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June 8, 2021

Debra A. Howland
Executive Director
New Hampshire Public Utilities Commission
21 South Fruit St. Suite 10
Concord, NH 03301

Re: Docket No. IR 20-166
Investigation into Compensation of Energy Storage Projects for Avoided Transmission and Distribution Costs
Report of May 27, 2021 Technical Session and Request to Amend Procedural Schedule

Dear Ms. Howland:

On October 12, 2020, the Commission issued an Order of Notice opening the above-referenced proceeding, which established a timeline for comments and reply comments, and scheduled a technical session on January 25, 2021. After the January 25 technical session, Staff proposed a procedural schedule on behalf of the docket participants that included an opportunity for additional reply comments and an additional technical session on May 27, 2021. The Commission approved the proposed procedural schedule on February 9, 2021.

During the May 27 technical session, participants reached agreement that an additional comment opportunity and technical session would be of value to the Commission's investigation.[1] Participants further agreed that the additional comments should address topics including, but not limited to: (1) the impact of pending changes to the Open Access Transmission Tariff relating to load reconstitution; and (2) the relevant impacts of Senate Bill 91, if enacted.

Based on the technical session discussions, Staff requests the Commission provide an additional opportunity for comments, filed in this proceeding by July 7, 2021. Staff also requests that the Commission schedule a technical session on July 30, 2021, at 10 a.m., where the proceeding participants may discuss the additional comments.

[1] Attached to this Report are three presentations discussed at the technical session: (1) a presentation developed by Commission Staff summarizing the comments and reply comments thus far; (2) a presentation by ISO-NE regarding the impact and relevance of FERC Order 2222 to this investigation; and (3) a presentation of the ISO-NE Participating Transmission Owners which discusses the timeline for Open Access Transmission Tariff changes that are relevant to this investigation.

Furthermore, the Order of Notice in this proceeding directed that the Staff of the Commission issue a recommendation to the Commission on this matter by July 12, 2021. In light of the additional opportunity for comments and technical session, Staff requests, on behalf of the parties, that the Commission extend the Staff Recommendation deadline to September 13, 2021. Staff also requests that the Commission defer or suspend any previously established comment or hearing opportunities until after the Staff Recommendation is filed.[2]

Thank you for your attention to this matter.

Sincerely,

/s/ Brian D. Buckley

Brian D. Buckley
Staff Attorney

cc: Service List
Attachment

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[2] The Order of Notice in this proceeding currently provides an opportunity for written comments on the Staff Recommendation on August 13, 2021, and a public comment hearing related to the Staff Recommendation on September 3, 2021. Notably, the latest version(s) of House Bill 2 would alter RSA 374-H so that the Department of Energy is responsible for this investigation and report to the legislature, rather than the Commission.

New Hampshire Public Utilities Commission

Docket IR 20-166

Investigation into Compensation of Energy Storage Projects for Avoided Transmission and Distribution Costs

Technical Session

Draft Summary of Stakeholder Comments *for Discussion Purposes Only*

Concord, New Hampshire

May 27, 2021

Section A. How public policy can establish price signals for storage projects that value avoided transmission and distribution (T&D) costs while simultaneously reducing wholesale electricity market prices

A. Consensus: Accurate price signals exist for wholesale markets; insufficient price signals exist for communicating when and where storage provides distribution value in NH

B. LCIRP and Incorporation of Non-Wires Solutions (NWS)
   1. For avoided distribution costs, there is disagreement about whether NWS are considered on equal footing with traditional investments within the existing LCIRP processes. Several commenters reference Order No. 26,358.

C. Balancing Distribution and Transmission Needs
   1. Disagreement about whether distribution-sited storage can reliably provide savings in both spaces simultaneously

D. Tariff-based Solutions
   1. A variety of tariff solutions were suggested, largely including some variation of time-based pricing

Discussion

1. Is there double counting for storage which participates in wholesale markets but also avoids RNS/LNS? If so, how can this be avoided?
2. Could visibility into state of charge, loading order, allow better access to both wholesale/retail compensation?
3. Obstacles regarding non-coincident demand charges?
4. Advantages/disadvantages of tariff-based price-signals versus one-off solicitations that result from the LCIRP process?

Section B. How to compensate energy storage projects that participate in wholesale electricity markets for avoided transmission and distribution costs in a manner that provides net savings to consumers

A. Consensus: Ensure compensation reflects actual achieved ‘avoided cost’ or ‘benefit’

B. Consensus: VDER and locational value studies are a start; further studies may be necessary to address stand-alone and co-located storage

C. Consensus: Appropriate for compensation to be different for behind-the-meter (BTM), co-located (e.g., solar + storage), and grid-scale storage
   1. Disagreement about whether compensation should include normal rate treatment, utility-third party contracts, bill credits, rate adjustments, time-of-use rates, and/or up-front rebates for avoided distribution costs.

D. Consensus: Enable access to wholesale markets for projects that are also compensated for avoided T&D
   1. Disagreement about whether utility-owned storage may also participate in wholesale markets

Discussion

1. Is it feasible to base compensation on verified net transmission cost savings and reconcile costs annually in EDC/TCAM/Retail Rates filing?
2. How to ensure net savings to ratepayers if compensation is based on performance related to projected peaks, rather than verified transmission cost savings?
3. How to ensure that distribution projects avoided would have otherwise been built?
4. How to account for uncertainty associated with ISO-NE discussions regarding load reconstitution?

Section C. How best to encourage both utility and non-utility investments in energy storage projects

A. Consensus: Support for enabling technologies/investments
   1. Multiple utilities discuss the need for sophisticated distribution platforms for measurement, control, information sharing etc. (e.g., Grid Mod)
   2. Others discussed need for greater visibility into distribution system information (i.e., hosting capacity, peak loading, etc.) and interconnection guidelines and processes

B. General policies to encourage storage
   1. One utility stakeholder: Market should determine amount, technological configuration, timing of storage through appropriate price signals, compensation model that accurately reflects value, and efficient access to wholesale markets including through aggregations. Not supportive of mandates or excessive compensation levels for the New Hampshire market.
   2. Non-utility stakeholders suggested RPS carve out or setting a storage target
   3. Another stakeholder suggests prioritizing simpler approaches in the short-term (e.g., direct procurement mandates or fixed price program to compensate for discharging at certain times)

C. Encouraging utility investments
   1. Some stakeholders suggested an additional utility incentive to encourage utility implementation of NWS in order to counteract misalignment of utility incentive to select traditional infrastructure investment

D. Encouraging non-utility investments
   1. Some stakeholders suggested allowing utility to earn higher return on third-party projects to minimize incentive to discriminate against third-party ownership; potentially based on net ratepayer savings. Potential for retail market for DERs. TOU rates. Need for clear/streamlined interconnection requirements. Reduced interconnection costs.

Section C. How best to encourage both utility and non-utility investments in energy storage projects (*continued*)

A. Consensus: LCIRPs are an appropriate venue for evaluating storage as NWS
   1. Disagreement about whether Order No. 26,358's revised planning processes are necessary
   2. Disagreement about whether utilities should be able to own, or should be entitled to operational control, versus contracting with third-parties through incentives/penalties
   3. Disagreement about whether third-party solicitations should be required, or are necessary
   4. "Price to beat" or similar option supported by multiple stakeholders, in which utility publishes proposal detailing their NWS before third parties submit their own proposals
   5. Disagreement about NWA framework set by New York PSC suggested as a model (but with no wholesale market risk assigned to ratepayers). Utility stakeholder asserts there are problems with NY model: unwillingness to contract, requirements of technology agnostic RFPs leading to review of unrealistic submissions. A positive aspect cited included utility ability to earn return on incremental value of third-party owned systems.

Discussion

1. Is preference for non-utility ownership consistent with the requirements placed on utility ownership within RSA 374-G?
2. Are out-of-market policies (e.g., RPS carve-out, storage target, etc.) consistent with the emphasis on efficient and accurate price signals within RSA 374-H?
3. Are technology agnostic RFPs the best approach to NWS, or should the utility also play an enhanced role in evaluating DER potential, including, but not limited to, storage?
4. How might a utility performance incentive be structured to ensure net savings to ratepayers?
5. How might third-party compensation structure ensure net savings to ratepayers?

Section D. The costs and benefits of a potential bring your own device program; how such a program might be implemented; statutory or regulatory changes that might be needed to facilitate such a program; and whether such program is storage-specific or should apply to all DERs

A. Consensus: General support for a BYOD program which compensates DERs
   1. Some stakeholders recommend this be inclusive of all technologies which are dispatchable (i.e., load reduction and injection of power)
   2. Some stakeholders recommend near-term focus on storage/storage plus generation to ensure adequate focus
   3. Some stakeholders highlighted the likelihood that ratepayer benefits may not be achieved, even if BYOD participants/aggregators have been compensated

Discussion

1. Is current structure of pilots (i.e., SBC-funded pilots within NHSaves) appropriate for scaling or expanding BYOD programs?
2. Would an alternative mechanism promote transparency, accountability, and facilitate a performance incentive which more accurately aligns with ratepayer savings?
3. Are distribution rates the appropriate place for utilities to recover costs associated primarily with avoided transmission savings?
4. Is a working group appropriate to address issues relating to the BYOD program?

Section E. Any statutory changes the general court should implement, including, but not limited to, changes to or exceptions from RSA 374-F or RSA 374-G, to enable energy storage projects to receive appropriate compensation for avoided transmission and distribution costs while also participating in wholesale energy markets

A. RSA 374-G: Utility-Owned Storage as Distributed Energy Resource
   1. In RSA 374-G:2,I.(b), storage is explicitly defined as electric generation equipment, and in some cases, a distributed energy resource
   2. In RSA 374-G:2,II., definition of distributed energy resources excludes electric generation equipment interconnected to distribution system at a single point/customer premise that is greater than 5 MW
   3. RSA 374-G:3, I-III limits uses of energy produced by [at least partly] utility funded electric generation equipment (impliedly greater than 5 MW)
      a. Equipment owned by utility- shall be used to offset line loses or for utility's own use
      b. Customer owned/sited, non-renewable- shall be used to offset customer's own use
      c. Customer owned/sited, renewable- shall be used to offset own use, mostly
   4. RSA 374-G:4,II limits utility-owned DER investments to six percent (6%) of peak load

Discussion
1. Does definition of DERs as electric generation equipment (RSA 374-G:2,I.(b)) also impliedly include standalone storage under RSA 374-G:3, I-III?
2. What are the arguments for why utility-funded electric generation/storage projects should/shouldn't face the restrictions placed upon projects greater than 5 MW/6 percent of load?
3. How does revising the definition of DERs in RSA 374-G:2 compare to eliminating RSA 374-G:3, I-III entirely?

Section E. Any statutory changes the general court should implement, including but not limited to changes to or exceptions from RSA 374-F or RSA 374-G, to enable energy storage projects to receive appropriate compensation for avoided transmission and distribution costs while also participating in wholesale energy markets

A. RSA 374-F, III.: The Functional Separation Principle
   1. In RSA 374-F:3, III, the legislature required that the generation services should be at least functionality separated from transmission and distribution services. The primacy of this principle has been diminished by the *Algonquin* decision.

B. Discussion
   1. Does wholesale market participation constitute a generation service or generation-related service?
      a. Utilities bid EE programs into FCM, but do not own the EE assets
      b. Could be read as prohibiting utility-owned projects from participating in wholesale markets.
      c. But RSA 374-F:3 allows utility ownership of “small scale distributed energy resources,” and *Algonquin* diminished the importance of the functional separation principle in the context of the other principles.

C. Other statutes
   1. CLF suggests: (1) amending LCIRP statute to require utilities to consider storage alternatives to distribution upgrades, with no size limitations; (2) amending RPS to include a new class for energy storage, potentially with 50 percent cap for what can be utility-owned.

Section F. Any other topic the commission reasonably believes it should consider in order to diligently conduct the proceeding

A. Do Low-Moderate Income (LMI) customer avoided costs warrant additional compensation/price signals than other customers?
B. How might the current VDER study and locational value study results impact co-located storage compensation?
C. How could the interconnection process for storage and net metered devices be improved? Is it important for consistency across utilities, municipalities, and regionally (i.e., New England)?
D. Should the legislature address fire safety code implications for energy storage?
E. Would performance-based ratemaking position NWS on equal footing with utility investments while not impairing system reliability or increasing ratepayer costs?

Commenters and Docket Information

- Docket IR 20-166
- Comments Received From:
  - Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
  - Public Service of New Hampshire d/b/a Eversource Energy
  - Unitil Energy Systems, Inc.
  - Edison Electric Institute
  - Clean Energy New Hampshire(CENH)
  - Conservation Law Foundation (CLF)
  - Key Capture Energy
  - Joint Comments of Representative Lee W. Oxenham and Ian R. Oxenham, Esq.
- Comments are available in the online docket book: https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-166.html

MAY 27, 2021

FERC Order No. 2222 Overview and Compliance Update

New Hampshire Investigation into Compensation of Energy Storage Projects – Technical Session

Henry Yoshimura

ISO NEW ENGLAND

Participation of Distributed Energy Resource Aggregations in Wholesale Markets | WMPP ID: 155

- Order No. 2222, issued on September 17, 2020, requires that ISOs/RTOs create a market participation model that allows distributed energy resources (DERs) to provide all wholesale services that they are technically capable of providing through an aggregation of resources
- To comply, ISO/RTOs either need to:
  – Revise their tariffs consistent with specific requirements from the Order, or
  – Demonstrate how current tariff provisions satisfy the intent and objectives of the Order
- The ISO filed a motion to extend the compliance filing deadline to **February 2, 2022**
- The focus of today's presentation is on Order No. 2222:
  – Compliance directives
  – Elements of the ISO's initial compliance proposal
  – Elements for further consideration
  – Process going forward

Note: The Wholesale Market Project Plan (WMPP) is published biannually, in summer and winter, and describes the current status of market initiatives.

ORDER NO. 2222

Compliance Directives

Terminology

- A ***DER*** is "any resource located on the distribution system, any subsystem thereof or behind a customer meter… [that] may include, but are not limited to … electric storage resources, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment…." (Order No. 2222 at P 114)
- A DER aggregation or ***DERA*** is one or more DERs participating together in the wholesale markets, "which acts as a single resource" (*Id.* at P 180)
- A ***DER aggregator*** is "the entity that aggregates one or more distributed energy resources for purposes of participation in the capacity, energy and/or ancillary service markets of the regional transmission organizations and/or independent system operators." (*Id.* at P 118)

Key Compliance Directives of Order No. 2222

- Order No. 2222 has eleven key compliance directives:
  1. Allow DERAs to participate directly in RTO/ISO markets and establish DER aggregators as a type of market participant; DERAs may include more than one technology type, i.e. heterogeneous aggregations
  2. Allow DER aggregators to register DERAs under one or more participation models that accommodate the physical and operational characteristics of the DERA
  3. Address size requirements for DERAs and individual DERs
  4. Address locational requirements for DERAs
  5. Address distribution factors and bidding parameters for DERAs
  6. Address information and data requirements for DERAs

Key Compliance Directives of Order No. 2222 (cont.)

7. Address metering and telemetry requirements for DERAs
8. Establish market rules on coordination between the RTO/ISO, DER aggregator, distribution utility, and *Relevant Electric Retail Regulatory Authorities (RERRAs)*
9. Address modifications to the list of DERs in a DERA
10. Address market participation agreements for DER aggregators
11. Implement opt-in provision for distribution companies with ≤ 4 million MWh of annual sales

- In the following slides, we present the ISO's high-level design approach to comply with Order No. 2222, previously presented to NEPOOL stakeholders

ORDER NO. 2222

Elements of the ISO's Initial Compliance Proposal

DERs would be able to participate under existing models or the proposed new models

- DERs can currently participate in ISO markets using any of the ISO's existing participation models for which they qualify
  - Five ISO-administered markets:
    - Forward Capacity Market
    - Forward Reserve Market
    - Day-Ahead Energy Market
    - Real-Time Energy Market
    - Regulation Market
  - Eleven ISO-administered market participation models including:
    - Desired Dispatch Point Dispatchable Generator
    - Do-Not-Exceed (DNE) Dispatchable Generator
    - Settlement Only Resource/Generator (SOG)
    - Continuous Storage Facility (CSF)
    - Dispatchable Asset Related Demand (DARD)
    - Demand Response Resource (DRR)
    - Several others
- ISO does not plan to change the existing participation market models with the Order No. 2222 compliance proposal
  - DERs that are currently participating under the existing models will be unaffected by the proposal
- ISO expects to propose two new models to facilitate heterogeneous aggregations to participate in the markets

General DERA characteristics under the ISO's initial proposal

- A DERA would:
  - Be an aggregation of one or more DERs, depending on the size and location of the DERs
  - Include one technology type or multiple technology types
  - Be generation only, or load only, or generation and load
  - Be settlement-only or dispatchable
  - Could simultaneously participate in wholesale markets and retail programs
- It is the DERA, not the constituent DERs, that would be offered into the markets, potentially dispatched, and settled by the ISO

Initially Proposed Settlement Only DERA Participation Model

- Settlement Only DERA (SODERA) model would be an extension of Directly Metered Load Asset and SOG models with aggregation
- A SODERA
  - Is not dispatchable by the ISO
  - Must meet proposed revenue quality metering requirements
  - May inject and/or withdraw energy to or from the grid
  - May participate in the Forward Capacity Market
  - May buy and/or sell energy in the Energy Market
  - Cannot provide reserves or regulation
    - It is not dispatchable and does not provide telemetry to the ISO

Initially Proposed Dispatchable DERA Participation Model

- Dispatchable DERA (DDERA) model would be an extension of Continuous Storage Facility (CSF) model
- A DDERA
  - Must be capable of receiving and responding to electronic Dispatch Instructions
  - Must meet proposed telemetry and revenue quality metering requirements
  - Must have Designated Entity to perform dispatch service, and submit and manage bids and/or offers
  - May inject, withdraw, and regulate
  - May participate in the Forward Capacity Market
  - May buy and sell energy in the Energy Market
  - May provide Reserves and Regulation

Proposed DERA Metering and Settlement Rules

- For both SODERAs and DDERAs, we proposed that meter readers would report to the ISO a single meter value for the DERA, which is the sum of the meter values of the DERs comprising the DERA
  - If the DERA meter value shows energy production, the production amount will be credited at the locational marginal price (LMP)
  - If the DERA meter value shows energy consumption, the consumption amount will be charged at the LMP
  - As noted later in this presentation, the ISO is considering approaches that allow Demand Response Resources (DRRs) to participate as part of a DDERA and be compensated under the existing DRR participation model consistent with Order No. 745
    - The load reduction performance of DRRs would be added to the DDERA meter values

Proposed Size Requirements

For a DERA:

- Minimum size is 100 kW
- No maximum size limit

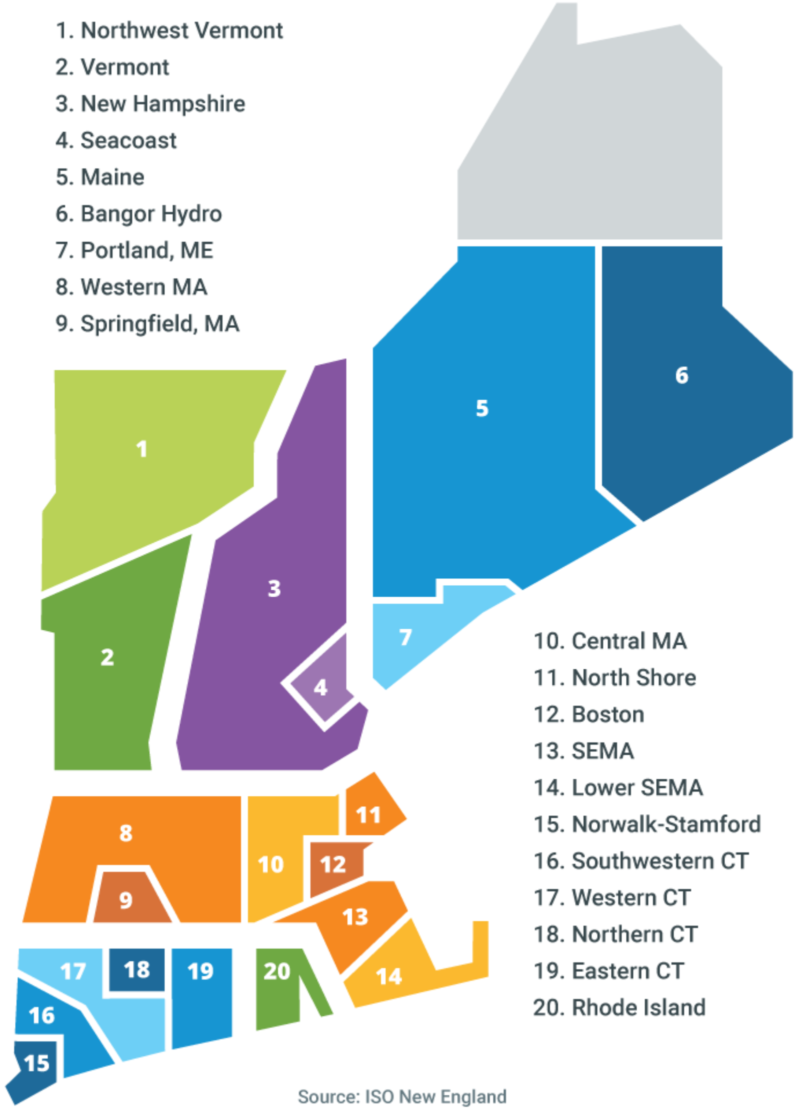
For a DER:

- No minimum size requirement
- No maximum size limit for a DER, provided that an individual resource with generation injection capability greater than or equal to 5 MW:
  - Cannot be a SODERA
  - Can participate as its own DDERA if it meets the definition of Distributed Generation
  - Can participate as a Generator Asset (but not as a DDERA) if it does not meet the definition of Distributed Generation
  - Consistent with the existing maximum size limit for a Settlement Only Resource and a Demand Response Asset
- Any DER greater than or equal to 100 kW, that is otherwise qualified to be a part of a DERA, may participate as a single resource DERA

Proposed Locational Requirements

- For a DDERA or a SODERA, all constituent DERs would be required to be located within the same metering domain and DRR Aggregation Zone
  - Metering domains generally follows a distribution utility's service territory within a single Load Zone
  - Currently, there are 20 DRR Aggregation Zones (map on next slide), which reflect transmission constraints
- The ISO's proposal would result in DERAs being single-node aggregations in ISO's market software, a DRR Aggregation Zone is a single Pnode
  - DER Aggregators are not required to provide distribution factors per the Order

New England Aggregation Zones



Source: ISO New England

DERA Registration – General Features Required by Order No. 2222

- DER aggregators must provide the ISO and the distribution utilities with information necessary to evaluate:
  - Eligibility of the individual DERs to participate in ISO markets through a DERA
  - Impacts on safe and reliable operation of the distribution and transmission systems
  - Information describing the DERA and constituent DER facilities, including:
    - Geographic and electrical location
    - Performance capabilities
    - Technology types
- Process must provide a timely, transparent review and not create barriers to entry
  - Provides adequate and reasonable time for distribution utility review
  - Specific review criteria
  - Up to a maximum of 60 days allowed
- Appropriate coordination with state and local regulatory authorities
- Flexibility for DER aggregators to add or remove DERs from a DERA
  - Notification of changes provided to ISO and distribution utilities without re-registering the entire aggregation
- Dispute Resolution procedures

Operational Coordination Framework

- With respect to ongoing operational coordination, Order No. 2222 requires that RTOs/ISOs:
  - Address data flows and communication between RTO/ISO, DER Aggregators, and the distribution utilities
  - Require DER aggregators to report any changes to offered quantity and related distribution factors that result from distribution line faults or outages
  - Include coordination protocols and processes for the operating day that allow distribution utilities to override RTO/ISO dispatch of a DERA to maintain the reliable and safe operation of the distribution system

ORDER NO. 2222

Elements for further consideration

Design Elements Where Changes are Anticipated or are Planned

- **DERA Participation Models:** The ISO explained to the NEPOOL Markets Committee on February 9, 2021 (slides 14-18) that its approach may be modified to better accommodate Order No. 745 compliant demand response resources
  - Current proposal compensates demand response by pricing the amount of energy withdrawn or injected into the grid by the DERA at the LMP, which is facilitated by demand response in the DERA
  - By contrast, Order No. 745 requires pricing the change in load (reduction-only) produced by demand response – the difference between baseline load and actual load during dispatch – at the LMP
  - Order No. 2222-A issued on March 18, 2021, strongly suggests that Order No. 745 compliant demand response must be allowed to be part of a DERA – *see* Order No. 2222-A at PP 23, 25, 26, 28, and 54
  - Accordingly, the ISO is considering the inclusion of Order No. 745 compliant demand response resources into a DERA

Design Elements Where Changes Are Anticipated or Are Planned (cont.)

- **Metering and Telemetry Requirements**
  - The current proposal requires DERs to be metered at the point of interconnection or retail delivery point of the facility with the grid
  - Permits DERs to be directly-metered at the device provided that the consumption or production of directly-metered DERs is separately reported and does not also increase or decrease the facility's load reported at the point of interconnection/retail delivery point - see slides 11-12 and 24-28 of the February 9, 2021 presentation
- This portion of the design may need to be modified based on the Meter Reader Working Group report and subsequent discussion at the Markets Committee
- And as previously discussed, the ISO is considering the integration of Order No. 745 compliant demand response into a DERA
  - The metering and telemetry requirements for DERAs consisting of Order No. 745 compliant demand response resources and other DERs needs further consideration

Design Elements Where Changes are Anticipated or are Planned (cont.)

- **Forward Capacity Market (FCM) changes**
  - The design presented to NEPOOL stakeholders on March 9, 2021 (slides 9 and 11-14) will need modification to accommodate Order No. 745 compliant demand response resources
  - The design described on March 9, 2021, slide 8 that applies the existing rules for overlapping interconnection impacts to DECRs, is being reviewed and may be revised

ORDER NO. 2222

Process Going Forward

Stakeholder Schedule

Stakeholder Committee and Date	Scheduled Project Milestone
MC: June 8-9, 2021 **TC: June 10, 2021**	Stakeholders to present any suggested changes to the ISO's proposal and propose suggestions for areas where design is under consideration – please notify the relevant committee Secretary by **May 28** if you want agenda time
MC: July 7-8, 2021 **RC: July 13, 2021** **TC: July 14, 2021**	Respond to suggestions made at the June Technical Committee meetings and to present any changes to its proposal
MC: August 10-11, 2021 **RC: August 17, 2021** **TC: August 24, 2021**	Continued discussion of the ISO's proposal focusing on what is new from the prior meetings
MC: September 13-14, 2021 **RC: September 21, 2021** **TC: September 28, 2021**	Present the final draft of the ISO's proposal and initial Tariff redlines; Members wishing to pursue alternative approaches should indicate their intentions to present at the October Technical Committee meetings

MC=Markets Committee, RC=Reliability Committee, TC=Transmission Committee, PC=Participants Committee

Stakeholder Schedule (cont.)

Stakeholder Committee and Date	Scheduled Project Milestone
MC: October 13-14, 2021 **RC: October 19, 2021** **TC: October 26, 2021**	Present any design refinements to the ISO's proposal and review Tariff redlines focusing on revisions since the prior meeting; Discussion of any potential amendments to the ISO proposal*
MC: November 9-10, 2021 **RC: November 16, 2021** **TC: November 19, 2021**	Discuss any remaining design refinements to the ISO's proposal and continue review of Tariff redlines focusing on what is new; Continued discussion of any potential amendments*
MC: December 7-8, 2021 **RC: December 14, 2021** **TC: December 13, 2021**	Vote on Order No. 2222 compliance proposal including any proposed amendments
PC: January, 2022	Vote on Order No. 2222 compliance proposal including any proposed amendments

* Members should provide their materials in advance so that they can be distributed by the posting date of the relevant Technical Committee meeting and should work with NEPOOL Counsel in the drafting of any desired Tariff changes or amendments to the ISO proposal

Regulatory Process

- The ISO intends to make its compliance filing on 2/2/2022 (assuming FERC approval of the ISO's compliance deadline extension request)
- The FERC requires each RTO/ISO to propose a reasonable implementation date with adequate support explaining how the proposal is appropriately tailored for its region and implements this final rule in a timely manner
  - Both the ISO and distribution utilities must consider the time it will take to implement the proposal
- The timing of FERC's review of the ISO's compliance proposal, and ultimate acceptance is uncertain
  - Timing could be influenced by stakeholder support or opposition, alternative perspectives from other RTO/ISO proposals, legal challenges and court proceedings

Additional Information

- The ISO recently launched a key project page for Order 2222. The page houses information including committee materials, regulatory filings and Orders, and other related materials
- The ISO posts regular updates on Order 2222 and other initiatives on the ISO Newswire

For More Information…

- Subscribe to the ***ISO Newswire***
  - [ISO Newswire] is your source for regular news about ISO New England and the wholesale electricity industry within the six-state region
- Log on to **ISO Express**
  - *ISO Express* provides real-time data on New England's wholesale electricity markets and power system operations
- Follow the ISO on **Twitter**
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- Download the **ISO to Go App**
  - *ISO to Go* is a free mobile application that puts real-time wholesale electricity pricing and power grid information in the palm of your hand

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Q&A AND DISCUSSION

Proposed changes to Monthly Regional Network Load calculation

Frank Ettori
(on behalf of Avangrid, Eversource, National Grid, VELCO, and Versant)
5/11/2021

Follow-up question

Q: Where is Monthly RNL used in Market Rule 1?

A: Monthly RNL is not used in Market Rule 1.

Follow-up question

Q:Where is Monthly RNL used in the Open Access Transmission Tariff(OATT)?

A:Monthly RNL is used once in the Definitions in Section I of the OATT, but only to say it's defined in Section II.21.2. Monthly RNL is used in the OATT and only a handful of times, as shown below:

- Section II.21.1 says Transmission Customers shall pay to the ISO an amount equal to its Monthly RNL times the applicable Local Network RNS Rate.
- Section II.21.2 is the determination of Network Customer's Monthly RNL – the language we have been mostly focused on.
- Section II.21.3 makes reference to the applicable Local Network RNS Rate being reduced to zero for monthly RNL associated with the charging load of an Electric Storage Facility (added in compliance with Order 841).
- Schedule 14 – Recovery of RBU Costs by Non-Incumbent Transmission Developers – Section 2.2 allows for ISO to allocate and invoice such costs on a pro-rata basis to Monthly RNL upon a FERC order approving costs for recovery.
- Schedule 16 – Blackstart Service – Transmission Customers are charged for Blackstart Service based on their pro-rata share of Monthly RNL.

Proposed tariff changes to RNL

Section I General Terms and Conditions

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses). ~~and shall not be credited or reduced for any behind the meter generation.~~ A Network Customer may elect to designate less than its total load as Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load. A Network Customer's Monthly Regional Network Load shall be calculated in accordance with Section II.21.2 of the OATT.

Tariff language to Monthly RNL

- **II.21.2 Determination of Network Customer's Monthly Regional Network Load:** Network Customer's "Monthly Regional Network Load" is its hourly load (including its designated Regional Network Load not physically interconnected with the PTF under Section II.18.3 of this OATT) coincident with the coincident aggregate load of all Network Customers served in each Local Network in the hour in which the coincident load is at its maximum for the month ("Monthly Peak"). Network Customer's Monthly Regional Network Load shall exclude (i) load offset by any resource that is not a Generator Asset, and (ii) load offset by the portion of the output of a Generator Asset that serves load located behind the same retail customer meter as the Generator Asset. For Regional Network Load located within the New England Control Area, the Monthly Regional Network Load of all Network Customers within a Local Network shall be calculated by the associated PTO. For Regional Network Load located outside of the New England Control Area, the Monthly Regional Network Load of all Network Customers shall be calculated by the associated PTO (in consultation with the ISO and the associated Balancing Authority).

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

Schedule

- Nov 17: PTO-AC discussion
- Dec 10:
  - Introductory discussion at Transmission Committee
- Jan:
  - Introductory discussion at Markets Committee
  - 1/26: Follow-up discussion at TC
- Feb:
  - Feedback from TC
  - Revised proposal at MC
- Mar 23: Revised proposal at TC
- April 6&27:
  - 4/6 Discussion at MC
  - 4/9 Unanimous Vote at PTO-AC
  - 4/27 Vote in favor at the TC
- May 11: Vote at MC
- June:
  - 6/3 Vote at NPC
  - File at FERC
- August: Effective date

Questions/Comments

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