UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Electric Storage Participation in Markets	)	
Operated by Regional Transmission	)	Docket Nos. RM16-23-000
Organizations and Independent System	)	AD16-20-000
Operators	)	

COMMENTS OF ISO NEW ENGLAND INC.

ISO New England Inc. ("ISO-NE") hereby submits its comments in response to the above-referenced Notice of Proposed Rulemaking issued by the Federal Energy Regulatory Commission ("Commission") on November 17, 2016 (the "Storage NOPR").

ISO-NE supports the Commission's efforts to minimize barriers to the participation of electric storage resources and distributed energy resources in the markets administered by regional transmission organizations ("RTOs") and independent system operators ("ISOs"). These resources may add valuable fast-responding capability to the New England system, contribute to operational capabilities and, if implemented properly, can help to meet system reliability needs and improve the efficiency of the markets.

As discussed in detail below, however, ISO-NE urges the Commission to focus on the desired outcomes and to not be overly prescriptive about the specific mechanisms and rule changes required to better accommodate electric storage and distributed energy resources in the wholesale markets or about the timeline to implement those changes. The Storage NOPR contemplates significant changes that will require substantial time and effort to develop and implement – likely much more than the 18 months (from the date of the final rule) proposed in the Storage NOPR, especially with respect to aggregations of distributed energy resources.

This problem is compounded by the fact that the Commission has recently issued several significant orders and notices of proposed rulemaking that each will involve substantial and interdependent changes to the software governing the energy markets. It could be inefficient and costly, and needlessly risky, to impose specific, independent implementation timelines for these projects. Rather than require a series of changes to this critical software, the Commission should provide each RTO and ISO with the flexibility to combine and sequence these software implementation efforts as appropriate, even if that results in later implementation of any individual piece.

In a similar vein, the Commission should avoid imposing "one-size-fits-all" requirements without a compelling need to do so. In a number of areas, the Storage NOPR is overly prescriptive, and does not recognize that specific provisions that might be sensible for one RTO or ISO may make little sense for another. ISO-NE urges the Commission to provide substantially more flexibility for each RTO and ISO to develop solutions that meet the Commission's goals in a manner consistent with existing market structures and practices.

Finally, the Commission should ensure that it does not inadvertently require ISO-NE to abandon its technology-neutral approach to the markets. The Commission should clarify that its emphasis on "participation models" is not intended to require RTOs and ISOs to implement a system where electric storage is subject to different requirements than other technologies for providing the same products.

After addressing these general points in the introduction, ISO-NE responds below to many of the specific provisions set forth in the Storage NOPR.

I. INTRODUCTION

New England has a long history of allowing electric storage and distributed energy resources to participate in its markets. A significant amount of pumped-storage hydroelectric facilities has participated in the New England markets for more than 30 years, and the region has a long-standing model that allows distributed energy resources to participate in both the capacity market and as price-takers in the real-time energy market (as Settlement Only Resources). ISO-NE also has a Dispatchable Asset Related Demand ("DARD") model that allows for demand-side participation of load and behind the meter distributed energy resources. Additionally, ISO-NE will be fully integrating demand response resources into its energy and operating reserve markets on June 1, 2018,[1] which would permit any facility with behind-the-meter controllable load, generation, or storage – including facilities that can inject energy into the electric system – to participate in the region's capacity, energy, and operating reserve markets on a comparable basis with traditional generation resources.

In recent years, ISO-NE has made several significant changes to its market rules that further encourage and accommodate the participation of electric storage resources and other distributed energy resources. In 2008, ISO-NE developed the Alternative Technology Regulation Resource ("ATRR") construct to enable energy storage devices (and other distributed energy

[1] The full participation of Demand Response Resources in the Day-Ahead and Real-Time Energy Markets is the second stage of a two-stage implementation process, which was proposed by ISO-NE to comply with Order No. 745. The Commission largely accepted ISO-NE's proposal in the following orders: 138 FERC ¶ 61,042 (issued January 19, 2012) (order on the ISO's Order No. 745 Compliance Filing); Letter Order Accepting Demand Response FCM Conforming Changes, FERC Docket No. ER12-947-000 (issued April 17, 2012); Letter Order Accepting Market Rule 1 Clarifications to Transition Period Rules for Demand Response, FERC Docket No. ER12-1550-000 (issued May 29, 2012); 142 FERC ¶ 61,027 (issued January 14, 2013) (order on ISO-NE's Market Rule 1 Demand Response FCM Conforming Changes for Full Integration); 144 FERC ¶ 61,140 (issued August 20, 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); 150 FERC ¶ 61,007 (issued January 9, 2015) (order accepting ISO-NE's Tariff revisions to fully integrate Demand Response Resources into the reserve markets); and Letter Order Accepting Demand Response Changes, FERC Docket Nos. ER16-167-000 and ER16-167-001 (issued December 23, 2015).

resources) to participate in the regulation market in a manner that acknowledges the physical capabilities of these potentially limited energy devices.[2] Then in 2016, ISO-NE filed, and the Commission accepted, market rule changes that will allow storage resources that participate in the regulation market as ATRRs to be associated with a dispatchable generator and a DARD for purposes of also participating in the energy market beginning in December 2018.[3] This change will better enable all types of electric storage resources to provide energy, reserves and other ancillary services. Also in 2016, ISO-NE filed market rule changes to improve the modeling (to better reflect their physical characteristics) and compensation of DARD pumps, which result in lower financial risks for market participants with pumped-storage hydroelectric facilities, a type of electric storage technology, and more optimal day-ahead market schedules and real-time dispatch solutions for the market as a whole.[4]

ISO-NE supports the Commission's goal of better accommodating electric storage resources and distributed energy resources in the wholesale markets administered by RTOs and ISOs. As mentioned above, these resources may add valuable fast-responding capability to the New England system, contribute to operational capabilities and, if implemented properly, can help to meet system reliability needs and improve the efficiency of the markets. However, as discussed in detail below, the Commission should proceed cautiously and provide RTOs and ISOs and other impacted entities considerable flexibility in how and when to implement the

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[2] *See* Market Rule 1 Revisions Regarding the Provision of Regulation by Non-Generating Resources, FERC Docket No. ER08-54-006 (filed August 5, 2008); Letter Order Accepting Tariff Revisions to Market Rule 1 Concerning the Provision of Regulation, FERC Docket No. ER08-54-006 (issued September 15, 2008).

[3] *See* Market Rule 1 Revisions to Increase Resource Dispatchability, FERC Docket No. ER17-68-000 (filed October 12, 2016); Order Accepting Proposed Tariff Revisions, 157 FERC ¶ 61,189 (issued December 9, 2016).

[4] *See* DARD Pump Parameter Changes, FERC Docket No. ER16-954-000 (filed February 17, 2016); Letter Order Accepting Dispatchable Asset Related Demand Pump Parameter Changes, FERC Docket Nos. ER16-954-000, ER16-954-001 (issued March 22, 2016).

changes contemplated in the Storage NOPR. Before addressing the specific substantive provisions of the Storage NOPR, ISO-NE provides the following general comments.

A. The Commission's Proposal Does Not Provide Sufficient Time for Submission of Compliance Filings

In the Storage NOPR, the Commission proposes to require each RTO and ISO to submit a compliance filing within six months of the date of a final rule.[5] Given the extent to which the Commission proposes to require modification of existing market constructs and creation of new ones, ISO-NE does not believe that six months is sufficient for submission of a compliance filing (except perhaps for an ISO or RTO that is already largely compliant).

For New England, the proposed provisions would require substantial changes to many areas of the tariff. The Storage NOPR explicitly applies to a wide range of resource types and aggregations thereof, and explicitly requires that those resources be able to provide (to the extent they are technically capable) *all* of the products and services covered in the tariff. This will require careful and substantial assessment, analysis, and development across each of those products and services.[6] Additionally, the changes proposed by the Commission will likely have implications for the assumptions that are used in transmission planning and in interconnection studies. Moreover, the Storage NOPR is unusual in the extent to which it implicates resources in the distribution system, at least some of which will be located behind the retail customer meter

[5] *See* Storage NOPR at P 159.

[6] As just one of many possible examples, the Storage NOPR does not address the eligibility of existing distributed energy resources to participate in capacity markets like ISO-NE's Forward Capacity Market ("FCM"). While existing distributed energy resources should be able to participate in the day-ahead and real-time markets to provide the system with energy and ancillary services, care must be taken with respect to their participation in the FCM. One of the primary determinates of the amount of capacity that ought to be procured through the FCM is a load forecast. Existing distributed energy resources that have been in operation and that do not participate in the wholesale market would have reduced historical net loads upon which the load forecast is based. If existing distributed energy resources were to begin to participate in the FCM, their participation could cause an under-representation of the net load forecast and a resulting shortfall in the capacity requirement to be procured in the FCM. Solutions to these types of scenarios are likely to be controversial and will take time for RTOs and ISOs to develop, vet through the stakeholder and regulatory processes, and to implement.

and subject to state regulation and jurisdiction. Developing the market design, rules, and procedures for distributed energy resource participation as proposed by the Commission will require close collaboration with the affected distribution utilities (each with its own priorities and capabilities) across multiple states (in New England's case). This is not typically required for wholesale market changes and will certainly lengthen the process. Given these numerous and significant hurdles, the assessment and development process alone is likely to require more than six months to do properly before starting the formal stakeholder process.

Furthermore, the subsequent stakeholder process for a substantial and complex set of changes such as those contemplated in the Storage NOPR will require more than the minimum four months typically allotted for stakeholder review of smaller changes to the tariff. Changes of this magnitude, and potential contentiousness, can easily require six (or more) months of stakeholder meetings to reach resolution. For these reasons, ISO-NE urges the Commission to establish a compliance deadline that is no sooner than one year after issuance of a final order.

B. The Commission's Proposal Also Does Not Provide Sufficient Time for Implementation and Fails to Consider the Interplay Between Several Recent NOPRs

In the Storage NOPR, the Commission proposes to require implementation of the reforms to become effective twelve months from the date of the compliance filing.[7] The Commission specifically seeks comment on "whether the proposed compliance and implementation timeline would allow sufficient time for each RTO/ISO to implement changes to its technological systems and business processes in response to a Final Rule."[8]

Even in the absence of competing priorities or interdependent projects, it would be challenging to implement the changes contemplated in the Storage NOPR in only one year. The

[7] *See* Storage NOPR at P 159.

[8] Storage NOPR at P 160.

Commission proposes to require integration of electric storage resources and distributed energy resource aggregations into *all* of the markets administered by ISO-NE – energy, operating reserves, regulation, and capacity. This will require potentially substantial changes to most, if not all, of ISO-NE's systems and databases. Among other things, ISO-NE will have to make substantial changes to critical software that runs the energy markets, most notably to accommodate the new voluntary bidding parameters (such as minimum charge time and minimum run time) described in the Storage NOPR, to enable any sort of state of charge management by ISO-NE, and to enable distributed energy resource aggregations to participate under existing market constructs. Planning, developing, testing, and implementing such software changes is critical and time consuming, and could easily require more than one year to accomplish, as ISO-NE's experience with implementation of price-responsive demand demonstrates. ISO-NE is currently working to integrate demand response resources into all of the markets it administers. This effort began in February 2016 and is scheduled to be completed on June 1, 2018 – almost two and a half years. Integrating electric storage resources and distributed energy resources as contemplated by the Commission in the Storage NOPR would likely be as, or more, demanding in terms of effort and time required.

Additionally, ISO-NE must balance other high priority projects (some of which already have Commission-approved effective dates), and must account for the substantial interdependencies between the Storage NOPR and other recent directives from the Commission. ISO-NE is currently working on other high-priority initiatives that require significant effort from the same teams that will be needed to develop the software changes required by the Storage NOPR. Among other things, those teams are currently working on critical cybersecurity enhancements,[9] implementation of the price-responsive demand changes,[10] and implementation of the two-settlement capacity market design.[11] While ISO-NE believes that the changes contemplated in the Storage NOPR are important, they are not so pressing as to warrant delaying work on these other high-priority projects.

Moreover, the Commission has undertaken several rulemaking actions recently without acknowledging the significant interdependencies among them. In addition to the Storage NOPR, the Commission issued a final rule regarding offer caps in November 2016,[12] a notice of proposed rulemaking regarding fast-start pricing in December 2016,[13] and a notice of proposed rulemaking regarding uplift cost allocation and transparency in January 2017.[14] Each of these initiatives directly affects the functioning of the energy markets, and each will likely require significant, and costly, changes to the software and systems used to administer those markets. It could be enormously inefficient and costly to impose different implementation timelines for these projects. It could also be needlessly risky to develop, test, and implement these various changes to the energy market software in rapid succession and with heavily overlapping timelines.

It is also worth noting that market participants will need time to modify their own systems to interface with significantly modified ISO-NE systems. Market participants cannot

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[9] For a description of ISO New England's recent and ongoing cybersecurity initiatives, *see* https://www.iso-ne.com/about/regional-electricity-outlook/cybersecurity-initiatives.

[10] *See, e.g.*, Part 1 of Two-Part Filing of Demand Response Changes, FERC Docket No. ER16-167-000 (filed October 29, 2015); Letter Order Accepting Demand Response Changes, FERC Docket Nos. ER16-167-000 and ER16-167-001 (issued December 23, 2015).

[11] *See, e.g.*, Order on Compliance Filing, 149 FERC ¶ 61,009 (issued October 2, 2014).

[12] *See* Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators, 157 FERC ¶ 61,115 (issued November 17, 2016).

[13] *See* Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, 157 FERC ¶ 61,213 (issued December 15, 2016).

[14] *See* Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators, 158 FERC ¶ 61,047 (issued January 17, 2017).

productively start their own development work until ISO-NE has substantially completed its own efforts.

Finally, the Commission must recognize that the economic and secure operation of distributed energy resources, which by definition are located within a distribution utility's service territory, requires substantial infrastructure development on the part of the region's distribution utilities. This may include the development of advanced metering infrastructure to measure retail consumption separately from the output of distributed energy resources participating in the wholesale market in the same settlement interval, and to report telemetry data to the distribution utility as well as to ISO-NE to ascertain the impact of distributed energy resource dispatch on distribution as well as transmission system security. And while ISO-NE could provide data to distribution utilities on the location and dispatch of distributed energy resources participating in the wholesale market, distribution utilities must develop and implement distribution management systems to ascertain the impact of distributed energy resources on the distribution system. Without such systems, distribution utilities cannot meaningfully assess the impact of distributed energy resource dispatch on distribution system reliability, safety, and power quality. It is unclear how long it might take for distribution utilities to develop the requisite metering, telemetry, and distribution system management infrastructure.[15] Importantly, current practices of distribution system management may not support the envisioned operation of distributed energy resources. For example, distribution utilities may not plan for the allowance of active dispatch of resources on their systems in response to wholesale signals such as frequency response. Distribution utilities may not coordinate with wholesale operators the maintenance outages of distribution facilities when such

[15] At small levels of penetration, manual procedures and communication may mitigate the risks associated with the operation of these facilities in the distribution system; however, as the amount of distributed energy resources grows these practices will not ensure the distribution system can be operated reliably.

outages would have no impact on the transmission system – but those distribution outages may affect the operability of distributed energy resources. Therefore, the Commission needs to provide ISO-NE with a substantial amount of time to work with the region's distribution utilities to allow them to develop the infrastructure that would effectively interact with wholesale market systems so as to provide economic, safe, and secure electricity services to all of the region's electricity consumers.

For all of these reasons, rather than impose a specific implementation deadline, the Commission should allow each RTO and ISO to determine how best to design, develop, test, and implement these various changes to the markets. The RTOs and ISOs, with input from stakeholders, are best positioned to prioritize these efforts to maximize their benefits, and to group and sequence them to reduce their risk and cost. The Commission should not require implementation of the Storage NOPR changes within a year of the final rule. Instead, the Commission should provide each RTO and ISO with the flexibility to combine and sequence these implementation efforts as appropriate, even if that results in later implementation of any individual piece. ISO-NE believes that it would be appropriate for the Commission to require each RTO and ISO to include a discussion of expected implementation timelines in the compliance filing.

C. The Commission Should Grant Each RTO and ISO the Flexibility to Determine How Best to Achieve the Goals of the Storage NOPR in Light of Regional Differences

With respect to many of the provisions of the Storage NOPR, one size does not fit all. For both electric storage resources and distributed energy resources, the Commission's overall intent in the Storage NOPR is clear, and ISO-NE supports the general goals that the Commission has set forth. However, in a number of areas, the Storage NOPR is needlessly prescriptive, and the

Commission should understand that specific provisions that might be sensible for one RTO or ISO may make little sense for another. For example, the considerations of a single-state RTO (especially single states like California or Texas that have already largely implemented advanced metering infrastructure) are often different from those of an RTO covering multiple states where advanced metering infrastructure has yet to be widely installed. Furthermore, it is counterproductive for the Commission to dictate specific provisions regarding detailed processes that have developed differently in each RTO and ISO, such as participation agreements, asset registration, and communication and information flows among affected entities.

In any final rule resulting from the Storage NOPR, ISO-NE urges the Commission to provide substantially more flexibility for each RTO and ISO to develop solutions that meet the Commission's goals in a manner consistent with its existing market structures and practices. This will ensure an effective overall design and efficient implementation. In its discussion of the specific Storage NOPR provisions below, ISO-NE identifies a number of areas where the Commission should be less prescriptive.

D. The Commission Should Not Inadvertently Require ISO-NE to Reorganize its Markets and Tariff Around Specific Technology Types

An important strength of the wholesale markets administered by ISO-NE is that they are to a large extent technology-neutral. This has long been a core design objective of the New England markets, and ISO-NE has worked in recent years to improve this neutrality, by better defining products and ensuring that different technologies that can provide services in the energy, capacity, reserve, and regulation markets are able to do so. ISO-NE believes that its markets work best when market participants decide on their own – in response to clear rules and incentives – how best to provide the well-defined products and services needed to reliably and efficiently operate the system. To this end, the markets in New England, and the tariff that governs them, are (for the most part) organized by product – not by technology.

The tariff sets forth the requirements that a resource must meet to provide, for example, energy, capacity, or reserves, and any resource, of any technology type, that meets those requirements may provide that product. This is a flexible arrangement that allows for the inclusion of new technology types as they emerge and that encourages market participants to undertake any type of project that they believe can compete economically to provide that product. In the same vein, a resource that can meet the requirements of more than one market is free to participate in multiple markets.

ISO-NE regularly reviews its market rules as new technologies emerge (and as understanding of existing technologies improves), to determine if it should update its market structures and modelling to better integrate a technology into the markets (such as the development of a granular wind forecast to better predict the output of wind resources and addition of new offer parameters for pumped-storage hydroelectric facilities). To accomplish this, rather than create a distinct set of market rules for each new technology, ISO-NE's preferred approach is to work with stakeholders to better understand a technology's physical characteristics and to consider how to use this information when clearing the markets to more effectively operate the facility and optimize the power system.

ISO-NE is deeply concerned that the Commission's emphasis on "participation models" and market participant types is inconsistent with ISO-NE's core market design objective to focus on *products* rather than *participant types*. The Storage NOPR could inadvertently require ISO-NE to fundamentally alter its technology-neutral approach, with potentially negative consequences for the efficiency of the markets. The Storage NOPR contemplates requiring RTOs and ISOs to create a specific participation model for electric storage resources, and sets forth proposed requirements for that participation model. Following this approach literally would seem to require the creation of a separate mechanism for certain resources to participate in the wholesale markets, *ipso facto* on different terms than those applicable to other types of resources.

The Commission's emphasis on "participation models" has the unfortunate potential to allow resource owners to engage in participation model "shopping" (effectively, a form of tariff rule arbitrage). In doing so, resource owners are inefficiently induced to contort their particular technologies, assets, and registration to fit one "participation model" over another because of the inescapable differences in eligibility, performance obligations, dispatch rules, and so on. Such rule arbitrage is the antithesis of efficient market design. It motivates resource owners to select the "model" of their liking, rather than to provide the actual products – regardless of technology – that the RTO or ISO requires to operate the power system efficiently and reliably.

Therefore, the Commission should simply provide general guidance to RTOs and ISOs to examine the requirements associated with each market product, and to assess whether and how to revise those requirements to better accommodate electric storage resources. For example, it would helpful for the Commission to clarify that creating a "participation model" for electric storage resources means only that an RTO or ISO must establish a clear path by which electric storage resources can participate in the wholesale markets and that it is entirely reasonable for such a model to consist of a combination of existing market constructs as a way to fully enable the participation of storage. In this manner, the Commission's general goal of better access for these resources can be accommodated without creating disparate treatment for different technologies and without forcing RTOs and ISOs to dramatically overhaul numerous other market requirements. For these reasons, ISO-NE urges the Commission to make clear in any final order associated with the Storage NOPR that RTOs and ISOs are not required to adopt a specific "participation model" construct and are free to incorporate electric storage resources and distributed energy resources in a manner consistent with the RTO or ISO's existing market constructs, so long as the Commission's goals of allowing them to provide the products and services they are technically capable of are met.

II. COMMENTS REGARDING ELIMINATION OF BARRIERS TO ELECTRIC STORAGE RESOURCE PARTICIPATION IN ORGANIZED WHOLESALE ELECTRIC MARKETS

A. Eligibility of Electric Storage Resources to Participate in Organized Wholesale Electric Markets

1. Electric Storage Resources Should Be Eligible to Provide Any Product that it is Technically Capable of Providing, But the Commission Should Not Require Different Treatment for Different Technologies

ISO-NE supports the Commission's general goal that electric storage resources should be able to "provide any capacity, energy, and ancillary service that it is technically capable of providing in the organized wholesale electric markets . . . [as well as] services that the RTOs/ISOs do not procure through a market mechanism, such as blackstart, primary frequency response, and reactive power, if they are technically capable."[16] To that end, upon a final order by the Commission, ISO-NE will work to remove barriers and limitations that may exist to participation in its markets by electric storage resources. ISO-NE does not believe, however, that electric storage resources should receive different treatment than other resource or technology types.

As indicated in Part I.D above, the markets in New England are generally organized by product, with product-specific requirements that apply to any resource that wishes to provide that product, regardless of resource or technology type. This is a flexible arrangement that

[16] Storage NOPR at P 48.

encourages market participants to develop any type of project that they believe can economically meet the power system's needs. It would make the markets less efficient if the Commission were to require the creation of separate requirements for different types of technology to provide a particular product – indeed, creating different requirements for different participants providing the same product could pose challenging issues of discriminatory treatment. So, while ISO-NE certainly agrees that electric storage resources should be eligible to provide any product that they are technically capable of providing, ISO-NE again urges the Commission to clarify that it does not intend to create special rules for electric storage resources, and that electric storage resources should be eligible to provide any product for which it meets the same requirements that apply to all resources. The Commission should simply direct each RTO and ISO to revise the market requirements applicable to all resources such that electric storage resources are appropriately accommodated.

2. The Commission Should Not Require RTOs and ISOs to Abandon Co-Optimization of Energy and Reserves

In the Storage NOPR, the Commission indicates that all RTOs and ISOs co-optimize the dispatch and pricing of energy and ancillary services, but nonetheless poses a series of questions aimed at exploring the possibility of changes to dispatch and pricing that would allow electric storage resources to provide ancillary services without also offering energy.[17] ISO-NE strenuously opposes this approach.

In New England, energy and reserves are co-optimized, and the benefits of this co-optimization are significant and well established. Co-optimizing energy and reserves allows both products to be provided in an efficient and cost-effective manner. If energy and reserves were not co-optimized, and resources had the option of not submitting energy supply offers into the

[17] *See* Storage NOPR at P 51.

energy market, a resource may be counted as reserves when it would have lowered system-wide costs to dispatch that resource for energy. The magnitude of this potential problem increases with the number of resources permitted to offer only reserves. Furthermore, if electric storage resources were permitted to provide operating reserves without offering energy as part of normal dispatch – treatment that ISO-NE would likely then have to extend to all resources in the market – ISO-NE would still have to establish some sort of contingency energy market supply offer from the resource to optimize the re-dispatch of the system in response to a contingency, so that ISO-NE could prioritize the conversion of reserves to energy in a way that minimizes cost and maximizes social welfare. This would put ISO-NE in the untenable position of creating, out of whole cloth, an energy market supply offer on behalf of a market participant.

While ISO-NE agrees that better integrating electric storage resources in the markets is an important goal, it does not warrant abandoning the benefits of co-optimizing energy and reserves. Requiring RTOs and ISOs to allow electric storage resources to provide reserves without also offering energy could adversely affect price formation, would make the markets less efficient, and would make both products more costly. ISO-NE (again) does not believe that electric storage resources should be subject to different rules than other resource or technology types. Electric storage resources should be subject to the same rules regarding the co-optimization of energy and reserves as all other resources (including the sustainability requirements defined by NPCC).[18]

Finally if the Commission were to require RTOs and ISOs to do this, it is not at all apparent to ISO-NE how this could be achieved, from a technical standpoint. Resource co-optimization in the real-time market cannot be performed without the physical and economic

[18] *See* Regional Reliability Reference Directory #5, available at www.npcc.org/Standards/Directories/Directory_5-Full%20Member%20Approved%20clean%20-GJD%2020150330.pdf.

data supplied as part of an energy supply offer. The physical data supplied in the form of an energy supply offer includes ramp rates and other essential data that are necessary to determine reserve assignments correctly during real-time operations. The price data supplied in the form of an energy supply offer are necessary to determine how to prioritize the conversion of reserves to energy when contingencies occur that do not require deployment of all the system's real-time reserves (as is usually the case). In summary, it is not clear how, from a technical standpoint, it would be possible to co-optimize the real-time markets – one of the foundations of ISO-NE's real-time market design – if a resource that provides real-time reserves did not concurrently provide an energy supply offer.

For all of these reasons, ISO-NE strongly opposes requirement that electric storage resources – unlike all other resources – be exempt from having to submit energy supply offers in order to provide reserve market products.

B. Bidding Parameters for Electric Storage Resources

1. ISO-NE Generally Supports the Required Bidding Parameters, but State of Charge Warrants Additional Consideration

In the Storage NOPR, the Commission describes five bidding parameters that it proposes to require RTOs and ISOs to implement to accommodate electric storage resources: state of charge, upper charge limit, lower charge limit, maximum energy charge rate, and maximum energy discharge rate.[19] A resource participating in the markets as an electric storage resource would be required to submit the information described by these parameters. ISO-NE agrees that upper charge limit, lower charge limit, maximum energy charge rate, and maximum energy discharge rate are appropriate bidding parameters for electric storage resources. State of charge, however, warrants additional consideration.

[19] *See* Storage NOPR at P 67.

As an initial matter, to characterize state of charge as a bidding parameter is a misnomer. State of charge is better thought of as a constantly changing physical characteristic in real-time, especially in the case of storage resources that can alternate quickly between charging and discharging. Any participant or ISO-NE forecast of a resource's state of charge for purposes of participating in the day-ahead market for the next day, made several hours prior to that day beginning, likely has a high degree of error, especially for smaller storage facilities as defined by available energy, as opposed to maximum capability. In addition, there is inherent volatility in the real-time market that can result in real-time dispatch being quite different than a day-schedule for these types of flexible resources, even if the state of charge for use in the day-ahead clearing was precisely known.

ISO-NE agrees with the Commission's proposal to require that an electric storage resource's state of charge be telemetered in real time,[20] and that this information is needed for reliable and efficient system operation (it is especially important for understanding the ability of a storage device to meet the sustainability requirements associated with providing reserves). But ISO-NE strongly recommends that the Commission not require state of charge as a day-ahead or real-time bidding parameter, nor require any optimization of this type of parameter in the day-ahead or real-time energy market, and instead let the RTOs and ISOs develop practices around how best to obtain communication of a resource's current state of charge, utilize the state of charge information, and potentially require participants to manage their state of charge using their energy market supply offers and demand bids (as some storage resources in the ISO-NE energy markets do today).

[20] *See* Storage NOPR at P 67.

2. The Commission Should Not Direct Implementation of the Voluntary Bidding Parameters at this Time

The Commission describes four additional bidding parameters that it proposes to require RTOs and ISOs to implement for electric storage resources, but that would be submitted only at the resource's discretion: minimum charge time, maximum charge time, minimum run time, and maximum run time.[21] ISO-NE suggests that the Commission not impose this requirement, but rather let each RTO and ISO determine whether and how to implement these parameters sometime in the future based on the experience gained through working with different types of electric storage technologies. That these parameters would be voluntary indicates that they are not needed by all storage types, or needed to clear the markets or to operate the power system. Furthermore, adding additional parameters that may not even be used will add significant complexity to (and possibly delay) the implementation of these changes, with potentially little value.

This is another area where the Commission should choose to be less prescriptive and allow the RTOs and ISOs to gain experience with storage resources using the core, required bidding parameters described in Part II.B.1 above. ISO-NE would work with stakeholders in the future to determine whether additional parameters (voluntary or otherwise) should be added. For example, ISO-NE worked closely with the owners of the pumped storage hydroelectric facilities to understand their needs, which resulted in adding minimum down time and minimum run time parameters to the DARD pumps and requiring the submitted parameters to be one hour or less, consistent with the physical capability of the technology. Capping these parameters at one hour also allowed ISO-NE to avoid implementing complex commitment logic for DARD pumps that only less flexible resources would require. A prescriptive approach that mandated rigid

[21] *See* Storage NOPR at P 68.

implementation logic that would support potential future technologies that were not interconnected to the system, rather than providing ISO-NE with flexibility to adjust implementations as warranted, would have increased the complexity of the project and delayed implementation of these valuable market enhancements.

3. RTOs and ISOs Should Not Be Required to Manage a Resource's State of Charge, Upper Charge Limit, and Lower Charge Limit

The Commission proposes to require that each RTO and ISO allow electric storage resources to self-manage their state of charge, upper charge limit, and lower charge limit, subject to deviation penalties.[22] ISO-NE agrees with this requirement and believes that RTOs and ISOs should have the discretion to determine whether and under what circumstances it may want to manage an electric storage resource's state of charge.

In general, ISO-NE believes that an electric storage resource should be *required* to manage its state of charge, upper charge limit, and lower charge limit, consistent with the product it is providing. These resources will be participating in a competitive market, and the responsibility properly belongs with the market participant itself to accurately represent the resource's capability to the market. ISO-NE believes that it should not be in the position of managing risk for its participants, or making judgments on behalf of the participant on the value of stored energy at the present moment in time versus the potential future value of that energy, which in turn influences the decision to charge or discharge throughout the day. Participants in markets should independently evaluate market prospects and express those to the RTO or ISO by means of a price-based offer that can be understood and implemented unambiguously by the RTO or ISO's economic dispatch and can be properly reflected in market prices.[23]

[22] *See* Storage NOPR at PP 69, 70.

[23] ISO-NE does recognize, however, that it may be necessary at times for an RTO or ISO to posture resources, including electric storage resources, for reliability purposes.

4. Bidding Parameter Implementation Time Depends on the Particulars of the Final Order

The Commission seeks comment on the time and resources that would be necessary for each RTO and ISO to incorporate these bidding parameters into their modeling and dispatch software.[24] The answer to this question depends heavily on the specific provisions of the final order. If the Commission accepts ISO-NE's suggestions above to: (1) only require implementation of state of charge in real time as an information communication requirement (for example, via telemetered information); (2) not require implementation of the proposed voluntary bidding parameters; and (3) require participants to manage their own bidding parameters (except when reliability needs dictate otherwise), then the implementation effort will be substantially shorter and easier than if the Commission does not accept these suggestions. Even accepting these suggestions, however, the changes contemplated in the Storage NOPR are significant.

C. Eligibility of Electric Storage Resources to Participate as a Wholesale Seller and Wholesale Buyer

ISO-NE supports the Commission's proposed requirements that an electric storage resource be dispatchable[25] and eligible to set the wholesale market clearing price as both a seller and buyer, as well as the capacity price,[26] and that such a resource be able to participate in the markets as a price-taker.[27] ISO-NE does not believe that its existing market rules would limit the ability of an electric storage resource to set such prices (once the dispatchability provisions mentioned above are implemented in December 2018).[28] ISO-NE also agrees that electric storage

[24] *See* Storage NOPR at P 71.

[25] *See* Storage NOPR at PP 81-83.

[26] *See* Storage NOPR at PP 81, 84.

[27] *See* Storage NOPR at PP 81, 85.

[28] *See* Storage NOPR at P 84. *See also* footnote 3 above.

resources should be eligible for make-whole payments consistent with the make-whole provisions applicable to other resources.[29]

The Commission seeks comment on "whether there should be a mechanism that identifies bids and offers coming from the same resource that ensures the price for the offer to sell is not lower than the price for the bid to buy during the same market interval so that an RTO/ISO does not accept both the offer and bid of a resource using the electric storage resource participation model for that interval."[30] ISO-NE does not believe that any such mechanism is necessary. If a single electric storage resource submits demand bids and supply offers that offset in the manner described by the Commission, ISO-NE is planning (starting in December 2018) to send the resource a single dispatch signal that reflects the net supply and demand dispatch. Hence, this situation does not present a problem needing resolution; it is self-correcting and there is no need to develop a complicated and costly mechanism to prevent it.

Furthermore, this is another area in which the Commission should avoid being overly prescriptive – this is precisely the sort of issue that RTOs and ISOs routinely address in the normal course of market development, and have the expertise to address properly. Each RTO and ISO should be free to address issues of this sort if and as necessary, developing solutions tailored to the particular market design of the region.

D. Minimum Size Requirement for Electric Storage Resources

In the Storage NOPR, the Commission proposes that "the minimum size requirement to participate in the organized wholesale electric markets under the proposed electric storage resource participation model must not exceed 100 kW."[31] As discussed in Part I.D above, ISO-

[29] *See* Storage NOPR at P 85.

[30] Storage NOPR at P 83.

[31] Storage NOPR at P 94.

NE does not believe that the Commission should impose technology-specific requirements in this manner. The Commission should not impose a specific “participation model” approach on RTOs and ISOs, and should permit ISO-NE to work with the region’s transmission organizations and utility distribution companies to set size requirements that they can reasonably accommodate in both the short and long term.

Because the core market design approach used in New England is product based – not technology or “participation model” based – imposing this 100 kW minimum size requirement could force ISO-NE to change the minimum size requirement for all resources in all markets. ISO-NE will need to do further assessment to determine how this may implicate participation in the market of non-storage technologies and whether this entails any additional implementation complexity that might further increase the costs or time needed for implementation for ISO-NE.

This requirement may also increase costs and implementation time requirements for the region’s transmission organizations and distribution utilities, since storage resources (and distributed energy resource more generally) as small as 100 kW will likely be located primarily on the distribution system. These transmission organizations and distribution utilities would need time for implementation because they must install the metering infrastructure and implement accounting procedures to measure the consumption and output of a potentially larger number of storage devices (resulting from a smaller minimum size requirement) separately from other customer consumption within their service territories.

E. Energy Used to Charge Electric Storage Resources

In the Storage NOPR, the Commission proposes “to require each RTO/ISO to revise its tariff to specify that the sale of energy from the organized wholesale electric markets to an electric storage resource that the resource then resells back to those markets must be at the wholesale LMP."[32] While ISO-NE agrees with this general principle, implementing it properly may be complicated and will depend on the diligent participation of the region's transmission organizations and distribution utilities.

1. In-Front-of-Meter Electric Storage Resources

In New England, transmission organizations are tasked with metering the amount of energy sold and purchased in the wholesale market on an interval basis. Generally, the sale of energy produced in each interval by a generator in front of the meter – that is, a generator that produces and injects power into the grid for resale – is directly metered. The metering of energy purchases, however, is much more complicated. To understand the difficulties associated with the Commission's proposed requirements (and indeed, their potential infeasibility), it may help to explain how energy purchases are actually measured in New England.

Given the lack of advanced metering infrastructure in New England, load-serving entities (the wholesale buyers of energy) are charged for the energy consumed by their retail customers by measuring on an hourly basis the import and export of energy (adjusted for any directly metered generation or load assets) in defined "meter domains." Meter domains are specific areas of a transmission or distribution owner's network, defined specifically for load measurement purposes on an interval basis. Most energy consumption by retail customers within each meter domain is determined as the difference between imports and exports (that is, directly metered tie lines) into that meter domain adjusted for any directly metered generation or load assets. The amount of energy consumed in a meter domain is then allocated to "profiled load assets" within the meter domain, where each profiled load asset is an aggregation of retail customers served by a specific load-serving entity. The actual consumption of all customers comprising a load asset is

[32] Storage NOPR at P 100.

not measured directly.[33] Rather, using class-average load profiles developed from load research conducted by the transmission or distribution utilities, the energy consumed in a meter domain each hour is allocated to each profiled load asset.

Given this indirect approach to energy consumption measurement, if some individual customers or resources located within the meter domain are settled directly (that is, directly metered) in the wholesale market either as a load or a generator (or both as in the case of electric storage), revenue-quality interval metering must be installed on these customers directly. By doing so – and *only* by doing so – such a customer can be billed or credited on an interval basis at the wholesale rate for the energy they produced or consumed. Furthermore, and again only by doing so, can the amount of load or generation these customers consume or produce be subtracted from or added to the energy allocated to each meter domain, in order to prevent a misallocation of energy consumption to the remaining consumers in the meter domain. Presently, these detailed computations are conducted by the region's transmission organizations, who have varying capabilities in this regard, from manual to more automated processes.

Should the number of electric storage and distributed energy resources proliferate, many of the region's transmission organizations would have to implement more robust business and technology solutions. At higher penetrations of electric storage or distributed energy resources, advanced metering infrastructure and communication systems would be required. Deployment of such infrastructure is costly, would take time to implement, and is not under the direct control of ISO-NE.

In summary, without the deployment of advance metering infrastructure, implementation of this aspect of the Storage NOPR may not be feasible, and may create load mis-measurement

[33] In fact, the specific customers aggregated to each load asset are unknown to ISO-NE and may change daily per state-regulated retail choice.

problems for billing load-serving entities in each metering domain. ISO-NE urges the Commission to reconsider the requirements in the Storage NOPR in light of these observations, and to provide regional flexibility to address the Storage NOPR's objectives as the development of the required metering infrastructure permits.

2. Behind-the-Meter Electric Storage Resources

The proposed requirement that all energy used to charge a storage device that is located behind the retail meter (and that is later used to provide services back into the wholesale market) will require many different complex metering and accounting practices to identify how much of that energy is used for retail purposes and when. In order for ISO-NE to settle wholesale services at wholesale prices, sub-metering (that is, metering at the level of the storage device) would be required to identify and quantify the wholesale energy used to charge the storage device, and to quantify any wholesale market services provided separately from the energy used (or energy produced should the customer also have a behind the meter generator) by the retail customer.

In order to ensure that all wholesale transactions balance and that there is no double payment for discharging a storage device (or double charge for charging a storage device), the distribution utility would need to report the sub-metered information to ISO-NE for settlement purposes; furthermore, it would need to use the sub-metered information from the storage device to "reconstitute" the load (that is, to adjust measured net load) at the retail delivery point so as to determine the retail consumption (for retail billing purposes) absent the discharge of energy from the storage device. The same procedure must also be used to ensure that the retail customer is not double-charged for energy that the device stores – absent reconstituting the load at the retail meter, consumption measured at the storage device's sub-meter would be charged the wholesale rate, and that same amount would be reflected at the retail meter and charged at the retail rate.

This requires the distribution utility to develop the necessary accounting practices and ensure that the appropriate metering is installed, tested, and routinely read; otherwise, double-charging would be simply unavoidable. Moreover, clear rules will be needed to address circumstances where the use of the stored energy is unclear at the time of charging (for example, an electric vehicle that may use the electricity for driving the vehicle or sell the electricity back into the wholesale markets). Importantly, ISO-NE has no way to ensure compliance with a requirement that behind-the-meter sales for resale are metered and reported to ISO-NE for settlement without the cooperation of each distribution utility.

ISO-NE strenuously urges the Commission to acknowledge these limitations, and to not impose requirements on RTOs and ISOs that are simply infeasible to execute without a material potential for double-charging (or double-crediting) customers. Remedying this problem cannot be achieved unless and until the impacted distribution utilities report they have developed the necessary infrastructure, standards, and practices to support wholesale settlement of behind-the-meter storage facilities. Otherwise, the Commission risks creating adverse incentives and market inefficiencies that could undermine effective integration of electric storage devices as envisioned, and that could undermine the wholesale market settlement process. It is also important to note that these same metering issues also apply to the deployment of distributed energy resources.

Note that ISO-NE's compliance with the Commission's Order No. 745 (regarding compensation for demand response resources)[34] did not involve complicated sub-metering and accounting solutions on the part of distribution utilities to separate retail consumption from wholesale services like the ones discussed above. Demand response resources sell capacity,

[34] *See* Demand Response Compensation in Organized Wholesale Energy Markets, 134 FERC ¶ 61,187 (issued March 15, 2011).

energy, and ancillary services into the wholesale markets and their reduction in energy usage in response to ISO-NE dispatch instructions is estimated from measurements at the participating retail customer's retail delivery point. Under this approach, metering located at the participating retail customer's retail delivery point – which could be the distribution company's retail meter or separate metering installed, maintained, and read by the market participant – is used to develop both a customer "baseline" consumption level and to measure actual consumption during dispatch. The difference between the baseline and actual consumption during dispatch estimates the reduction in energy usage in response to dispatch, which is then settled at the wholesale price. Retail settlement of the participating customer's consumption continues to be based on the retail meter data without any adjustment.

Under that approach, the distribution company need not install any additional metering or adopt any accounting practices to separate wholesale from retail activities – that is, the approach used for demand response resources pursuant to Order No. 745 requires no incremental effort from the distribution utility whatsoever. This is an ill-conceived approach from a market design standpoint, however. Specifically, the consequence of this simplicity is the duplication of compensation. When the demand response resource responds to dispatch, it receives both a wholesale market payment and a reduction in retail charges for the same reduction in energy usage. This is the well-known double-compensation problem that comprised ISO-NE's principal objection to Order No. 745.[35]

In the Storage NOPR, in contrast to Order No. 745, the Commission seems intent on avoiding such duplication of compensation by clearly separating retail from wholesale

[35] *See, e.g.*, Maximizing Net Benefits Using Price-Responsive Demand Response, presentation of Robert Ethier at Technical Conference on Demand Response Compensation in Organized Wholesale Energy Markets in Docket No. RM10-17-000 (September 13, 2010); Comments of ISO New England Inc., filed in the Commission's Supplemental Notice of Proposed Rulemaking and Notice of Technical Conference in Docket No. RM10-17-000 (filed October 13, 2010).

activities.[36] The Commission should also carefully consider that the Storage NOPR provisions create different pricing schemes for behind-the-meter resources that might choose to participate in the wholesale markets either as demand response or pursuant to the Storage NOPR provisions – a form of 'rule arbitrage' that could skew incentives and reduce market efficiency.

An alternative approach would be to allow a customer with storage or other distributed energy resource to participate directly in the wholesale market and be charged or credited at wholesale prices for its entire net load as measured from its retail delivery point. This approach is consistent with ISO-NE's current Asset-Related Demand ("ARD") and Dispatchable Asset Related Demand rules. The advantage of this approach is that only one meter, located at the customer's retail delivery point, is needed to measure net consumption – no sub-metering or special accounting practice is needed, and the economics associated with such an approach is the same as that achieved by the more complicated method described above (involving sub-metering and reconstituting the load at the retail delivery point).

Implementing such an approach, however, implicates the region's transmission organizations in the same way as that described above for in-front-of meter electric storage resources – should the number of electric storage or distributed energy resources proliferate utilizing the Asset-Related Demand and Dispatchable Asset Related Demand constructs, the computations that transmission organizations must conduct to settle electric storage or distributed energy resources separately from other load assets would likely become unmanageable and would require implementation of advanced metering infrastructure.

Finally, ISO-NE requests that the Commission clarify that the rules proposed in the Storage NOPR would not prohibit wholesale market participation by storage that participates as

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[36] *See* Storage NOPR at PP 102, 134.

a demand response resource (where storage can sell capacity, energy, and reserves, but does not pay the wholesale price for charging) and an ATRR only (where storage can sell regulation, but does not pay the wholesale price for charging).

III. COMMENTS REGARDING PARTICIPATION OF DISTRIBUTED ENERGY RESOURCE AGGREGATORS IN THE ORGANIZED WHOLESALE ELECTRIC MARKETS

A. Eligibility to Participate in the Organized Wholesale Electric Markets through a Distributed Energy Resource Aggregator

1. The Commission Should Not Require ISOs and RTOs to Accommodate Aggregations of Different Types of Distributed Energy Resources

In the Storage NOPR, the Commission proposes to require that ISOs and RTOs allow aggregations of different types of distributed energy resources to participate in wholesale markets. For example, the Commission states that “there may be different types of resources in these aggregations, some in front of the meter, some behind the meter with the ability to inject energy back to the grid, and some behind the meter without the ability to inject energy to the grid.”[37] Elsewhere, the Commission states that aggregated distributed energy resources may be able to “meet any minimum size and performance requirements, particularly if the operational characteristics of different distributed energy resources in a given distributed energy resource aggregation complement each other.”[38] Further, the Commission defines distributed energy resources “as a source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, thermal storage, and electric vehicles and their supply

[37] Storage NOPR at P 151.

[38] Storage NOPR at P 125.

equipment."[39] Taken together, these statements suggest that the Commission proposes to require RTOs and ISOs to accommodate heterogeneous aggregations of distributed energy resources; that is, aggregations of different resource types, such that, for example, a single aggregation might consist of a battery, distributed generation assets, and electric vehicles.

Elsewhere in the Storage NOPR, the Commission suggests that distributed energy resource aggregations might be homogeneous; that is, limited to groupings of assets of the same type. The Commission discusses an example where resources would be permitted to "aggregate with other distributed energy resources with common physical or operational characteristics and qualify as a market participant using the [electric storage resource] participation model proposed here."[40] Context suggests that this statement might *only* apply to distributed energy resource aggregations participating as storage, but if so, this again serves to raise questions about whether and when distributed energy resource aggregations may be heterogeneous versus homogeneous.

ISO-NE strongly urges the Commission not to require RTOs and ISOs to accommodate heterogeneous aggregations, but rather provide flexibility for how to aggregate distributed energy resources consistent with the existing market design. ISO-NE believes that heterogeneous distributed energy resource aggregations will greatly limit the RTO or ISO's ability to maximize the benefit to the system that could be provided by the component parts of the aggregation, because the relevant operational capabilities will be camouflaged – or wholly lost – when the aggregator attempts to formulate and submit an offer to represent the blended or averaged capabilities of the components. Limiting distributed energy resource aggregations to assets that have common physical or operational characteristics – homogeneous groupings – avoids many of these problems.

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[39] Storage NOPR at note 2.

[40] Storage NOPR at note 66.

Aggregating distributed energy resources is a means to enable participation of these smaller resources in the wholesale markets. But it is important to keep in mind that aggregation itself is not the goal. The Commission must balance the benefit of providing greater access to these resources against the costs. Aggregations of dissimilar resource types will reduce transparency and the accuracy of information available to the RTO or ISO and distribution companies in the operation of the power system, may make it very difficult for participants to properly reflect their aggregation's capability to the market (greatly reducing the benefit of these resources), and may make monitoring and mitigation of their offers more difficult. Moreover, there are a number of reasons to doubt the desirability or efficacy of heterogeneous aggregations of distributed energy resources.

First, ISO-NE believes that any load that participates on the supply side as demand response (that is, participates under the Order No. 745 framework using a baseline to calculate the resource's performance) is specifically excluded from participating as part of a distributed energy resource aggregation. These have distinct settlement rules that cannot be mixed with other supply resources and must remain separate. For example, Order No. 745 recognized that payments to resources supplying demand response in the real-time energy market creates a settlement imbalance in which the amount of supply provided exceeds demand by the amount of real-time demand response produced. ISO-NE addressed this shortcoming by not including payments and charges associated with demand response resources in the real-time energy market settlement, but rather allocated these to load effectively as an uplift charge. If an aggregation included demand response and non-demand response resource components, ISO-NE would need to establish rules to disaggregate these components for purposes of settlement – rules that at best would be complicated, and at worst infeasible. All of that would be unnecessary if demand response and non-demand response resources were required to participate in the market separately in the first place. If this is not the case, ISO-NE requests that the Commission clarify the rules that must apply to such resources.

Second, any load that participates on the demand side of the wholesale market should only be allowed to participate in aggregations with other load. Certain charges and credits are allocated to load (such as capacity charges, marginal losses, ancillary service charges, uplift charges, and real-time demand response charges) that are not allocated to supply resources. Any consumption on the power system must be settled as load and should not be allowed to be "self-supplied" by other resources within an aggregation in an effort to avoid or bypass these types of charges and credits. In other words load should be part of its own load-based aggregation and not grouped with distributed generation resources.

ISO-NE supports allowing aggregated load to participate in the markets under the ARD framework. It is important to note that in this demand-side framework, participants are responsible for regularly communicating their physical parameters (such as minimum consumption, maximum consumption), which becomes challenging for an aggregator as the number of facilities within an aggregation increases and is compounded by intermittent distributed generation whose output may fluctuate frequently. ISO-NE has no visibility into what is driving the load or could be changing the load in the future, and it is essential for a participant to provide accurate capability information to ISO-NE even if the assets were in an aggregation of different underlying technologies.

Third, electric storage resources also do not benefit from participating in aggregations with other non-storage distributed energy resources as the state of charge parameter would no longer be useful to the RTO or ISO in setting limits dynamically and the participant would have to manage the physical limits themselves as frequently as every ten minutes. In this scenario, the RTO or ISO loses visibility as to what the available energy is on the resource.

Fourth, intermittent resources that are aggregated with non-intermittent resources effectively would need to self-schedule their aggregated resource's output into the market and would be unable to take advantage of the do not exceed ("DNE") dispatch model. This eliminates ISO-NE's ability to dispatch these resources properly to manage congestion when transmission constraints bind, and largely limits the aggregated resource's ability to set the real-time market price, as opposed to other resources using the DNE dispatch model.

Fifth, non-intermittent resources with different physical and economic characteristics such as minimum run time, minimum down time, and minimum loading levels would effectively end up having to self-schedule into the market when dispatched to reflect these types of physical limitations (for example, aggregation offers with a one hour minimum run time, but has portions of their aggregation with longer run times and thus must be self-scheduled when dispatched within the aggregation) or self-schedule into the market to participate at all depending upon the nature of the aggregation. If ISO-NE dispatches a resource that looks flexible, but then the resource needs to self-schedule to meet its physical requirements, ISO-NE might have selected a different resource to more cost effectively meet the system need. Self-scheduling creates added financial risk for the participant, can reduce the efficiency of the dispatch, and can contribute to creating uplift or exacerbating excess generation conditions.

Finally, ISO-NE is steadily transitioning the energy market design away from self-scheduling, and toward requiring all energy supply (and demand) to be priced. This is fundamentally a more efficient, cost-effective market design than one where many resources self-schedule energy production and consumption. As examples of this ongoing effort, ISO-NE has made DNE dispatch changes that required certain intermittent resources to be dispatchable, as well as technical improvements contained in the dispatchability provisions that will become effective in December 2018.[41] A Commission requirement to accommodate heterogeneous groupings of distributed energy resources would represent a significant step backwards in that effort. It would likely result in more self-schedules into the market that the RTO or ISO would not be able to dispatch and thus potentially create more unpriced manual operator actions (and possibly more administrative pricing) to manage system conditions. While allowing aggregations only of distributed energy resources with common physical and operational characteristics does not necessarily address all of the foregoing issues with integrating distributed energy resources into the markets, that approach would be superior and consistent with the dispatch framework that ISO-NE uses in operating its system.[42]

For all of these reasons, ISO-NE strongly urges the Commission to not require accommodation of heterogeneous aggregations of distributed energy resources. The Commission should instead provide flexibility to RTOs and ISOs to determine how best to accommodate these resources, which may be best achieved through a combination of modifications to size limits and specific aggregation rules. Allowing RTOs and ISOs to work with their stakeholders to evaluate the most effective manner to integrate distributed energy resources, balancing

[41] *See* footnote 3 above.

[42] For supply-side resources ISO-NE provides three dispatch approaches in the energy market: Desired Dispatch Point ("DDP"), Do Not Exceed ("DNE"), and "limited energy," (which will become effective in December 2018). For demand-side resources, there are two dispatch approaches in the energy market: DDP and limited energy (again, effective in December 2018). The supply-side DDP dispatch model is used for resources that have control over their input fuel. The supply-side DNE dispatch model is used for resources that do not have control of their input fuel and uses a forecast model to ensure optimal use of the transmission system and the fuel available to these intermittent resources. The limited energy dispatch model builds upon the same framework as the DDP dispatch model, but also uses the state of charge to constantly modify maximum limits to respect the available energy and unused storage to ensure proper reserving accounting and achievable dispatch instructions.

reliability, market efficiency, and available information technology solutions will provide the best outcome for the participation of distributed energy resources in the markets.

2. The Commission Should Allow Each RTO and ISO to Determine Appropriate Size Requirements for Individual Distributed Energy Resources Participating in an Aggregation

The Commission seeks comment on whether it should establish minimum or maximum capacity limits for individual distributed energy resources participating in an aggregation,[43] and about the proposed requirement that distributed energy resource aggregations must meet the minimum size requirements of the participation model that they use to participate in the organized wholesale electric markets.[44] While ISO-NE generally believes that distributed energy resource aggregations should be required to meet the requirements applicable to other resources seeking to provide the same product, ISO-NE strongly believes that such determinations should be left to each RTO and ISO to determine in conjunction with stakeholders and in light of regional differences.

B. The Commission Should Give RTOs and ISOs Discretion Regarding Geographic Scope of Distributed Energy Resource Aggregations

The Commission proposes to require RTOs and ISOs to "establish locational requirements for distributed energy resources to participate in a distributed energy resource aggregation that are as geographically broad as technically feasible."[45] Furthermore, the Commission specifically seeks comment on the problems that might arise "if the distributed energy resources in a particular distributed energy resource aggregation are not limited to the same pricing node or behind the same point of interconnection."[46]

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[43] *See* Storage NOPR at P 135.

[44] *See* Storage NOPR at P 136.

[45] Storage NOPR at P 139.

[46] Storage NOPR at P 141.

ISO-NE strongly urges the Commission not to impose a requirement that RTOs and ISOs accommodate distributed energy resource aggregations at more than one pricing node or interconnection point. The Commission acknowledges critical reasons that RTOs and ISOs limit aggregations to a single node or interconnection point, such as concern about transmission constraints and price formation,[47] but then suggests that such concerns may be overly stringent and outdated in light of technological advances.[48] This suggestion is deeply concerning, and appears unfounded. To the contrary, ISO-NE believes that these concerns absolutely warrant the limitation and are not sufficiently addressed by technological improvements.

Energy markets are dispatched on a nodal basis. This is one of the fundamental precepts of efficient energy markets in a large transmission system. It allows an RTO or ISO to properly manage and price transmission constraints that arise, often unpredictably, between nodes. If distributed energy resources are permitted to aggregate across more than one node, an RTO or ISO's ability to manage that constraint is diminished, and it will not be able to reflect the constraint's impact properly in energy market pricing. A dispatch signal sent to a single resource will impact more than one node in a manner governed by the laws of physics which the RTO or ISO cannot control or modify, potentially worsening the situation rather than ameliorating it and possibly requiring manual operator actions to manage the constraint, rather than resolving the issue through the dispatch solution. Such outcomes would plainly undermine proper energy market price formation.

Allowing aggregations to span multiple nodes is even more complicated in the case of partial dispatch, in which case some or all of the change in output directed by the RTO or ISO might come at a node other than the one needed or intended by the RTO or ISO (see additional

[47] *See* Storage NOPR at P 138.

[48] *See* Storage NOPR at P 138.

discussion in Part III.C below on the use of distribution factors). Improved metering, telemetry, and communication do not address this problem, unless the Commission's vision is that the pieces of an aggregation that are at different nodes can submit separate demand bids and supply offers and can be dispatched separately (in which case the "aggregation" would seem to be nothing more than a roundabout means of lowering the size requirements of the resources that can participate in the markets, which could be accomplished to much better effect if done directly).

ISO-NE also believes that aggregations need to be further constrained to a single distribution utility (or meter domain) to facilitate coordination when dispatching an aggregation and use the existing meter domain energy market settlement infrastructure. For similar reasons as identified above, requiring aggregations to span multiple distribution utilities would again be nothing more than a roundabout means of lowering the size requirements of the resources that can participate in the markets, which could be accomplished to much better effect if done directly. The Commission should not impose such complexity in the initial implementation of these aggregations.

The required coordination between the RTO or ISO, the distributed energy resource aggregator, and the distribution utility (discussed in more detail in Part III.G below) will be sufficiently challenging in the simple case where there is only one distribution utility involved with each aggregation. If the Commission requires RTOs and ISOs to accommodate aggregations at more than one distribution utility (which could occur even at one pricing node), then the coordination of a dispatch of an aggregation could require communication with more than one distribution utility for each individual aggregation. Under the partial dispatch scenarios discussed above, it would prove challenging to provide meaningful information to the distribution utilities about the impact on their systems (since the RTO or ISO would not know how the underlying assets in each distribution utility's area will respond). In these cases, the RTO or ISO would need to determine how the aggregation would offer into the market, so the RTO or ISO would know how to communicate with each impacted distribution utility.

The energy market currently settles each asset that participates in the market at its location; however, allowing aggregations across distribution utilities would add additional complexity to the settlement processes requiring a different model for dispatch than is used for settlement. Each meter domain (which generally corresponds to a distribution utility) has an unmetered load asset which is used to assign any load that is out of balance in the meter domain (effectively what is left over based upon losses, directly metered tie lines, generation and load and profiled load). The ISO would need to collect meter-domain specific information per distributed energy resource aggregation in order to perform the unmetered load calculations which would then need to be rolled into the overall energy market settlement. In these cases an aggregation would effectively be settled by meter domain, even though the aggregation spanned multiple meter domains.

In sum, while ISO-NE supports the goal of accommodating well-designed distributed energy resource aggregations, the benefit they stand to provide does not warrant creating complex mechanisms that are difficult to administer; that could make it more difficult to manage congestion; that would negatively impact efficient, nodal price formation; that may negatively impact reliability; and that may not allow full utilization to enhance reliability. Managing assets in the distribution network on the scale that will be required by distributed energy resource aggregations will be a significant enough challenge without adding the additional complexities associated with managing a single resource at multiple nodes. Furthermore, it is not even clear whether there is sufficient interest from market participants in such an arrangement to warrant their development.

For these reasons, ISO-NE strongly urges the Commission not to impose a requirement that RTOs and ISOs accommodate distributed energy resource aggregations at more than one pricing node or interconnection point at this time. Instead, the Commission should allow each RTO and ISO to develop and implement these aggregations at a single node with flexibility for how to address scenarios where an aggregation at a node may span multiple distribution utilities. With the benefit of experience, RTOs and ISOs can work with stakeholders in the future to determine whether and how to explore expanding the geographic scope of these aggregations further.

In response to the Commission's question regarding whether commenters "would prefer that we require the RTOs/ISOs to adopt consistent locational requirements," ISO-NE again urges the Commission to provide for flexibility to address regional differences. As a notable example, accommodating aggregations of distributed energy resources across more than one pricing node may be considerably more complex for a region having a mesh network, such as New England, than one having a largely radial network. In the latter case, the effect of aggregating resources in making congestion management less efficient may be a lesser concern. But this is not the case in New England, illustrating again the crucial importance of accommodating regional differences in any final order on distributed energy resources.

C. The Commission Should Not Direct the Use of Distribution Factors in the Administration of Distributed Energy Resource Aggregators

In the Storage NOPR, the Commission proposes "to require each RTO/ISO to revise its tariff to include the requirement that distributed energy resource aggregators (1) provide default distribution factors when they register their distributed energy resource aggregation and (2) update those distribution factors if necessary when they submit offers to sell or bids to buy into the organized wholesale electric markets."[49] The Commission furthermore proposes "to require each RTO/ISO to revise the bidding parameters for each participation model in its tariff to allow distributed energy resource aggregators to update their distribution factors when participating in the organized wholesale electric markets."[50] The Commission explains that these proposed requirements will enable an RTO or ISO "to know which resources in a distributed energy resource aggregation will be responding to their dispatch signals and where those resources are located."[51]

ISO-NE believes that it would be a mistake for the Commission to impose the use of distribution factors[52] in an RTO or ISO's administration of distributed energy resource aggregators. There are a number of ways that an RTO or ISO might choose to handle dispatch of aggregations of distributed energy resources, and the Commission should not impose on all regions an approach that happens to work in one. Rather, the Commission should allow each RTO and ISO to develop an approach that works well in light of each region's particular network configuration, infrastructure, and existing operational processes.

Distribution factors may be appropriate for some very small portions of the system – notably, a radial portion of the system. Indeed, the proposed rule appears to contemplate a power system in which a distributed energy resource is connected to a single node on the transmission system, such as in a radial system. In a radial configuration, a distributed energy resource that

[49] Storage NOPR at P 143 (footnote omitted).

[50] Storage NOPR at P 143.

[51] Storage NOPR at P 142.

[52] "Distribution factors", as used in the Storage NOPR refers to the proportion of a distributed energy resource that is physically located at a particular node or distribution line. This is in contrast to the widespread use of the term "distribution factor" or "power transfer distribution factor" which describes the incremental power flows that result from injections at a specific node on the power grid, and a corresponding withdrawal from a different node.

produces 1.0 MW would be modeled as impacting net load and supply at the single node to which it is connected by 1.0 MW. Radial configurations, therefore, are conducive to the provision of distribution factors that reflect the proportion of a distributed energy resource connected radially to a specific node on the electric system.

For a mesh network, however, such as most of New England, using distribution factors as the basis for dispatch is problematic. In a mesh network, each asset is connected to multiple nodes, and the impact on power flows to each of the connected nodes when the asset is dispatched up or down changes frequently whenever the grid topology is reconfigured. This may happen due to substation switching operations, planned transmission and distribution maintenance that takes facilities out of service for short durations, or unexpected transmission and distribution equipment outages. A participant would be unable to predict the changing power flows to multiple connected nodes without possessing the same detailed knowledge of grid configuration used by ISO-NE and the distribution utilities in real-time operations. As a result, any stated distribution factors could bear little relation to reality. That is, even if the aggregator knew precisely how much energy a distributed energy resource would produce at a given time in response to dispatch, it would not be able to accurately assess how that production would flow into the electric system at each node unless the aggregator modeled the entire system power in real-time – which it cannot do (lacking the extensive real-time transmission system information that ISO-NE employs for that purpose).

Furthermore, while distribution factors that specify what proportion of a distributed energy resource aggregation’s capability is located at which specific nodes might make some sense if every component of the distributed energy resource aggregation were only dispatched to its full capability or not at all, it is entirely unclear how they would apply if the aggregation were partially dispatched.[53] Distributions factors based upon the maximum MW output of an aggregation may be very different than the distribution factors at the minimum MW output. Thus aggregations that are composed of many different types of distributed energy resources with different physical characteristics and inherently different cost structures would need to make assumptions about the level of dispatch when determining the distribution factors in order to reflect their potential impact to the power system at different dispatch levels and different power flow conditions. If these resources were also providing reserves they would need to make similar assumptions for how the reserves would be distributed among different nodes. Because the level of dispatch is not known at the time distribution factors are submitted, using a single set of factors would be inherently inaccurate as dispatch levels and system conditions change. Given the potential future growth of distributed energy resources, accommodating them by building inherent inaccuracies into the power system in this manner seems ill-conceived.

Even in cases where there is a homogenous grouping of resources, such as an aggregation of electric storage resources with similar cost structures, the distribution factors could be different depending upon if the aggregation was charging versus supplying as a function of the state of charge of each underlying storage asset. As a simple example, imagine an aggregation of three 1 MW storage assets at different nodes with identical costs for charging and supplying. Asset A is fully charged, Asset B is fully discharged, and Asset C can either discharge or charge. If the aggregator participant was expecting the aggregation to be dispatched as supply, the distribution factors would be 50% for Asset A's node, 0% for Asset B's node, and 50% for Asset C's node. If the aggregator was expecting the aggregation to be dispatched as charging, the distribution factors would be 0% for Asset A's node, 50% for Asset B's node, and 50% for Asset

[53] This problem will be especially difficult if the Commission requires RTOs and ISOs to permit aggregations at more than one node, which ISO-NE opposes, as discussed in Part III.B above.

C's node. If the participant was expecting a partial dispatch instruction (based upon economics), these factors could be yet some other set of values.

In aggregations with mixes of storage and distributed generation resources, distribution factors may have to be negative to reflect where consumption may be occurring versus production. And depending upon the size (MWh capability) of the storage resources in an aggregation, the aggregator may have to update these parameters frequently (every 10 minutes) as the state of charge of these facilities (that is, the ability to charge and discharge) changes based upon the dispatch.

These issues, and the problems with the Storage NOPR's direction on aggregation, are compounded by their impacts on distribution utility power networks. The inability for participants to provide accurate distribution factors for the bulk power system (especially due to partial dispatch scenarios), implicates the ability of the RTO or ISO to coordinate with the distribution utilities. Specifically, the RTO or ISO will not be able to pass information on to the distribution utilities about how many MW are being dispatched at each node. Even in cases where the aggregation is at a node with a 100 percent distribution factor, the RTO or ISO may not be able to communicate to a distribution utility what assets are going to be dispatched under any partial dispatch scenario. It is possible that a single node could be associated with multiple distribution utilities, so while the RTO or ISO would know that it was expecting at the node, the RTO or ISO would not be able to communicate how much response was expected in each of the distribution utilities' service territories.

In scenarios where the distribution system is not radial to the transmission system, a single resource located in the distribution network may have sensitivities to multiple nodes in the transmission system. It is not reasonable for an aggregator to try to submit distribution factors for each node as they would not have visibility to these sensitivities. As an example, ISO-NE has addressed this problem with ARDs located in the distribution network by only supporting aggregations of ARDs that have similar sensitivities to each node, so that an aggregated node can be modelled to reflect the impacts to the system of the ARD for which the ARD has a 100 percent distribution factor. This approach may or may not be appropriate for distributed energy resource aggregations and would require further evaluation and coordination with the distribution utilities.

Importantly, there is no need for the Commission to force a distribution factor approach on all RTOs and ISOs.[54] Distribution factors are a mechanism for a participant with an aggregation spanning multiple nodes to communicate to the RTO or ISO where the aggregator expects injections or withdrawals to occur on the system on a nodal basis. There are other ways that an RTO or ISO might determine which resources in a distributed energy resource aggregation will be responding to the RTO or ISO's dispatch signals. For example, rather than providing distribution factors, an aggregator could report the expected MW capability at each node, or size limits for being dispatchable in the markets could be lowered, reducing the need to aggregate across multiple nodes to participate. This would achieve the same objective through a different mechanism. For these reasons, the Commission should respect regional differences and allow each RTO and ISO to work with its stakeholders to determine and develop the most appropriate approach to dispatch of distributed energy resources.

[54] The Commission seeks comment on "alternative approaches that may provide the RTOs/ISOs with the information from geographically or electrically disperse resources in a distributed energy resource aggregation necessary to reliably operate their systems." Storage NOPR at P 143.

D. The Commission Should Let Each RTO and ISO Determine What Information to Collect from Distributed Energy Resource Aggregators

In the Storage NOPR, the Commission details, over several paragraphs, the information that a distributed energy resource aggregator would be required to provide to the RTO or ISO. This information includes bidding parameter-type information,[55] information about each of the distributed energy resources in the aggregation,[56] and aggregate settlement data.[57] The Commission asks whether there are information and data requirements that other resources are subject to that should not apply to distributed energy resources in an aggregation,[58] and whether distributed energy resource aggregators should be required to provide any additional information.[59] The Commission even addresses the length of time that an aggregator should be required to maintain data regarding its distributed energy resources.[60]

These proposed provisions are far too prescriptive. The Commission should not include these sorts of details in a final order regarding distributed energy resource aggregators, and it is concerning that the Commission would consider imposing a single set of information requirements on all RTOs and ISOs. Each RTO and ISO has different processes and procedures in place that have evolved over time, that reflect different complex settlement and communication infrastructures, and that reflect important regional differences. Determining what information is needed from market participants, how and when to gather it, and how it should be updated and maintained is something that each RTO and ISO does routinely in the regular course of business. Each RTO and ISO has considerable experience administering such processes, and

[55] *See* Storage NOPR at P 145.

[56] *See* Storage NOPR at P 145.

[57] *See* Storage NOPR at P 147.

[58] *See* Storage NOPR at P 146.

[59] *See* Storage NOPR at P 147

[60] *See* Storage NOPR at P 147.

should be left to develop these requirements in conjunction with stakeholders in a manner consistent with existing practices and regional needs. It is clear that the requirements must not be onerous, and that the information and data requirements that apply to distributed energy resource aggregations must not pose inefficient or undue barriers to their participation. In a final rule, the Commission should limit its provisions regarding information and data requirements to such high-level guidance.

E. Modifications to the List of Resources in a Distributed Energy Resource Aggregation

In the Storage NOPR, the Commission proposes to require tariff modifications that would "allow a distributed energy resource aggregator to modify the list of resources in its distributed energy resource aggregation without reregistering all of the resources if the modification will not result in any safety or reliability concerns."[61] This requirement seems to be based on the experience of one market participant in PJM.[62]

ISO-NE agrees with the Commission that registration requirements should not present a barrier to the participation of distributed energy resources.[63] As with the information requirements discussed above in Part III.D, however, ISO-NE believes that the Commission is being far too prescriptive with respect to such provisions. ISO-NE already has processes in place with respect to the aggregation of some types of resources (notably demand response resources and ATRRs), which do not require re-registration of underlying assets as they change, and which do not present a barrier to participation. Rather than impose specific requirements about how each RTO and ISO should manage asset lists of distributed energy resource aggregations, the Commission should simply direct that registration requirements not present an undue barrier to

[61] Storage NOPR at P 149.

[62] *See* Storage NOPR at P 148.

[63] *See* Storage NOPR at P 148.

participation, and otherwise allow each RTO and ISO to work with its stakeholders to develop specific provisions that work for its region.

F. Metering and Telemetry System Requirements for Distributed Energy Resource Aggregations

In the Storage NOPR, the Commission seeks comment on "whether the RTOs/ISOs need to establish metering and telemetry hardware and software requirements for each of the different types of distributed energy resources that participate in the organized wholesale electric markets through distributed energy resource aggregations, as well as whether we should establish specific metering and telemetry system requirements and, if so, what requirements would be appropriate."[64]

ISO-NE has already established metering and telemetry requirements for resources participating in its various markets. Accordingly, the Commission need not establish specific metering and telemetry system requirements for distributed energy resources. Consistent with comments above urging the Commission to avoid being overly prescriptive and providing for regional flexibility, the Commission should permit ISO-NE to simply have distributed energy resources meet the existing metering and telemetry requirements specific to the markets in which distributed energy resources participate.

In New England, five-minute interval data is (or will be soon) used for energy, reserve, regulation, and capacity market settlement.[65] But depending on the market within which a resource participates, the telemetry requirement varies. For example, in the energy market,

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[64] Storage NOPR at P 151.

[65] *See, e.g.* Letter Order Accepting Implementation of Sub-Hourly Settlements, FERC Docket No. ER16-1838-000 (accepting change to five-minute settlement interval in the Real-Time Energy Market and for Real-Time Reserves effective March 1, 2017) (issued July 26, 2016); ISO New England, Inc. Filing in Compliance with Order No. 825, FERC Docket No. RM15-24-000 (tariff revisions to settle the Regulation Market on a five-minute basis effective December 1, 2017) (filed January 11, 2017); Order on Tariff Filing and Instituting Section 206 Proceeding, 147 FERC ¶ 61,172 FERC (accepting Forward Capacity Market design that includes measurement of scarcity conditions in five-minute increments beginning June 1, 2018) (issued May 30, 2014).

locational marginal prices are established every five minutes. Further, the capacity market utilizes a five-minute settlement interval to determine the performance of a resource – and ultimately its capacity settlement – in providing energy and operating reserves during capacity scarcity conditions. Since a five-minute settlement interval is used for resources participating in the energy, reserve, regulation, and capacity markets, five-minute interval data is needed. To the extent that an energy resource is measured using hourly revenue-quality interval meters, ISO-NE allows the use of telemetry data in interpolating hourly meter readings to determine output for each five-minute interval. Generally, telemetry data for resources participating in the energy markets is submitted to ISO-NE every ten seconds. However, resources participating in the regulation market must submit telemetry data approximately every four seconds in order to measure the resource's response to a four-second automatic generation control signal. ISO-NE recommends that distributed energy resources simply meet these same product-based metering and telemetry requirements.[66]

As the Commission notes, "there may be different types of resources in these [distributed energy resource] aggregations, some in front of the meter, some behind the meter with the ability to inject energy back to the grid, and some behind the meter without the ability to inject energy to the grid."[67] The Commission further proposes "that each RTO/ISO should rely on meter data obtained through compliance with … distribution utility or local regulatory authority metering system requirements whenever possible for settlement and auditing purposes, only applying additional metering system requirements for distributed energy resource aggregations when this

[66] Consideration should be given to adjusting the data from meter devices measuring the input and output of a distributed energy resource participating in the wholesale market for distribution losses since the "delivery point" for wholesale power is the transmission system.

[67] Storage NOPR at P 151.

data is insufficient."[68] The Commission is concerned that "metering and telemetry systems are often expensive potentially creating a burden for small distributed energy resources. While telemetry data about a distributed energy resource aggregation as a whole is necessary for the RTO/ISO to efficiently dispatch the aggregation, telemetry data for each individual resource in the aggregation may not be."[69]

Regardless of the type of distributed energy resource – regardless of technology and whether it is in front of the meter or behind the meter, and with or without the ability to inject energy to the grid – ISO-NE believes that every distributed energy resource should meet the same metering and telemetry requirements as all other resources. To address the metering and accounting practices that must be put in place to delineate between wholesale and retail activities,[70] an additional meter is required (and in New England, this likely means it must be installed because of the general lack of this type of metering infrastructure) to directly measure the output (or in the case of storage, both input and output) of the distributed energy resource. Given that an additional meter must be installed, additional metering costs cannot be avoided. Accordingly, these meters should be capable of measuring input and output for a five-minute settlement interval, and report telemetry data at the rates required of all other resources depending on the market within which the resource chooses to participate. And because the input or output of a distributed energy resource aggregation is equal to the sum of the input or output of the individual resources comprising the aggregation, metering and telemetry would be required for each individual resource. At this time, ISO-NE is not aware of any approach that can

[68] Storage NOPR at P 152.

[69] Storage NOPR at P 150.

[70] *See* Storage NOPR at P 102.

reliably measure the input and output of an aggregation of distributed energy resources without measuring each individual resource comprising the aggregation.[71]

It should be noted that in New England, the telemetry requirements for demand response resources are slightly different from that of other resources. While five-minute interval metering of each individual asset comprising a demand response resource is required for energy settlement, demand response resources must submit telemetry data every five minutes, and must submit telemetry data every one minute if the resource is to provide 10-minute operating reserves. These less stringent telemetry requirements were developed to allow a demand response resource to read the pulses sent out by the existing retail billing meter, which is owned and maintained by the distribution utility, to report settlement and telemetry data to ISO-NE. This approach avoided the need for demand response resources to install additional metering. But distributed energy resources generally cannot leverage the existing retail billing meter to report input and output given that the retail meter cannot measure wholesale and retail activity separately. So again, because a distributed energy resource must install a separate meter to measure its input and output separately from any retail consumption and production activity, ISO-NE believes that this device should meet the same meter data and telemetry requirements that apply to all other resources.

Finally, the ISO believes that it will be important to review the cyber-security implications of integrating distributed energy resources into the markets. While this is not

[71] ISO-NE is aware of proposals to use statistical means by which to estimate the real-time input and output of an aggregation of distributed energy resources without measuring each individual resource comprising the aggregation. By definition, such an approach introduces error given that the sample used to represent the entire population will vary from the population. These errors would be exacerbated by allowing heterogeneous technologies to participate in aggregations and allowing aggregations to consist of geographically dispersed resources. Further, attributing the impact of a statistically-measured and geographically-dispersed distributed energy resource aggregation on a nodal basis in order to determine distribution factors is not clear. Finally, the impact on transmission or distribution system operations of a given level of statistical error in telemetry data on distributed energy resource input and output is not known, and will likely vary by location. Accordingly, the Commission should not to require such approaches.

contemplated specifically in the Storage NOPR, there is increasing concern that the communication of metering, telemetry and other data originating from smaller, disaggregated resources could create a means by which to disrupt or hack into systems used by wholesale and distribution system operators. Thus, the risks associated with the transfer of metering, telemetry, and other data to system operators, and the potential impacts involving data confidentiality, integrity, and availability of critical information must be carefully assessed. This assessment should result in standards and guidelines designed to protect communication endpoints and pathways between the distributed energy resource, the resource's aggregator, the distribution utility, and the RTO or ISO. These standards and guidelines would guide the development of the final metering, telemetry, and communication system design, and would guide the implementation of business processes to monitor the operation of such systems to identify and address any potential or actual abuses.

G. Coordination Between the RTO or ISO, the Distributed Energy Resource Aggregator, and the Distribution Utility

ISO-NE agrees with the Commission that successful implementation of distributed energy resource aggregations will require close coordination between the RTO or ISO, the aggregator, and the distribution utility.[72] This is critical for the reliability and safety of both the distribution and transmission systems, and is also important in ensuring that the efficiency of the markets is not subverted by adverse incentives and potential double payments.

1. The Distribution Utility Will Have Primary Responsibility to Ensure that the Distributed Energy Resources in a New or Modified Aggregation Meet All Applicable Requirements

In the Storage NOPR, the Commission enumerates several important aspects of coordination between the RTO or ISO, the distributed energy resource aggregator, and the

[72] *See* Storage NOPR at P 153.

distribution utility with respect to registration of a new aggregation or modification of an existing aggregation. First, such coordination will "ensure that all of the individual resources in the distributed energy resource aggregation are technically capable of providing services to the RTO/ISO through the aggregator and are eligible to be part of the aggregation (i.e., are not participating in another retail or wholesale compensation program . . .)."[73] Second, such coordination will allow the distribution utility "to assess whether the resources would be able to respond to RTO/ISO dispatch instructions without posing any significant risk to the distribution system and to ensure these resources are not participating in any other retail compensation programs."[74] Third, this coordination will "provide the relevant distribution utility or utilities the opportunity to report such information to the RTO/ISO for its consideration prior to the RTO/ISO allowing the new or modified distributed energy resource aggregation to participate in the organized wholesale electric market."[75]

It is worth emphasizing the large and critical role envisioned here for the distribution utility in facilitating the participation of these assets in the wholesale markets. The Commission is correct that it is the distribution utility that will be primarily responsible for assessing whether the individual assets associated with a distributed energy resource aggregation are properly metered, are technically capable of providing service to the RTO or ISO, are not participating in another retail program, and are able to participate in the wholesale markets without safety or reliability risks to the distribution system, and to report all of this information to the RTO or ISO. These are roles the RTO or ISO cannot itself perform, and so the distribution utility will essentially be certifying to the RTO or ISO that the assets underlying a new or modified

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[73] Storage NOPR at P 154.

[74] Storage NOPR at P 154.

[75] Storage NOPR at P 154.

aggregation meet all of these requirements. The RTO or ISO will be dependent on the distribution utilities to ably perform these functions if distributed energy resource aggregations are to function as envisioned by the Commission. ISO-NE urges the Commission to explicitly recognize the RTO and ISO's limitations in this regard in any final order resulting from the Storage NOPR.

Further, the Commission must give clear guidance to distribution utilities regarding its proposal that "distributed energy resources that are participating in one or more retail compensation programs such as net metering … will not be eligible to participate in the organized wholesale electric markets as part of a distributed energy resource aggregation."[76] Certainly, there are a wide range of retail programs that could be construed as a "compensation program" within which a retail customer with a behind-the-meter distributed energy resource is participating. For example, is a customer purchasing its energy requirements at a time-varying retail rate designed to promote price-responsive demand ineligible for wholesale market participation? Are customers receiving system benefits charge subsidies, renewable energy credits, or tax incentives for its behind-the-meter distributed energy resource eligible? There is no clear or consistent means for the activities contemplated by the Commission to be executed without direct guidance to the reporting distribution utilities as to how such questions should be answered.

2. Ongoing Coordination Between the RTO or ISO, the Distributed Energy Resource Aggregator, and the Distribution Utility

ISO-NE agrees with the Commission that successful integration of distributed energy resources will also require close ongoing coordination among the RTO or ISO, the aggregator,

[76] Storage NOPR at P 134.

and the distribution utility.[77] The Commission specifically seeks comment on "the level of detail necessary in the RTO/ISO tariffs to establish a framework for ongoing coordination between the RTO/ISO, a distributed energy resource aggregator, and the relevant distribution utility or utilities."[78] As ISO-NE has stated elsewhere in these comments, the Commission need not and should not be overly prescriptive regarding the level of detail needed in each RTO and ISO's tariff regarding coordination among these entities. Each RTO and ISO has well-established processes and procedures in place regarding coordination and communications with market participants, and adapting and applying those provisions for new entities (such as distributed energy resource aggregators) is something that each RTO and ISO does routinely in the regular course of business. The Commission should allow each RTO and ISO to develop these requirements in conjunction with stakeholders in a manner consistent with existing practices and regional needs.

One particular facet of ongoing coordination deserves mention, however. As discussed above, there are some situations in which, to avoid resources being paid twice for providing the same energy, a distributed energy resource's retail metering will need to be adjusted to account for its wholesale activities. This will be an important adjustment to ensure that incentives are not skewed, double compensation is avoided, and ultimately that the markets work efficiently. Such adjustments to the resource's retail metering may be beyond ISO-NE's purview, and in any final order arising from the Storage NOPR, the Commission must consider and account for this limitation.

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[77] *See* Storage NOPR at P 155.

[78] Storage NOPR at P 155.

H. The Commission Should Issue No Directives Regarding Market Participation Agreements

ISO-NE urges the Commission to exclude from the final rule any specific directives regarding market participation agreements for both electric storage resources and aggregations of distributed energy resources. In New England, all market participants are subject to a single Market Participant Service Agreement, which requires market participants to abide by the tariff and applicable operating procedures. There are not different versions based on resource or technology type, and there are not different versions for different markets and services. There is no need to alter this simple and proven approach to accommodate either electric storage resources or aggregations of distributed energy resources.

With respect to electric storage resources, the Commission asks each RTO and ISO to specify "whether resources that qualify to use the participation model for electric storage resources will participate in the organized wholesale electric markets through existing or new market participation agreements."[79] Nothing in the Commission's Storage NOPR suggests that ISO-NE's existing Market Participant Service Agreement would be in any way inappropriate as applied to electric storage resources.

With respect to aggregations of distributed energy resources, the Commission states:

> Since the individual resources in these distributed energy resource aggregations will likely fall under the purview of multiple organizations (e.g., the RTO/ISO, state regulatory commissions, relevant distribution utilities, and local regulatory authorities), these agreements must also require that the distributed energy resource aggregator attests that its distributed energy resource aggregation is compliant with the tariffs and operating procedures of the distribution utilities and the rules and regulations of any other relevant regulatory authority. We therefore propose that each RTO/ISO revise its tariff to include a market participation agreement for distributed energy resource aggregators. We do not propose

[79] Storage NOPR at P 31.

> specific requirements for such agreements at this time, but instead seek comment on the information these agreements should contain.[80]

Again, ISO-NE does not believe that a new or different agreement is required to accommodate distributed energy resource aggregations. ISO-NE's existing Market Participant Service Agreement will adequately address the relationship between the ISO and the aggregator. Indeed, the existing Market Participant Service Agreement in New England currently, and successfully, covers entities that aggregate demand response resources. Moreover, there is no need for the Commission to be prescriptive about how each RTO and ISO will ensure that the individual resources in an aggregation comply with the applicable requirements and regulations – again, the current Market Participant Service Agreement requires such compliance. Likewise, there is no need for the Commission to require an attestation from the aggregator *that is part of the market participation agreement*.

Each RTO and ISO has different mechanisms in place to communicate with its participants, and to gather and verify information about the participant's assets. For example, in New England, these sorts of verifications are more typically addressed in the asset registration process, and ISO-NE can see no reason or benefit in the Commission requiring significant changes to the Market Participant Service Agreement when the same results can be obtained in a manner more consistent with existing processes. In any case, the RTO or ISO will have to coordinate closely with the affected distribution utilities, which might be a superior source of information about the underlying assets than the aggregator itself. For these reasons, the Commission should issue no directives regarding market participant agreements and should instead allow each RTO and ISO to determine how best to ensure that an aggregator's underlying

[80] Storage NOPR at P 157.

distributed energy resources are compliant with the tariffs and operating procedures of the distribution utilities and the rules and regulations of other relevant regulatory authorities.

IV. CONCLUSION

ISO-NE appreciates the opportunity to provide these comments on the Commission's Storage NOPR, and respectfully requests that the Commission carefully consider these comments in any subsequent rulemaking.

Respectfully submitted,

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