memo

To: NEPOOL Markets Committee

From: Matt White, Vice President, Market Development and Settlements
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Subject: Flexible Response Services for a Dynamic System

In the 2025 Annual Work Plan, the ISO indicated that in Q1 it would share its next steps on flexible response capabilities to address greater operational uncertainties with an increasingly weather-dependent resource mix.[1] This memorandum summarizes the ISO's current direction and work underway on this topic.

In brief, the ISO is assessing a combination of new probabilistic forecasts and enhancements to the co-optimized energy and reserve markets. The approach adapts conceptually familiar market design elements for an increasingly dynamic system. We expect these enhancements can cost-effectively and reliably handle greater operational uncertainties with New England's evolving mix of weather-sensitive resources and net loads. Below we discuss the motivating issue, the ISO's current thinking and directions, and next steps.

Dynamic System Challenges

Uncertainties in available supply and consumers' demand are inherent features of power systems. Increasingly weather-sensitive net load (i.e., net of behind-the-meter generation) and the continued development of weather-dependent energy resources add new sources of uncertainty. Although forecasting improvements for weather-dependent energy resources' output can help reduce these uncertainties, forecasts remain imperfect. As a result, we anticipate it will become increasingly important for the region to maintain greater flexibility among its supply and demand resources during the operating day, enabling the system to reliably balance unanticipated changes in net load and renewables' output whenever they arise.

These issues are not unique to New England. Increasing operational uncertainties, a catch-all term for unanticipated fluctuations in net load and weather-sensitive supply during the operating day, has emerged as a concern in many regions.[2] To date, no standard or best practice has emerged among

[1] ISO New England's 2025 Annual Work Plan (October 11, 2024), slide 21. *Available at* https://www.iso-ne.com/static-assets/documents/100016/2025_awp_final_10_11_24.pdf.
[2] See generally *Modernizing Wholesale Electricity Market Design*, 179 FERC ¶ 61,029, at PP 5–6, 9–13 (2022).

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ISOs/RTOs for procuring, pricing, and maintaining sufficient flexibility to address this system need.[3] Nevertheless, given New England's continued development of renewable-energy resources (including significant behind-the-meter solar resources), we believe it would benefit the region's clean energy transition to proactively consider market and operational enhancements that can reliably accommodate these increasing operational uncertainties over time.

Markets and Flexibility

From markets and operations perspectives, there are three inter-related dimensions to this issue. The first, more operational one, is: how much flexibility is needed, under what conditions, and over what timeframes? The second, market-focused one, is: how to ensure the costs of that flexibility are transparently signaled to market participants, and those providing it are appropriately compensated? Third is the omnipresent question of how to achieve these goals cost-effectively, so that consumers' cost concerns are addressed and the system is operated efficiently?

At a precise level, none of these questions is simple to answer. Conceptually, achieving the first requires continuously "positioning" the system during the operating day with sufficient unloaded ramping capability (including "fast-enough" offline response capability) to balance any unanticipated changes in supply and demand. While there may be different ways to do so at a technical level, we think useful progress can be made on all three dimensions by leveraging the existing co-optimized energy/reserve market design framework to handle this dynamic system need.

Current Thinking and Directions

To address these questions, the ISO is assessing a number of potential enhancements to its suite of operational tools and the co-optimized energy and reserve markets. This effort presently comprises four distinct yet inter-related assessment areas:

1. Developing a dynamic, real-time probabilistic forecast of the system's energy ramping needs, in a way that can account for various sources of uncertainty in the system's near-term energy supply and demand;

2. Procuring dynamically-determined incremental quantities of existing real-time reserve products (10- and 30-minute reserves), in amounts that vary during the operating day based upon the probabilistic forecast of the system's near-term potential ramping needs;

3. Assessing a new, longer response real-time reserve product (such as a 60- or 90-minute reserve), also with dynamically-determined demand quantities;

4. Corresponding changes to the day-ahead market's ancillary service demand quantities (for existing and/or any new products), so the system is set up prior to the operating day consistent with anticipated real-time conditions.

[3] *Id.,* PP 21–23.

Probabilistic forecasts. The first of these areas reflects the fact that, increasingly, operational uncertainties can vary materially with system conditions from day to day and at different times of the day. As a simple example, at mid-day on a day with intermittent sun and clouds moving across the region, there can be considerable fluctuations in aggregate solar PV output and (therefore) net load on the bulk power system. This can create uncertainty in future net load from one dispatch interval to the next, and from hour to hour. In contrast, at (say) 3 AM on the same day, there is negligible uncertainty in solar PV output (as solar output at night is predictably zero). These dynamics make the system's energy ramping needs different from hour to hour, and from day to day.

Probabilistic forecasts seek to quantify, in a way that can be incorporated into operations and the markets, the likelihood (i.e., percentiles) of these potential changes to available supply or net load. Such forecasts provide useful information about the system-level energy ramping rates that may be required to reliably manage such uncertainties, and can (potentially) account for many sources of uncertainty. The state of statistical modeling and machine learning has progressed rapidly in the last few years. As such, we expect probabilistic forecasting models for near-term changes in the system's energy ramping needs can now be cost-effectively developed.

Reserves. The second and third areas in the above list examine how such probabilistic forecasts for near-term ramping needs can be incorporated into the markets. The goals in doing so are to ensure that improved information on near-term ramping needs is used cost-effectively, priced transparently, and results in the system maintaining (through co-optimization) energy ramping capability in amounts commensurate with system risk. The probabilistic forecasts provide a time-varying measure of this risk, and can guide how much incremental reserve capability is warranted at different times of day, and for different system conditions.

This potential approach not only reflects the increasing dynamics of New England's power system, but is also intended to achieve cost-effective solutions. By carrying less incremental reserves when net load uncertainty or ramping needs are forecast to be low, unnecessary costs can be avoided; and by increasing incremental reserves when net load uncertainty or ramping needs are forecast to be higher, reliability can be maintained (and with greater real-time price stability). Using the existing real-time market's co-optimization to procure the dynamically-determined incremental reserves (which provide ramping and offline fast-response capability) identifies the system's least-cost means to do so.

As to the specifics of how much incremental reserves to procure in the form of 10-minute, or 30-minute, or longer-response (e.g., 60- or 90-minute) reserve products, this requires empirical assessment. Ten-minute ramping capability can be essential to balance unanticipated changes in supply or net load that occur quickly, but 10-minute reserves are also the most costly timed-reserve product. Longer-response reserve products may have a much lower cost (as there is a greater supply of resources that can provide them), but their usefulness depends on how well our probabilistic forecasting tools can anticipate changing system ramping needs 30-, or 60-, or 90-minutes out. We expect to study this issue (e.g., via simulations) to inform any specific design proposals.

Day-ahead considerations. Last, while addressing operational uncertainties necessitates focusing on real-time markets and operating day conditions, conforming changes to the recently-introduced day-ahead ancillary services market may be appropriate. The rationale for doing so is not to change that design per

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se, but to make adjustments that may be necessary for the proposed real-time market enhancements. This could include addressing day-ahead versions of any new real-time reserve products, or modifying demand quantities to better account for the range of dynamic needs that may arise the next operating day. The particulars of what may be involved have not been evaluated, and remain an area for assessment.

Caveats. The foregoing thinking and current directions will continue to evolve as the ISO's assessment and modeling work proceeds. Evaluations sometimes generate new insights and promising alternative approaches. Still, we are mindful to not let the perfect become the enemy of the good in developing operational and market enhancements to support the evolving grid. New England's power system is becoming increasingly dynamic, and extending conceptually-familiar market designs with new probabilistic modeling capabilities appears a promising next step to reliably address increasing operational uncertainties and, in turn, cost-effectively support this aspect of the region's clean energy transition.

Next Steps and Timing

Three observations guide the ISO's current perspectives on the timing of these potential enhancements. First, the operational uncertainties we seek to address have not posed a reliability risk to date, but rather comprise a risk that – if unaddressed – will grow with time. Accordingly, there is time to evaluate and perform the assessments summarized above, discuss the findings and develop proposals collaboratively with stakeholders, and implement changes in coming years.

Second, the current directions summarized above will require quantitative modeling to develop and vet a probabilistic forecasting model, perform simulations to assess the efficacy of different incremental reserves, and evaluate whether these operational and market enhancements will achieve their intended goals. This is technical work that we anticipate to continue through 2025. Thus, a reasonable expectation for the ISO to begin discussions on a specific proposal, with qualitative and quantitative impact analysis information, would be sometime in 2026. We expect to be able to sharpen that timeframe as our assessment work proceeds.

Third, an important limitation on the ISO's resources lies on the implementation end. Presently, the ISO and its related vendors have a substantial queue of time-sensitive work ahead that will heavily load the ISO's implementation resources throughout 2025 and 2026.[4] Accordingly, we anticipate implementation of any specific proposal would be in 2027, as the resources necessary to implement it will not be available before then.

We welcome stakeholder feedback on this memorandum, and look forward to discussing these issues at the March NEPOOL Markets Committee meeting.

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[4] These include implementing FERC Order 881 (ambient transmission line ratings), Order 841 (day-ahead storage modeling enhancements), Order 2222 (distributed energy resource integration), the MW-dependent Fuel Price Adjustments, and several major IT infrastructure enhancements (on the latter, *see* 2025 Annual Work Plan, *op cit.,* slide 29).

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