UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

ISO New England Inc. and	**)**	
New England Power Pool	**)**	**Docket No. ER22-983-000**
Participants Committee	**)**	

MOTION FOR LEAVE TO ANSWER AND ANSWER OF
ISO NEW ENGLAND INC.

Pursuant to Rules 101(e), 212, and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC"),[1] ISO New England Inc.[2] ("ISO-NE" or the "ISO") submits this Motion for Leave to Answer and Answer ("Answer") to intervenors'[3] protests and comments,[4] filed in response to the ISO's filing of revisions to the Tariff in compliance with the Commission's *Participation of Distributed Energy Resource Aggregations*

[1] *See* 18 C.F.R. §§ 385.101(e), 385.212, 385.213 (2021).

[2] Capitalized terms used but not defined in this Answer have the meaning ascribed to them in the ISO New England Inc. Transmission, Markets, and Services Tariff (the "Tariff").

[3] This Answer refers to the following parties, collectively, as "Intervenors"" Advanced Energy Economy, PowerOptions and the Solar Energy Industries Association ("AEE et al."); Acadia Center, Conservation Law Foundation, Environmental Defense Fund, Massachusetts Climate Action Network, Natural Resources Defense Council, Sierra Club, and the Sustainable FERC Project (collectively, "Environmental Organizations"); Advanced Energy Management Alliance ("AEMA"); Voltus, Inc. ("Voltus"); and Massachusetts Attorney General ("MA AG") .

[4] Protest and Comments of Advanced Energy Management Alliance ("AEMA"); Comments and Limited Protest of Environmental Organizations ("Environmental Organizations"); Protest and Comments of Advanced Energy Economy, PowerOptions, Solar Energy Industries Association ("AEE et al."); Comments and Partial Protest of Massachusetts Attorney General Maura Healy ("MA AG"); Protest, Comment and Request for Deficiency Letter of Voltus, Inc., Docket No. ER22-983 (April 1, 2022) (collectively, "Protests").

in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order Nos. 2222, 2222-A and 2222-B[5] submitted in this docket on February 2, 2022.[6]

I. INTRODUCTION

The Compliance Proposal contains revisions to Sections I, II, and III of the Tariff that fully comply with the requirements set forth in Order No. 2222. The Intervenors' Protests challenge, and ask that the Commission reject or modify, several aspects of the Compliance Proposal. These relate to: (i) the metering of Distributed Energy Resources ("DERs") participating in a DER Aggregation ("DERA"); (ii) the timing and scope of a Host Utility's eligibility review of individual DERs seeking to participate in a DERA; and (iii) the compatibility of the proposed participation models with DER Aggregator business choices.

As addressed in Section III of this Answer, Intervenors' arguments fail on procedural grounds and lack merit. Fundamentally, they fail to demonstrate that any aspect of the Compliance Proposal is unjust and unreasonable or otherwise non-compliant with Order No. 2222. Many of the arguments seek to re-write the requirements of Order No. 2222, or to reform the New England Markets, in a manner that goes beyond the scope of the Order. The Commission therefore should reject Intervenors' Protests and accept the Compliance Proposal as filed, without conditions or modifications.

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5 *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 (2020) ("Order No. 2222"); Order Addressing, Arguments Raised on Rehearing, Setting Aside Prior Order in Part, and Clarifying Prior Order in Part on Rehearing 174 FERC ¶ 61,197 (2021) ("Order No. 2222-A"); Order Addressing Arguments Raised on Rehearing. Setting Aside in part and Clarifying in Part Prior Order, 175 FERC ¶ 61,227 (2021) ("Order No. 2222-B").

6 *Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Allow for the Participation of Distributed Energy Resource Aggregations in New England Markets*, Docket No. ER22-983-000 (February 2, 2022) ("Compliance Proposal").

II. MOTION FOR LEAVE TO FILE ANSWER

This Answer responds to comments and protests that AEE et al., AEMA, Environmental Organizations, MA AG and Voltus submitted, respectively, in response to the Compliance Proposal. While the Commission's Rules of Practice and Procedure allow parties to file answers to comments, the Commission's rules prohibit answers to protests.[7] The Commission, however, has the authority to waive this prohibition.[8] The Commission has found good cause to permit answers in various circumstances, including where the answer would assure a complete record in the proceeding,[9] lead to a better understanding of the issues in the proceeding,[10] permit the issues to be narrowed or clarified,[11] aid in the disposition of the issues raised by the protests,[12] or otherwise assist the Commission in its decision-making process.[13] This Answer achieves these purposes. It clarifies misconceptions contained in certain of the Protests, assures a complete record by providing a response to several proposals that are either beyond the scope of the proceeding or are otherwise unworkable, and provides a better understanding of the issues relating to the Compliance Proposal. For these reasons, the ISO respectfully requests that the Commission grant this motion for leave to answer and consider the following answer in ruling on the Compliance Proposal.

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7 *See* 18 C.F.R. § 385.213(a)(2).

8 *See* 18 C.F.R. § 385.101(e).

9 *See, e.g.*, *High Island Offshore Sys., L.L.C.*, 113 FERC ¶ 61,202, at P 8 (2005).

10 *See, e.g.*, *CenterPoint Energy–Miss. River Transmission, LLC*, 141 FERC ¶ 61,080, at P 4 (2012).

11 *See, e.g.*, *TransColorado Gas Transmission Co.*, 111 FERC ¶ 61,208, at P 4 (2005); *PJM Interconnection, L.L.C.*, 84 FERC ¶ 61,224, at 62,078 (1998).

12 *See, e.g.*, *Transcontinental Gas Pipe Line Co.*, 140 FERC ¶ 61,251, at 62,258 n.6 (2012).

13 *See, e.g.*, *S. Cal. Edison Co.*, 141 FERC ¶ 61,100, at P 5 (2012); *ISO New Eng. Inc. & New Eng. Power Pool*, 140 FERC ¶ 61,177, at P 6 (2012).

III. ANSWER

A. The Compliance Proposal's Metering Provisions Meet the Objectives and Requirements of Order No. 2222

In this section of the Answer, the ISO addresses blanket criticisms of, and proposed alternatives to, the Compliance Proposal's metering approach for behind-the-meter ("BTM") DERs[14] that Intervenors present in their Protests. These include arguments that the Compliance Proposal fails to offer a valid submeter option, that submetering should be used for settlement purposes for BTM DERs, and that third-party meter reading should be allowed for DERs participating in a DERA. For the reasons stated below, the Commission should reject these arguments. The ISO's Compliance Proposal complies with Order No. 2222's requirements, and the proposed alternatives are either unworkable or would result in double counting for services provided in a manner that goes against the express requirements of Order No. 2222.

1. *The Metering Requirements of the Compliance Proposal Comply with Order No. 2222 in a Manner that is Consistent with New England's Operating Arrangements*

In Order No. 2222, the Commission required that Regional Transmission Operators/Independent System Operators ("RTOs/ISOs") "establish market rules that address metering and telemetry hardware and software requirements necessary for distributed energy resource aggregations to participate in RTO/ISO markets."[15] Order No. 2222 extended RTOs/ISOs flexibility with respect to these requirements, mandating only that RTOs/ISOs explain

[14] In this Answer, BTM DERs refer to DERs located at an end-use customer facility that participate in a DERA.

[15] Order No. 2222 at P 262.

the basis for the proposed metering and telemetry requirements, and why those requirements are not an undue burden for individual DERs participating in an aggregation.[16] The Order also expressed a preference that RTO/ISO proposals rely on retail metering currently in place for DERs, to the extent possible, in order to avoid unnecessary costs, and required that RTO/ISO metering proposals address double counting concerns.[17]

The Compliance Proposal explains that in New England,[18] the Transmission Owners Agreement ("TOA") and the Tariff govern metering responsibility. Pursuant to Section 3.06(a)(vii) of the TOA, the responsibility for metering resources and loads that settle through the Energy Market rests with the Participating Transmission Owners ("PTO"), and, per Section 3.06(a)(x), the PTOs must "provide the ISO with revenue metering data or cause the ISO to be provided with such revenue metering data."

To effectuate this responsibility, the PTOs rely upon the Host Participant or Host Utility,[19] or its Assigned Meter Reader, to read meter data and provide it to the ISO for Energy Market settlement and energy balancing.[20] Pursuant to Section 5.2 of the ISO's Manual M-28,[21] these entities are responsible for: (1) reporting interval energy quantities for Load Assets, Generator

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16 *Id.*

17 *Id.* at PP 264, 269.

18 Compliance Proposal at 32-33.

19 Defined in Tariff, Section I.2.2 as "a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering[.]"

20 Defined in Tariff, Section I.2.2 as the entity that "reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO." The Assigned Meter Reader is most often the distribution utility in a particular metering domain, but could also be an agent working on behalf of the distribution utility.

21 ISO New England Manual for Market Rule 1 Accounting, Manual M-28, https://www.iso-ne.com/static-assets/documents/2020/08/manual_28_effective_rev62_2020_08_06.pdf ("M-28").

Assets, and Tie Line Assets; (2) reporting meter reconciliation data for use in resettlement process for Load Assets, Tie-Line Assets, and Generator Assets; and (3) prompt reporting of any discovered metering, calculating, or reporting errors with respect to an asset to the ISO and the Market Participant(s) owning or having rights to the asset.

Metering responsibilities and requirements for Demand Response Assets that participate as part of a Demand Response Resource ("DRR") aggregation are established in Section III.3.2.2(c) of the Tariff. Demand Response Assets are not settled in the Energy Market in the same manner as Load Assets, Generator Assets, or Tie Line Assets, but are instead settled based on the measurement of load reductions against a pre-determined baseline. Given these distinctions, Market Participants with DRRs (rather than the PTOs) are responsible for submitting meter data to the ISO for DRR settlement purposes. To ensure integrity of the submitted data, the Tariff requires Market Participants with DRRs to make retail billing meter data and any interval meter data from the Host Participant for the facilities associated with a Demand Response Asset available to the ISO upon request.[22]

The Compliance Proposal incorporates, in Section III.6.4 of the Tariff, requirements for the metering and telemetry of DERAs. The metering and telemetry requirements comply with Order No. 2222 in a manner that is consistent with New England's existing arrangements. They also ensure that the requirements apply consistently across all resources using the same participation model, and in the case of the new DRDERA and SODERA models the new requirements draw from, and parallel, the metering and telemetry requirements that are in place for the existing models.

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22 *See* Tariff, Section III.3.2.2(c)(iv).

Under the Compliance Proposal, metering of BTM DERs must be located at the Retail Delivery Point ("RDP") of the facility hosting the BTM DER(s) or, alternatively, at a BTM DER under the condition that the BTM DER's meter data be reported such that its output or load does not impact the load reported for the RDP. The alternative is a "submetering" option for BTM DERs, contained in Section III.6.4(e) of the proposal. This alternative allows a DER's interconnection point to be located behind a RDP to the extent that the pertinent Host Participant Assigned Meter Reader can accommodate such a configuration, i.e., where the Assigned Meter Reader is capable of reconstituting the load at the RDP, or can accept a parallel metering arrangement,[23] so that the metered DER does not impact the reported load at the RDP.[24] This approach permits submetering for BTM DERs while narrowly addressing double-counting concerns, and ensures the integrity of wholesale markets.

The metering and telemetry requirements submitted for compliance with Order No. 2222 are addressed in Section III.6.4 of the Compliance Proposal filing. Despite their criticisms, the Protests fail to demonstrate that the proposed requirements are unjust and unreasonable or otherwise inconsistent with the mandates of Order No. 2222. None of the Intervenors' criticisms of the Compliance Proposal have merit, and the various alternatives proposed are flawed or otherwise unworkable.

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[23] For purposes of this Answer, parallel metering refers to a separate meter for a DER that is independent of a meter located at the RDP of a facility. Performance measured at this meter has no impact or effect on the RDP meter.

[24] This language also permits other, yet-to-be-defined, approaches to be used if it allows a BTM DER's meter data be reported such that its output or load does not impact the load reported for the RDP. The implementation timeline for capabilities related to load reconstitution for sub-metered DERs behind a RDP remains speculative at this time.

2. Submetering of BTM DERs For Purposes of Energy Market Participation Creates Double Counting/Compensation Risks Left Unaddressed By Intervenors' Proposals

The Protests' primary challenges concern the metering location of the BTM DERs that participate in a DERA.[25] Specifically, the Protests advocate for the Commission to mandate that the metering located at a BTM DER be used to measure the DER's performance. In contrast, as explained above, the Compliance Proposal requires that the metering of BTM DERs be located either at the RDP of the facility hosting the BTM DER(s) or, alternatively, at a BTM DER (*i.e.* a submeter) so long as the meter data is reported so that the DER's output or load does not impact the load reported for the RDP. The Compliance Proposal includes this submetering option for BTM DERs in response to feedback from stakeholders.

Metering at the RDP, or submetering at the BTM DER combined with reconstitution or through parallel metering, as the ISO proposes, is necessary to ensure that the meter measures the services provided by a BTM DER that are delivered to the grid, and is required under Order No. 2222 to prevent the "double counting" of the same energy.[26] To illustrate, assume a BTM DER that is a 4 MW generator, which produces power at full output for an hour, or 4 MWh. A submeter located at the BTM generator would register 4 MWh of production. However, if the customer at this location consumed 3 MWh of energy for its own end-use purposes during the same hour, only 1 MWh would be delivered to the grid. A meter located at the RDP of this facility would show a 1 MWh energy injection for the hour. That 1 MWh is a sale for resale subject to the Commission's jurisdiction, and ought to be compensated at wholesale market prices.

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[25] *See* e.g. AEMA at 2; Environmental Organizations at 5-6; AEE et al. at 17-26; Voltus at 8-13.

[26] Order No. 2222, PP 160-161.

Conversely, the submeter located at the BTM DER would show the amount of energy produced by the generator. That energy is consumed first by the customer facility; only the excess energy that is not consumed by the customer facility is delivered to the grid for resale. The 3 MWh consumed by the customer facility should not be compensated at wholesale market prices as that energy never reached the grid for resale. Instead, the customer facility received the benefit of the power produced by the BTM DER, reducing its power purchased (and thus costs incurred) from the grid.

Intervenors' Protests advocate for a submetering approach sans reconstitution or parallel metering, where the output reported by the submeter located at the BTM DER in the example would be used for wholesale market settlement, resulting in a higher payment based on 4 MWh of energy production. This approach, in effect, would allow DER Aggregators to be paid for 4 MWh even though only 1 MWh was delivered to the grid for wholesale sales.[27]

A BTM DER should not be permitted to simultaneously sell energy into wholesale markets, and at the same time consume that same energy and avoid being charged for it. And, in fact, Order No. 2222 explicitly seeks to avoid this outcome by prohibiting such double counting.[28]

Importantly, and as stated above, while the RDP is the preferred metering location for a DERA participating in the wholesale markets, the Compliance Proposal accommodated feedback provided during the stakeholder process on this issue, in that the proposed rules allow for submetering when the BTM DER's meter data can be reported such that its output or load does

[27] This approach also allows 3 MWh generated by BTM DER, which was immediately consumed by the retail customer facility, to be counted as a supply resource, credited at LMP, while at the same time being separately counted as a load reducer, reducing the facility load by 3 MWh for retail market purposes. Other retail customers would bear the cost of 4 MWh, but only receive the benefit of 1 MWh of service.

[28] Order No. 2222 at PP 160-161.

not impact the load reported at the RDP.[29] This can be accomplished by employing either parallel metering, or, what is commonly referred to as "load reconstitution" where submetering is employed. Returning to the earlier example, if the meter used for wholesale settlement is located at the BTM DER device (i.e., a submeter), subtracting the submeter reading from the RDP meter reading would eliminate the double counting. Specifically, +4 MWh of DER production would be subtracted from the unadjusted RDP meter reading (which shows +1 MWh of energy injection), resulting in a *final* RDP meter reading of -3 MWh (where a negative value indicates that the host facility consumed energy). The DER Aggregator would be paid in the wholesale market for producing 4 MWh, and the 3 MWh consumed by the host facility would no longer be accounted for in the wholesale market as a reduction in load, but rather as a purchase of 3MWh of energy. By reconstituting RDP load in this manner, the 3 MWh consumed by the host facility would no longer be "double counted as both a load reduction and a supply resource."[30]

Accordingly, the ISO urges the Commission to reject the Protests, and accept the metering provisions contained in the Compliance Proposal as filed. The ISO's proposed rules comply with the requirements of Order No. 2222 on metering and telemetry. In contrast to the alternatives proposed, they avoid double counting of services, prevent cost shifting from customers with DERs to customers without DERs, ensure that services measured in fact reach the grid, and rely on existing and anticipated retail metering infrastructure in New England, consistent with Order No. 2222.

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[29] Where the BTM DER is a storage device such as a battery, metering at the BTM DER would double count the energy used to charge the battery – once at the BTM DER meter, and once again at the retail customer's RDP meter. Double counting in this case would create a double bill – once at wholesale rates and once again at retail rates.

[30] Order No. 2222 at P 161.

3. *Submetering of DERs Participating as Part of a Demand Response Resource or a Demand Response DERA is Inconsistent with Current Practice and Was Previously Rejected by the Commission.*

The Compliance Proposal allows DERAs to use the existing DRR model and proposes the new DRDERA model for use by aggregations that include demand response DERs. The DRR model is an existing model that the Commission approved related to Order No. 745;[31] it enables an aggregation of demand response DERs (referred to as "Demand Response Assets" in the Tariff) that have demand reduction capabilities to participate in the Day-Ahead and Real-Time Energy Markets, and provide Operating Reserves and capacity.[32]

The DRDERA model is a new participation model, detailed in proposed Section III.6.5 of the Compliance Proposal; it enables demand response DERs to aggregate with non-demand response DERs as required in Order Nos. 2222 and 2222-B. The DRDERA model allows an aggregation of DERs with demand reduction capability and energy injection capability to provide

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31 The Commission largely accepted the ISO's proposal to comply with Order No. 745 in the following orders: *ISO New England Inc.*, 138 FERC ¶ 61,042 (2012) (order on the ISO's Order No. 745 Compliance Filing); *ISO New England Inc. and New England Power Pool*, Docket No. ER12-947-000 (April 17, 2012) (delegated letter order accepting the ISO's Demand Response FCM Conforming Changes); *ISO New England Inc. and New England Power Pool*, Docket No. ER12-1550-000 (May 29, 2012) (delegated letter order accepting the ISO's Market Rule 1 Clarifications to the Transition Period Rules for Demand Response); *ISO New England Inc.*, 142 FERC ¶ 61,027 (2013) (order on the ISO's Market Rule 1 Demand Response FCM Conforming Changes for Full Integration); *ISO New England Inc.*, 144 FERC ¶ 61,140 (2013) (order on the ISO's Market Rule 1 Clarifications to the Full Integration Rules for Demand Response and Revisions to Address the Treatment of Net Supply); *ISO New England Inc. and New England Power Pool*, Docket Nos. ER16-167-000 & ER16-167-001 (Dec. 23, 2015) (delegated letter order accepting delay of full integration of demand response into the wholesale markets by one year, until June 1, 2018); and *ISO New England Inc. and ,New England Power Pool*, Docket No. ER17-2164-000 (Oct. 17, 2017) (delegated letter order accepting revisions to implement full integration of demand response).

32 The DRR model already accommodates aggregations as small as 100 kW, allows for aggregations as geographically wide as possible, is technology neutral and enables an aggregation to provide all the services it is technically capable of providing, all of which are requirements under Order No. 2222. A DRR that injects energy into the grid as a result of it being dispatched by the ISO is paid wholesale prices for the amount injected. Therefore, the Compliance Proposal does not propose any changes to the DRR model.

energy in the form of demand reduction or energy injection and to provide Operating Reserves and capacity.

Several Protests take issue with the ISO's proposal for the metering location of BTM DERs participating as part of a DRR or a DRDERA.[33] Specifically, they argue that the Compliance Proposal is inconsistent with Order No. 2222 because it requires that DRR metering be located at the RDP.[34] The Intervenors thus propose that the ISO allow load reductions produced by a BTM DER to be measured and reported via a submeter at the device.

Intervenors' proposal contravenes Order No. 2222, the Commission's orders addressing the ISO's Order No. 745 compliance filings, and the ISO's current DRR metering requirements established to comply with Order No 745.[35] In the context of the ISO's compliance filing on the Order No. 745 proceeding, the Commission responded to arguments that demand response performance be measured by directly metering behind-the-meter generation or directly metering demand reductions of individual load-consuming devices, effectively the same as the submetering proposed by the Intervenors in this proceeding. The Commission determined that RDP metering was appropriate for DRRs, stating that:

> [I]n the context of discussing ISO-NE's settlement system as it relates to demand response, the impact a customer has on the grid is what determines how the ISO will operate the grid. *Measuring demand response at the retail delivery point*

[33] *See, e.g.*, AEE et al. at 20-22; AEMA at 23-24.

[34] The Compliance Proposal extends existing metering treatment for DRRs to demand response DERs participating in a DRR or a DRDERA. Order No. 745 allows such DERs to reduce load from the grid (as measured from the RDP) where the load reduction is compensated as a supply resource. Further, Order No. 745 provides that the RDP load is not to be reconstituted so the host facility also gets the benefit of the load reduction. Order No. 2222-B explicitly requires that demand response DERs in a DERA should continue to be treated in this manner, consistent with the requirements of Order No. 745, while non-demand response DERs do not have to be treated pursuant to Order No. 745. See Order No. 2222-B, PP 42-43.

[35] *See ISO New England Inc.*, Order No. 745 Compliance Filing, Docket No. ER11-4336-000 (Aug. 19, 2011), Filing Letter p. 5.

> *allows ISO-NE to effectively manage the grid because this point accurately reflects the load's impact on the New England transmission system.* As we stated in Order No. 745-A, from the perspective of the grid, the manner in which a customer is able to produce a load reduction in the wholesale market from its validly established baseline (whether by shifting production, using internal generation, consuming less electricity, or other means) does not change the effect or value of the reduction to the wholesale grid.[36]

The facts underlying this determination hold true today.

For example, if a load-reducing device or a BTM generator providing demand response is directly submetered at the device, any load reduction or generation measured at that device could be offset by the load of other devices at that facility increasing at the same time, which would reduce the demand reduction delivered to the grid. But all wholesale consumers would be billed based on performance measured at the submeter, ignoring the offsetting load increase from other devices at the facility and ignoring the (corresponding) reduced demand reductions delivered to the grid.

The result would be a distinct, and arguably more problematic, form of double compensation in contravention of Order Nos. 745 and 2222, one which the Protests fail to acknowledge or address. Specifically, submetering DRR aggregations or DRDERAs would allow a single facility to have multiple demand response DERs, each with its own meter, and each registered in the wholesale market in the same or in different aggregations. This has the potential to result in the same load reduction or energy production within the facility being compensated *twice* at the wholesale level under the same or separate DERAs.

To illustrate, return to the example of a facility with multiple BTM DERs, including a BTM generator and a dispatchable load. This facility could include a demand response DER associated

[36] *ISO New England, Inc.*, Order Denying Rehearing, 139 FERC ¶ 61,116 at P 12 (2012) (emphasis added).

with the BTM generator measured at the RDP meter, and a separate demand response DER associated with the dispatchable load measured at a submeter. Assume that the normal operation of the facility (i.e., when it is *not* dispatched to produce a demand reduction) is that the BTM generator produces 50 kW of power in each interval, and the dispatchable load simultaneously consumes 50 kW in each interval so that the RDP meter shows 0 kW of consumption.

When the DRR or DRDERA into which these demand response DERs are aggregated is dispatched, the dispatchable load is reduced, and the submeter used to measure the performance of the dispatchable load at this facility changes from -50 kW to 0 kW (i.e., a 50 kW demand reduction). For this load reduction the demand response DER would receive 50 kW of performance credit at the wholesale level. At the same time, the meter at the RDP, which is separately used to measure the performance of the BTM generator but <u>also</u> accounts for the submetered dispatchable load, would show a change from 0 kW to +50 kW (i.e., a 50 kW power injection). Accordingly, the demand response DER metered at the RDP would also receive 50 kW of performance credit at the wholesale level. In short, if DER performance can be measured at the submeter for purposes of wholesale transactions, a single 50 kW demand reduction could result in two wholesale payments to two separate DERs – a 50 kW payment for generation that normally serves the customer's demand but is injected into the grid when demand is reduced, and a 50 kW payment for reduced demand measured at a submeter, which allowed energy to be injected into the grid, resulting in 100 kW of total compensation.

However, the normal operating position of this facility as measured from its RDP was that the facility places no generation or load on the system (its RDP meter reading was 0 kW). And when dispatched, it produces only a single +50 kW energy injection. Thus, the only amount the

ISO can use to balance supply and demand on the electricity grid in real time using this facility is 50 kW, not 100 kW.

As this example illustrates, allowing the use of submetering to record the performance of a DER in the wholesale market could lead to double counting the demand reduction performance of demand response DERs. These concerns are compounded when a number of different devices within a facility are separately submetered and, potentially, registered in different aggregations.[37] Accordingly, RDP metering is the only appropriate approach to measuring the amount of demand response produced and delivered to the grid to help balance supply and demand in real time.[38]

Intervenors' proposals fail to address these concerns or to address how the proposal could be fashioned to prevent them. Specifically, they fail to address requirements or limitations on DERAs that would prevent double counting. In contrast, the Compliance Proposal avoids this concern, and Interveners fail to demonstrate that the proposal is unjust and unreasonable or otherwise inconsistent with the requirements of Order No. 2222.

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37 New technology provides new opportunities for potentially double counting demand reductions through the use of submetering. For example, a BTM generator at a facility with its own submeter could be registered as part of a DRR. Meanwhile, a battery at the same facility also with its own submeter could be registered as part of a separate DRR. Different DRRs have different energy market offers, which allow them to be dispatched at different times. Accordingly, the first DRR with the BTM generator may offer in such a way so that it is dispatched to produce energy for which it receives payment based on its submetered production. However, the other DRR consisting of the battery could have a different offer, which allows it to charge using the energy generated by the BTM generator. By charging the battery, the BTM generator's production is not delivered to the grid in the form of demand reduction. Then in a later period, the battery could offer such that it is dispatched to discharged, also resulting in a demand reduction payment using the energy it stored from the BTM generator. This introduces a new form of potential double counting in which the same energy is paid for twice in the form of demand response *in different time periods* – once when originally generated (and stored) and once again when the stored energy is discharged. This potential double counting is facilitated by allowing device level metering of demand response devices.

38 *ISO New England, Inc.*, Order Denying Rehearing, 139 FERC ¶ 61,116 at P 12 (2012).

4. Proposals Seeking Third Party Metering Are Inconsistent with ISO Operating Arrangements and Introduce Data and Settlement Issues

In their respective Protests, AEE et al. and Voltus argue that, in addition to allowing the use of submetering (without reconstitution) for the measurement and settlement of BTM DERs, third party meter readers should be permitted to read and report data from such submeters (i.e., third party metering).[39] In an effort to bolster support of this position, AEE et al. proclaims that NYISO allows for third party metering and that ISO-NE already allows for third party metering for DRRs. These Intervenors thus argue that third party metering is consistent with the TOA and the Tariff.[40]

At the outset, in New England, submetering is not currently supported for DRRs, or any other resource. As previously explained in this Answer, however, for DRRs, a party other than the PTO or the Host Utility (*e.g.*, a DRR aggregator or a party contracted to provide metering services for the DRR aggregator) is responsible for reporting the consumption of each Demand Response Asset that is part of the DRR. Each Demand Response Asset's consumption is measured from its RDP – not a submeter. These third party arrangements are allowed for DRRs because those resources do not settle in the Energy Market using only the generation, tie line and load meter data that are employed for settlement of other assets in the market, but rather using measurements of load reductions against a separately determined baseline. Therefore, the PTOs' obligations with respect to metering and reporting the energy balance do not extend to metering of Demand Response Assets, which therefore must be handled in a separate manner using third-party meter readers. The Compliance Proposal extends these alternative metering arrangements to demand response DERs seeking to participate in a DRDERA.

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39 *See* AEE et al at 45-47; Voltus at 10-11.

40 *See* AEE et al. at 45.

The Compliance Proposal does not require or permit third party metering of BTM DERs participating as any resource type other than a demand response DER in a DRR or DRDERA, because doing so would directly encroach on the PTOs' responsibilities under the TOA (discussed above), and could potentially introduce data quality issues similar to those experienced with DRRs.

In accordance with the Tariff, the ISO engages in extensive efforts to monitor for and address invalid meter data provided by third-party meter readers.[41] On average, approximately 20% of the data that DRR aggregators report to the ISO for performance calculations fails initial data quality validations. Thus, the ISO's data validation efforts are critical to ensuring the quality of the meter data, and ultimately the settlement, of transactions that are handled by third party meter readers.

Intervenors have failed to explain how data validation would be accomplished under their proposal, a critical, and the ISO believes, fatal, flaw to their argument that the Compliance Proposal should permit third parties to provide submetering data services. In addition to not explaining how double counting would be addressed through the use of submetering, no party has explained to date how validation of submetered data would be accomplished. The ISO believes it would be administratively infeasible, especially for potentially large numbers of DERs comprising a DERA. The chief complication is that this submetered data is not directly comparable to RDP data. Host Utilities must collect RDP data for retail billing purposes (using revenue quality metering subject to state-regulated quality requirements), which represents an independent source of data that can be used to verify any data submitted by Market Participants to the ISO for settlement purposes. For example, the ISO uses Host Utility RDP billing data to verify the validity

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41 *See e.g.* Section III.3.2.2(c) – Additional Metering and Telemetry Requirements for Demand Response Assets.

of data submitted to the ISO by DRR aggregators. Because DRR data submitted by DRR aggregators must be measured from the RDP as previously explained, these data can be directly compared to Host Utility RDP data.[42] Here, it is not clear how submetered data would be compared with RDP data as these meters measure different things, and the Intervenors provide no suggestions for how this could be accomplished.

Consistent with the TOA, the PTOs continue to be the appropriate entity to provide meter reading services (through the Host Utility/Participant construct), and the Commission should reject the Intervenors' proposals that seek to allow third party metering for all BTM DERs as contrary to the existing meter-reading construct in New England and unnecessarily disruptive.

B. The Registration Provisions of the Compliance Proposal are Consistent with the Flexibility Extended in Order No. 2222

In this section, the ISO responds to certain Intervenors' attempts to revisit Order No. 2222's requirements related to the registration of DERAs, and specifically the eligibility review of individual DERs seeking to participate in a DERA.

Briefly, in Order No. 2222, the Commission required RTOs/ISOs to incorporate in their respective tariffs a process for Host Utility review of the eligibility of DERs participating in a DERA, triggered by the DER Aggregator's initial notification. Order No. 2222 provides that the Host Utility's review should include an examination of whether each DER is capable of wholesale market participation (*e.g.*, the DER is not also participating in a retail program that prohibits wholesale market participation, has valid operating agreements, etc.), and whether the DER would

[42] *See* Tariff, Section III.3.2.2(c)(iv).

pose risks to the reliable and safe operation of the distribution system.[43] The Order further stated that the time period for the Host Utility's review should not exceed 60 days.[44]

Consistent with Order No. 2222, the Compliance Proposal incorporates in Section III.6.7 of the Tariff a detailed registration process that is transparent, sets expectations for all parties and was developed in concert with stakeholders. The Compliance Proposal incorporates the Commission allowed 60-day eligibility review period.

1. The Compliance Proposal's Initial Review is Consistent with Order No. 2222

In their Protest, the Environmental Organizations argue that the Compliance Proposals' "60 days is an unreasonably long time" for the an eligibility review, that the Host Utilities' review process should be shortened to "perhaps 15 days," and that Host Utilities should be required to make filings with the Commission laying out their reasons in the event they need additional time.[45] The Environmental Organizations further argue that the scope of the Host Utilities' review should be limited to only impacts of DER participation in a DERA that were not reviewed in any state interconnection studies previously performed for those DERs.[46]

These arguments should be rejected. Environmental Organizations seek, via this proposal, to modify the terms of Order No. 2222 long after the time for rehearing requests has passed, and their arguments should be rejected on that ground alone. Further, as the Commission has already determined, 60 days is an appropriate amount of time for Host Utility review given the potential complexities involved in determining whether a given DER is eligible to participate in a DERA. Recognizing the complexity of the process, the ISO proposed a 60-day eligibility review, and no

43 *See id.* at P 292.

44 *See id*.

45 Environmental Organizations at 12.

46 *Id.* at 10-11.

party objected to that proposal during the lengthy stakeholder process. Environmental Organizations provide no justification for their significantly shortened time period, a proposal that simply ignores the express language of Order No. 2222, as well as the underlying concerns that warrant the more lengthy time period included in the Compliance Proposal. Accordingly, the Compliance Proposal's registration review process should be accepted.

2. The Compliance Proposal's Modification Review Period is Necessary to Ensure Impacts of Changes to a DERA are Appropriately Studied, and Therefore is Consistent with Order No. 2222.

Order No. 2222 further required that RTOs/ISOs establish a process for the addition or removal of individual DERs from a DERA without the need for the DER Aggregator to re-register or re-qualify the DERA for market participation. Further, the Order states that it "may be appropriate for each RTO/ISO to abbreviate the distribution utility's review of modifications to the distributed energy resource aggregation,"[47] but Order No. 2222 did not mandate a period shorter than 60 days for the review of modifications to a DERA. Consistent with these requirements, the Compliance Proposal incorporates, in Section III.6.7(e), a detailed and transparent process for modifying a DERA without the need for re-registration/qualification. Under that process, Host Utilities (or their agents) will have up to 60 days to review changes to a DERA under the same criteria used for initial registration.

AEE et al.'s Protest argues that the DERA modification review process should be "streamlined" by shortening the 60-day window for modification review, stating that 60 days will result in attrition from DERAs and a need to again immediately update the DERs in an aggregation following the close of the 60-day window.[48] This objection was not raised in the stakeholder

[47] *Id.* at P 336.

[48] AEE et al., at 37-38.

process and therefore alternative timeframes were not discussed among NEPOOL stakeholders. The Compliance Proposal's 60-day timeframe to review modifications to a DERA is appropriate, as it will afford the time, where necessary, for Host Utilities to restudy an entire DERA to determine whether proposed changes produce reliability or safety impacts from interactions between new combinations of DERs in the DERA that were not present in the original DERA composition. The specific modifications will dictate the need and extent of Host Utility review; the ISO cannot prejudge the amount of time it should take to conduct DERA modification reviews other than it should not take more than 60 days. The 60-day limit on the modification review time period is reasonable, and should therefore be accepted without modification or condition.

C. The Participation Models in the Compliance Proposals Meet the Order No. 2222's Requirements to Allow for the Participation of Heterogeneous Aggregations of DERs

This section addresses Intervenors' claims that the DERA participation models, discussed in detail in the Compliance Proposal, are inconsistent with Order No. 2222, which required that RTOs/ISOs allow DER Aggregators to register DERAs under one or more participation models that accommodate the physical and operational characteristics of the DERA. To that end, the Commission required that RTOs/ISOs modify existing participation models, create new participation models, or employ some combination thereof in order to allow for the participation of DERAs. The Commission, however, provided RTOs/ISOs with "flexibility to determine how best to revise the participation models set forth in its market rules to facilitate the participation of distributed energy resource aggregations."[49]

Consistent with the requirements of Order No. 2222, the Compliance Proposal includes seven participation models that are technology neutral and allow a mix of technologies to

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[49] Order No. 2222 at P 120.

participate in the same DER aggregation. Each model includes technical, operational and performance requirements that are appropriate for the services being provided under the model. These requirements are consistent with both Order No. 2222 and existing Tariff requirements associated with those services.

Intervenors, however, assert that the proposed participation models are inconsistent with Order No. 2222 because they (1) do not allow for the submetering of BTM DERs;[50] (2) include requirements that fail to take into account the physical and operational characteristics of DERs;[51] and (3) otherwise impose undue burdens on Market Participants. For the reasons stated below, these arguments must be rejected, as they are without merit, or are otherwise an attempt to change existing wholesale market services masked behind undue burden arguments. As further discussed below. The standards and requirements associated with each participation model in the Compliance Proposal are tailored to the products and services offered in the New England Markets. Intervenors effectively ask that the Commission require the ISO to change the wholesale services it offers in order to accommodate them, but Order No. 2222 did not mandate that ISO/RTOs modify their wholesale services to achieve such accommodations, and the requested changes are

[50] *See* AEE et al. at 17-26; AEMA at. 2. The arguments made regarding the failure of individual participation models (other than the ATRR model, which is addressed below) to allow for submetering are indistinct from the arguments addressed above and the ISO will not restate them here.

[51] Voltus at 17; AEE et al. at 26-35. As discussed in detail in this Answer, submetering of BTM DERs is not a requirement of Order No. 2222, creates double counting concerns, and therefore should not be required by the Commission. Protests that criticize the Compliance Proposal for the lack of a submetering requirement in particular participation models should therefore be rejected for the reasons previously stated and will not be addressed further.

otherwise problematic[52] For these reasons, the Commission should reject Intervenors' requested relief.

1. *The Continuous Storage Facility Participation Model Meets the Requirements of Order No. 2222*

The Compliance Proposal extends the use of the Continuous Storage Facility ("CSF"), and Binary Storage Facility ("BSF") models to DERAs. The CSF and BSF models, as originally designed, accommodate Electric Storage Facilities. In particular, the CSF model was developed for fast responding new storage technologies such as batteries, and the BSF model was developed to accommodate other storage technologies such as pumped-storage hydroelectric facilities. As noted in the Compliance Proposal, these two models, were designed for an individual storage or co-located generation/storage resource located at a single point of interconnection ('POI"). The Compliance Proposal through Section III.6.1(e) expands the existing CSF and BSF models to accommodate an aggregation of DERs that may have similar physical and operational characteristics as the storage resources.

Use of the CSF and BSF models will allow an aggregation of DERs with dispatchable energy injection capability, dispatchable energy withdrawal capability, and/or regulation capability to provide Day-Ahead or Real-Time energy services (as a supplier or a consumer), Operating Reserves, and/or regulation products simultaneously. Under proposed Section III.6.1(e)(i) a DERA using the CSF or BSF models need not have any storage technologies in the

[52] ISO also notes that with the limited exception of Environmental Organizations' proposals with respect to registration (addressed above), Intervenors have failed to provide the Commission with actionable alternatives to the Compliance Proposal in the form of specific Tariff amendments and instead argue that the Commission require that the Compliance Proposal be modified based on conceptual and theoretical principles. To the extent, however, that such Intervenors seek to ask the Commission to explicitly adopt amendments that failed to receive NEPOOL stakeholder support, the ISO's memos outlining specific criticism of and questions regarding those amendments are attached as Appendix A to this Answer.

aggregation to participate in the market using these models, which makes this approach technology neutral. This approach recognizes that a heterogeneous aggregation of loads and generation could together act like a storage device that withdraws energy when prices are low (or negative) and injects energy when prices are high, which is exactly how an Electric Storage Facility behaves.

Intervenors argue that the CSF model has limitations that will prevent DERAs from using it and that such limitations render the model non-compliant with Order No. 2222. AEMA, for example, states that the CSF model "contains barriers to entry for aggregations of customer loads with BTM DERs," because, "a CSF must be registered as an ATRR, a Generator Asset and a DARD."[53] These requirements, according to AEMA, create barriers to entry resulting from the CSF model's use of a DARD to dispatch the load consumption for the CSF. Specifically, AEMA argues that the CSF model's use of a DARD is problematic because the load associated with a CSF must be fully dispatchable, a requirement to which they object,[54] and because employing a DARD "requires the aggregator to be the Load Serving Entity (LSE) for the aggregation of customer loads."[55] AEMA further notes that "[s]erving load is a distinct and separate business model from aggregating DERs and it comes with a host of regulatory requirements and risks that require unique knowledge and capabilities that do not overlap with those possessed by most aggregators."[56]

ISO-NE recognizes that not all current DER Aggregator business models will be consistent with, and provide for use of the CSF or BSF models. For that reason, the ISO provides many other market participation models for DER Aggregators to use – DERAs that inject energy only can use the Generator Asset model; DERAs that provide demand response only can use the DRR model;

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[53] AEMA at 18.

[54] *Id.* at 19.

[55] *Id.* at 20.

[56] *Id.*

DERAs that inject and/or withdraw energy and provide demand response can use the DRDERA model, and DERAs that inject and/or withdraw energy but are not dispatchable by the ISO can use the SODERA model. The CSF model does require that any DERAs seeking to use it be dispatchable and be able to meet the offer requirements of a CSF, including that the DER Aggregator serve the load of the aggregated customer loads. These requirements do not render the CSF model inconsistent with Order No. 2222, which requires that RTOs/ISOs provide business model neutral participation models, but does not require that an ISO/RTO modify existing participation models to serve particular business model needs of aggregators. Currently, all Market Participants that offer CSFs into the market must meet the current rules' dispatchability requirements, and must meet the current rules' requires for participation as a DARD. There is nothing to prevent a DER Aggregator from taking the steps necessary to be able meet these requirements, and the ISO's proposal does not impose *additional* obligations on aggregators beyond those that apply to other resource providers using the same model. Further, for those aggregators not capable of complying with the existing CSF model requirements, the ISO's proposal includes other participation models for the aggregation of generation, load, and/or demand response.

Finally, the assertion that DER Aggregators do not have the skills of an LSE, and vice versa, is not a market barrier, but rather reflects a business choice made by the parties, which the ISO expects will evolve as market designs – such as the aggregated CSF model – present DER

Aggregators with incentives to participate in wholesale markets by serving customer demand using BTM DERs.[57]

For the foregoing reasons, AEMA's assertions do not constitute a valid basis for rejecting the ISO's Compliance Proposal and should be rejected.

2. The SODERA Participation Model Is Not Intended to Allow for Payments for Demand Reductions, But Other Participation Models Allow Such an Aggregation

Voltus argues that the SODERA participation model is not workable, in part because "it does not capture the value of load reductions."[58] In the first instance, Voltus is correct, the SODERA model is designed to pay for a DERA's energy injection, and bill for its energy withdrawal if the DER Aggregator chooses to serve the load of a SODERA. The SODERA model does not pay for load reductions because load reduction is not a service included in the SODERA model.[59] This is because the SODERA model is based on the Settlement Only Generator construct, which is available only for non-dispatchable resources and, therefore, excludes demand response, which receive compensation in the ISO markets only via ISO dispatch. Instead, the Compliance Proposal provides other participation models for combinations of DERs that can provide load reductions, including the DRR and the DRDERA models.[60] Voltus does not explain why it is

[57] ISO-NE notes that some DER Aggregators are LSEs. For example, Tesla Energy Ventures filed with the Texas Public Utility Commission in August 2021 seeking to serve load. In November 2021, the PUC approved Tesla to be a LSE in Texas. Docket No. 52431, Public Utility Commission of Texas, Notice of Approval (November 3, 2021).

[58] Voltus at 24.

[59] The SODERA model, like the aggregated CSF model, allows a DER Aggregator electing to serve customer demand using that model to accrue cost savings. The primary difference between the two models is that demand under the CSF model would be dispatched by the ISO subject to a priced demand bid submitted by the DER Aggregator, whereas any demand served by the DER Aggregator under the SODERA model would be settled at the LMP but would not be subject to ISO dispatch.

[60] The current DRR rules, changes to which are beyond the scope of Order No. 2222, already allow a DRR to be paid for energy injections. The proposed rules for DRDERAs will similarly allow energy injections to be monetized by the DERA Aggregator.

unable to achieve its objectives using these alternative models, or why the failure of the ISO to modify its existing Settlement Only Generator construct to account for load reductions is inconsistent with the mandates of Order No. 2222. The SODERA model does allow a DER Aggregator to include load reducing or load controlling DERs, which can accrue cost savings for the DER Aggregator, or be used to maximize the value of other DERs within the aggregation that generate power, which would be settled at the LMP but would not be subject to ISO dispatch.

3. The ATRR Participation Model Already Allows for Aggregations and the Metering Requirements for DER Participation Are Reasonable Based on the Services Offered

The Compliance Proposal allows DERAs to use the existing ATRR model, with minor modifications made to the model to bring it into compliance with Order No. 2222. The ISO proposed no changes to the metering requirements of the model, however. These requirements include five-minute interval metering *for submetered single-facility ATRRs*,[61] and a general prohibition on the use of submetered data for aggregated ATRRs. Five-minute interval metering is required for submetered single-facility ATRRs so that the ISO can verify that four-second telemetry matches the five-minute data within the required accuracy and precision. Five-minute interval metering is not required for ATRRs metered at the RDP.

In its Protest, AEE et al. challenges the ATRR model metering requirements, arguing that "[i]t is not clear that interval metering (on a five-minute interval) is necessary for ISO-NE to verify regulation produced by a behind the meter device in response to a four second Automatic Generation Control . . . and ISO-NE does not explain how it helps in this regard. It is also unclear

[61] Pursuant to ISO-NE Operating Procedure No. 18, Section V(D)(3)(b), ATRRs are required to directly report data to the ISO. Host Utilities do not perform services for ATRRs.

why sub-metered devices would be prohibited from participating in aggregations, and in fact the entire purpose of Order No. 2222 is to enable and facilitate aggregations."[62]

In response to AEE et al.'s first criticism, interval metering is necessary to verify the accuracy of meter data received from the submeter. More specifically, for any submetered resource where the meter is not owned and read by an independent third party, other sources of data are needed to verify the meter's validity. Under current practices, Market Participants of single-facility ATRRs that submit submetered telemetry data to measure ATRR performance are subject to additional requirements, such as submitting documentation demonstrating that other devices at the facility act independently from the ATRR, and are required to submit revenue-quality metering data from both the ATRR submeter and from the RDP. This allows for the comparison of the summation of four second ATRR data over a five minute interval to the five minute revenue-quality metering data from the ATRR to determine the accuracy of the ATRR telemetry, as well as the comparison of the five-minute revenue-quality metering data from the ATRR to the five-minute revenue-quality metering data from the utility's RDP meter[63] to see if the response of the ATRR is registering at the RDP. This approach verifies the delivery of the ATRR's response to the grid.

In response to AEE et al.'s second criticism, it would be highly impractical to extend the practice of submetering from single-facility ATRRs to aggregated ATRRs. First, the line diagrams of each small facility seeking to submeter an ATRR would need to be reviewed by both the DER Aggregator and the ISO to verify and address interaction of devices at each facility, in the same

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[62] AEE et al. at 48.

[63] The meter at the RDP, for example, is read by the Host Utility. Having that source of data is essential to establishing the validity of any sub-metered data.

way that this is done for individual submetered facilities today.[64] This verification process is likely to be extremely time intensive, and ultimately infeasible for large aggregations. Further, the methodology employed today for verifying the accuracy of submetered data would need to be extended to all facilities in the aggregation, which would increase significantly the potential risk for meter data errors, and quality control issues. It is for these reasons that the current market rules allow for single-facility ATRRs to provide submetered telemetry data to demonstrate performance, but require aggregated ATRRs to provide telemetry data at the RDP. AEE et al. does not provide a sound rationale to justify modifications to these current measures; simply pointing to Order No. 2222's goal of facilitating aggregations is not a sufficient basis for mandating changes that are impractical and which increase the risk of error.

1. *Order No. 2222 Did Not Require Modification to Demand Response Compensation or Baseline Calculation Rules*

In their Protests, Intervenors correctly acknowledge that the Compliance Proposal does not modify the existing Demand Response rules in New England, beyond allowing Order No. 745 compliant resources to participate in a DERA with non-Demand Response Resources,[65] because, as they also correctly note, such changes are beyond the scope of Order No. 2222.[66] Despite this acknowledgement, AEE et al., and AEMA argue that the Commission should require that ISO add a new baseline option to allow submetered output to quantify load reduction at the submeter.[67]

[64] As an example, energy management systems are often programmed to cycle loads off to reduce peak load. In such cases a BTM DER such as a battery, may increase its load in response to an AGC signal but the energy management system simultaneously reduces air conditioning load, counteracting the performance of the BTM DER.

[65] *See e.g.*, AEE et al. at 31-34, 41-43; AEMA at 9-11.

[66] AEE et al., at 32.

[67] AEE et al. at 31-34, 41-43; AEMA at 9-11.

Intervenors' request is, as they acknowledge, beyond the scope of Order No. 2222, and for this reason alone should be rejected. Moreover, it is substantively deficient for the same reasons outlined above regarding submetering. The submetering of DRRs is problematic because it has the potential to result in inaccurate compensation for services that are provided to the grid. RDP metering measures service delivered to the grid. In the case of demand response, it measures demand reduction delivered to the grid. Measuring demand reduction from a submeter does not measure demand reduction delivered to the grid because the facility may change its energy consumption and/or energy production simultaneously at other devices, which then reduces service delivered to the grid. Submetering also introduces the possibility of double counting the amount of demand reduction delivered to the grid as previously explained above.

To address these concerns, AEE et al. proposes that DER Aggregators attest that the BTM DER and the rest of the load at a facility are not interdependent. Such an attestation would have little value. Facilities are constantly evolving, and a DER Aggregator using submetering would have little idea that customers may be taking actions that neutralize the demand reductions being delivered to the grid.

AEE et al. also asserts that the performance of DERs that are frequently dispatched will not be adequately captured by a historical baseline approach relying on deviations from normal load patterns, which implies that a new baseline methodology ought to be adopted.[68] AEE et al. have not introduced in this proceeding an alternative methodology, or demonstrated how such an alternative would be more accurate than the ISO's current methodology. More fundamentally, Order No. 2222 does not mandate changes to the ISO's existing baseline calculation methodology, and thus AEE et al.'s criticism is beyond the scope of this proceeding.

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[68] AEE et al. at 16.

In another attempt to expand the scope of the Order No. 2222 compliance requirements, AEMA states that the Commission recognized in Order 2222 that there are shortcomings in existing demand response models and claims that the Commission directed ISOs/RTOs to address them, [69] when the Commission stated that:

> In order to participate in RTO/ISO markets, distributed energy resources tend to participate in RTO/ISO demand response programs. While these demand response programs have helped reduce barriers to load curtailment resources, they often limit the operations of some types of distributed energy resources, such as electric storage or distributed generation, as well as the services that they are eligible to provide.[70]

AEMA, however, ignores the explanatory footnote accompanying that statement, which states that:

> [W]hen participating through demand response programs, distributed energy resources generally can only operate to reduce customer demand at the meter, *and any injection/generation cannot exceed customer demand. Consequently, these resources are prevented from injecting additional electricity into the grid to make sales of electricity in RTO/ISO markets*.[71]

New England's current DRR model does not suffer from this limitation. The current DRR model already pays for incremental injections from dispatched DRRs, and the ISO does not propose to change this. Indeed, the Compliance Proposal extends this feature to include all injections, whether or not the aggregation is dispatched in the DRDERA model.

AEMA asserts that changes to the Compliance Proposal should be made to allow "best available data" for the metering of DRRs participating in a DERA, suggesting that 5-minute interval metering is too expensive or burdensome for DERs.[72] The New England Markets require

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[69] AEMA at 10.

[70] Order No. 2222 at P 28.

[71] Order No. 2222 at n. 58.

[72] AEMA at 15.

the use of five-minute interval data for metering of all resources, and this obligation extends to DRRs.[73] Thus, current DRR aggregators are able to provide the ISO with five-minute data.

What AEMA seeks is not a reduction of barriers to participation in wholesale markets, but special treatment for BTM DERs for which five-minute metering is not in place. AEMA therefore wants BTM DERs to be allowed to provide a service on different terms than other similarly situated resources. This is inconsistent with Order No. 2222, which states that its intent is to enable aggregations of DERs to participate in the wholesale markets when such aggregations can "meet certain qualification and performance requirements, particularly if the operational characteristics of different distributed energy resources in a distributed energy resource aggregation complement each other," in ways that individual DERs are unable to.[74] For these reasons, the Commission should reject AEMA's request.

D. The Compliance Proposal Should be Evaluated Against the Requirements of Order No. 2222 and Comparisons of the Compliance Proposal to Other RTO/ISOs and Self Serving "Best Practices" Should Be Dismissed

In an effort to bolster its blanket assertions that the Compliance Proposal, Voltus' Protest includes materials against which, it argues, the Commission should evaluate the ISO's Compliance Proposal.[75] These include a matrix providing Voltus' comparison of the RTOs/ISOs' compliance proposals, and Voltus' set of "best practices" for Order No. 2222 compliance. The Commission should reject Voltus' Protest, including the extraneous documents, and evaluate the Compliance Proposal against the requirements that the Commission adopted in Order No. 2222.

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[73] Section III.3.2.2(c) – Additional Metering and Telemetry Requirements for Demand Response Assets.

[74] Order No. 2222 at P 26.

[75] Voltus at 7, 21.

In Order No. 2222, the Commission allowed for flexibility in meeting numerous Order 2222 requirements.[76] The RTO/ISO comparison matrix provides no information or discussion of starting points for each region, and fails to account for market and governance differences between regions. For example, as discussed above, ISO-NE's Demand Response Resource model already allows for a DRR to be compensated for energy injected onto the system, whereas other regions may not. This type of comparison therefore is of little use in evaluating whether the Compliance Proposal meets the requirements of Order No. 2222. In additional, the self-serving best practices document seeks to compare the Compliance Proposal against a wish list of sorts that does not directly correspond to the requirements of Order No. 2222, and in some cases contradicts or seeks to redefine the requirements of the Order long after the time for rehearing has passed, and therefore must be rejected.

IV. CONCLUSION

For the reasons stated in the Compliance Proposal and in this Answer, the ISO respectfully requests that the Commission reject the Protests, and accept the Compliance Proposal and the Tariff revisions reflected therein, without modifications or conditions, as compliant with Order Nos. 2222, 2222-A and 2222-B, to become effective on the dates requested therein.

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[76] *See e.g.* Order No. 2222 at P 171 (regarding size requirements); P 120 (regarding participation model requirements); P 262 (regarding metering and telemetry requirements); P 293 (with respect to registration requirements).

Respectfully submitted,

By: *__/s/ Graham Jesmer__*

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Dated: April 20, 2022

Appendix A

memo

To:	NEPOOL Markets Committee
From:	ISO New England ("the ISO")
Date:	November 4, 2021
Subject:	Response to Advanced Energy Economy's Amendments to ISO New England's Order No. 2222 Compliance Proposal

Background and General Response

At the NEPOOL Markets Committee meeting on October 14, 2021, Advanced Energy Economy ("AEE"), represented by individual Market Participants, proposed several amendments to the ISO's proposed compliance approach to Order No. 2222, which concerns the participation of distributed energy resources ("DERs") and distributed energy resource aggregations ("DERAs") in wholesale markets. Draft Tariff changes reflecting the proposed amendments were later circulated for the ISO's review.

The ISO appreciates AEE's feedback and has carefully evaluated each proposed amendment. In reviewing the proposed amendments, the ISO observed that all of the amendments, save for the amendment concerning the periodic review of the success of the DERA models (Amendment 5), affects the ISO's existing rules related to the provision of demand response and associated metering location provisions. However, Order No. 2222 at P118 says that:

> We clarify that, because demand response falls under the definition of distributed energy resource, an aggregator of demand response could participate as a distributed energy resource aggregator. However, ***this final rule does not affect existing demand response rules.*** (Emphasis added).

Given that AEE's proposed amendments affect the ISO's existing rules related to demand response, the ISO views them as out-of-scope with respect to the Order No. 2222 compliance proposal being developed. A significant amount of analysis, stakeholder consideration, and implementation effort went into the ISO's existing approach to demand response and the Commission did not find in Order No. 2222 that the ISO's existing demand response rules were unjust or unreasonable.

While the ISO appreciates that AEE may have a different perspective on the ISO's current demand response rules, regardless of the ISO's concerns with the scope of AEE's proposals, it could not support the amendments based on the substantial record and experience that the New England region has with respect to the issues raised by the amendments. The remainder of this memo summarizes the substantive concerns identified by the ISO with respect to each amendment.

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Amendment 1a: Add-back baseline methodology

AEE proposes that the ISO adopt a baseline methodology, which AEE states the NYISO will use for their demand response program. This method is viewed as preserving a high baseline level for demand response resources ("DRRs") that respond frequently to dispatch (e.g., every day) by allowing the load reduction of a DRR to be added to the observed, metered load of a DRR during a dispatch. The reconstituted gross load is then used to establish the DRR's baseline going forward.

Under the ISO's current, FERC-approved baseline methodology, meter data from days on which a DRR was not dispatched is used to establish the baseline. If a DRR is dispatched frequently, such as every day, there may be no meter data from days on which the DRR was not dispatched to establish the baseline, or the meter data used to establish the baseline could be from a different month, season or even year. To ensure that there is some data from the current season upon which to establish a baseline representing the DRR's current load shape, the ISO's methodology uses some data from days on which a DRR was dispatched to establish the baseline should the DRR be dispatched on many consecutive days.

The ISO's current baseline methodology was informed by events that occurred in 2007 in which facilities participating in the then effective Day-Ahead Load Response Program ("DALRP") extracted payments for load reductions that they were, in fact, not making. These facilities accomplished this result by establishing an artificially high baseline, clearing in the DALRP by offering at the minimum offer price, and allowing load to return to normal levels. This approach allowed participants to obtain demand response payments for normal load levels. And by clearing every day thereafter by offering at the minimum offer price allowed by the DALRP at the time, the baseline became static and remained at a high level, which allowed payments for apparent, rather than real, load reductions to continue indefinitely. This behavior necessitated a change in the program rules in which normal load levels outside of DRR dispatch could be periodically observed, which then can be used to determine a reliable baseline.[1]

The AEE amendments would, in the view of the ISO, facilitate demand reduction payments for normal load levels, which the changes proposed by the ISO in Docket No. ER08-538-000 and in every demand response program change made since that time sought to avoid.[2] For example, the AEE amendment to Section

[1] *See* ISO New England Inc., Docket No. ER08-538-000, Filing of Changes to Day-Ahead Load Response Program (February 5, 2008), accepted by the Commission in ISO New England Inc., Order Accepting Tariff Revisions, 123 FERC ¶ 61,021 (2008).

[2] The memo found at the following link describes the analysis conducted by ISO-NE to establish the baseline methodology currently required under Section III.8.2 of the Tariff – https://www.iso-ne.com/static-assets/documents/2015/08/a03_iso_memo_08_24_15.docx. Through the course of its analysis, ISO-NE analyzed multiple options and the current methodology was chosen given its performance with respect to accuracy, bias, and variability, its ability to estimate baselines for different day-types, and its ease of administration. The memo summarizes the issues, analyses conducted, and recommendations – it also includes links to all of the materials presented to stakeholders at the time and all of the analysis conducted, which were filed with the Commission in support of ISO-NE's proposed revisions to its demand response model in Docket No. ER16-167-000 (https://www.iso-ne.com/static-assets/documents/2015/10/er16-167-000_part_1.pdf), which the Commission accepted by Letter Order on December 23, 2015.

III.1.10.1A(e)(iii) would allow a DRR to offer at any price, including "a price that is below the Demand Reduction Threshold Price in effect for the Operating Day." This means that a DRR could offer at $0/MWh or lower (e.g., down to the offer floor price of -$150/MWh),[3] which would guarantee that the resource would clear and be dispatched. And if a DRR is dispatched, the AEE amendment to Section III.8.4.1(b) would add back to actual metered load the amount dispatched by the ISO to establish the resource's baseline going forward. This strategic offering behavior could continue forever, which would freeze the baseline at a high level and create the same situations as those described in Docket No. ER08-538-000. Under this approach, the DRR's actual load outside of a dispatch would never be observed, or if observed at some point, could be from a different month, season, or year. Further, the AEE approach would allow a DRR to increase load to an abnormally high level for a short amount of time so as to establish a high baseline, and then freeze that high baseline in place by clearing everyday thereafter by offering at a very low price.

Finally, the AEE amendment to Section III.1.10.1A(e)(iii) allows a DRR to offer and be dispatched at price levels for which the Market Participant knows it will not receive any payment. Since the apparent demand reduction produced under these circumstances is not in response to an increase in electric energy prices or to an incentive payment designed to induce lower consumption of electric energy, the apparent demand reduction does not appear to meet the Commission's definition of demand response.[4]

Amendment 1b: Allow generation to count as load reduction

AEE proposes that the ISO allow load reductions produced by a behind-the-meter generator to be measured at the generator. This is contrary to the ISO's current rules, which requires load reductions produced by a DRR be measured at the retail delivery point ("RDP"). As part of the ISO's Order No. 745 compliance filing, the ISO proposed that each customer facility providing demand response be metered at its RDP.[5] The ISO

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[3] According to Section III.1.10.1A(e)(iii) of the AEE Amendments:

> [A]ny price specified below the Demand Reduction Threshold price in effect for the Operating Day that clears in the Day-Ahead and Real-Time Energy Markets will result in the Demand Response Resources and Distributed Energy Resources associated with a Demand Response Distributed Energy Resource Aggregation using the Demand Response Add-Back Baseline shall receive *no settlement payments* for either the Day-Ahead or Real-Time Energy Market. (Emphasis added).

The language does not specify what happens if a resource is dispatched to reduce load at negative prices. Since the language says that the resource receives no settlement payments should this occur, it could be construed that a resource that reduces load when LMPs are negative would receive no charges as delivery of a service at negative prices can be interpreted to be a negative settlement payment.

[4] Demand response is defined by the FERC as a reduction in the consumption of electric energy by customers from their expected consumption *in response to an increase in the price of electric energy or to incentive payments* designed to induce lower consumption of electric energy. 18 CFR 35.28(b)(4) (2010) (emphasis added).

[5] *See* ISO New England Inc., Docket No. ER11-4336-000, Order No. 745 Compliance Filing (August 19, 2011), Filing Letter p. 5.

argued that demand response performance should always be measured at the RDP, which effectively is the DRR's point of interconnection with the New England Control Area and the point at which the ISO observes a DRR's contribution to balancing supply and demand *on the grid*.[6] For example, assume a facility that increases its behind-the-meter generator output by 1 MW also increases 1 MW of its consumption simultaneously when dispatched. If the ISO were to measure demand response by metering the generator alone, it would conclude that 1 MW of demand reduction was provided. But if the ISO measures at the RDP, it would conclude that 0 MW were provided as demand from the perspective of the grid would not have changed.

The ISO's Order No. 745 proposal was opposed by a coalition of demand response providers and an industrial energy consumer group. These parties wanted to be able to measure demand response performance by directly metering behind-the-meter generation, which is what AEE's proposed revision to Section III.8.2A would allow. The Commission considered the evidence presented and found that the ISO's approach to be the preferred one. In ISO New England, Order Denying Rehearing, 139 FERC ¶ 61,116 (2012) at P12, the Commission said:

> The Commission explained in the Compliance Order that, in the context of discussing ISO-NE's settlement system as it relates to demand response, the impact a customer has on the grid is what determines how the ISO will operate the grid. *Measuring demand response at the retail delivery point allows ISO-NE to effectively manage the grid because this point accurately reflects the load's impact on the New England transmission system.* As we stated in Order No. 745-A, from the perspective of the grid, the manner in which a customer is able to produce a load reduction in the wholesale market from its validly established baseline (whether by shifting production, using internal generation, consuming less electricity, or other means) does not change the effect or value of the reduction to the wholesale grid. (Emphasis added)

The ISO has not seen sufficient evidence presented by AEE for making a change to this approach in the context of the Order No. 2222 compliance.

Amendment 2: Allow submetered load to participate as demand response

AEE proposes that the ISO allow load reductions from a DER to be measured against a baseline at an "Alternative Point of Load Reduction", which is defined by AEE in its proposed revision to Section I.2.2 as "a load meter behind the Retail Delivery Point…." However, this approach ignores the Commission's finding

[6] Additionally, ISO-NE stated that metering at the RDP was necessary to address additional issues including: 1) if demand response were measured at a point other than the retail delivery point, the danger of double-counting the amount used to balance supply and demand in real time is greatly enhanced; 2) all retail delivery points have revenue-quality meters installed, operated, and maintained by the customer's utility distribution company. In many cases, the same meter could be used to measure the demand response (or generation) provided by a customer to the grid, thus minimizing costs; and 3) because the meter at the retail delivery point is read by the utility distribution company for retail billing purposes**,** the meter data recorded by the utility can be used by the ISO to verify the meter data submitted by demand response providers to the ISO for settlement purposes. *See,* ISO New England Inc., Docket No. ER11-4336-000, Order No. 745 Compliance Filing (August 19, 2011), Yoshimura Testimony, pp. 18-27.

cited above in response to Amendment 1b. Restated again here, the Commission found that *"[m]easuring demand response at the retail delivery point allows ISO-NE to effectively manage the grid because this point accurately reflects the load's impact on the New England transmission system."* Again, AEE has not presented sufficient evidence that this approach needs to be modified in the context of the Order No. 2222 compliance.

Amendment 3: Allow DER Aggregators to meter the injection, withdrawal and the load reduction of all DERs within each DER Aggregation

AEE proposes that the ISO allow a third-party, such as the DER Aggregator, to meter the energy injections, withdrawals, and/or the demand reductions of DERs. Under the ISO's current rules for DRRs (and proposed rules for DRDERAs), non-utility third parties perform the metering for demand reductions. Since the ISO does not propose to change any of its demand response rules through its Order No. 2222 compliance filing, AEE's amendments to Sections I.2.2, and III.6.4 with respect to the use of third parties to meter demand reductions are unnecessary.

However, the metering of generation and load, which is used for Energy Market accounting in New England, is distinct from the metering of demand reductions. With respect to the metering of generation and load in New England, the Participating Transmission Owners ("PTOs") are responsible for providing the metering of all Generator Assets, Load Assets, and Tie Line Assets participating in the New England wholesale markets.

For resources participating in the New England energy, capacity and ancillary services markets (including distribution-connected assets), the Host Participant or Host Utility,[7] or its Assigned Meter Reader,[8] are responsible under Section 5.2 of M-28 for: (1) reporting of interval energy quantities for Load Assets, Generator Assets, and Tie Line Assets; (2) reporting of meter reconciliation data for use in resettlement process for Load Assets, Tie-Line Assets, and Generator Assets; and (3) prompt reporting of any discovered metering, calculating, or reporting errors with respect to an asset to the ISO and the Market Participant(s) owning or having rights to the asset.

The Tariff allows the responsible Host Utility to designate an agent in the form of an Assigned Meter Reader – i.e., a third-party – to help fulfill its meter reading responsibilities. Thus, third-party metering is already permitted in New England. Because the PTO retains the responsibility for providing the metering of Generator Assets, Load Assets, and Tie Line Assets in its footprint, they would also be responsible for retaining and coordinating with any third-party used to help meet the PTOs meter reading responsibilities.

[7] Defined in Tariff, Section I.2.2 as "a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering[.]"

[8] Defined in Tariff, Section I.2.2 as the entity that "reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO." The Assigned Meter Reader is most often the distribution utility in a particular metering domain.

Since the PTOs are responsible for providing the metering of all Generator Assets, Load Assets, and Tie Line Assets, the PTOs would need to establish the requirements for the use of third-party meter readers so that they could continue to meet their obligations in reporting the load and generation within their respective footprints for Energy Market settlement purposes. The ISO is not in a position to certify third-party meter readers since meter reading jurisdiction in New England falls to the Host Utilities. Also, it would be inefficient for the ISO to administer such requirements as it has no expertise in meter reading and would need to develop procedures accounting for each PTO's meter reading processes.

Amendment 4a: Remove the requirement for DRRs and DRDERAs to clear in the energy market to provide spinning reserves

In support of Amendment 4a, AEE asserts that no other ISO requires load to be dispatched for energy in order to provide spinning reserves. This argument, however, fails to consider that this requirement is related to the DRR dispatch approach taken by the ISO, which affords DRRs with significant benefits. In New England, DRRs are subject to the "commitment" process similar to that of Generator Assets. The commitment process affords DRRs with specific benefits, such as the ability to specify a notification time, start-up time, minimum reduction time, minimum time between reductions (minimum down time), etc., in its Energy Market Offers. The inter-temporal constraints specified by a DRR in its offer would be honored in the dispatch algorithm. This result was achieved by treating DRRs *as an alternative to a generation resource* by modelling demand response as a proxy or virtual generator using the ISO's existing generator commitment and dispatch system. This approach was in response to Order No. 745 in which the Commission concluded:

> [W]hen a demand response resource participating in an organized wholesale energy market administered by an RTO or ISO *has the capability to balance supply and demand as an alternative to a generation resource* and when dispatch of that demand response resource is cost-effective as determined by the net benefits test described herein, that demand response resource must be compensated for the service it provides to the energy market at the market price for energy, referred to as the locational marginal price (LMP). *See* Order No. 745 at P2 (emphasis added).

Generators that have been dispatched and have satisfied their notification and start-up time can be designated to provide TMSR. Since DRRs are modeled as a direct alternative to Generator Assets, both sets of resources are treated similarly in the commitment and dispatch process. Allowing a DRR that has not been dispatched to provide TMSR would extend different and more favorable treatment to DRRs relative to Generator Assets. It would also require a change to the way DRRs are designated to provide reserves given that the same dispatch and reserve designation infrastructure used for Generator Assets was also used for DRRs.

Even if the ISO were to consider the AEE proposed amendment in spite of these concerns, since practically all DRRs currently bid notification and start-up times greater than zero in their Energy Market Offers, making this change would create little to no benefit.

Further, such changes to the existing demand response program rules and infrastructure are unnecessary. New technologies with technical characteristics in which they are always in a dispatched state – such as dispatchable loads or those with batteries that can move to different dispatch points (both charging and discharging) instantaneously – are able to participate under the new aggregated CSF model that the ISO is proposing for Order No. 2222 compliance. This model was specifically developed to allow such new technologies to sell products associated with that technical capability – such as TMSR – to the New England Markets in a manner that is consistent with other resources with similar characteristics and capabilities.

Amendment 4b: Allow submetering for DERs providing regulation service

AEE proposes that the ISO telemeter regulation service provided by a behind-the-meter DER at the device. The telemetering location of ATRRs is not currently specified in the ISO New England Governing Documents. The ISO's general practice is to telemeter regulation service at the resource's point of interconnection with the grid; for an end-use customer facility, the telemetering location would be at the RDP. This requirement better ensures the measurement of service provided to the grid. For example, take a large facility with two large compressor motors that operate air conditioning or refrigeration equipment in which only one motor participates in the wholesale market. The motor participating in the wholesale market could be dispatched down to reduce load, but the other motor at the facility that is not in the market may increase its load so that the facility can maintain a constant temperature, which negates the service provided by the motor participating in the market. In this instance, telemetering at the device would result in a payment even though no service may have been provided to the grid.

However, given the novelty of services provided by new technologies such as batteries, the ISO is testing different approaches so that it can observe and gain experience with these technologies. In one approach, an aggregation of residential homes with batteries is providing regulation service in which service is measured from the RDP of each home.[9] In other limited circumstances, regulation service has been telemetered at the battery to the extent the Market Participant demonstrates that all of the other devices at the facility function independently from the battery. Further, the Market Participant must collect and make available to the ISO upon request revenue quality interval meter data for both the ATRR device and the RDP to enable the ISO to assess the accuracy of the ATRR telemetry data.

AEE's amendments to Sections III.6.4, III.14.2(c), and III.14.2A propose that the ISO permanently adopt an approach in which any facility with a regulating device be telemetered at the device. Further, AEE proposes that no revenue quality interval meter data be provided as a check on the telemetry provided from the device. Finally, AEE proposes that the Market Participant not be required to demonstrate that all of the other devices at the facility function independently from the regulating device – only an attestation is required. The ISO is uncomfortable with this proposal as it would not be feasible to review potentially thousands of facilities (e.g., residential customers with a Tesla Powerwall and/or an EV) all claiming that the devices at the facility are acting independently of regulating device and relying entirely on an attestation of

[9] *See* https://greenmountainpower.com/network-of-powerwall-batteries-delivers-first-in-new-england-benefit-for-customers/.

the Market Participant, and where there would be no data against which to assess the accuracy of the telemetry data submitted by the Market Participant.[10]

Accordingly, the ISO plans to maintain the current approach to telemetering ATRRs at the RDP or point of interconnection with arrangements made on a case-by-case basis, and to evaluate whether updates to OP-18 should be made in the future (likely in 2022), which would apply to all ATRRs, not just to the ones participating in the market as part of a DERA.

Amendment 5: Periodically review the success of the DERA models

AEE proposes that the ISO Tariff should require that the Internal Market Monitor ("IMM") periodically evaluate the effectiveness of the ISO's DERA model by determining the extent to which the new DERA models are being used, and whether they have reduced barriers to DER participation in the New England Markets.

During the discussion at the October 2021 Markets Committee meeting, certain stakeholders noted that it would not be a good idea to put such a requirement in the Tariff. If such a requirement were in the Tariff, an evaluation would be required even if it was not needed or if there was insufficient experience or data upon which to conduct an evaluation. The ISO agrees with these stakeholders. A required review requirement, particularly one that just focuses on the "success in removing barriers to the participation of DERAs in the capacity, energy, and ancillary service markets administered by ISO-NE,"[11] as proposed by AEE is problematic. First, it is unclear what "success" in this context means. Second, any report of the IMM should not be limited to examining elimination of market barriers. Lack of participation may not be the result of a market barrier. Rather lack of participation could be due to retail program participation that prohibits wholesale market participation, or otherwise makes such wholesale market participation uneconomic. Finally, such a periodic requirement may introduce an element of uncertainty to Market Participants that itself discourages participation – for example, if Market Participants think that the upcoming IMM report could result in major changes in the future, they might be discouraged from participating in the market, or may delay participation in anticipation of more favorable, future treatment.

In the future should stakeholders believe that the ISO's Order No. 2222 compliance implementation requires any changes, such concerns should be brought through the NEPOOL stakeholder process for consideration together with proposals to modify the ISO's participation model.

[10] Note that metering or telemetering wholesale service at the RDP allows the submitted data to be compared to the utility distribution company's revenue quality meter data used for retail billing purposes.

[11] *See* AEE proposed change to Section III.A.17.2.5.

ISO new england

memo

To: NEPOOL Participants Committee

From: ISO New England

Date: December 29, 2021

Subject: ISO New England's Response to Advanced Energy Economy's Revised Amendment 1A Regarding an Add-Back Baseline Methodology

On December 8, 2021, the NEPOOL Markets Committee voted to support the ISO's proposed Tariff changes designed to comply with FERC Order No. 2222, which concerns the participation of distributed energy resource aggregations in wholesale markets. Several amendments to the ISO's proposal were offered by Advanced Energy Economy ("AEE"), none of which were supported by the Markets Committee. However, AEE's Amendment 1A regarding the incorporation of an add-back baseline methodology, which was presented at the December Markets Committee meeting, included modifications to address concerns previously expressed by the ISO.[1] The purpose of this memo is to provide the ISO's further analysis and position on revised Amendment 1A as presented to the Markets Committee in December.[2]

The specific change presented by AEE at the December Markets Committee meeting is highlighted below in yellow:

Section III.1.10.1A(e) (ii) (a)

Demand Response Resources and Distributed Energy Resources associated with a Demand Response Distributed Energy Resource Aggregation using the Demand Response Add-Back Baseline methodology pursuant to III.8.4 may specify a price that is below the Demand Reduction Threshold Price in effect for the Operating Day. For purposes of clearing the Day-Ahead and Real-Time Energy Markets and calculating Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, any resource associated with a Demand Response Distributed Energy Resource Aggregation using the Demand Response Add-Back Baseline shall receive no positive[3] settlement payments for either the Day-Ahead or Real-Time Energy Market.

Following the December Markets Committee meeting, ISO staff met with members of the AEE coalition to better understand the proposed amendment as it relates to the ISO's Order No. 2222 compliance effort. In our understanding, Amendment 1A was designed to enable Demand Response Resources ("DRRs") to

[1] AEE Amendment 1A was first described at the October Markets Committee meeting. Specific Tariff language was provided at the November Markets Committee meeting, which was subsequently modified and presented at the December Markets Committee meeting.

[2] The ISO's positions on the remaining AEE Amendments are summarized in a memo provided to the Markets Committee at its November 2021 meeting.

[3] AEE added the word "positive" to its Tariff change proposal during the December Markets Committee meeting.

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participate in both retail demand response programs[4] and ISO-administered wholesale markets simultaneously. AEE explained that the specific revision highlighted above was intended to eliminate the incentive for a participant to inflate the DRR's baseline by eliminating Energy Market payments of the DRRs using the AEE-proposed Demand Response Add-Back Baseline methodology ("Add-Back Baseline") – a concern that was previously raised by the ISO. It was reasoned by AEE that, absent Energy Market compensation, a Market Participant would have no reason to inflate a DRR's baseline, which is used to determine the Real-Time Energy Market performance of a DRR.

The ISO believes that it is reasonable and appropriate for a DRR to participate in both retail demand response programs and in wholesale markets simultaneously so long as wholesale services are not double counted in the process. However, while the ISO appreciates AEE's effort to address the ISO's concerns regarding baseline integrity, the ISO still does not support the revised Amendment 1A for several reasons, as further explained below.

First, Amendment 1A still provides incentives for a participant to inflate the DRR's baseline despite the revision. Eliminating positive settlement payments in the Energy Market may reduce the financial incentive *in that market* for a participant to inflate the baseline of a DRR. However, it is our understanding that DRRs using the Add-Back Baseline will be participating in the Forward Capacity Market ("FCM"). Under revised Amendment 1A, there remains a financial incentive for a participant to inflate the baseline of a DRR for FCM settlement purposes. This is because, all other things equal, a DRR with a higher baseline can meet a higher Capacity Supply Obligation – and thus earn the participant higher monthly capacity payments – than one with a lower baseline. Further, the performance of a DRR in response to Capacity Scarcity Conditions is exaggerated if its baseline is inflated. While we agree that eliminating positive Energy Market settlement payments helps mitigate the incentive to inflate the baseline to some degree, it does not wholly eliminate the incentive to inflate a DRR's baseline.

Second, revised Amendment 1A could result in the submission of Demand Reduction Offers into the Energy Market that do not reflect the cost associated with the dispatch of DRRs. The current Energy Market design motivates resource owners to submit accurate, cost-based offers into the Energy Market by allowing resource owners to financially benefit (assuming no market power issues) from making such offers. A resource owner that submits an above-cost offer could end up not being dispatched when LMPs are higher than actual costs, whereby the resource owner misses out on earning profits. Conversely, a resource owner that submits below-cost offers could end up being dispatched when LMPs are lower than actual costs, whereby the resource owner sees an erosion of profits. Under revised Amendment 1A, the financial motivation of a DRR owner to submit a cost-based offer like other Energy Market resources is disrupted since the DRR owner would not earn any positive revenues, and thus earns no profits, through the Energy Market. Rather, a DRR owner's Demand Reduction Offer under Amendment 1A would likely be motivated by other factors, such as submitting offers so as to maintain a higher baseline for use in capacity markets.

Third, the Add-Back Baseline may result in the double counting of wholesale capacity market services. For example, the Massachusetts Clean Peak Energy Portfolio Standard, cited above, is designed to reduce monthly and annual system peak demand. The ISO understands that this program puts a high premium (i.e., the program grants substantially more clean peak certificates) on reducing load at the time of the Actual

[4] For example, one of these programs includes the Massachusetts Clean Peak Energy Portfolio Standard. *See* 225 CMR 21.00 *et seq.*

Monthly System Peak,[5] which is defined as "[t]he highest net demand for electricity in a calendar month ***in ISO-NE Control Area***" (emphasis added).[6] By reducing annual and monthly peak loads, the participants can reduce their allocation of capacity costs. But if retail program participants also participate as a capacity supply resource in the FCM, the Add-Back Baseline would facilitate the double counting of wholesale capacity services provided by these resources (i.e., by granting both load and supply credits for the same resource/service).

When participants in retail demand response programs reduce their load during peak load hours, they receive compensation through the retail program and they, or load serving entities, also receive savings through a lower capacity cost allocation. The Add-Back Baseline would then add the calculated load reduction (for which they have already received a financial benefit) back to the participant's actual metered load to create a higher baseline for FCM participation purposes. This higher baseline then allows the very same load reduction produced in response to the retail demand response program to be counted and remunerated as a supply resource in the FCM. This results in double-counting the capacity provided by these participants – once as a load reduction and once again as a supply resource – which is a result the Federal Energy Regulatory Commission ordered the ISO to avoid in Order No. 2222.[7] In contrast, the ISO's Order No. 2222 compliance proposal is narrowly designed to avoid counting more than once the services provided by DRRs in wholesale markets by using a baseline methodology that permits only load reductions supplied *in addition* to those produced in response to retail demand response programs to be counted as a wholesale market resource.

Other consequences of the aforementioned double counting in the capacity market that result from Amendment 1A include potential reliability issues, or unnecessarily higher customer costs. By consistently reducing annual and monthly peak loads, the participants in retail demand response programs help lower the ISO's Installed Capacity Requirement ("ICR") by reducing forecasted load. However, if these same participants are allowed to obtain a Capacity Supply Obligation for the same load reductions, the double-counting issue identified above could result in an under procurement of capacity. For example, assume an ICR equal to expected system load – e.g., 10 MW – and the Forward Capacity Auction ("FCA") procures 3 MW of DRRs and 7 MW of generation to satisfy the ICR. However, if the expected system load upon which the ICR is based already includes the 3 MW load reduction from DRRs participating in retail demand response programs, the actual load the ISO would see in real time will be 10 MW when the DRRs perform. And with only 7 MW of generation capacity acquired through the FCA, the system is deficient in serving real-time energy requirements by 3 MW. That is, by counting the 3 MW DRR as both a reduction in the ICR and as a capacity supply resource, the ISO would end up under-procuring the ICR by 3 MW as 7 MW of generation cannot supply 10 MW of load. The resulting under-procurement of capacity could be addressed by increasing the ICR by 3 MW so that the DRRs can acquire Capacity Supply Obligations without displacing the acquisition of needed capacity. However, increasing the ICR in this manner does not produce any incremental reliability benefit because the reliability benefit of the DRRs was already captured through the

[5] *See* 225 CMR 21.05(6)(b).
[6] *See* 225 CMR 21.02.
[7] *See* Order No. 2222 at PP 160-161. The ISO further notes that double counting is generally problematic as it could distort price offers into wholesale markets that affect price formation and increase total system costs, result in cost-shifting from participating to non-participating customers, and potentially contribute to reliability issues.

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reduced load produced in response to retail demand response programs. Thus, increasing the ICR in this manner would only serve to increase customer costs without increasing reliability benefits.

For these reasons, the ISO cannot support revised Amendment 1A as presented to the NEPOOL Participants Committee.

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