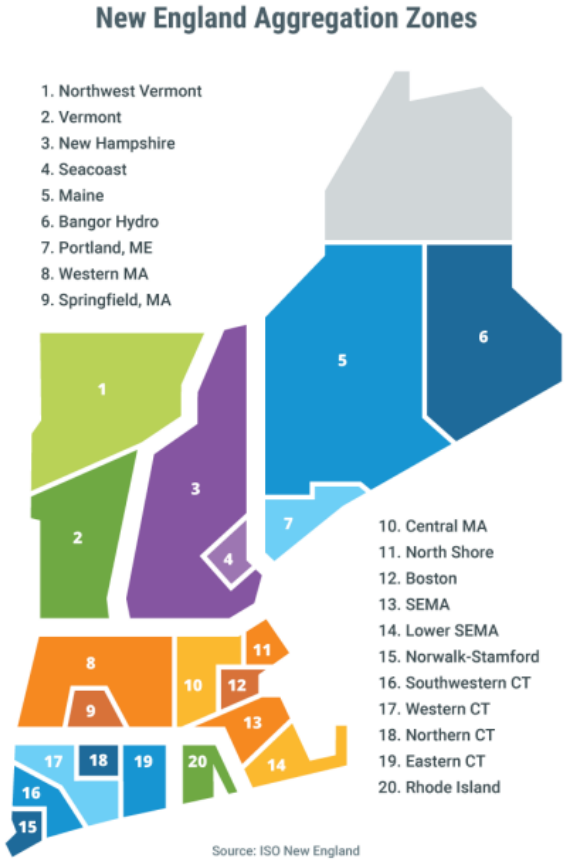
- The price-responsive demand model allows demand response resources (**DRRs**) to bid reductions from demand response assets (**DRAs**) into and receive dispatch signals from the day-ahead and real-time energy markets, 30-minute operating reserves, and the 10-minute spinning and non-spinning reserve markets.[1]
  - DRRs can be mapped to active-demand capacity resources that can bid into the Forward Capacity Market.[1]
  - DRRs are technology-agnostic, can be aggregations of DRAs in the same Aggregation Zone (see slide 6), and must be able to reduce demand by at least 100 kW.[1]
- ISO-NE calculates demand response performance relative to a baseline that estimates what demand would have been absent the dispatch.[1]
- Customers who participate in retail programs can participate in ISO-NE markets by contracting with an aggregator, which is registered as an ISO-NE Market Participant, to be part of a DRR.[2]
- Retail demand response program participants face challenges to ISO-NE wholesale market participation in DRRs due to:
  - Size and locational requirements
  - Metering and telemetry requirements
  - Data sharing and participation models
  - Baselines for market performance calculations

[1]See ISO-NE Market Rule 1
[2]An individual customer also could register itself as Market Participant, DRR, and DRA if it can reduce demand by 100kW or more.

Existing challenges to retail demand response program participation in ISO-NE wholesale markets

Size and locational requirements

- **Minimum size requirements for DRAs limit the number of customers eligible to participate.**
  - DRAs must be able to reduce demand by at least 10 kW.[1]
    - Aggregations of customers with demand reductions <10 kW are allowed if customers' demand "represents a homogeneous population as determined by the ISO".[1]
    - Market rules do not explicitly define "homogeneous population", though ISO-NE shared that such a population could include single family homes and apartments.[2] Customers with <10kW demand reductions not in a homogenous population would not be eligible.
- **Minimum size and locational requirements for DRRs limit the number of potential aggregations.**
  - DRR aggregations must be able to reduce demand by at least 100 kW.[3]
    - A recent report by the Energy Systems Integration Group indicates reaching 100 kW may be challenging.
  - DRAs in an aggregation must be in the same Aggregation Zone[3] (see map to the right).
    - Utility jurisdictions may include multiple Aggregation Zones, which means that multiple aggregations may be necessary for participants in a single retail program.



Source: ISO-New England

See Market Rule 1: [1]III.8.1.1, [3]III.8.1.2
[2]Correspondence with ISO-NE

Existing challenges to retail demand response program participation in ISO-NE wholesale markets

Metering and telemetry requirements

- **Some customers may lack, not be willing to pay, or not be able to afford metering and telemetry infrastructure required for market participation.**
  - ISO-NE operating procedures require:
    - 5-minute interval metering and telemetry for day-ahead and real-time energy markets[1,2]
    - 1-minute telemetry for 10-minute spinning and non-spinning reserve markets[3]
    - 5-minute interval metering for auditing Forward Capacity Market[4]
  - Advanced metering infrastructure (AMI) deployment is limited in New England states other than Maine and Vermont (see table).
    - Deployment is generally similar across customer classes within states.
  - Existing AMI may not be able to support market participation.
    - AMI may not be configured to record energy at 1- and 5-minute intervals
    - AMI Network may not have bandwidth for 1- and 5-minute telemetry

State	Connecticut	Massachusetts	Maine	New Hampshire	Rhode Island	Vermont
AMI as share of all investor-owned utility meters (2023)[5]	18%	2%	99%	11%	0%	97%

See Market Rule 1: [1]III.3.2.1.1, [3]III.1.7.19.2.3, [4]III.1.5.1.4 and III.13.1.1.1.4.
See [2]OP-18(V)(A)
[5]The 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.

Existing challenges to retail demand response program participation in ISO-NE wholesale markets

Data sharing and participation models

- **Utilities and ISO-NE lack automated processes for data sharing and coordination on demand response.**
  - Retail programs have called events without ISO-NE's awareness.[1]
  - Utilities and ISO-NE established coordination calls in summer 2024 to decide on the dispatch of demand response resources.[1]
  - ISO-NE does not have visibility on retail program participants if they are not market participants (e.g. metering data, location).[1]

- **The DRR model does not leverage all of 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.[2]
  - 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 DRR.[3]
  - 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.

[1]Based on comments made in Retail Demand Response Working Group on 12/06/24 and 1/24/25
See Market Rule 1: [2]III.8.4, [3]III.1.10.6.h

Existing challenges to retail demand response program participation in ISO-NE wholesale markets

Baselines for market performance calculations

- **Retail program participation can reduce calculated demand response performance in ISO-NE wholesale markets.**
  - The baseline is the average of metered demand during the interval of the dispatch (e.g. 5:25-5:45PM) on preceding days.[1]
    - The number of preceding days depends on whether the event is on a weekday, Saturday, or Sunday/holiday.
    - ISO-NE adjusts baseline to account for differences in baseline and metered demand prior to dispatch and excludes days with forced/scheduled curtailment or no dispatch.[1]
  - Participation in retail programs can reduce the baseline if retail events occur in the days used to determined the baseline.
  - A lower baseline decreases the calculated demand reduction (the difference between baseline and metered demand during interval of dispatch).

See Market Rule 1: [1]III.8.2.1-4

Impacts of FERC Order 2222 on retail demand response program participation in ISO-NE wholesale markets

FERC Order 2222 background

- FERC issued Order 2222 in September 2020 to allow distributed energy resource aggregations (DERAs) to participate in wholesale electricity markets.

- ISO-NE filed its first compliance filing in 2022 and made subsequent filings in 2023 and 2024 to address sections rejected by FERC.
  - Prior to the filing, committees of the New England Power Pool (NEPOOL) reviewed the proposal.[1]
  - In parallel, ISO-NE hosted stakeholder meetings with New England electric utilities, NECPUC, and distributed energy resource aggregators.[1]

- ISO-NE is compliant with all FERC Order 2222 directives as of November 2024 after FERC issued an order accepting ISO-NE's last set of revisions to its earlier filings.
  - ISO-NE and CAISO are currently the only ISOs/RTOs in full compliance.

- ISO-NE's Order 2222-compliant rules will take effect in:
  - Energy and reserve markets on November 1, 2026
  - The Forward Capacity Market during Forward Capacity Auction 19 in February 2026

[1]See first compliance filing page 44

ISO-NE compliance filings

Participation models and size requirements

- **ISO-NE created technology-agnostic participation models for DERAS.**
  - Demand Response Distributed Energy Resource Aggregation (DRDERA)[1]
    - Demand response can participate alongside DERs that inject and/or withdraw energy.[2]
  - Settlement-Only Distributed Energy Resource Aggregation (SODERA)[1]
    - Non-dispatchable resources can participate alongside flexible loads in day-ahead energy market.[3]

- **ISO-NE permitted DERAs to use existing participation models:**
  - Binary Storage Facility, Continuous Storage Facility, and Alternative Technology Regulation Resource.[1]

- **New participation models do not have minimum size requirement for the DERs that comprise a DERA.[2,3]**

- **All participation models have a minimum aggregation size of 100 kW.[1]**

- **Dual participation in retail programs and wholesale markets is allowed.[4]**

See 2/2/2022 compliance filing: [1]III.6.1, [2]III.6.5 [3]III.6.6, and [4]III.6.7(d)(3)

ISO-NE compliance filings
Utility, aggregator, and PUC roles

- **PUCs have authority over:**
  - The resolution of disputes between aggregators and utilities[1]
  - Roles assigned to distribution utilities by ISO-NE through its position as regulator
  - Rules governing dual participation in retail programs and wholesale markets[2]

- **Distribution utilities have authority to**:
  - Review DERA eligibility and the incremental safety and reliability impacts of DERs in DERAs on the distribution system during DERA registration process[3]
  - Override ISO-NE dispatch of DERAs to prevent safety and/or reliability issues in the distribution system[4]

- **ISO-NE established rules for ongoing coordination between itself, utilities, and aggregators,** including[4]:
  - Aggregators must abide by utility rules and operate within limits of distribution system
  - Utilities must notify aggregators about distribution system constraints
  - ISO-NE will coordinate with utilities to manage “conflicting operational directives”, which can include dispatch instructions and ahead-energy market results

See 2/2/2022 compliance filing : [1]III.6.7(c)(v), [2]III.6.7(d)(3), [4]III.6.8

[3] Interconnection confirms safety of individual DERs. This review assesses whether a DER, due to its participation in a DERA, adversely impacts safety or reliability

ISO-NE compliance filings

Impacts on retail demand response program participation in ISO-NE wholesale markets

- **More customers will be eligible to have DERs in an aggregation.**
  - New participation models do not have minimum size requirements for DERs in DERAs.
  - Residential and small commercial customers, including retail program participants, that lack the maximum 10 kW demand reduction required to be a DRA in existing rules (see slide 6 for details and caveats) will be eligible to register DERs in DERAs.

- **More types of aggregations will be possible**:
  - DRDERA aggregations can provide a mix of demand reduction, energy injection, and withdrawal.[1]
    - Aggregations could include participants from multiple retail programs (e.g. Wi-Fi thermostat and battery storage).
  - SODERA aggregations can include *non-dispatchable energy* injections/withdrawals (e.g. rooftop PV), require *hourly* — not 5-minute — metering data, and *do not require telemetry.*[2,3]
  - Generator and Binary/Continuous Storage now allow aggregations.[4]
  - Aggregations through Alternative Regulation Technology Resource can be 100 kW or larger (as opposed to 1 MW or larger under current rules).[4]

See 2/2/2022 compliance filing : [1]III.6.5, [2]III.6.5, [4]III.6.1
See [3]OP-18 VI(A)(d)

Challenges remaining to retail demand response program participation in ISO-NE wholesale markets after FERC Order 2222 implementation

Remaining challenges to retail program participation in ISO-NE wholesale markets

- To participate in ISO-NE wholesale markets, retail demand programs confront:
  - General challenges with DERA development
  - Specific challenges due to dual participation in 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 challenges to DERA development

Metering and telemetry and size and locational requirements

- **Retail program participants may still lack, not be willing to pay for, or not be able to afford metering and telemetry infrastructure necessary for market participation.**
  - 5-minute metering will still be necessary for all participation models excepts SODERA.[1,2,3]
  - 5- and 1-minute telemetry will still be required for real-time energy and reserve market participation respectively.[1,4]
- **Existing AMI networks may not have bandwidth for 1- and 5-minute telemetry even if meters can record at these intervals.**
- **Minimum size and locational requirements for DERAs limit the number of potential aggregations.**
  - DERAs must have capability to reduce and or inject power by at least 100 kW or have 100 kW regulation capability.[5] Challenges described for 100 kW DRR aggregations may still apply (see slide 6).
  - DERs in a DERA must be in the same Aggregation Zone and *metering domain*.[6]
    - Since metering domains generally align with utility service, aggregations largely will not be able to cover multiple utilities.[7] This requirement could significantly affect aggregations in municipal utility service territories due to their size.
    - In utility service territories that include multiple Aggregation Zones multiple aggregations would be necessary for participants in a single retail program.

See 2/2/2022 compliance filing: [1]III.3.2.1.1, [2]III.6.5, [4]III.1.7.19.2.3,[5]III.6.1, [6]III.6.2, [7]Page 26 footnote 67. See [3]OP-18 VI(A)(d)

General challenges to DERA development
Double counting of DER load impacts related to submetering

- **Retail program participants may not be willing to pay for or not be able to afford submetering or parallel metering for behind-the-meter (BTM) DERs.**
  - ISO-NE allows submetering or parallel metering of BTM DERs if metering infrastructure can remove the load impacts of DERs at the Retail Delivery Point (i.e. the main meter).[1]
    - This approach would turn net building load into gross building load.
    - Submetering/parallel metering allows DERAs to separate the load impacts of DERs from buildings.
  - Without submetering/parallel metering, DERAs would have to use net building load.
    - Net building load could obscure DER load impacts, which could lead to inaccurate estimations of the economic value of an aggregation.
      - E.g. for residential building with battery storage, building load could offset battery injections and not be distinguishable from withdrawals.
  - Submetering and parallel metering can be expensive and can undermine the economics of DER participation in a DERA.
- **Existing AMI and utility data systems may not have functionality to remove double counting with submetered BTM DERs.** .
  - To remove 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 submeter
    - Adding the DER load profile back to the building's load

[1]See 2/2/2022 compliance filing page 35

General challenges to DERA development
DERA registration

- **Utilities may not have systems, processes, or criteria for assessing the safety and reliability impacts of DERAs[1].**
  - Lack of automated systems and processes could slow down reviews.
  - Lack of transparency could result in anti-competitive behavior by utilities.
  - Lack of standards could result in inconsistent outcomes across utilities.
  - Variation in utility review processes could increase the complexity of recruitment, registration, and dispute resolution from aggregator's perspective.

- **Utilities may not have systems to automatically determine eligibility** based on[1]:
  - DER location relative to Aggregation Zones and metering domains
    - DERA Aggregation Zones are the same as ISO-NE uses now for DRRs (see slide 6)[2]
  - Whether a DER is part of another asset that participates in ISO-NE markets (i.e. prevent double counting of load impacts and double compensation to a DER owner)

- **Utilities may not have systems to automatically share data with ISO-NE and aggregators.[1]**
  - Lack of systems to automatically share interconnection data could impede registration process.

[1]ISO-NE is coordinating with distribution utilities on the requirements for systems needed to support DERA registration
[2]See 2/2/2022 compliance filing page 26

General challenges to DERA development

Aggregator access to customer and grid data

- **Aggregators may not be able to readily access data they need for DER enrollment, registration, operation, and settlement.**
  - Aggregators may need data on DER location, interconnection, and hosting capacity to support enrollment.
  - Aggregators may need metering and grid data to make decisions on DER operations.
  - Aggregators are the Assigned Meter Reader for DERs in a DERA, which requires that they report metering data to ISO-NE for settlement of wholesale market transactions.[1,2]
    - Aggregators may assign a host utility as the Assigned Meter Reader.
  - Utilities may not have automated systems that enable third party access to customer and grid data.
  - Lack of standard data processes across utilities and states could increase effort for aggregators and impede the development of aggregations.

See 1/31/24 compliance filing: [1]III.6.4

[2]ISO-NE is coordinating with distribution utilities on the requirements for systems needed to support reporting metering data

General challenges to DERA development
Dispute resolution and dispatch overrides

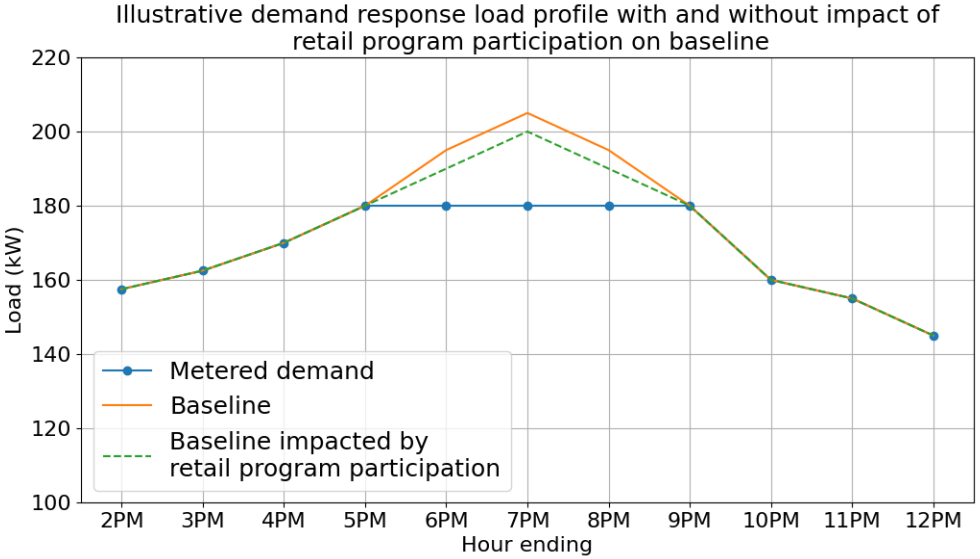
- **PUCs can develop processes for resolving disputes between utilities and aggregators.**
  - Disputes may arise over utility decisions in DER registration process.
  - Absent PUC involvement, resolution of these disputes defaults to ISO-NE processes.[1,2]

- **Utilities do not have frameworks for overriding dispatch signals from ISO-NE.[3]**
  - Lack of transparent decision-making could affect aggregators' ability to make informed bids and increase their exposure to non-performance penalties from ISO-NE.[4]

See 2/2/2022 compliance filing: [1]Page 37, [4]III.6.8(e))
See [2]ISO-NE Tariff Section 1.6
[3]ISO-NE is coordinating with distribution utilities on the requirements for systems needed to support operational coordination, which includes dispatch overrides. See III.6.8 in the 2/2/2022 compliance filing for details.

Dual participation challenges
Baselines for market performance calculations

- **Retail demand response program participation can still reduce the calculated performance in ISO-NE wholesale markets.**
  - DRA baseline method (slide 9) applies to DRDERAs but not other participation models.[1,2]
  - Program participation can reduce the baseline calculated for wholesale market performance.
    - Calculated demand reductions are lower with a reduced baseline. As the figure illustrates, the distance between the metered demand during the 5-9pm event is *greater* with the original baseline (orange) and *lower* with the baseline impacted by retail program participation (green).



[1]See Market Rule 1 III.8.2
[2]See 2/2/2022 compliance filing III.6.5

Dual participation challenges
Double compensation and conflicting grid services

- **PUCs need a framework to avoid double compensation and conflicting dispatches for dual participants.**
  - ISO-NE and a utility could make overlapping requests that create a **double compensation risk.**
    - E.g. 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, which would be unfair.
  - ISO-NE and a utility could make conflicting requests that create an **operational risk** to the distribution system and or bulk power system.
    - E.g. ISO-NE could dispatch a battery to *withdraw energy* to address a wholesale market need and a utility could dispatch a battery to *inject energy* to address a distribution grid need.
      - These dispatches conflict, which may result in one or both services not being provided and potentially leading to operational issues.
      - Conflicting requests also expose aggregators to non-performance penalties.

Actions to address challenges to retail program participation in ISO-NE wholesale markets

Actions to address challenges to DERA development
Metering and telemetry

- **PUCs can determine whether existing and planned AMI meet ISO-NE's metering and telemetry requirements** by requesting that utilities report whether:
  - Existing and/or planned AMI:
    - Record at 5-minute intervals and provide telemetry at 5- and 1-minute intervals
  - Existing and/or planned AMI networks and data systems:
    - Have bandwidth for 5-minute metering and 5- and 1-minute telemetry
- **Utilities can propose investments in AMI** that support 5-minute metering and 5- and 1-minute telemetry.
- **PUCs can consider engaging with ISO-NE on the feasibility of telemetry requirements used in other jurisdictions,** including requirements that are:
  - **Conditional on DER size, DERA size, or grid services provided**
    - CAISO does not require telemetry for DERAs ≤ 10 MW that do not provide ancillary services.[1]
  - **Calculated and not measured**
    - CAISO permits aggregators to use statistical sampling of metering data when interval metering is not available for some participating customers.[2]
  - **For aggregations overall**, not individual meters associated with participating DERs
    - New York ISO requires that aggregators provide metering and telemetry for the aggregation.[3]

See [1]CAISO 179 FERC ¶ 61,197 paragraph 152, [2]CAISO 179 FERC ¶ 61,197 paragraph 165, and NYISO 179 FERC ¶ 61,198 paragraph 186

Actions to address challenges to DERA development
Size and locational requirements

- **PUCs can request that utilities assess the impacts of size and locational requirements on DER aggregations.**
  - Utilities can determine whether aggregations are possible with existing retail program participants based on the location and size of participant's DERs.
    - E.g. Eversource could see if there are least 100 kW of ConnectedSolutions participants in each Aggregation Zone that overlaps with its service territory.

- **PUCs 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 than spans multiple metering domains would complicate meter reading and settlement.[2]
  - Discussions with ISO-NE may clarify whether it is possible for their systems to support DERAs that operate across metering domains.

[1]CAISO compliance filing, Docket No. ER21-2455-000, July 19, 20211 p. 17)
[2]ISO-NE 2/2/2022 compliance filing page 26 footnote 68
[3]185 FERC ¶ 61,021

Actions to address challenges to DERA development
Double counting of DER load impacts related to submetering

- **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 submetering installed by utilities.
  - California has established standards for third-party embedded submetering in electric vehicle supply equipment (EVSE) as part of its order requiring submetering of EVs.
  - The field accuracy of embedded submetering allowed by California (+/- 0.5%) falls short of CAISO and ISO-NE requirements (+/- 0.2%).[1]
    - PUCs can engage with DER providers to understand how accuracy may improve over time.
  - PUCs can consider engaging with ISO-NE on the accuracy requirements for DERAs.
    - 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.[1]
- **PUCs can determine whether it is possible to remove 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)
  - Separate the impact of BTM DERs from building load

[1] See OP-18 V.B.8 and OP-18 Appendix C)

Actions to address challenges to DERA development
DERA registration

- **PUCs can request that utilities propose frameworks for assessing the safety and reliability impacts of DERAs on the distribution system.**
  - Framework could identify risks posed by DERAs and describe the methods, criteria, and metrics used to assess those risks and determine need for distribution system upgrades.
  - Coordination of PUCs across New England could support the standardization of safety and reliability review.
  - PUCs can also initiate processes to streamline interconnection processes so that customers can more quickly sign-up for DERAs (interconnection is required for registration).
  - PUCs can require that utilities adopt the latest IEEE-1547 standard for DER interconnection if they have not already adopted it.
- **Utilities can make investments and develop systems that enable DERA registration to:**
  - Automatically determine whether a DER is part of another asset that participates in ISO-NE markets to prevent double compensation.
  - Automatically determine whether DERs are in Aggregation Zones and metering domains associated with a DERA.
  - Automatically assess the incremental safety and reliability impacts of DERs participating in a DERA on the distribution system.
  - Automatically share interconnection and other registration data with aggregator.

Actions to address challenges to DERA development
Aggregator access to customer and grid data

- **PUCs can require that utilities develop systems to enable aggregator access to:**
  - DER location and interconnection data to support DERA registration
  - Hosting capacity, load characteristics (e.g. peak demand), and distribution system infrastructure (e.g. feeder capacity) data on to support DER operation
    - Feeder- and node-level data can support localized decisions on DER siting and operation.
    - Frequent updates to hosting capacity data can make data more useful to developers.
    - Consolidated Edison 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.
  - Customer metering data and telemetry to support DER operations and settlement with ISO-NE.
    - Adoption of protocols such as Green Button Connect could enable customers to give aggregators access to metering data.
    - PUCs can engage with aggregators and utilities to determine specific requirements for sharing metering and telemetry.

Actions to address challenges to DERA development
Dispute resolution and dispatch overrides

- **PUCs can establish processes for resolving disputes** between utilities and aggregators that result from utility decisions during DERA eligibility, safety, and reliability reviews.
  - Transparent rules could reduce the frequency of disputes and speed up their resolution.

- **PUCs can request that utilities propose frameworks for overriding ISO-NE's dispatch signals to DERAs.**
  - 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 non-performance penalties from ISO-NE.

Actions to address dual participation challenges
Baselines for market performance calculations

- **PUCs can consider engaging with ISO-NE on changes to the calculation of baselines for DRDERAs to exclude days with retail program events.[1]**
  - This approach extends logic of excluding days that have reductions in demand that differ from typical usage such as forced/scheduled curtailments.
  - Excluding retail program events from baseline calculation could increase the calculated performance in ISO-NE wholesale markets.
  - Expanding the scope of exclusions could force the baseline calculation to incorporate days that are less recent, which could make the baseline less accurate.

- **Utilities can share data on customer event participation with ISO-NE**
  - ISO-NE needs to know which customers participate in retail program events to change baseline calculation.

[1]Changes to the baseline calculation may require FERC approvals as ISO-NE defines the calculation in its market rules (see section III.8.2).

Actions to address dual participation challenges
Double compensation and conflicting grid services

- **PUCs can establish a framework[1] that prevents double compensation**:
  - **Switching**: Allow customers to 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 retail program or wholesale market.
    - E.g. a battery could provide wholesale services except during summer peak events called by a utility. This approach is likely easier for retail programs that have few events.
  - **Parallel participation:** Only compensate a participant for one of the two dispatch responses (retail program or wholesale market).
    - PUCs can 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 non-identical participation and switching.
  - **Non-identical participation**: Prohibit a retail program participant from participating in a wholesale market that could require a DER to provide the same service as the retail program.
    - E.g. A retail program providing energy services would not provide wholesale energy services.
- **PUCs can establish a framework that prevents conflicting dispatches.**
  - PUCs could work with aggregators, utilities, and ISO-NE to identify the types of conflicting dispatches that may occur and establish criteria for determining which dispatch a customer should respond to in each case (e.g. a dispatch for energy injection to maintain distribution system reliability may take precedent over wholesale energy).

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

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Acknowledgements

This work was funded by the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy under Contract No. DE-AC02-05CH11231. The author thanks Sydney Forrester (Berkeley Lab) for her review of this work.

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Acronyms

- AMI: Advanced metering infrastructure
- BTM: Behind-the-meter
- DERA: Distributed energy resource aggregation
- DRA: Demand response asset
- DRDERA: Demand response distributed energy resource aggregation
- DRR: Demand response resource
- PUC: Public utility commission
- RDP: Retail delivery point
- SODERA: Settlement-only distributed energy resource aggregation