memo

To: ISO New England

CC: NEPOOL Markets Committee

From: David Naughton, Executive Director, Internal Market Monitor, ISO New England

Date: February 4, 2026

Subject: Recommended Changes to the Day-Ahead Ancillary Services Market

The Internal Market Monitor (IMM) recommends three targeted market design adjustments to improve the cost effectiveness of the joint energy and day-ahead ancillary services (DA A/S) market. Specifically, we recommend:

1. **An upward adjustment to the Strike Price formulation** to better align it with the short-run marginal costs of resources providing these ancillary services.

2. **A downward adjustment to the Forecast Energy Requirement (FER)** to reflect the expected contribution of renewable generation.

3. **A review and potential downward adjustment to the non-performance factor (NPF)** included in the ten- and thirty-minute operating reserve requirements in both the day-ahead and real-time markets.

These recommendations are grounded in our ongoing analysis of DA A/S market outcomes, participant offer behavior, and discussions with market participants. Collectively, they represent narrow but meaningful refinements to key input parameters—changes that can enhance cost effectiveness while remaining aligned with the core objectives of the DA A/S design. They also address conditions that, based on current trends, are likely to persist as the region advances further into the energy transition.

We also recognize the concerns stakeholders have raised regarding DA A/S costs, particularly in the broader context of overall high energy costs.[1] In light of these concerns, we recommend that the ISO and stakeholders prioritize evaluation and implementation of these recommended adjustments.[2]

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[1] Incremental DA A/S costs over the first eleven months have totaled an estimated $921 million, or 9% of total wholesale energy and ancillary services costs. This equates to approximately $8.58/MWh, or $0.00858/kWh, of load served.

[2] The IMM will also be issuing future reports on the competitiveness and performance of DA A/S and may include further recommendations based on our analysis. This includes a full one-year look-back report planned for May 2026. However, the recommendations in this memo are sufficiently supported by current findings and stand on their own without reliance on future IMM assessments.

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Day-Ahead Ancillary Services Background

The Day-Ahead Ancillary Services market, launched in March 2025, procures and prices operating reserve products needed to meet system reserve requirements, as well as physical energy to satisfy expected real-time load. The market is designed to ensure the system is positioned to reliably meet the ISO's next-day operating plan, while compensating and incentivizing resources to be prepared to perform in real time.

The energy and ancillary service requirements are satisfied through the purchase of **options on energy**—a novel construct for procuring A/S in organized wholesale markets. This structure provides strong incentives for resources to cover their day-ahead positions when real-time energy prices rise above their marginal costs, or buy out at a replacement cost based upon the real-time energy price. Unlike the more common forward-sale reserve construct, this design recognizes that elevated real-time energy prices—not only real-time reserve prices—often signal heightened reliability risks, particularly under energy-constrained system conditions in New England.[3]

The strong incentives and price signals created through this market construct can provide meaningful reliability benefits. While the costs of DA A/S are immediately visible, the reliability benefits are harder to quantify because they rely on counterfactual assessments and longer-term performance data. Even so, our analysis indicates that DA A/S has increased the day-ahead commitment of long-lead-time generation in place of fast-start resources during periods of stressed system conditions.[4] This shift yields both market and reliability benefits: instead of relying on supplemental commitments and uplift payments after the day-ahead market closes, long-lead-time resources receive advance notice of expected operation and assume a financial obligation that strongly incentivizes performance. At the same time, freeing fast-start resources—often limited by fuel constraints—for reserves rather than day-ahead energy supports a more efficient and reliable operating plan. As the system enters real time, these commitments increase the overall bench strength of available long-lead-time and fast-start dispatchable resources.

Day-Ahead Ancillary Services Costs

The costs of DA A/S to date have exceeded expectations. From March through January, we estimate that DA A/S costs totaled **$921 million**, representing approximately **9%** of the total value of the

[3] Specifically, the real-time LMP signals the replacement cost if day-ahead reserve resources cannot perform in real-time when needed.
[4] Dónal O'Sullivan, *IMM Quarterly Market Performance Report: Summer 2025 Report Highlights*, (December 2025, slide 13.

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energy and ancillary services (E&AS) market, equating to $8.58/MWh of load served.[5,6,7] The table below compares the estimated cost of DA A/S to the prior energy-only day-ahead construct.

Table 1: Estimated Incremental Cost of Day-Ahead Ancillary Services (March 2025 through January 2026)

Category	No DA A/S ($M)	DA A/S ($M)	Delta ($M)	Delta (%)
DA LMP	$8,923	$8,680	-$243	-2.7%
FER	$0	$928	$928	
FRS	$0	$383	$383	
EIR	$0	$23	$23	
Total DA Charges/Credits	**$8,923**	**$10,013**	**$1,091**	**12.2%**
Cost of Incremental RT Energy[8]	$128	$128	$0	-0.3%
Actual Closeouts	$0	-$169	-$169	
Total Costs/Revenue Change	**$9,051**	**$9,972**	**$921**	**10.2%**

Importantly, there are two offsetting cost reductions not captured in the table above.[9] The first relates to the missing money to be recovered through the capacity market, and DA A/S net revenue should put downward pressure on capacity supply offer prices and capacity prices. However, these cost impacts will not be realized until the next capacity auction in 2028. Second, the Forward Reserve Market, which expired with the implementation of DA A/S, cost between $63 to 101 million per year in the three years prior to DA A/S (2022-2024).[10]

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[5] The cost estimates are derived from two simulations: (1) the current joint DA energy and A/S market design, and (2) the former energy-only day-ahead construct. These simulated incremental costs differ from settlement costs—which have totaled $1.136 billion between March 1, 2025, and January 29, 2026 ($900 million for FER and $236 million for the DA A/S products)—because the simulations capture the interaction of constraints that jointly determine the LMP and the FERP. As a result, incremental costs are lower than settlement costs, given that the DA A/S design generally results in lower LMPs than the prior energy-only market. See also IMM's Fall 2025 Quarterly Markets Report (February 2026), Figure 3-15, pg. 43.

[6] Total Energy and Ancillary Services costs include day-ahead and real-time energy, reserve, regulation, and NCPC costs. Given the timing of this memo, the total E&AS data is incomplete for January 2026. Notably, real-time energy, day-ahead and real-time reserves, FER payments, regulation, and NCPC only go through January 29, 2026.

[7] For the purpose of this calculation, cost per load served is estimated using Net Energy for Load (NEL).

[8] The "Cost of Incremental RT Energy" captures the fact one scenario may clear more energy supply in the day-ahead market relative to another and therefore need to procure less energy supply in the real-time market. Consequently, this field is calculated as (real-time load obligation – day-ahead load obligation) * real-time LMP, mimicking the deviation settlement logic.

[9] Uplift or Net Commitment Period Compensation (NCPC) is another cost-category that our assessment to date does not account for and are expected to be lower under the current DA A/S construct.

[10] IMM 2024 Annual Markets Report (May 2025), 188, https://www.iso-ne.com/static-assets/documents/100023/2024-annual-markets-report.pdf

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By comparison the ISO's Impact Assessment (IA) for the DA A/S design indicated an **annual cost of about $140 million**, or roughly **3%** of the E&AS market, based on 2019–2021 market data.[11] Although the IA was not intended to forecast future prices, it seemed to play a meaningful role in shaping stakeholder expectations—especially given that it was the only quantitative cost reference available prior to market implementation. Based on our discussions with stakeholders, this appears to have been particularly the case for expectations around the level of the Forecast Energy Requirement Price (FERP).

System and market conditions have changed in meaningful ways since the IA study period. These changes—including higher load levels, shifts in the supply mix, and higher natural gas prices—have applied upward pressure on both energy and ancillary service costs. As a result, if the IA were re-run using 2025 market data, DA A/S costs would be higher than those estimated based on 2019–2021 conditions.

However, changes in market fundamentals alone do not fully explain the observed level of DA A/S costs. Participation levels and offer prices have deviated materially from IA assumptions. In practice, participation has been lower[12], and offer prices higher, than assumed in the IA—including relative to IMM Benchmark Levels and estimated risk premium expectations. These differences have resulted in tighter market supply conditions, high cross-product opportunity costs, and ultimately a higher marginal cost of meeting both energy demand and operating reserve requirements.

While new markets often require time to mature—and participation and offer strategies may evolve as suppliers gain experience—the magnitude and pace of any resulting cost reductions remain uncertain. At the same time, it is important that market outcomes continue to reflect fundamental cost drivers. The recommendations in this memo are therefore aimed at the cost pressures

[11] As with most economic studies, the IA relies on assumptions about participant behavior and the nature of the competitive environment. In this case, the IA is premised on a model of profit-maximizing behavior under competitive conditions. Consistent with that framework, participants are assumed to offer their full physical capability at the estimated cost of meeting the obligation, which comprises three components: expected closeout cost, avoidable input costs, and a risk premium. As noted in our filed comments on DA A/S: "In practice, the effectiveness of DASI likely will depend on the level of participation in the market; the competitiveness of price formation and related risk premiums (…)" [pg. 2]. Further the IMM stated that "A risk premium is a third input into a competitive offer for ancillary services. While not expressly included as a component of the Benchmark Level, risk premiums are reflected in the conduct test thresholds (i.e., the 200%/150% bandwidths). How Market Participants will formulate and reflect risk on offer prices is perhaps the biggest unknown in the absence of data" [pg. 16]. See IMM comments at https://www.iso-ne.com/static-assets/documents/100005/imm_comments_on_dasi.pdf

[12] Offered capabilities exceed reserve requirements several-fold; however, once energy demand is accounted for within the joint energy and A/S clearing process, the supply available to meet reserve requirements declines. See Figures 3-6 and 3.7, for example, in the IMM's Spring 2025 QMR. The tighter supply/demand balance due to participation levels can have meaningful impacts on day-ahead market outcomes, particularly on high-load days. While the IA assumes near-full participation of fast-start and ramping capability, actual participation rates are roughly 30% lower. Participants may choose not to offer their full capability for a variety of business reasons, and physical withholding rules exist to address cases where non-participation would otherwise be economic and consistent with the exercise of market power (see Market Rule 1, Appendix A, III.A.4).

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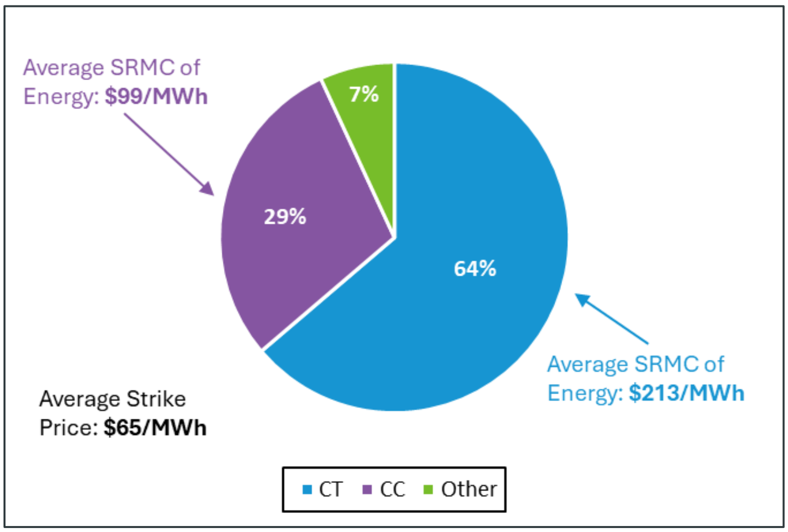
associated with offer price and participation levels, while maintaining consistency with the core design objectives.

Recommendation #1: Upward adjustment to the Strike Price formulation to better align it with the short-run marginal costs of resources providing these services.

The day-ahead ancillary service mix is dominated by Combustion Turbines (CT) and Combined Cycle (CC) generators, at approximately 64% and 29% of cleared capability, respectively. The short-run marginal cost (SRMC) of these resources frequently exceeds the Strike Price—particularly for CT units, but also for CC units that often clear in higher-cost duct-firing or upper-block operating ranges. The percentage share and weighted-average SRMC[13] of these technologies are shown in the following figure.

Figure 1: DA A/S Resource Mix Overview (March 1, 2025 through January 31, 2026)



There is substantial variation in marginal costs across the cleared resources—even within an hour and reserve products—that is not shown in the weighted-average values presented above. Even so, the figure highlights the magnitude of the average spread between SRMCs and the Strike Price. This spread creates a performance-incentive gap that the recommended adjustment is intended to address.

Specifically, in this range, higher real-time prices increase closeout costs without providing any additional incentive for the resource to produce in real time, and therefore cannot physically cover or hedge its DA A/S position. Suppliers may therefore reflect this closeout risk in higher DA A/S offer prices or, in some cases, opt not to participate when the expected financial exposure is uneconomic. Our analysis of supply offers as well as information from our participant consultations on mitigation indicates that this is occurring in practice. Increasing the Strike Price to more closely align with the

[13] The short-run marginal cost estimates captured in this figure are based on day-ahead energy supply offer blocks.

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SRMC of the resources providing the ancillary services would reduce expected closeout costs and associated risk premiums, thereby putting downward pressure on DA A/S offer and clearing prices. Mitigating this risk exposure through a higher Strike Price may also attract more participation.

From a reliability perspective, there are two important considerations. First, resources whose SRMC exceeds the Strike Price provide limited incremental reliability value in this range (between Strike Price and SRMC) because operating below SRMC to cover a closeout charge is not profit-maximizing. In other words, there is no incentive for the resource to physically cover its position until the market supply curve reaches its SRMC.[14] Second, CT commitments—as well as their associated SRMC levels—tend to be strongly correlated with periods of elevated system reliability risk. This relationship is likely to persist as the system continues to rely on fast -start, dispatchable resources to manage steep ramps and peak-load conditions. Accordingly, increasing the Strike Price to more closely align with the SRMC of a CT will better reflect system price levels associated with higher reliability risks. This can improve DA A/S cost effectiveness while maintaining strong performance incentives and reliability benefits.

Considerations in setting the Strike Price ("a balancing act"): Currently, the Strike Price is set equal to the expected real-time LMP plus $10/MWh. Importantly, the Strike Price is known in advance of the day-ahead offer deadline so that participants can formulate their supply offers based on their expected costs of taking on a DA A/S obligation, including risk, relative to the Strike Price.[15]

The $10/MWh adder places the option slightly out-of-the-money relative to the expected real-time prices derived from the ISO's Gaussian Mixture Model (GMM). This buffer was intended to reduce consumer costs by lowering expected closeout costs without materially diminishing performance incentives under stressed system conditions. Determining the appropriate Strike Price therefore requires balancing incentive strength against cost. If the Strike Price is set too high relative to SRMC, incremental performance incentives weaken, increasing the risk of poor real-time performance and elevated real-time prices. Conversely, if the Strike Price is set too low, the resulting obligations become too costly relative to the system value of non-performance.[16]

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[14] Resource owners participating in DA A/S are incentivized to take actions to ensure they can respond and cover their position in real time if energy prices exceed their SRMC when sufficiently compensated. These actions may be short-term—such as fuel procurement, generation preparations, or other operational readiness steps—or longer-term, including fuel contracting, investment decisions, staffing, and outage scheduling. However, when a resource is far out-of-the-money in expectation (SRMC >> Strike Price), the incentive to take such short-term preparatory actions may be muted.

[15] A competitive supply offer can generally be explained in three components: (1) the expected closeout cost of the option (the expected real-time price minus the Strike Price); (2) the avoidable input cost, representing the opportunity cost of taking actions to prepare for real-time performance; and (3) a risk premium.

[16] ISO New England Inc. and New England Power Pool, *Markets and Services Tariff to Establish a Jointly Optimized Day-Ahead Market for Energy and Ancillary Services*, FERC filing, Docket No. ER24-275 -000 (October 2023). For a detailed discussion on the determination of the Stike Price and the balance between consumer costs and resource incentives, see the testimony of Dr. Matthew White, pages 81-92.

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In addition, forecasting hourly real-time prices is inherently challenging and will become more difficult as weather-dependent resources grow and price volatility increases. Market outcomes to date suggest that uncertainty in price forecasts under expected low-price, low-stress conditions,—and the corresponding expected closeout costs—can drive DA A/S costs that are disproportionately high relative to the system's reliability risk.[17] Setting a Strike Price that more closely aligns with the SRMC of a CT under such conditions can help mitigate the cost impact of forecasting error without unduly weakening incentives.

As noted above, there is substantial heterogeneity in the SRMCs of resources that provide day-ahead ancillary services—within the same hourly interval and reserve product. As a result, increasing the Strike Price will raise it above the SRMC for some resources while leaving it below the SRMC for others. As the ISO and stakeholders evaluate this recommendation, they will need to consider the appropriate SRMC and how best to balance market costs with strong performance incentives and reliability outcomes. Consideration should also be given to incorporating a **dynamic** SRMC (i.e., one that adjusts with fuel input costs) as a **floor** within the current GMM-derived Strike Price methodology, which would cover conditions when the CT SRMC is below the expected real-time energy price, potentially resulting in costly in-the-money options.[18]

Recommendation #2: A downward adjustment to the Forecast Energy Requirement (FER) to reflect the expected contribution of renewable generation.

The Forecast Energy Requirement (FER) is satisfied through energy awards to physical supply resources and/or Energy Imbalance Reserves (EIR), ensuring sufficient cleared physical capability to meet the next-day load forecast. Historically, the ISO relied on the out-of-market Reserve Adequacy Analysis (RAA), run after the day-ahead clearing, to make supplemental, long-lead-time commitments necessary to meet expected next-day load and operating reserve requirements. The DA A/S construct effectively brings that RAA process into the market, significantly reducing the need for supplemental commitments through the RAA process. The RAA is still run after the day-ahead market and key supply-side inputs include day-ahead commitments of non-fast-start resources and estimates of real-time renewable generation (wind and solar)—an input that is particularly relevant to this recommendation.

The FER demand quantity (i.e., the ISO's load forecast) is calculated **net of expected behind-the-meter renewable generation**, predominantly rooftop and utility-scale solar that does not actively participate in the wholesale energy markets (including wholesale settlement-only generation). We recommend extending this adjustment to include **front-of-the-meter renewable generation**—that is, renewable resources that can participate in the wholesale market and are included by the ISO

[17] IMM Summer QMR (November 2025). See, e.g., Figure 3-13 on pg. 45 showing that overall GMM tends to underestimate closeout costs.

[18] During periods of expected high prices, the GMM-derived Strike Price would be more likely to bind. There may also be periods when the GMM-derived price is well below prevailing market expectations (e.g., June 24, 2025) but still exceeds the SRMC of a CT. The proposed approach does not address such instances directly; however, we recommend that the ISO continue to evaluate enhancements to the GMM price forecasts and/or ISO processes for determining the Strike Price under those stressed conditions.

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Operators in conducting the RAA. Essentially, this would entail reducing the FER demand quantity by the difference in expected real-time production and cleared day-ahead awards of front-of-the-meter renewables.

This adjustment establishes a more consistent treatment of renewable generation across real-time operations and the day-ahead market. It better aligns the FER with the role that renewable forecasts already play in the RAA process and reinforces the design objective of using the day-ahead market to establish a reliable and efficient next-day operating plan.

In practice, the adjustment primarily affects wind and solar resources that clear only a fraction of their expected real-time production in the day-ahead market. Summary statistics on the gap between real-time renewable production and cleared day-ahead energy (and EIR) are shown for the period March 1, 2025, through January 31, 2026, in the table below.

Table 2: Summary Statistics – Additional Real-Time Production of FTM Solar and Wind relative to Day-Ahead Energy and EIR Awards

Statistic	Value (MW per hour)
Mean	410
P5	26
P25 (Q1)	208
Median	384
P75	579
P95	896

As a practical matter, many renewable resources may not increase day-ahead participation despite higher day-ahead prices (LMP and FERP), due to contractual arrangements, risk tolerance, or other operational considerations. Indeed, we have not seen a shift in renewable resource participation levels in the day-ahead market since DA A/S.[19] While virtual supply has played an important role in recent years in filling this gap and supporting price convergence between the day-ahead and real-time markets, virtual supply does not contribute to the FER constraint. Instead, relatively more expensive physical supply or EIR offers must clear to satisfy the FER constraint. Importantly, this recommended adjustment **does not limit** the ability of renewable resources to participate actively in the day-ahead energy and A/S markets.

Interactions between the LMP and the FERP: Cleared physical supply offers receive the **LMP plus the FERP**, which together represent the all-in marginal cost of physical supply needed to meet the load forecast. To date, the FERP is significantly higher than anticipated. However, our simulation studies show that the cost of meeting operating reserve requirements is the primary driver of DA A/S costs (roughly 80%), although most of these costs flow through the FERP. Notably, our analysis shows that when the FER constraint is not applied, the incremental cost of meeting operating

[19] We also encourage the New England states to consider how Power Purchase Agreements (PPAs) or programs for sponsored policy resources can be structured to encourage, or to not inadvertently disincentivize, participation in the day-ahead market.

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reserve requirements accounts for about 80% of the total incremental cost—$210 million of the $258 million incurred in the first six months (March–August 2025).[20] Without the FER constraint, most of these incremental costs flow instead into a higher LMP. The analysis highlights that the underlying system cost of meeting the ~2,300 MW total reserve requirement—rather than the cost of meeting the load forecast—is the primary driver of DA A/S costs.

Some market participants have also expressed concern about the difficulty of predicting and hedging the FERP. These challenges may diminish as more market data becomes available and as financial products emerge that jointly hedge LMP and FERP exposure. By reducing the FER, this recommendation places downward pressure on the combined cost of the LMP and FERP—the marginal cost of day-ahead physical energy. While the recommendation may not fully resolve current concerns about the level or predictability of the FERP, we continue to emphasize that the relevant marginal cost under the joint energy and A/S market construct is LMP plus FERP, and that risk-management tools will likely need to evolve to reflect this combined cost.

Design considerations: This recommended approach increases market sensitivity to renewable forecast error. Accordingly, further discussion is needed regarding whether vendor forecasts used by the ISO or participant-provided forecasts should be used, and whether an explicit uncertainty factor should be incorporated in an FER or FRS adjustment.[21]

Recommendation #3: Review and consider downward adjustment to the resource non-performance factor applied to the operating reserve requirements.

The Total Ten-Minute Reserve Requirement is based on the largest system contingency and is adjusted by a Non-Performance Factor (NPF) to account for historical concerns regarding resource performance. The Total Ten-Minute Reserve requirement serves as an input when calculating other reserve requirements (i.e., the TMSR Requirement, the Total Reserve Requirement), and as a result the NPF serves to affect all 10- and 30-minute reserve requirements. The NPF was most recently modified in October 2015, when it was reduced from 25% to 20%. The table below summarizes the hourly increase in the Total Ten-Minute Reserve Requirement in the day-ahead market attributable to applying a 20 percent NPF, relative to no adjustment (NPF = 0), over the period March 1, 2025, through January 31, 2026.

[20] IMM Summer QMR (November 2025), 46-47. This analysis will be updated to cover for periods after August 2025 and included in future IMM reports.
[21] Renewable generators day-ahead offers would be expected to include a volumetric risk component, reflecting the risk of real-time to day-ahead deviations that are loss-incurring, and would therefore be reflected in market clearing prices. An uncertainty adjustment would be consistent with this expected behavior.

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Table 3: Summary Statistics – Impact of the 20% NPF on the Total Ten-Minute Reserve Requirement in the Day-ahead Market

Statistic	Value (MW)
Mean	254
P5	249
P25 (Q1)	249
Median	250
P75	250
P95	283

Since the 2015 update, several significant market design changes have strengthened performance incentives for generation resources. These include the introduction of Pay for Performance (PFP), with escalating performance rates since June 2018, increases in reserve penalty pricing effective June 2018, and most recently, the implementation of the DA A/S initiative in March 2025. Collectively, these reforms have raised the financial incentives for resources to perform when it matters by compensating for obligations that are tightly linked to real-time performance.

ISO New England has also presented evidence indicating improved performance across five of six PFP performance metrics. Of particular relevance, the ISO has observed **measurably improved average performance among the fast-start fleet** in response to post-contingency dispatch instructions, even while noting that opportunities for further improvement remain.[22]

Given the improved performance trends, the IMM supports and recommends a reassessment of the current NPF using a data-driven analytical approach. While the ISO operations group routinely reviews the NPF, it is now timely to consider changes in light of the strengthened market-based performance incentives embedded in the energy and reserve markets. A reevaluation may indicate that the existing 20% factor is higher than necessary relative to current—and improving—performance outcomes, and that a downward adjustment could better align reserve requirements with demonstrated system needs without compromising reliability.

Conclusion and Next Steps

The IMM is issuing these market-design recommendations pursuant to its responsibilities under Market Rule 1, Appendix A. The recommendations outlined in this memo will require further evaluation by the ISO and stakeholders. If adopted, these changes are expected to place downward pressure on DA A/S costs, are narrowly targeted in scope, can be implemented in the near term, and present a low risk of unintended consequences. We recommend that this evaluation and implementation efforts be prioritized and advanced expeditiously to improve the cost-effectiveness of the DA A/S market design.

[22] ISO New England memo to the NEPOOL Markets Committee, *Performance of Capacity Resources and Pay for Performance,* (September 2022), a03_mc_2022_09_13-14_performance_of_capacity_resources_memo_rev1.pdf

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