An Assessment of the Day-Ahead Ancillary Services Market

Internal Market Monitor

JUNE 8, 2026

Preface/Disclaimer

The Internal Market Monitor ("IMM") of ISO New England Inc. (the "ISO") has prepared this report on the performance and the competitiveness of the Day-Ahead Ancillary Services (DA A/S) Market.

This report fulfills the requirement of Market Rule 1, Appendix A, Section III.A.17.2.5, *Additional Ad Hoc Reporting on Performance and Competitiveness of Markets*:

> In furtherance of its function under Section III.A.2 of this ***Appendix A***, including without limitation Sections III.A.2.3(e) and (k) therein, the Internal Market Monitor shall perform independent evaluations and prepare ad hoc reports on the overall competitiveness and performance of the New England Markets or particular aspects of the New England Markets, including the competitiveness and performance of a major market design change. The Internal Market Monitor shall have the sole discretion to determine when to prepare an ad hoc report and may prepare such report on its own initiative or pursuant to a request by the ISO, New England state public utility commissions or one or more Market Participants. However, the Internal Market Monitor will report on the competitiveness and performance of any new major market design change within one to three years, respectively, of the effective date of operation of the market design change, or as soon as adequate data becomes available. While the Internal Market Monitor may solicit or receive input of the External Market Monitor, Market Participants and other stakeholders, including New England state public utility commissions, the methodology and criteria used to conduct its independent analysis shall be at the sole discretion of the Internal Market Monitor. The Internal Market Monitor shall describe its methodology and criteria used in an ad hoc report of its significant findings and, if any, recommendations. The Internal Market Monitor shall file with the Commission and post to the ISO's website a final version of an ad hoc report. Thereafter, the Internal Market Monitor shall continue to report on the competitiveness and performance of any market design change that has been the subject of an ad hoc report in its quarterly or annual reports under Sections III.A.17.2.2 and III.A.17.2.4.

All information and data presented here are the most recent as of the time of publication.

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Section 1
Executive Summary

The Day-Ahead Ancillary Services Market introduced the most significant reforms to New England's wholesale energy markets in over twenty years. Under this design, the Day-Ahead Market jointly clears energy and Day-Ahead Ancillary Services (DA A/S) to meet expected next-day load and operating reserve requirements. The initiative was launched on February 28, 2025.

This report evaluates the competitiveness and performance of the DA A/S design during its first year of operation. While the analysis is based on a limited period, it provides a comprehensive assessment of market outcomes and will be further supplemented by ongoing quarterly reporting on market performance and a required three-year full performance review.[1]

The report begins with an overview of the market design, followed by detailed analysis of market costs, cost drivers, and comparisons with the New York ISO market. We then assess market competitiveness, mitigation effectiveness, and market performance metrics, including reliability impacts. The final section presents results from an IMM survey of market participants, offering qualitative data and additional insight into how the design reforms have been experienced in practice.[2]

In our assessment, we conclude that DA A/S costs are consistent with competitive market participant behavior. However, competitiveness does not necessarily translate into efficient outcomes. In February 2026, we put forward a set of targeted recommendations to improve the cost-effectiveness of the DA A/S design based on our ongoing monitoring and assessment work.[3] These include refinements to the Strike Price methodology, adjustments to the Forecast Energy Requirement (FER), and a review of contingency-response related performance parameters affecting the ten- and thirty-minute reserve requirements. One of these changes (the latter) was implemented on May 1, 2026, while the ISO is currently working with stakeholders on detailed design changes for the remaining two recommendations.[4] We continue to believe that these changes will meaningfully improve cost-effectiveness and overall market performance.

A number of key findings emerge from this one-year assessment.

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[1] Appendix A, Market Rule 1, I.A.17.2.5 requires the IMM to assess the competitiveness of major market design changes within one year (subject to sufficient data) and to evaluate market performance within three years.

[2] The IMM appreciates the time and thoughtful responses provided by the market participants who participated in the survey.

[3] ISO-NE Internal Market Monitor (David Naughton), "Recommended Changes to the Day-Ahead Ancillary Services Market," memo, February 4, 2026, https://www.iso-ne.com/static-assets/documents/100032/2026_02-imm-memo-with-daas-recommendations.pdf

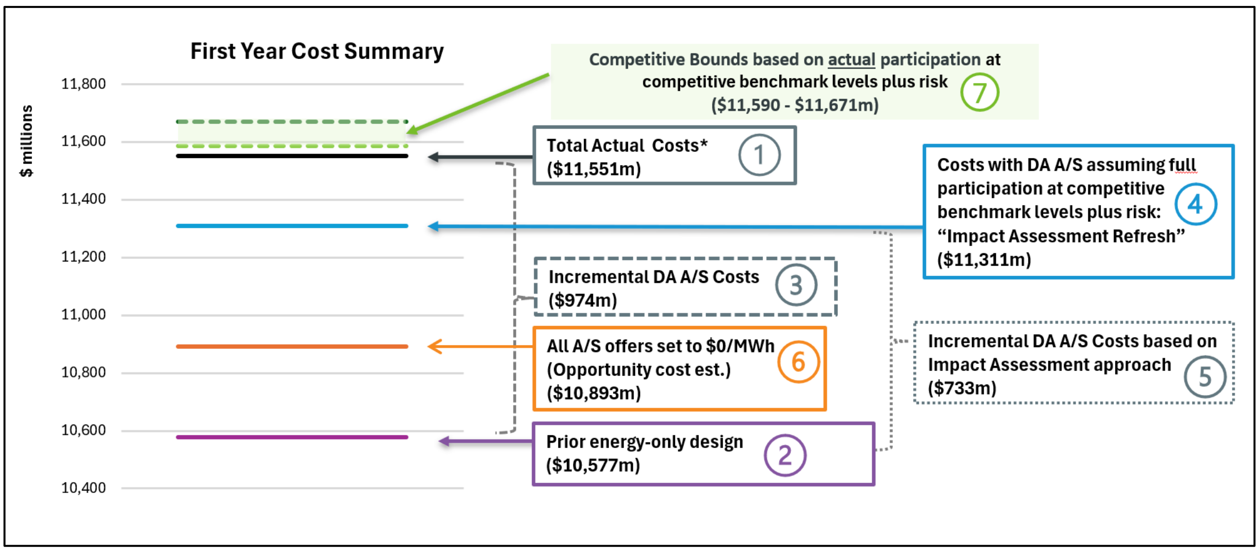
[4] The report does not quantify the impact of these changes; backcast-based estimates have been provided by the ISO to stakeholders as part of ongoing design discussions. See ISO New England, "Day-Ahead Ancillary Services Post-Implementation Adjustments," presentation to NEPOOL Markets Committee, May 12–14, 2026, https://www.iso-ne.com/static-assets/documents/100035/a06_mc_2026_05_12-14_daas_post_implementation_adjustments_presentation.pdf

Estimated Incremental Costs of DA A/S Totaled $974 Million in the First Year, with 12 Days Accounting for 50%

The first twelve months of DA A/S operation corresponded to a period of elevated fuel and energy costs, and several multi-day periods of exceptionally high demand and extreme weather events that had not been experienced in some years. Overall, energy and ancillary services (E&AS) costs from March 2025 through February 2026 totaled **$11,500 million** ($11.5 billion), the highest since 2022 and the second highest since 2008 in nominal terms.[5]

A core part of this assessment includes a series of simulation studies to evaluate DA A/S costs and identify key cost drivers and assess competitive outcomes. The figure below summarizes total E&AS costs from these simulations. The key values from the simulation studies are labeled with a number and referenced in the narrative below to facilitate interpretation.

Figure 1-1: Day-Ahead Ancillary Services Cost Estimates and Drivers



*Based on simulated DA A/S market rules used as the benchmark for counterfactual comparisons. Total costs modeled in the simulation include LMP, FER, DA Flexible Response Services and EIR net costs, and the cost of real-time incremental energy.

First, we compare outcomes under the new co-optimized energy and ancillary services market to those under the prior energy-only design to estimate incremental costs of the design. Total simulated E&AS costs amounted to **$11,551 million** ①, closely matching actual costs and reflecting strong model benchmarking performance throughout the study period. We estimate that costs under the prior energy-only market would have been **$10,577 million** ②, meaning that total incremental costs were **$974 million** ③, about 9% higher than the prior energy-only design, or $8.23/MWh of load served.

[5] Actual total energy and ancillary services costs include day-ahead and real-time energy, reserve, regulation, and NCPC costs.

DA A/S costs were concentrated in a relatively small number of stressed operating days. Specifically, 12 days accounted for roughly 50% of incremental costs, with a five-day winter storm event (Winter Storm Fern) contributing about 40%, and a single day (January 27, 2026) accounting for 18%. These "**Top 12 Days**" are particularly important to analyze because they reflect periods when reliability risks are elevated and strong price signals and performance incentives are most critical. Accordingly, we assess market competitiveness and performance during these days in greater detail throughout the report.

Higher-than-Expected DA A/S Costs Primarily Reflect Changes in Market and System Conditions

DA A/S costs were significantly higher than those estimated in ISO-NE's original Impact Assessment (IA), which used 2019–2021 data and estimated incremental costs of **$140 million** (approximately 3% of total E&AS costs). Significantly different market fundamentals and system conditions during the 2025/26 period—including higher natural gas prices, increased energy price volatility, shifts in the supply mix, and more frequent stressed conditions—put upward pressure on costs.

To model these effects collectively, we conducted an "IA Refresh" using the same methodology as the original IA, which assumes full participation and competitive offer pricing (including risk premiums). When developing the IA, the ISO made assumptions about participant behavior and the nature of the competitive environment. Like many economic studies, ISO-NE premised assumptions on market participation on profit-maximizing behavior under competitive conditions. Consistent with that framework, participants were assumed to offer their full physical capability at the estimated cost of meeting the DA A/S obligation. This approach provides a full-participation, competitive-equilibrium benchmark reflecting an expected long-run market outcome.

Under these assumptions, total costs would have been **$11,311 million ④**, implying incremental DA A/S costs of **$733 million ⑤** ($5.66/MWh). Updated market conditions therefore explain roughly 75% of the observed incremental costs of $974 million. The remaining **~$240 million** in incremental costs (not explained by updated market/system conditions) is primarily attributable to lower participation and higher offer prices than benchmark levels.

Higher-than-Expected Costs also Reflect Differences Relative to Assumed Market Behavior and Highlight the Role of Opportunity Costs in Price Formation

In practice, participation has been lower and offer prices higher than assumed in the IA, resulting in tighter supply conditions, higher cross-product opportunity costs, and a higher marginal cost of meeting energy and ancillary service requirements.

Under these conditions, opportunity costs play a key role in price formation by ensuring that resources are indifferent between providing energy and ancillary services in the co-optimized market. Although difficult to quantify opportunity costs precisely, simulation results show that even if all DA A/S historically-offered capability were offered at $0/MWh, total E&AS costs would be **$10,893 million ⑥**, indicating that the system would still incur **$316 million** ($2.67/MWh) in incremental costs to satisfy FER and FRS constraints.

Ultimately, market participation decisions depend on a myriad of factors, including commercial strategy considerations, physical and operational constraints, and perceptions of market risk.

Importantly, our survey results suggest market complexity also played a role in participation decisions. Some participants indicated that they adjusted their offer behavior over time as they became more familiar with the market, but many indicated that they wanted additional training to enhance their understanding and comfort with specific market features. These findings are consistent with the broader analysis in this report, which shows that risk, uncertainty, and market design features play a significant role in shaping offer behavior and market outcomes.

➔ We recommend that the ISO provide additional and ongoing technical training related to DA A/S to facilitate and accelerate market participation.

DA A/S Costs were Consistent with Competitive Market Participant Behavior

Our competitiveness analysis indicates that DA A/S market outcomes were broadly consistent with competitive behavior. Specifically, we find that:

- Participation levels have generally not raised **physical withholding** concerns that would impact overall competitive cost estimates. Participation levels continue to trend upwards with market experience. While there has generally been sufficient offered capability to meet the load and reserve requirements, we find that the level of participation is particularly impactful on market costs and prices on high load/stress days. The IMM continues to consult with participants regarding their participation levels to guard against potential physical withholding.

- There is also no indication of impactful **economic withholding** on overall costs. Observed market costs were consistent with simulated costs using competitive offer benchmarks, indicating that offer levels from participating resources were broadly consistent with competitive, risk-adjusted offer behavior. To assess whether market outcomes are consistent with competitive offer behavior, we conducted two simulations in which DA A/S offers are set at IMM benchmark levels, differing only in how the risk premium is defined. Together, these risk methodologies provide a range of competitive outcomes: one based on a return-per-unit-of-risk metric (Sharpe) and one based on a more conservative tail-risk measure (conditional Value at Risk). Market costs of **$11,551 million** ① are consistent with, and even slightly below, the IMM's **competitive bounds of $11,590 and $11,671 million** ⑦, although that result is driven largely by a small number of high-cost days; for most of the year, costs were closely aligned with the IMM's competitive benchmarks.

- **DA A/S offer mitigation** occurred infrequently and effectively addresses circumstances where offers both materially exceeded benchmark expectations and had a measurable effect on clearing prices. One notable exception arises when price impact thresholds fell below $3/MWh, which occur during times when system conditions were generally unstressed and market power is not a concern. Almost thirty-percent of mitigations occurred under these conditions. The ISO plans to address as part of their DA A/S market enhancements work in 2026 by incorporating a $3/MWh price impact floor, a sensible measure that will address these observed instances of over-mitigation.

- DA A/S markets exhibit moderate concentration, and some realized outcomes—particularly for DA TMSR—show tight post-clearing reliance on a relatively small set of suppliers when capability is assessed after commitment. These "ex-post" measures can help identify intervals that warrant closer monitoring. However, they likely overstate the extent of market power. In the day-ahead market, clearing reflects the joint satisfaction of multiple requirements, so there is not a single marginal unit that can be isolated; changes in any binding constraint generally affect the dispatch and reserve provision of multiple units and this inherent substitutability can mitigate market power concerns.[6]

The Strike Price and Expected Closeout Cost Calculator (the "GMM") Showed Systematic Bias

The ISO's Gaussian Mixture Model (GMM) model for determining key DA A/S values—specifically the strike price and expected closeout—exhibited systematic bias in its first year of operation, understating real-time LMPs on average. This under-forecasting bias is evident in actual outcomes falling frequently in the upper tail of the predictive distribution and carried through to expected closeout charges, which were also systematically understated relative to actual closeout charges.

These findings have two important implications. First, when the model produces Strike Prices and expected closeout values that are below prevailing market expectations, the IMM may need to adjust mitigation values to offset this misalignment, potentially leading to higher offer prices and increased day-ahead market costs.[7] Indeed, the IMM performed such adjustments during many high-stress days. Second, implementing a Strike Price floor—consistent with our recommendation to better align the strike price with the short-run marginal costs of resources providing ancillary services—offers a meaningful secondary benefit by eliminating forecasting errors below the marginal cost of a combustion turbine.

➔ Even with the IMM's recommended strike price adjustments, we encourage the ISO to continue to invest in its modeling tools and processes to ensure that expected real-time energy prices and closeout costs better track prevailing market conditions.

Evidence of Reliability Benefits is Promising but Preliminary

We have considered stakeholder interest in the reliability benefits of DA A/S, particularly in light of higher-than-expected costs. Accordingly, we developed a framework that combines empirical analysis with survey responses to evaluate changes in resource performance and commitment patterns. Given that this assessment is based on a single year of operation, the results should be interpreted with caution, and the framework will continue to evolve as additional data and stakeholder feedback become available.

The DA A/S design incorporates features that support reliability—most notably transparent pricing and stronger performance incentives—but participant behavior also reflects the combined influence of energy, capacity, and ancillary services market incentives. Therefore several observed

[6] In addition, efficient market outcomes need not include surplus TMSR capability, and the market can re-optimize commitment and reserve awards in response to offers.

[7] The relationship between strike price levels and market outcomes is nuanced and requires further study. In particular, while lower strike prices relative to prevailing market conditions increase expected closeout costs and likely increases overall day-ahead costs, however this effect is at least partially offset by higher realized closeout costs.

reliability effects remain preliminary and cannot yet be treated as causal, and therefore care should be taken in attributing observed performance improvements to DA A/S alone.

Early indications are encouraging but mixed.

- **Outage rates:** Combustion turbine availability has improved, reflected in lower outage rates which have fallen from 18% to 11% for resources taking on DA A/S obligations.

- **Natural gas procurement:** We measured if gas-fired generators scheduled additional natural gas day-ahead to meet DA A/S positions, in the context of stronger incentives to be prepared to perform. We did not find a measurable change in the amount of natural gas scheduled to meet real-time needs, even during winter months when intraday gas procurement is more uncertain. About 97% of natural gas needs continue to be scheduled day-ahead.

- **Operational changes:** On the other hand, survey responses indicate that DA A/S awards influence operational decisions; 71% of respondents reported taking actions in response to awards, most commonly procuring fuel.

- **Day-ahead commitments:** More commitments of long-lead time resources occur under DA A/S, with no commitments made through the out-of-market next-day Reserve Adequacy Analysis (RAA) process; under DA A/S such commitments face financial obligations and stronger performance incentives, and create additional responsive capability in real-time.

Potential Cost Implications for the Capacity Market and Uplift

DA A/S has introduced a market-based revenue stream for flexible, fast-start combustion turbines, which comprise the majority of cleared resources, and therefore has implications for how costs are recovered across wholesale markets. First-year DA A/S revenues averaged approximately $3.50/kW-month fleetwide, compared to about $1.30/kW-month under the former Forward Reserve Market in 2023 and 2024. These additional revenues reduce the reliance on out-of-market uplift payments and contribute to a shift in cost recovery toward market-based mechanisms. They also have implications for capacity market pricing by offsetting a portion of the "missing money" reflected in competitive capacity offers and, over time, are expected to be incorporated into Net Cost of New Entry estimates, placing downward pressure on future capacity market costs.

Absent DA A/S, additional commitments of long-lead-time generation would likely have been required after the day-ahead market to meet expected load and reserve requirements. As a result, DA A/S may reduce NCPC by limiting reliance on post–day-ahead (RAA) commitments. However, the magnitude of these reductions is highly uncertain and sensitive to assumptions about operator behavior. Estimated savings are bounded at approximately $35 million annually, with more realistic outcomes likely significantly lower (e.g., roughly $11 million under peak conditions).

Continued Monitoring and Openness to Refinements Will Be Important

The new market design has been in operation for only one year. Given the magnitude of the design change, it is not surprising that refinements are being considered based on early experience to improve or balance cost-effectiveness. While we do not include additional design recommendations in this assessment, further changes may be warranted for ISO and stakeholder consideration as more data become available and our monitoring and assessment work continue. Future analysis will help determine whether the patterns observed in the first year reflect long-run outcomes or transitional effects.

Section 2
Introduction and Assessment Scope

In fulfillment of its obligations under the ISO-NE tariff, the Internal Market Monitor (IMM) has prepared this report on the performance and the competitiveness of the Day-Ahead Ancillary Services (DA A/S) Market. This report is filed with the Federal Energy Regulatory Commission pursuant to Appendix A, Market Rule 1, I.A.17.2.5, which requires the IMM to assess the competitiveness of major market design changes within one year (subject to sufficient data) and to evaluate market performance within three years.

This report goes beyond a narrow assessment of "competitiveness" and instead evaluates the first year of operation of the DA A/S market and the broader day-ahead market. A subsequent review will be conducted in 2028, after the DA A/S design has been in place for three years.

Prior to this report, the IMM has already put forward a set of targeted recommendations to improve aspects of the DA A/S design.[8] These include refinements to the strike-price methodology, adjustments to the Forecast Energy Requirement (FER), and a review of parameters affecting the quantity of reserve procurement. This report does not attempt to quantify the impact of these recommended changes. Rather, the analysis is intended to inform these recommendations and to highlight areas where adjustments may improve certain aspects of design performance.

The implementation of DA A/S represents one of the most significant changes to the ISO New England market design in recent years. Prior to DA A/S, the day-ahead market committed resources to satisfy operating reserve requirements but did not create financial obligations nor compensate resources for these ancillary services capabilities. Instead, reserve providers were primarily compensated for these capabilities through the Forward Reserve Market (FRM) or infrequent real-time reserve pricing. In addition, the process for managing differences between day-ahead schedules from physical resources and expected real-time operating conditions relied on actions that took place after the day-ahead market clearing was complete.

That prior energy-only design created several challenges. First, because the day-ahead market was not transparently procuring operating reserves, resource owners were not explicitly aware that the ISO was relying on them for these services in its operating plan. Second, the value of reserve capability was not clearly reflected in day-ahead market prices. Third, when the set of resources committed through the day-ahead market proved insufficient to satisfy reliability needs, the ISO relied on out-of-market actions to ensure reliability.

The DA A/S reforms were developed to address these limitations, but, at the same time, these reforms have made certain costs more visible through marginal pricing principles. Under the prior market structure, some of the costs associated with maintaining reserve capability and operational

[8] The memo titled *Recommended Changes to the Day-Ahead Ancillary Services Market* is available here: https://www.iso-ne.com/static-assets/documents/100032/2026_02-imm-memo-with-daas-recommendations.pdf

flexibility were reflected through mechanisms such as the FRM or uplift payments rather than through explicit day-ahead ancillary service payments.

Under the new design, reserve procurement costs are incorporated more directly into market settlements. As a result, one of the most prominent features of the first year of DA A/S has been the magnitude of the increase in energy and ancillary services costs associated with the initiative. Stakeholders have focused on these costs and raised a central question: what benefits does the market produce in return?

We start to answer that question in this report. Because a new market design that visibly increases market payments will inevitably be judged against its costs, the evaluation in this report places emphasis on benefits as well as costs. However, some of the expected benefits of DA A/S — particularly those associated with increased participant incentives and improved system preparedness —are inherently more difficult to measure than the costs. Market payments can be directly observed in settlement data, while benefits are not as easily captured. For this reason, the report evaluates a broader set of metrics that are closely tied to the objectives of the reform. These include changes in fuel scheduling, day-ahead commitment, and unit availability and performance.

The report is organized around three broad analytical questions.

1. **What was the incremental cost of this initiative?** This includes a review of energy and ancillary services settlements, a structured assessment of incremental cost, and a benchmarking to ancillary services costs in the New York ISO market.
2. **What factors drove these costs?** This includes an analysis of the role of system conditions and participant behavior. The analysis of participant behavior includes a review of market participation, an evaluation of the market structure and offer behavior, and an assessment of mitigation effectiveness.
3. **What benefits has this initiative produced?** This includes a review of the market's performance as well as a high-level evaluation of preliminary reliability benefits.

To address these questions, the report uses several complementary methods, including analysis of observed market outcomes, simulation-based counterfactual analysis, and survey evidence from market participants.

The first year of any major market reform will inevitably involve adaptation. Participants are still learning the details of the market, the ISO is accumulating experience with the new design, and the data from a single year may reflect system conditions that are not representative of long-run outcomes. For these reasons, this report should be understood as a first-year review rather than a final assessment of the long-run performance of the market.

Section 3
Market Design Overview

The Day-Ahead Ancillary Services Market represents a set of reforms to the day-ahead market with the objectives of procuring the ancillary service capabilities necessary to meet reliability requirements, pricing those capabilities in a transparent manner, and compensating the resources that provide those capabilities.[9]

Glossary

DA A/S: The ancillary services products that are procured in the DA A/S market

DA A/S market: The day-ahead ancillary services market

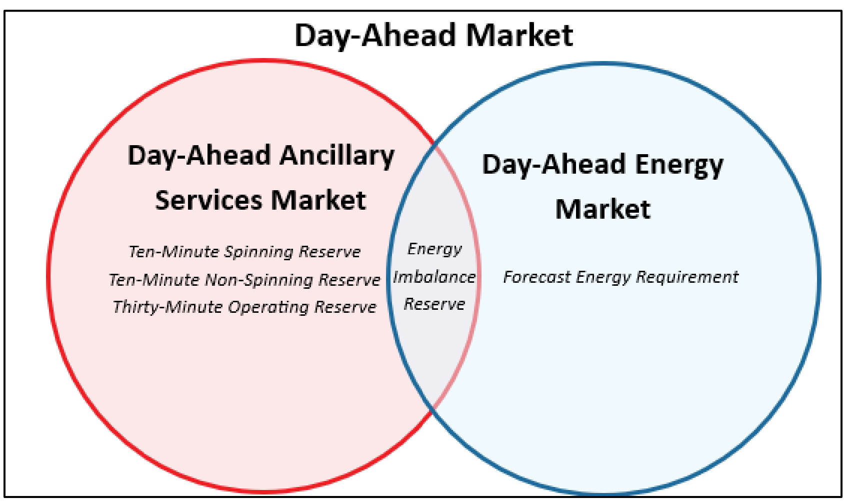
DA energy market: The day-ahead energy market

DA market: The jointly optimized DA energy and DA A/S market

These market reforms impacted both the energy and ancillary services markets. The introduction of the DA A/S market was accompanied by a significant alteration to the energy market with a new market constraint that ensures that enough physical capability is procured day-ahead to satisfy the ISO's load forecast. Importantly, the DA A/S market and the existing day-ahead energy market collectively form the day-ahead market, which jointly clears energy and ancillary services in a co-optimized process that determines the optimal allocation of energy and ancillary services to satisfy the system's requirements.

A conceptual representation of the DA A/S market reforms is depicted in Figure 3-1 below.

Figure 3-1: Conceptual Representation of DA A/S Market Reforms



[9] See Page 16 of the testimony of Dr. Matthew White in support of DA A/S contained within the ISO's filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

An overview of these market reforms is provided below in order to set the groundwork for the discussion of market costs and performance that follows.

3.1 Day-Ahead Ancillary Services Market

The DA A/S market is a voluntary market in which the ISO procures certain ancillary service capabilities one day in advance of when they are needed. Resources that have these capabilities can receive compensation for them in return for taking on a financially-binding obligation that is linked to the real-time LMP.

3.1.1 Requirements and Products

Flexible Response Services

Flexible Response Services (FRS) provide the fast-starting and fast-ramping capability needed for the ISO to respond quickly to large supply losses. These services correspond to operating reserves and are based largely on the system's largest contingencies, consistent with analogous requirements in the real-time market.[10] These requirements are:

- The **Ten-Minute (Total 10) Reserve Requirement** is the amount of 10-minute reserve capability (spinning or non-spinning) that is required by the system. It is based on the system's first contingency multiplied by a non-performance factor, which changed from 120% to 115% on May 1, 2026.[11]
- The **Ten-Minute Spinning Reserve (TMSR) Requirement** represents the amount of the Total 10 requirement that must be met through spinning reserves. This amount is generally set at 25% of the Total 10 requirement but can range between 25% to 100%.
- The **Total Reserve (Total 30) Reserve Requirement** is the total amount of 10-minute and 30-minute reserve capability required by the system. The amount in excess of the Total 10 reserve requirement is generally 50% of the system's second contingency plus an additional amount known as Replacement Reserves, which varies between 160 MW and 180 MW depending on the season.

To help satisfy these requirements, resources may make offers for the following products: [12]

- **Ten-Minute Spinning Reserve (TMSR):**
    - This is capability that is synchronized to the grid and capable of responding within ten minutes.

[10] For more information about the determination of operating reserve requirements, see ISO-NE Operating Procedure No. 8: https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf

[11] This change took effect for the operating day of May 1, 2026. For more information about the motivation behind this change, see: https://www.iso-ne.com/static-assets/documents/100034/a05_reserve_nonperformance_factor_updates.pdf.

[12] There are some exceptions to the general reserve capability descriptions provided here. For information about the calculation of reserve capability, see Section III.1.7.19.2 of the ISO-NE Tariff, available here: https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

    - This reserve product can be used to satisfy the TMSR, Total 10, and Total 30 requirements.
- **Ten-Minute Non-Spinning Reserve (TMNSR):**
    - This is capability that is not synchronized to the grid but can start and respond within ten minutes.
    - This reserve product can be used to satisfy the Total 10 and Total 30 requirements.
- **Thirty-Minute Operating Reserve (TMOR):**
    - This is capability that may or may not be synchronized to the grid but is capable of responding within thirty minutes.
    - This reserve product can be used to satisfy the Total 30 requirement.

Energy Imbalance Reserves

Energy Imbalance Reserve (EIR) provides reserve capability used to help meet the load forecast. Physical supply resources with 60-minute reserve capability can be compensated by clearing EIR awards. The market clearing engine procures EIR to help satisfy the **Forecast Energy Requirement (FER)**, which ensures that expected next-day demand is met through a combination of day-ahead energy awards on physical resources and EIR awards. [13]

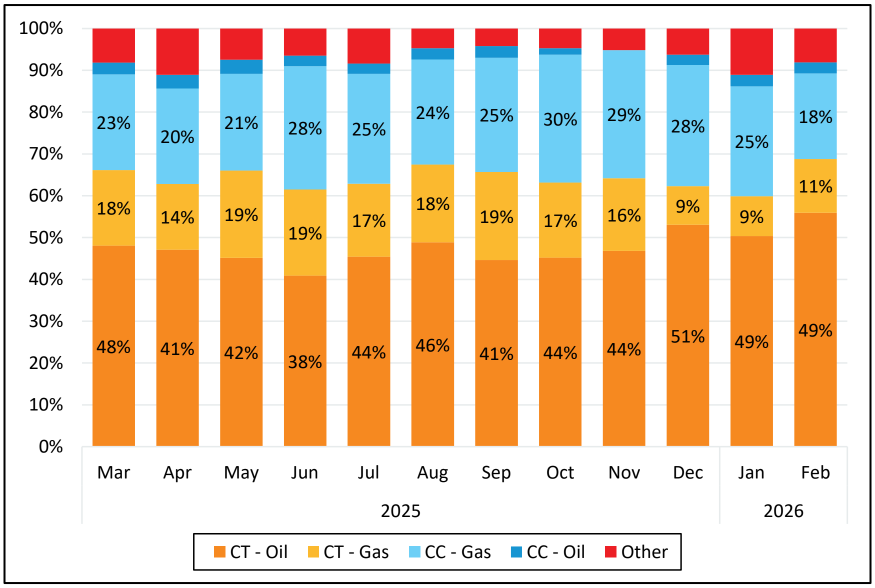
Observed DA A/S Clearing

Combustion turbine (CT) and combined-cycle (CC) resources accounted for most DA A/S clearing during the first year of the market. These resources were primarily fueled by natural gas and oil.[14] Figure 3-2 shows monthly DA A/S clearing by technology and fuel type, expressed as shares of total clearing (MWh), with each column summing to 100%.

[13] The FER is discussed in much more detail in Section 3.2.

[14] While some of these resources can run on multiple fuels (i.e., are dual-fuel capable), when they do run, they generally run exclusively on one fuel. For these “dual-fuel” resources, we use the fuel underlying the energy offer for a specific hour.

Figure 3-2: DA A/S Clearing by Technology and Offered Fuel



Combustion turbines dominated DA A/S clearing each month over this period. Oil-fired CTs typically accounted for roughly 40–50% of cleared awards, while gas-fired CTs contributed an additional 10–20%. CT resources supplied nearly all TMNSR awards in every month and also made meaningful contributions to TMOR and EIR clearing.

Combined-cycle units offering on gas also represented a substantial share of DA A/S clearing, generally in the range of 20–30% each month. These units were the primary suppliers of TMSR throughout the year.

Other resource types had only a limited role. Pumped-storage hydro and pondage hydro were the only other resource types to account for more than one percent of cleared DA A/S awards during the first year of the DA A/S Market.

3.1.2 Settlement

DA A/S awards are settled using a two-part call option settlement design. The first settlement depends on the day-ahead market; resources that receive a DA A/S award earn a credit at the ancillary service clearing price and the MWh quantity of awards. The second settlement depends on the real-time market; resources with a DA A/S award incur a closeout charge as follows:

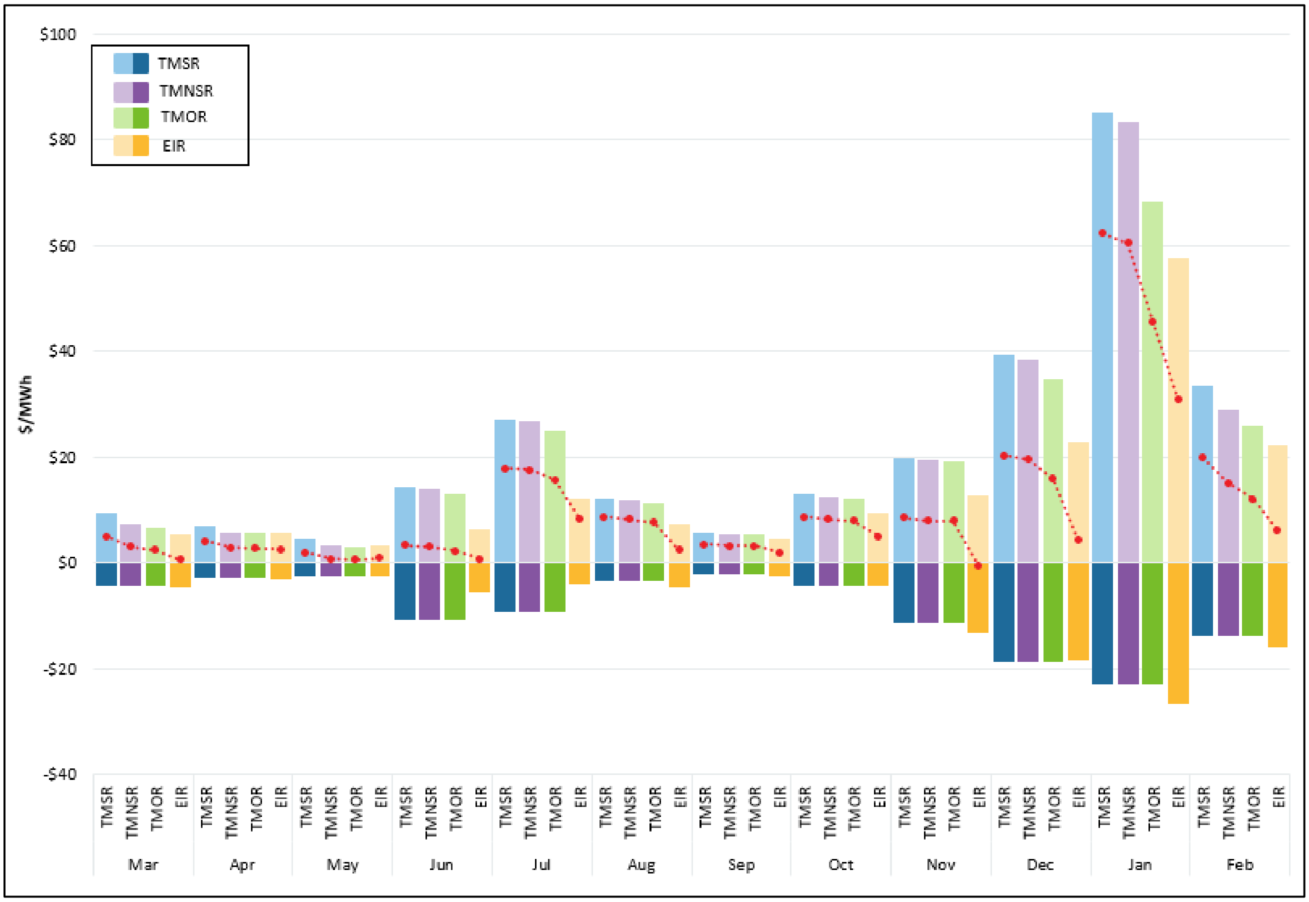
$$Closeout\ charge = Award\ MW \times \max\left(LMP_{Hub}^{RT} - Strike\ Price, 0\right)$$

This equation is an important part of the DA A/S market design as it creates a new financial link to the real-time energy market for a resource with a DA A/S award. If the real-time Hub LMP exceeds the strike price (often denoted by *K*), then resources with a DA A/S award incur a closeout charge. However, if the real-time Hub LMP is less than the strike price, then resources with DA A/S awards incur no charge. The current design sets the hourly strike price at the expected real-time Hub LMP plus a $10 adder.

Observed DA A/S Clearing Prices

Figure 3-3 below captures this two-part settlement over the first year of DA A/S. This figure shows the average hourly DA A/S clearing prices as positive values and realized closeout charges as negative values by product and month.[15] This figure also depicts the clearing price less the realized closeout charge, which we refer to as the *net* clearing price, with a red circle.

Figure 3-3: Average Hourly DA A/S Clearing Prices by Product and Month



The DA A/S clearing prices were highest in the summer (specifically, July 2025) and winter months (specifically, December 2025, January 2026, and February 2026). These are months when the power system tends to experience more stressed conditions, which can lead to higher and more volatile energy prices. We provide additional information on several acute periods during the first year of DA A/S throughout this report in order to provide additional insight into the drivers of the higher costs observed during these months.

Given their price formation mechanics, the clearing prices of the three FRS products (TMSR, TMNSR, and TMOR) were closely aligned, while the clearing price for EIR (i.e., the Forecast Energy

[15] The EIR values depicted in this figure are the average hourly values for only the hours when cleared EIR MWs were greater than zero.

Requirement Price or FERP) was lower nearly every month.[16] In general, realized closeouts were lower than DA A/S clearing prices, resulting in positive net clearing prices for all products in every month with the exception of EIR in November 2025.

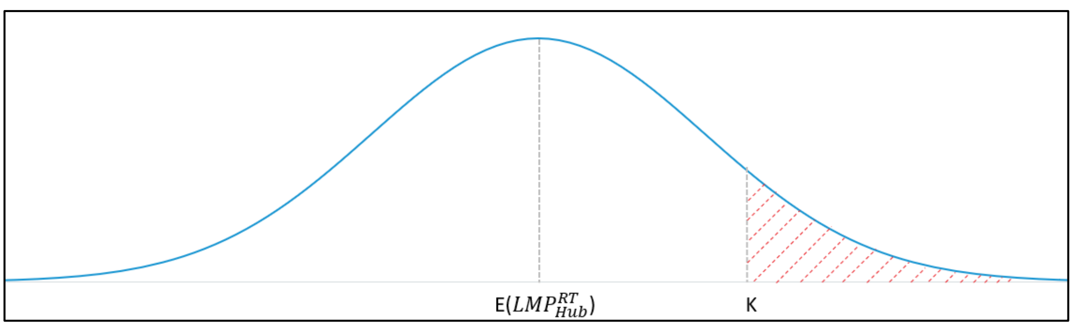
3.1.3 Offer Formulation

The settlement structure described above is foundational to the formulation of a DA A/S offer. This is because, by virtue of receiving a DA A/S award, a resource incurs an (otherwise avoidable) cost in expectation due to the closeout charge. Under the DA A/S design, this cost is referred to as the **Expected Closeout (charge)**. The expected closeout is a critical element of the design because it underpins a competitive DA A/S offer and forms the basis of the mitigation framework.

Conceptually, the expected closeout exists because the real-time LMP could fall between a range of possible values depending on the actual system conditions that occur. For example, lower-than-expected loads could lead to reduced real-time LMPs, while the unexpected trip of a large generator could lead to heightened real-time LMPs. The former scenario is unlikely to create a closeout charge for a resource with a DA A/S award but the latter scenario might.

A simplified graphical representation of this idea is presented in Figure 3-4 below. The x-axis in this figure depicts all the possible values of the real-time LMP that could occur and the blue line defines the likelihood of each of those values; more extreme values of the real-time LMP are less likely to occur (as indicated by the lower level of the blue line at those values), and less extreme values are more likely to occur (as indicated by the higher level of the blue line at those values). This figure depicts the expected value of the real-time LMP as $E(LMP_{Hub}^{RT})$ and the strike price as K. All values of the real-time LMP above K would lead to a closeout charge; this range is indicated in the figure with the dashed red line.

Figure 3-4: Distribution of Real-Time Energy Prices



A central goal of the design is to create strong incentives for resource owners to be prepared to cover their DA A/S positions with physical generation (consistent with a covered call framework).

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[16] Specifically, FRS clearing prices "cascade up." This means, for example, that the shadow price of the Total 30 requirement will appear not only in the TMOR clearing price, but will also "cascade up" into the TMNSR and TMSR clearing prices because these products also help satisfy this requirement. The result is the following relationship between clearing prices for the FRS products: $CP_{TMSR} \geq CP_{TMNSR} \geq CP_{TMOR}$.

Otherwise, the resource effectively buys out of its position at the market's replacement cost reflected in the real-time LMP, potentially incurring net losses.

In addition to the expected closeout, which is relevant to all resource types, there are two other components to a competitive DA A/S offer as defined by the ISO. The first, which is called the **Avoidable Input Cost (AIC)**, represents input energy-related costs incurred by a subset of DA A/S providers (gas and energy storage) that could otherwise be avoided but for the DA A/S award. And the second is a **risk premium**, which captures the uncertainty in net revenues associated with clearing a DA A/S award.

3.1.4 Mitigation

To safeguard competitiveness, DA A/S incorporated a new mitigation framework.[17] This framework is designed to reduce price-impactful exercises of market power while preserving room for competitive offers that reflect reasonable expected values for closeout costs, avoidable input costs and risk. It utilizes the same conduct-and-impact approach that is commonly employed to mitigate market power throughout New England's wholesale markets. The conduct test identifies offers that may be inconsistent with competitive behavior, while the impact test assesses the effect of those flagged offers on market clearing prices. If a DA A/S product offer fails the conduct test, and the impact test fails in any hour, the submitted offer price is replaced during market clearing with a reference price that is intended to represent a competitive offer.[18] This reference price, referred to as a **Benchmark Level** under the DA A/S design, is equal to the sum of the expected closeout and, as applicable, the AIC.

[17] For more information about DA A/S mitigation, see Section III.A.8 of the ISO-NE Tariff, available here: https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf.

[18] One unique aspect of the DA A/S mitigation design is that a DA A/S product offer is mitigated in a given hour if the offer fails the conduct test in that hour and there is a price impact failure in any hour of that same day (i.e., the impact test failure does not need to occur in the same hour as the conduct test failure for DA A/S mitigation to occur).

The conduct test compares the DA A/S offer price to an estimate of an upper-end competitive price. This latter price is referred to as the **Conduct Test Threshold Price**, and all offer prices that exceed this value are flagged for possible mitigation. The conduct test threshold price is defined as the sum of:

1. 200% of the expected closeout charge;[19] and
2. 150% of the AIC.[20]

The impact test used for the DA A/S market determines whether DA A/S offers that are flagged by the conduct test have a material effect on increasing DAM clearing prices beyond acceptable levels.[21] For this purpose, materiality is defined by the **Impact Test Threshold**, which is set at 150% of the median difference between (1) the conduct test threshold prices for all Day-Ahead Ancillary Services offers submitted for the offer-hour and (2) the Benchmark Levels for all Day-Ahead Ancillary Services offers submitted for the offer-hour.[22] In the majority of hours, this means the threshold is 150% of the expected closeout.

3.2 Day-Ahead Energy Market

Prior to DA A/S, the market clearing outcomes in the day-ahead market did not always align with expected real-time conditions. For example, less physical energy supply could clear than was expected to be needed in real time.[23] When that happened, there was a day-ahead "energy gap" (i.e., the amount of day-ahead energy awards on physical resources was less than the expected real-time load.)

[19] The 200% multiplier was intended to give suppliers reasonable room to reflect risk premiums, forecasting error in estimated closeout values, and expected differences between Day-Ahead and Real-Time outcomes. The ISO concluded that this level captured a reasonable range of competitive offer behavior without materially weakening market power protections. For additional discussion on this topic, please see pages 90-92 of the testimony of Dr. Parviz Alivand in support of DA A/S contained within the ISO's filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

[20] The 150% multiplier was intended to allow for resource-specific variations in fuel and charging costs, as well as potential inaccuracies in the ISO's standard cost formulas. The ISO concluded that this level provided a reasonable allowance for competitive cost variation while maintaining an effective conduct screen. For additional discussion on this topic, please see pages 101-102 of the testimony of Dr. Parviz Alivand in support of DA A/S contained within the ISO's filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

[21] This evaluation is performed for each hour using all resources that submitted DA A/S offers for that hour, and it measures whether conduct-test-flagged offers increase any Day-Ahead Market price, including the DA LMP and each of the four DA A/S clearing prices.

[22] The 150% factor provides a 50 percent buffer above the base threshold measure to account for the limitations of using a single mitigation run and to avoid unnecessary mitigation of offers that may be flagged in that run but, on their own, would not materially affect market prices. Based on its market simulations, the ISO concluded that this level appropriately balances avoiding over-mitigation and preventing under-mitigation For additional discussion on this topic, please see pages 104-111 of the testimony of Dr. Parviz Alivand in support of DA A/S contained within the ISO's filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

[23] Physical energy supply refers to generators, demand response resources, and imports.

3.2.1 Forecast Energy Requirement

To address this "energy gap," the day-ahead market introduced a new constraint—**the Forecast Energy Requirement (FER)**—which requires sufficient capability from physical resources to meet the ISO's load forecast. The market satisfies the FER through a combination of day-ahead energy awards on physical resources and EIR awards.[24]

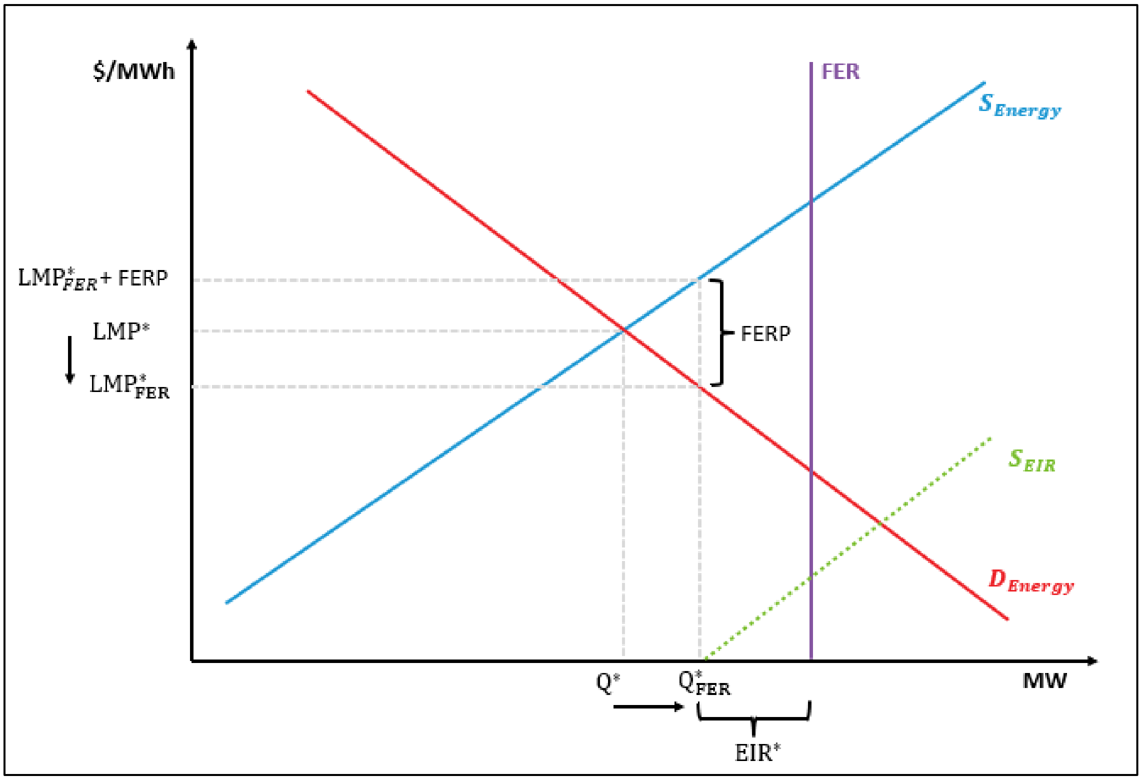
For their contribution to satisfying the FER constraints, physical supply resources with day-ahead energy awards and EIR awards are paid the **FER Price (FERP)**. Notably, the addition of the FER constraint fundamentally changed the paradigm for energy compensation to physical resources in the day-ahead market; physical resources are now compensated for their energy via a combination of the LMP and FERP, whereas prior to DA A/S they received energy compensation solely via the LMP. The **FER credit** represents the payment to physical supply resources with day-ahead energy awards for their contribution to satisfying the FER constraint. The FER credit is allocated as a charge primarily to real-time load obligation (RTLO) on a pro-rata basis.[25]

A simplified graphical representation of the impact that the FER has on day-ahead energy market clearing is presented in Figure 3-5 below.

[24] For more information about Energy Imbalance Reserves (EIR), see Section 3.1.1.

[25] For more information on how the FER credit is charged, see Section III.3.2.1(q)(4)(iii) of the ISO-NE Tariff: https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf

Figure 3-5: The Impact of FER on Day-Ahead Energy Market Clearing



Prior to DA A/S, the intersection of the energy supply curve (blue line) and energy demand curve (red line) determined the quantity of cleared energy (Q^*) and the clearing price for that energy (LMP^*). With the introduction of the FER (purple line), the market clearing changes. The market clearing engine must find a combination of energy on physical resources and EIR (dashed green line) to satisfy the FER. In the figure above, the market now clears a higher quantity of energy (Q^*_{FER}) and the remainder of the FER is satisfied via cleared EIR (EIR^*) such that Q^*_{FER} + EIR^* = FER. **Importantly, the LMP with the FER included (LMP^*_{FER}) is lower than the LMP without it (LMP^*).** However, physical resources with energy awards as well as resources that clear EIR awards receive the FERP because of their contribution to satisfying the FER.[26] As such, physical resources with energy awards now receive $LMP^*_{FER} + FERP$ as energy market compensation, which covers the marginal cost of energy supply.

[26] In this example, the FERP is set by energy supply and demand rather than by EIR, although that can and frequently does occur.

Section 4
Market Costs

This section presents the settlement costs associated with DA A/S in its first year as well as an estimate of the incremental costs of DA A/S relative to an energy-only design intended to replicate the day-ahead market design prior to DA A/S. As such, this analysis distinguishes between *settlement costs* and *incremental economic cost*.

Settlement costs measure the credits and charges created by the DA A/S design, including DA A/S credits and closeout charges, and FER credits and charges. Although these items determine who pays and who receives money, they do not, by themselves, measure the incremental cost of the new market design because the same market design change also affects other settlement-related factors (e.g., day-ahead LMPs).

For this reason, we also present a simulation-based estimate of incremental economic cost. Importantly, the simulations do not measure all offsetting or interactive effects, including the retirement of the Forward Reserve Market (FRM), potential reductions in NCPC, future effects on capacity-market offer behavior and Net CONE, or changes in investment and retirement incentives. Consequently, the simulation-based results can be best understood as measures of the incremental day-ahead and deviation-settlement effects of introducing the FER and FRS requirements, not as a full cost-benefit analysis of the initiative.

Key Takeaways

During the first year, net DA A/S payments totaled $261.7 million ($2.21/MWh of load served) and were heavily concentrated in winter months, which accounted for roughly 60% of the total. FER credits were much larger at approximately $1 billion ($8.49/MWh), also showing strong seasonality with nearly two-thirds occurring in winter. Therefore, total year one settlement payment/costs totaled over **$1.25 billion**, or $10.70/MWh of load served.

Simulation results indicate that the implementation of the DA A/S market increased total incremental costs relative to the prior day-ahead design by about **$974 million** in its first year ($8.23/MWh of load served), a lower amount than settlements costs primarily reflecting the interplay between the FERP and (lower) DA LMP. A small number of high-cost days drove a disproportionate share of this increase: just 12 days accounted for roughly 50% of incremental costs, with a five-day winter storm event alone contributing about 40%, and a single day (January 27, 2026) responsible for 18%.

Net costs for the Flexible Response Services in New England averaged $2.10/MWh of load, which was higher than the costs of similar products in a comparable market (NYISO). These higher prices in New England reflect both system characteristics (e.g., high reserve requirements relative to load) and design features, in particular the DA A/S call-option settlement design, which is intended to enhance reliability through stronger performance incentives than a forward sale construct as exists in New York.

4.1 Settlement Costs

The DA A/S products represent a small percentage of overall energy and ancillary services (E&AS) costs.[27] This can be seen in Table 4-1, which shows the *net* settlements for the DA A/S products by season for the first year.[28,29]

Table 4-1: DA A/S Settlements ($ millions)

DA A/S	Spring 2025	Summer 2025	Fall 2025	Winter 2026	Total
DA TMSR (net)	$3.7	$16.6	$8.5	$45.6	**$74.4**
DA TMNSR (net)	$6.3	$26.1	$16.1	$65.1	**$113.6**
DA TMOR (net)	$2.9	$13.3	$7.8	$36.3	**$60.3**
EIR (net)	$0.2	$1.4	$1.7	$10.1	**$13.4**
Total (net)	**$13.1**	**$57.4**	**$34.1**	**$157.1**	**$261.7**
Total E&AS Costs	$1,284	$2,346	$1,610	$6,261	**$11,500**
% Total E&AS Cost	1%	2%	2%	3%	**2%**

Net DA A/S payments totaled $261.7 million during the first year, representing about 2% of total E&AS costs over the period, or $2.21/MWh of load served.[30] TMNSR payments represented the largest component at $113.6 million, followed by TMSR at $74.4 million, and TMOR at $60.3 million. EIR payments were relatively small at $13.4 million in total, contributing little to overall costs. Importantly, while the total DA A/S payments are highly seasonal—with Winter 2026 accounting for the majority these payments (60%)—they tended to move in-line with overall E&AS markets costs, generally accounting for 1 to 3% of these overall E&AS market costs.

FER credits have accounted for much larger share of total E&AS costs throughout the first year. This can be seen in Table 4-2 below, which shows total FER credits by quarter.

[27] Total energy and ancillary services costs include day-ahead and real-time energy, reserve, regulation, and NCPC costs.

[28] The months included in each season are: Spring: Mar-May, Summer: Jun-Aug, Fall: Sep-Nov, Winter: Dec-Feb

[29] For the purposes of calculating the settlement value of the DA A/S market, we sum the initial credit and the closeout charge to calculate a final *net* payment/charge.

[30] Load served, or Net Energy for Load, during the one-year period totaled 118,400 GWh, or 13,516 MW on average per hour.

Table 4-2: FER Settlements ($ millions)

	Spring 2025	Summer 2025	Fall 2025	Winter 2026	Total
FER Credit	$74.4	$122.2	$166.9	$641.6	$1,005.1
Total E&AS Costs	$1,284	$2,346	$1,610	$6,261	$11,500
% Total E&AS Cost	6%	5%	10%	10%	9%

FER credits totaled approximately $1 billion during the first year of DA A/S, accounting for approximately 9% of total E&AS costs over the period, or $8.49/MWh of load served. The average annual FER price was $7.13/MWh (including all hours, even when the FERP was zero). Like DA A/S payments, FER credits vary by season with the largest value occurring in winter; FER credits during the winter accounted for $641.6 million, or roughly 64% of total FER credits. FER credits represented between 5-6% of total E&AS costs during spring and summer before climbing to 10% for both the fall and winter. The increase during the fall was related to the high level of generator outages and a reduction in net interchange in the day-ahead market,[31] while the winter increase was related to increased payments during a multi-day period of stressed system conditions.

4.2 Incremental Costs

We performed market simulations to better understand the incremental impact of DA A/S on market outcomes relative to the day-ahead market (DAM) design that was in place prior to March 1, 2025. To perform these simulations, we used an in-house market simulation tool that both replicates the logic of the day-ahead market (DAM) that exists in production today and also provides the flexibility to modify constraints and other key inputs.[32,33]

The simulations indicate that the initiative increased total day-ahead and deviation-settlement costs relative to the prior energy-only design, but the increase appears through different settlement components than the underlying economic driver may suggest. In the full DA A/S case, the large share of the incremental payments appears as FER credits and net DA A/S credits. In a no-FER simulation, similar underlying FRS-procurement costs tend to appear through higher DA LMPs instead.

[31] For more in-depth coverage of this period, see the IMM's Fall 2025 Quarterly Markets Report, available here: https://www.iso-ne.com/static-assets/documents/100032/2025-fall-quarterly-markets-report.pdf.

[32] Importantly, while the IMS benchmarks very well against the GE market clearing engine (MCE) that is used in production at ISO-NE, the simulation results should be viewed as indicative rather than exact. The market simulator captures the main co-optimized commitment, scheduling, constraint, and pricing logic that has been benchmarked to production-market outcomes, but it does not reproduce every production-engine feature.

[33] Due to simulation-related constraints, December 5, 2025, and January 3, 2026, are not reflected in any of the simulation results.

Incremental Cost of DA A/S

In order to estimate the impact of DA A/S on market costs, the following scenarios were simulated:

1) **No DA A/S**: a scenario in which all DA A/S constraints (FER, FRS) are 'turned off.' This scenario is intended to reflect the pre-March 2025 day-ahead market.[34]
2) **DA A/S:** a scenario in which all DA A/S constraints are 'turned on.' This scenario is intended to reflect the current day-ahead market.

The following table provides a high-level comparison of these two scenarios.

Table 4-3: Estimated Change in Market Costs

Category	No DA A/S ($M)	DA A/S ($M)	Delta ($M)	Delta (%)
DA Energy	**$10,437**	**$11,153**	**$716**	**6.9%**
LMP	$10,437	$10,127	-$309	-3.0%
FER Price	$0	$1,026	$1,026	
DA A/S	**$0**	**$261**	**$261**	
Credits	$0	$453	$453	
Closeouts	$0	-$192	-$192	
Total Charges/Credits	**$10,437**	**$11,415**	**$978**	**9.4%**
Cost of Incremental RT Energy	$140	$136	-$4	-2.9%
Total Cost/Revenue Change	**$10,577**	**$11,551**	**$974**	**9.2%**

We estimate that DA A/S resulted in an increase of $974 million (9.2%) in total costs over the first year. The majority of the incremental cost increases are in the form of higher day-ahead energy market payments, where we estimate an increase of $716 million relative to the 'No DA A/S' scenario. While energy payments via the day-ahead LMP decreased by $309 million relative to the 'No DA A/S' scenario, this is more than offset by a $1,026 million FER credit.[35] Net payments to the new DA A/S awards ($261 million) represent all of the remaining estimated cost increase. The simulations indicate very little change in incremental real-time energy purchases between the two scenarios.[36]

[34] The IMM did *not* adjust energy offers in this scenario in any way (e.g., there was no adjustment to reflect the way participants with FRM obligations were required to offer in the real-time market under that market design).

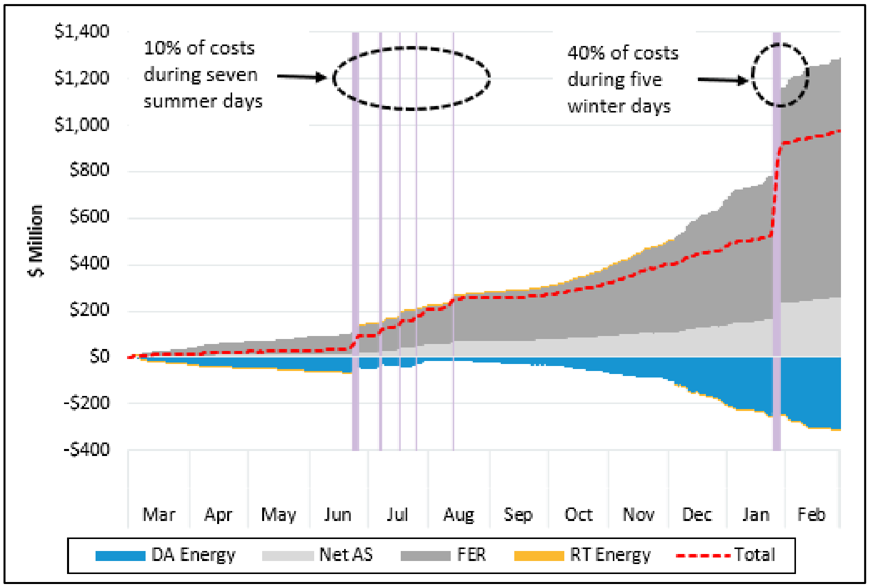
[35] See Figure 3- and the associated text for an explanation of this impact this design has on the day-ahead LMP.

[36] We calculate the cost of incremental real-time energy as (real-time load obligation – day-ahead load obligation) * real-time LMP, mimicking the deviation settlement logic. These costs can differ because one scenario may clear more energy supply in the day-ahead market relative to another and therefore need to procure less energy supply in real-time market. Importantly, we assume no changes in the real-time LMP between the two scenarios, which is a conservative assumption in hours where DA A/S improved the day-ahead operating plan and reduced the likelihood of moving up a steep real-time supply curve.

High-Cost Days

It is important to call out the outsized impact that a small set of high-cost days had on the incremental costs of DA A/S during its first year. This can be seen in Figure 4-1, which shows the cumulative total incremental change in market cost broken down by cost component over the first year of DA A/S.

Figure 4-1: Cumulative Incremental Change in Market Costs



We found that 12 days, most of which were associated with multi-day periods of stressed system conditions, accounted for approximately 50% of incremental costs of DA A/S in its first year (we note these in the figure above with light purple bars). These 12 days include a five-day period from January 25, 2026, to January 29, 2026, that coincided with Winter Storm Fern, as well as the following seven days in Summer 2025: June 23 through June 25,[37] July 7, July 17, July 25, and August 13. We estimate that one day alone, January 27, 2026, accounted for 18% of the incremental DA A/S costs and that the five-day period between January 25, 2026, to January 29, 2026, accounted for 40% of these incremental costs.

To provide some idea of the impact of these high-cost days on incremental costs, we present Table 4-4, which shows the estimated incremental DA A/S costs for only the 12 highest-cost days within the year as well as the costs for all other days of the year. For reference, the table also shows the full year costs (in gray).

[37] The three-day period in June was characterized by hot and humid leading to very high peak loads.[37] Events during this period culminated on June 24 when the grid experienced capacity scarcity conditions (CSC). For more coverage on this period, see the IMM's Summer 2025 Quarterly Markets Report, available here: https://www.iso-ne.com/static-assets/documents/100029/2025-summer-quarterly-markets-report.pdf.

Table 4-4: Comparison of Incremental DA A/S Costs: High-Cost Days to All Other Days

Category	Incremental Cost ($M) *12 Highest-Cost Days*	Incremental Cost ($M) *All Other Days*	Incremental Cost ($M) *Complete Year*
DA Energy	**$386**	**$331**	**$716**
LMP	$44	-$353	-$309
FER Price	$342	$684	$1,026
DA A/S	**$93**	**$169**	**$261**
Credits	$134	$319	$453
Closeouts	-$41	-$151	-$192
Total Charges/Credits	**$478**	**$500**	**$978**
Cost of Incremental RT Energy	$11	-$15	-$4
Total Cost/Revenue Change	**$489**	**$485**	**$974**

Day-ahead energy costs represent the majority of the incremental costs for both the 12 highest-cost days ($368 million of $489 million, or 79%) and all the other days ($331 million of $485 million, or 68%). Notably, while we see the $684 million increase in FERP-based energy payments for the other days being offset by a $353 million reduction in LMP-based payments, we see the $342 million dollar increase in FERP-based energy payments for the 12 highest-cost days associated with an *increase* in LMP-based payments of $44 million. Additionally, we see a higher percentage of the DA A/S credits being offset by closeouts in the other days ($151 million of $319 million, or 47%) than we do for the 12 highest-cost days ($41 million of $134 million, or 31%).

4.3 Cost Benchmarking

In this section, we compare day-ahead reserve costs for ISO-NE against those for the New York Independent System Operator (NYISO), which has comparable loads and reserve requirements. Importantly, while both New England and New York procure ancillary services through a co-optimized market-based mechanism, there are important design differences: ISO-NE utilizes a call-option settlement approach based around the real-time price of energy, while NYISO uses a forward sale settlement approach, in which day-ahead reserve positions are settled against real-time reserve prices.[38]

Day-ahead reserve costs for ISO-NE and NYISO are shown in $/MWh of load in Table 4-5 below, alongside metrics that illustrate the comparability of the two regions.

[38] For example, if a NYISO generator cleared day-ahead reserves at $10/MWh but did not provide reserves in real time when reserve prices were $2/MWh, the reported net day-ahead reserve cost would be $8/MWh ($10/MWh - $2/MWh). This includes scenarios when the generator did not provide real-time reserves because it was dispatched up for energy.

Table 4-5: Day-Ahead Ancillary Services Costs in ISO-NE Compared to NYISO

Concept	ISO-NE	NYISO
DA Reserve Costs,[39,40] *$/MWh of Load*	**$2.10**	**$1.39**[41]
Average Load, *MW*	13,516	17,329
Largest Contingency,[42] *MW*	1,261	1,310
Largest Contingency, *% Share of Load*	9%	8%

When measured on a $/MWh of load basis, ISO-NE features higher day-ahead reserve costs than NYISO, with a premium of roughly $1/MWh of load. While FER credits are not directly accounted for in the $2.10/MWh of load, the FER constraint indirectly impacts this total as it contributes to overall scarcity in the day-ahead market. Based on counterfactual simulations, the ISO-NE day-ahead reserve cost would have been $1.82/MWh of load in the absence of the FER constraint.[43] This indicates that the ISO-NE reserve premium is largely a function of market design. The call-option settlement approach in ISO-NE is designed to provide stronger real-time performance incentives, and the premium for these incentives must be weighed against their reliability benefits.[44]

[39] The *DA Reserve Cost* for ISO-NE represents the net FRS costs (i.e., the FRS credits less the realized closeout charges).

[40] The reserve cost data for NYISO were provided by Potomac Economics. The products included in this calculation are 10-minute, 30-minute, and spinning reserves. We thank Potomac for their data contributions.

[41] Note that $1.39/MWh of load represents the *Gross* DA reserve costs for NYISO. This is the sum of DA reserve credits, and ignores scenarios where resources might be dispatched up to provide energy and therefore buy back real-time reserves in the two-settlement system. *Net* reserve costs would deduct the costs of purchasing real-time reserves in these scenarios, and would be a useful comparison to the ISO-NE FRS credits less closeout charges. To bound this estimate, we also calculate the difference between NYSIO day-ahead reserve prices and real-time reserve prices, regardless of whether assets were truly buying back real-time reserves or not. This yields a lower-bound estimate of $0.48/MWh of load. We estimate NYISO net day-ahead reserve costs to fall between $0.48/MWh-$1.39/MWh; in any scenario, ISO-NE FRS products come at a price premium when compared to NYISO day-ahead reserves.

[42] The *Largest Contingency* for NYISO was estimated based on technical documentation (Link) alongside public information on generator sizes.

[43] See Section 0 for more information on the counterfactual simulation that does not include the FER,

[44] See Section 10 for a discussion of the reliability benefits observed over the first year of DA A/S.

Section 5
Assessment of Cost Drivers

In this section we explore the impact that changes in system conditions and observed participant behavior have had on DA A/S costs. We also attempt to disentangle the relationship between reliability requirements (i.e., FRS requirements, FER) to better understand the cost drivers during the first year of this new market design.

Key Takeaways

We find that changing system conditions and differences between assumed and actual market behavior explain a large percentage of the observed cost increase relative to the ISO's 2023 DA A/S Impact Assessment, which was an important component of the market design process.

Specifically, we find that an update of the ISO's 2023 Impact Assessment, which assumes full participation and competitive offer formulation, would have resulted in incremental costs of $733 million based on actual data from the first year of DA A/S. Again, a small number of high-stress days disproportionately influenced results: just 13 days accounted for roughly half of total incremental costs, and without them, DA A/S impacts would have been closer to original expectations, underscoring the impact of system stress events on overall DA A/S costs.

We also find that the FRS constraints are the primary underlying driver of incremental costs: absent the FER constraint, roughly $613 million (about 65%) of total incremental DA A/S costs would persist. The addition of the FER constraint largely changes the clearing prices in which these costs manifest, rather than their root cause.

Opportunity costs have played a role in price formation although it is difficult to precisely quantify their overall impact. However, simulation results show that even if all historically-offered DA A/S capability were offered at $0/MWh, the system would still incur $316 million ($2.67/MWh) in incremental costs to satisfy FER and FRS constraints.

5.1 System and Market Conditions

System and market conditions have changed in meaningful ways since ISO-NE brought the market reforms associated with DA A/S through the stakeholder process and ultimately filed the design changes with the Federal Energy Regulatory Commission (FERC) in October, 2023.[45] These changes, which include higher natural gas prices, more extreme weather events, and changes in the supply mix, have applied upward pressure on both energy and ancillary service costs.

Additionally, market participation levels and offer prices are materially different from the assumptions made by ISO-NE in their Impact Analysis (IA) work to estimate indicative costs for DA

[45] The ISO's filing to FERC is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

A/S.[46] In practice, participation has been lower and offer prices higher than was assumed in the IA. 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.

Given these differences, the IMM conducted a "refresh" of the IA (which we refer to as the "IA Refresh") to better understand what the costs of DA A/S might look like under the same full participation and competitive offer assumptions used in the original IA but based on actual data from the first year of the initiative.

The Original IA

In order to capture a range of market conditions, the original IA was performed over a three-year historical period from January 1, 2019, to December 31, 2021. ISO-NE premised market participation and offer price assumptions in the IA on a model of profit-maximizing behavior under competitive conditions. Consistent with that framework, participants were assumed to offer their full physical capability at an estimated competitive cost of meeting the obligation.

The estimated incremental costs associated with DA A/S from the IA are presented as totals and as percentages of total E&AS costs by year in Table 5-1 below.[47]

Table 5-1: Estimated Incremental Costs from DA A/S (ISO-NE Impact Analysis)

Year	Incremental Costs ($M)	E&AS Costs ($M)	% E&AS Costs
2019	$127	$4,207	3.0%
2020	$104	$3,704	3.4%
2021	$188	$6,189	3.0%
Average	**$140**	**$4,490**	**3.1%**

The IA estimated that DA A/S costs would have averaged $140 million per year from 2019 to 2021, representing about 3.1% of total E&AS costs. While total E&AS costs varied meaningfully by year, the IA results indicated that DA A/S costs would remain a relatively small and stable share of the overall market.

A more granular summarization of the IA results is presented in Table 5-2 below. This table compares average actual market values from the three-year period (2019-2021) against estimated market values assuming DA A/S had been in place for the same three-year period.

[46] For more information on the IA, see ISO-NE's presentation titled *Day-Ahead Ancillary Services (DASI)* from the April 11-13, 2023, NEPOOL Markets Committee meeting, available here: https://www.iso-ne.com/static-assets/documents/2023/04/a07a_mc_2023_04_11-13_dasi_design_r1.pdf

[47] It is important to note that ISO-NE presented the estimated DA A/S costs relative to total wholesale market costs, which includes Forward Capacity Market (FCM) and transmission costs. We present the estimated DA A/S costs relative to just energy and ancillary services costs as this is our common way to "standardize" costs throughout the document.

Table 5-2: Estimated Change in Market Costs from DA A/S, 2019-2021 (ISO-NE IA)

Category	No DA A/S ($M)	DA A/S ($M)	Delta ($M)	Delta (%)
DA Energy	**$4,405**	**$4,588**	**$183**	**4.2%**
LMP	$4,405	$4,462	$58	1.3%
FER Price	$0	$125	$125	
DA A/S	**$0**	**$22**	**$22**	
Credits	$0	$90	$90	
Closeouts	$0	-$69	-$69	
Total Charges/Credits	**$4,405**	**$4,609**	**$205**	**4.6%**
Cost of Incremental RT Energy	$104	$40	-$65	-62.0%
Total Cost/Revenue Change	**$4,509**	**$4,649**	**$140**	**3.1%**

In the ISO's IA, the increase in markets costs occurred primarily in the day-ahead energy market where costs increased by $183 million (4.2%). Meanwhile, DA A/S costs were estimated to add only $22 million to market costs, with $90 million of DA A/S credits being offset by $69 million in closeout charges. Notably, the IA estimated a significant reduction (62%) in real-time energy payments.[48]

The "Refreshed" Impact Assessment

System conditions and competitive offers changed considerably between the 2019-2021 period used by the ISO for its impact analysis and the first year of DA A/S. Some of the relevant changes are listed in Table 5-3 below.

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[48] This reduction is likely the result of a "market response" assumption that the ISO incorporated into their simulation work. The ISO assumed that lower day-ahead LMPs under the new design would induce additional priced demand bids, increasing day-ahead cleared energy and supporting price convergence with expected real-time LMPs. The IA therefore added additional energy demand bids to the simulation. This assumption is best understood as a long-run equilibrium response, not as evidence that such behavior was expected to occur in the first year. However, this action increased the amount of demand cleared day-ahead, resulting in smaller real-time deviations and therefore smaller real-time charges/credits. For more information about this modeling assumption, See Page 84 of the testimony of Ben Ewing in support of DA A/S contained within the ISO's filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

Table 5-3: Differences in System Conditions and Competitive Offer Components

Index	(1/1/2019 – 12/31/2021) Average	(3/1/2025 – 2/28/2026) Average	Delta (%)
DA Gas Price[49] ($/MMBtu)	$3.24	$6.82	110.5%
DA Hub LMP ($/MWh)	$33.48	71.44	113.4%
DA Load Forecast (MW)	13,151	13,019	-1.0%
Summer Peak Load[50] **(MW)**	25,095	26,586	5.9%
Winter Peak Load[51] **(MW)**	19,512	20,221	3.6%
Competitive Offer[52] **($/MWh)**	$10.00	$12.78	27.8%
Expected Closeout ($/MWh)	$3.20	$7.74	141.9%
AIC ($/MWh)	$0.48	$3.35	597.9%
Risk Premium ($/MWh)	$6.33	$1.70	-73.1%

Notably, the average price of gas increased by over 100% between the years covered in the IA ($3.24/MMBtu) and the first year of DA A/S ($6.82/MMBtu). This resulted in a commensurate increase in the day-ahead Hub LMP, which rose from $33.48/MWh to $71.44/MWh. While there was little change in the average day-ahead load forecast between the two periods, the system experienced higher summer and winter peak loads during the first year of DA A/S.[53]

Meanwhile, compared with ISO-NE's original IA, the "IA Refresh" produced a higher average competitive offer ($12.78/MWh compared with $10.00/MWh), but the mix of components changes: expected closeout and AIC are higher, while the risk premium is lower. The increase in expected closeout was generally in-line with that observed for energy market prices, while the marked increase in the AIC largely stemmed from the extreme natural gas prices observed during Winter Storm Fern. The reduction in the (Sharpe-based) risk premium reflects changes in total profit

[49] The gas price is the Intercontinental Exchange next-day index price for Algonquin Non-G.

[50] This represents the maximum peak hourly load observed in June, July, or August. For the 2019-2021 period, this represents the average of the three summer maximums. This information comes from: https://www.iso-ne.com/static-assets/documents/2023/08/enepk_report.xlsx.

[51] This represents the maximum peak hourly load observed in December, January, or February. For the 2019-2021 period, this represents the average of the three winter maximums. This information comes from: https://www.iso-ne.com/static-assets/documents/2023/08/enepk_report.xlsx.

[52] The values shown for the competitive offer and its components (Expected Closeout, AIC, and Risk Premium) are simple (unweighted) averages across all resources and hours within each study period/day set. The averages are based on all submitted offers rather than the subset selected by the market-clearing engine to provide DA A/S.

[53] The peak load observed in summer 2025 was the highest recorded load in New England in over 10 years. See the IMM's Summer 2025 Quarterly Markets Report for more information: https://www.iso-ne.com/static-assets/documents/100029/2025-summer-quarterly-markets-report.pdf.

variability (relative to the real-time-only alternative) from taking on a DA A/S award for participating resources.[54]

The high-level results of a comparison between the IMM's "IA Refresh" and the simulated "No DA A/S" scenario are provided in Table 5-4 below.

Table 5-4: Estimated Change in Market Costs from DA A/S (IMM "IA Refresh")

Category	No DA A/S ($M)	IMM Refresh ($M)	Delta ($M)	Delta (%)
DA Energy	**$10,437**	**$11,029**	**$592**	**5.7%**
LMP	$10,437	$10,214	-$222	-2.1%
FER Price	$0	$815	$815	
DA A/S	**$0**	**$146**	**$146**	
Credits	$0	$340	$340	
Closeouts	$0	-$194	-$194	
Total Charges/Credits	**$10,437**	**$11,175**	**$738**	**7.1%**
Cost of Incremental RT Energy	$140	$136	-$5	-3.3%
Total Cost/Revenue Change	**$10,577**	**$11,311**	**$733**	**6.9%**

We estimate that the incremental cost of DA A/S using the similar assumptions to those used in the original IA would have resulted in an increase of $733 million (6.9%) in total costs over the first year.[55] This is an indication that changes in system and market conditions explain a large share (75%) of the total estimated incremental costs of DA A/S during its first year. Notably, the "IA Refresh" shows that not only did the level of incremental costs ($733 million) increase substantially relative to the original IA ($140 million) but so did the ratio of these costs relative to total market cost (6.9% in the "IA Refresh" versus 3.1% in the original IA).

As was the case with the estimated incremental costs of DA A/S discussed in Section 4.2, we observe a similar phenomenon of high-cost days playing a large role on incremental costs in the "IA Refresh". We estimate that 13 days, most of which were the same as those noted in Section 4.2, accounted for approximately 50% of incremental costs of DA A/S in the "IA Refresh."[56] Absent

[54] This could happen if the composition of participating resources shifts over time toward units for which DA A/S participation adds less incremental variance, or more generally where real-time energy margins frequently offset closeout exposure.

[55] The "IA Refresh" uses actual values from the first year of DA A/S while maintaining the following assumptions of the original IA: (1) all generators make DA A/S offers at their Economic Maximum (EcoMax) and all DARDs at their Max Consumption; (2) all generators and DARDs make DA A/S offers priced at their Benchmark Level plus a risk premium determined by the Sharpe ratio (see Section 6.3 for more information); (3) Wind, solar, and demand response resources do not make DA A/S offers; (4) the Maximum Daily Award Limit (MDAL) for all resources was set such that they could not bind. The "IA Refresh" did not include any additional energy demand bids as were done in the original IA (noted in Footnote 4848). Additionally, all DA A/S offers were based on Benchmark Levels that incorporated participant-submitted values that were approved by the IMM as well as any interventions the IMM made to expected closeouts, reflecting the assumption that these adjusted values most accurately represented competitive offers.

[56] The days were: June 23-24, 2025; July 6-7, 2025; July 17, 2025; July 29-30, 2025; August 12-13, 2025, and January 25-28, 2026.

these 13 days, the incremental costs of DA A/S in the “IA Refresh” would have represented only 4.0% of total market costs, making it more in-line with the original IA (3.1% of total market costs). These results suggest that market performance during periods of system stress crucially impacted program costs in a way they did not during the years covered in the IA. In fact, there were eight days in the “IA Refresh” when the incremental DA A/S costs exceeded two percent of the total annual incremental DA A/S costs, while there was only one such day in three years when this occurred in the IA.

If changes in system and market conditions account for $733 million of the total $974 million that we estimate for the incremental costs of DA A/S, a natural follow-up question is: what explains the remaining $241 million? The most important differences between the “IA Refresh” and observed first-year outcomes are likely to be (1) participation and (2) differences between observed DA A/S offer prices and estimated competitive offer prices (including risk premiums).

The IA assumed broader participation of eligible capacity than was actually observed during the first year of the new design. These quantity-side decisions reduce market liquidity, raise inter-product opportunity or “redispatch” costs, and can amplify tight-hour price effects. Market participation is looked at in more detail in Section 6.1.

Additionally, differences between observed DA A/S offer prices and cost-based benchmarks also likely contributed to higher prices. Additional coverage of DA A/S offer prices is provided throughout this document, including an analysis of marginal DA A/S offers (Section 5.3), a discussion of risk premia (Section 6.3), comparison of DA A/S offer prices relative to benchmark levels (Section 7) and an evaluation of expected closeout accuracy (Section 8.2).

5.2 Impact of New Market Constraints

DA A/S introduced several new constraints into the day-ahead market at the same time, which has made it challenging to determine the extent to which each constraint has driven observed outcomes. In this section, we analyze the relationship between specific constraints and costs to determine the key drivers of observed costs in the first year of the new market design.

5.2.1 Flexible Response Services

The FRS constraints are the set of constraints that were added in DA A/S to ensure that the ISO has enough fast-starting and fast-ramping capability to quickly respond to a large supply loss. One important insight related to the incremental cost of DA A/S that the IMM first made in its Summer 2025 Quarterly Markets Report (QMR) is that, while the costs primarily manifest themselves in the FER payment, they primarily originate from the FRS requirements.[57] To arrive at that conclusion, we used the Integrated Market Simulator to run the following scenario:

1) **FRS Only**: a scenario in which the FER constraint is 'turned off' but the FRS constraints remain 'turned on.' This scenario is intended to reflect a modified version of the current DAM that doesn't have the FER constraint.

We re-ran this FRS Only scenario using a full year of market data and the results are compared against the No DA A/S case in the table below.

Table 5-5: Estimated Change in Market Costs with only the FRS Constraints

Category	No DA A/S ($M)	FRS Only ($M)	Delta ($M)	Delta (%)
DA Energy	**$10,437**	**$10,805**	**$368**	**3.5%**
LMP	$10,437	$10,805	$368	3.5%
FER Price	$0	$0	$0	
DA A/S	**$0**	**$216**	**$216**	
Credits	$0	$397	$397	
Closeouts	$0	-$181	-$181	
Total Charges/Credits	**$10,437**	**$11,020**	**$84**	**5.6%**
Cost of Incremental RT Energy	$140	$170	$30	21.1%
Total Cost/Revenue Change	**$10,577**	**$11,190**	**$613**	**5.8%**

We estimate that incremental DA A/S costs would have been $613 million if only the FRS constraints had been incorporated into the market clearing process and there was no FER constraint. This equates to 65% of the estimated total incremental DA A/S costs ($974 million). Notably, the incremental cost increases shift from FERP-based payments when the FER is included to LMP-based payments when the FER is removed. This finding highlights the distinction between a settlement channel (the FERP), and the main cost driver (the FRS requirements). Because energy,

[57]For more information, see section 3.5.7 of our Summer 2025 QMR, available here: https://www.iso-ne.com/static-assets/documents/100029/2025-summer-quarterly-markets-report.pdf.

EIR, and FRS awards compete for the same scarce resource capability in the co-optimized market, FRS scarcity can raise the marginal cost of satisfying the FER. When the FER constraint is removed, the same underlying scarcity is reflected more directly in the day-ahead LMP.

Co-optimization of energy and reserves has several important cost implications. The first is that energy prices are likely to rise. This happens because some low-cost supply that would otherwise be dispatched to provide energy may instead be used to satisfy one of the reserve requirements, which may result in higher-cost supply at the margin and consequently a higher energy price. The second is that clearing prices now incorporate cross-product opportunity costs, which are the costs incurred by resources (in the form of foregone profits) when the market clearing engine schedules them to satisfy one requirement when it would have been more profitable to meet another.

We can get a sense of the order of magnitude of these cost implications in Table 5-5. For example, day-ahead LMP-based payments increased by **$368 million** (3.5%) between the No DA A/S and the FRS Only scenarios. This increase in energy market costs should be generally indicative of the cost associated with the "redispatch" of energy to satisfy reserve requirements and any opportunity costs that show up in the LMP.[58]

Another way to assess the scale of opportunity costs is to set all DA A/S offer prices for resources that historically offered into the market to $0/MWh and then determine the cost of meeting day-ahead market constraints—energy balance, FER, and operating reserve requirements—based on offered capability.[59] Any non-zero DA A/S clearing prices that result from this approach are in theory a result only of cross-product opportunity costs, because DA A/S offer prices play no role (as they are set at $0/MWh). Under this simulation, total E&AS costs amount to $10,893 million, implying incremental costs of **$316 million** ($2.67/MWh). This approach is somewhat analogous to real-time reserve prices, which are based solely on opportunity cost (or administrative penalty factors).

5.2.2 Forecast Energy Requirement

The *incremental* impact of the FER constraint (*incremental* to a scenario that already includes the FRS constraints) must account for the remaining 35% ($361 million) of the estimated total incremental DA A/S costs ($974 million). It is likely that using the market simulator to assess the impact of the FER constraint alone would result in a substantially lower incremental cost estimate given the interaction of FER constraint and the FRS constraints disappears when only the FER constraint is modeled. In other words, the costs of constraints are not additive; the incremental cost of satisfying the FER increases as ancillary service capability becomes scarcer.

For the year, the FER constraint represents a larger share of the estimated incremental DA A/S costs than when we looked at it over the first six months in our Summer 2025 QMR (at that time it

[58] The term "redispatch" is a common shorthand for the co-optimized displacement of energy by reserve awards. Strictly speaking, however, the market clearing engine only produces a single co-optimized dispatch (i.e., there is no initial "dispatch" and then subsequent "redispatch").

[59] An important caveat here is that setting EIR offer prices to $0/MWh in this simulation has the effect of clearing more "cheap" EIR awards than relatively more expensive energy from physical supply.

accounted for ~19%). This is largely the result of two days: January 26 and January 27, 2026. We estimate that the incremental impact of the FER constraint on these two days added $165 million to incremental DA A/S costs. In other words, absent these two days, the incremental impact of the FER constraint would have only been $195 million (rather than $361 million), representing about 28% (rather than 35%) of estimated total incremental DA A/S costs ($702 million, which represents the incremental costs of DA A/S with January 26, 2026, and January 27, 2026, removed).

5.3 FRS Costs Examined

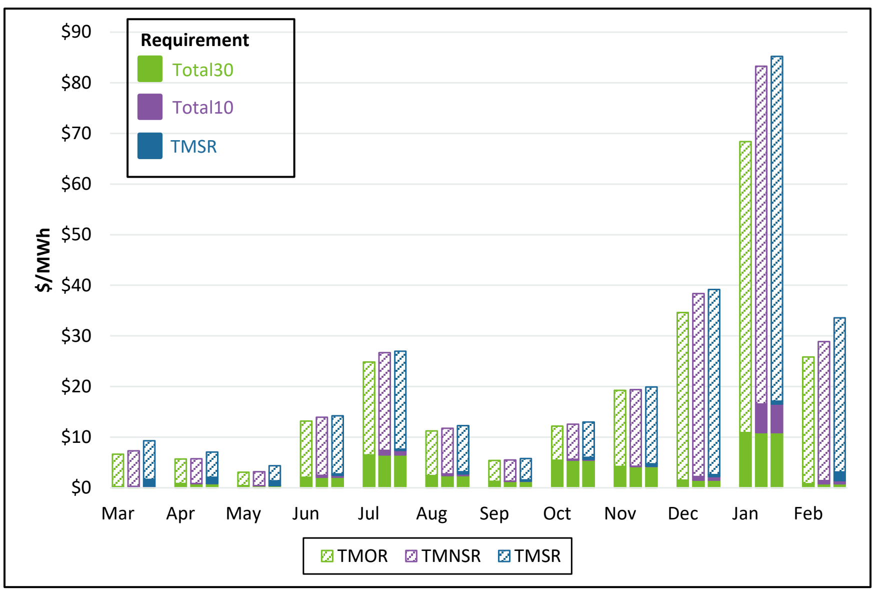
The following section explores how opportunity costs and the various cost components of a DA A/S offer may have impacted FRS clearing prices.

5.3.1 Opportunity Costs

To estimate the extent to which opportunity costs impacted FRS clearing prices, we assumed that highest offer price of a DA A/S product cleared to satisfy that requirement was the "marginal" offer. The difference between this offer price and the ancillary services clearing price is our estimate of the opportunity cost for a specific FRS requirement in that hour. This approach indicated that opportunity costs were $77 million, which represents a low-end estimate of the opportunity costs given that the *true* marginal DA A/S offer may have a lower offer price.

The impact of opportunity costs associated with each FRS requirement impacted average hourly FRS product clearing prices is depicted by month in Figure 5-1 below. The portion of each column reflects the opportunity cost associated with a specific FRS constraint (e.g., the shaded green series reflects opportunity cost of satisfying the Total 30 requirement) while the total height of the column is the average monthly clearing price for the specific FRS product.[60]

Figure 5-1: Impact of Opportunity Costs on FRS Clearing Prices



Opportunity costs made up a small but, at times, meaningful portion of FRS clearing prices during the first year of DA A/S. The most impactful requirement on FRS clearing prices was the Total 30 requirement, which binds in every hour under this design, although its impact did vary considerably by month. Interestingly, the months with high Total 30-related opportunity costs coincide with

[60] As mentioned in Section 3.1.2, the clearing price of the FRS products tend to be closely aligned given their price formation mechanics. Specifically, FRS clearing prices "cascade up," which produces the following relationship between the product clearing prices: $CP_{TMSR} \geq CP_{TMNSR} \geq CP_{TMOR}$.

periods of system stress (July and January) or high levels of generator outages (October and November). Of additional relevance is the finding that four of the five days with the highest average hourly Total 30-related opportunity costs occurred during the four-day period from January 26-29, 2026. Section 5.3.3 examines the drivers of outcomes on the highest DA A/S cost days, including those observed in January.

Opportunity costs associated with the Total 10 requirement, which bound in 33% of hours over the first year, impacted TMNSR and TMSR clearing prices to various degrees over the course of the year. These costs can be seen most visibly in January 2026. Similar to the observation above, the four-day period from January 26-29, 2026, had four of the five days with the highest Total 10-related opportunity costs.

Lastly, the opportunity cost associated with the TMSR requirement, which bound in only 20% of hours in the first year, generally did not have a significant impact on TMSR clearing prices. TMSR-based opportunity costs played no role in clearing prices on 11 of the top 12 high-cost days.[61]

5.3.2 Offer Costs

This section explores how the various cost components of a DA A/S offer may have impacted FRS clearing prices. Specifically, this section examines the relationship between the expected closeout, the Avoidable Input Cost (AIC), and the offer price of the "marginal" offer for the Total 30 requirement.[62,63]

It is important to note that it is not possible to separate the offer price of the "marginal" offer into its distinct components (i.e., expected closeout, the AIC, and risk) given that participants do not submit offer prices at this granularity. For this reason, in Figure 5-2 below, we simply overlay the monthly average "marginal" offer price for the Total 30 requirement (shown as green columns) with two line series: (1) a red line that shows the monthly average expected closeout and (2) a black line that shows an estimate of the AIC component of the "marginal" offer, also averaged by month.[64]

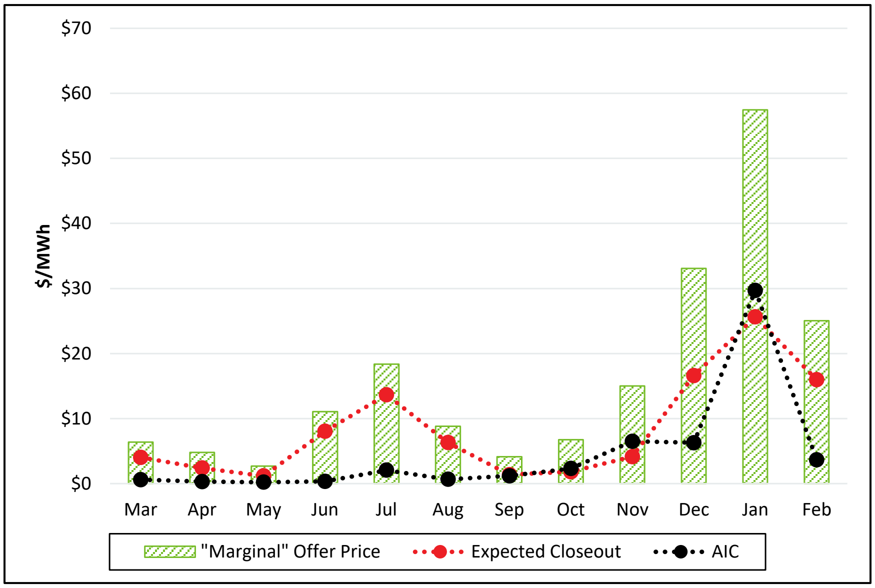
[61] The 12 high-cost days are defined in Section 4.2.

[62] As discussed in Section 5.3.1, we use the offer with the highest offer price for any DA A/S product cleared to satisfy that requirement as the proxy for the "marginal" offer.

[63] We only look at the Total 30 requirement here because it is the most impactful FRS requirement in regard to FRS product price formation as well as the most straight-forward to assess.

[64] Our estimate of the AIC assumes that the AIC was fully reflected in a resource's offer price. As such, it can be viewed as an upper limit on the extent to which this offer component may have appeared in FRS offer prices.

Figure 5-2: “Marginal” Offer Price for Total 30 Requirement with Offer Components



The offer price of the “marginal” offer for the Total 30 requirement shows a strong positive relationship with the expected closeout value, rising during periods when the expected closeout was higher (e.g., July, December, January, and February) and falling during other periods when the expected closeout was lower. Meanwhile, the AIC component displays a clear seasonality, appearing to have very little relevance outside of the winter. This likely stems from how the AIC is determined for gas resources, where the AIC is intended to reflect the portion of the gas purchase cost that is not expected to be covered by energy production in the real-time market.[65]

During the winter, high gas prices can create large AIC components particularly in conditions where lower-price resources are expected to set the price of energy in the real-time market. Using this approach for estimating the AIC, we find that the five days where the AIC may have had the largest impact on the shadow price of the Total 30 requirement (and therefore on the clearing prices of all the FRS products) were the five days from January 25-29, 2026.

5.3.3 Key Drivers and Outcomes for the 12 Highest-Cost DA A/S Days

When examining the relationship between fixed and priced demand—defined here as demand expected to be met through real-time energy—and the load forecast in the day-ahead market, we find no evidence of systematic underclearing. On average, the sum of cleared fixed and priced load exceeded the load forecast by approximately 1.4% both during the first year of DA A/S and in the year prior (March 1, 2024, to February 28, 2025). However, on the 12 highest-cost DA A/S days, the

[65]The AIC for a gas resource = $\max\{0\,,(Gas\ Price\ \times\ Resource\ Average\ Heat\ Rate) - Expected\ Realtime\ LMP\}$. For more information, see Section III.A.8.2.2.(a) of the ISO-NE Tariff: https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

level of offered and cleared demand relative to the load forecast appears to play a more prominent role in FER outcomes.

In Table 5-6 (Summer) and Table 5-7 (Winter), we examine the drivers of the FER price outcomes observed across these 12 days, including the role of load clearing relative to the DA load forecast and broader system conditions.

Table 5-6: Summer Highest-Cost DA A/S Days

	23-Jun	24-Jun	25-Jun	7-Jul-25	17-Jul	25-Jul	13-Aug
Forecasted Load	23,800	25,310	23,960	22,800	24,200	23,000	24,100
Temp (min)	69	74	74	72	74	72	67
Temp (max)	90	97	89	86	88	89	88
Natural Gas Price	$4.37	$5.75	$5.01	$3.26	$11.30	$4.92	$4.27
DA LMP	$111.14	$156.73	$83.79	$103.56	$125.64	$115.31	$84.95
TMSR Price	$81.30	$113.66	$62.62	$62.60	$69.15	$65.02	$70.68
TMNSR Price	$81.30	$113.66	$62.62	$62.60	$69.15	$65.02	$70.68
TMOR Price	$73.52	$107.99	$57.81	$56.13	$51.33	$62.28	$62.03
FER Price	**$0.20**	**$3.24**	**$24.75**	**$0.00**	**$15.99**	**$0.27**	**$23.49**
Net Interchange	1,898	2,236	2,442	2,468	3,706	2,081	2,643
Outages	1,504	2,131	1,827	2,017	1,504	1,442	1,169
DA A/S Offered MWs	8,755	8,848	8,949	6,910	8,780	9,043	9,100
Cleared load as % of RT Load Obligation	95%	93%	94%	100%	96%	102%	101%
Cleared load as % of DA Load Forecast	**101%**	**99%**	**95%**	**101%**	**97%**	**105%**	**99%**

Table 5-7: Winter Highest-Cost DA A/S Days

	25-Jan	26-Jan	27-Jan	28-Jan	29-Jan
Forecasted Load	19,500	19,650	19,700	19,600	19,550
Temp (min)	4	14	5	2	3
Temp (max)	19	22	19	21	21
Natural Gas Price	$45.22	$45.22	$89.84	$99.32	$60.99
DA LMP	$433.96	$436.01	$639.14	$423.31	$346.81
TMSR Price	$219.08	$365.43	$750.60	$327.92	$141.32
TMNSR Price	$219.08	$365.43	$750.60	$327.92	$131.27
TMOR Price	$214.49	$328.24	$423.16	$313.78	$105.73
FER Price	**$60.82**	**$231.18**	**$349.80**	**$32.88**	**$15.74**
Net Interchange	106	1,076	1,900	2,936	2,400
Outages	3,934	4,553	4,295	4,416	4,286
DA A/S Offered MWs	9,788	8,662	8,599	9,227	9,315
Cleared load as % of RT Load Obligation	93%	98%	97%	99%	99%
Cleared load as % of DA Load Forecast	**96%**	**94%**	**94%**	**97%**	**97%**

For these 12 days, load clearing outcomes exhibit clear seasonal differences when compared to the day-ahead load forecast. During the summer high-load periods, cleared load generally remains close to the forecast and at times exceeds it, indicating a mix of under- and overclearing. By contrast, the tight winter days are characterized by consistent underclearing, with cleared load falling below the DA forecast on all observed days.

These differences in clearing behavior are reflected in FER pricing outcomes. For the summer tight days, FER prices are relatively low and tend to increase when the system underclears relative to the forecast, while remaining near zero on days when the system overclears. For the winter tight days, FER prices are significantly higher; however, their magnitude does not vary in a clear way with how much the system underclears. Similar levels of underclearing on some tight winter days correspond to a wide range of FER outcomes, indicating that underclearing alone does not explain the size of FER prices for these days.

Other system conditions distinguish the winter period from summer. Winter days are associated with higher outage levels and, at the onset of the higher FER period, reduced net interchange. These conditions coincide with the period in which FER outcomes are elevated, suggesting tighter overall system conditions. Natural gas prices are also notably higher in winter, aligning with the broader increase in FER prices, although differences in gas prices across individual winter days do not closely track the variation in FER outcomes.

It is difficult to attribute the high FER prices alone to any one factor, and indeed evidence to date indicates that supply-side (e.g., outages and interchange over the fall season) as well as demand-side factors impact the FERP. However, during the high-stressed winter period the data indicates that LSE under-clearing (compared to the load forecast) likely had significant impact on the high FER pricing outcomes.

Section 6
Assessment of Market Competitiveness

This section evaluates whether DA A/S market outcomes are consistent with competitive behavior. In so doing, this section serves as the IMM's competitiveness assessment that is required under Section III.A.17.2.5 of the ISO-NE Tariff.

An accurate assessment of the level of competition is crucial because it helps indicate the extent to which the costs incurred by load for these services reflect competitive market outcomes rather than the exercise of market power. A fundamental feature of competitive markets is the presence of both multiple buyers and multiple sellers, which limits the ability of any individual participant to influence price. While this describes the day-ahead energy market,[66] the DA A/S market deviates from this idealized version in a very notable way: the market has only one buyer, the ISO, who is purchasing these services on behalf of load.

Accordingly, the objective of this assessment is not to test whether the DA A/S market satisfies the conditions of perfect competition. Rather, the goal is to evaluate whether the observed market outcomes are consistent with the outcomes one would observe in a competitive market. Given the characteristics of the market, this assessment requires a close examination of the supply side of the DA A/S market.

Consequently, the subsequent analysis focuses on the supply side of the market. The first section examines the overall level of market participation. The second section explores the structure of the supply, looking specifically at the level of market concentration and estimating the extent to which the exercise of market power is possible. The third section evaluates how observed DA A/S outcomes compare against outcomes produced using IMM-estimated competitive offers.

Key Takeaways

DA A/S market outcomes indicate that costs were broadly consistent with competitive market conditions during the period.

Offered FRS capability consistently exceeded requirements and increased over the first year of DA A/S, though available supply is more constrained after accounting for market clearing effects—particularly for TMSR, which exhibits relatively tight margins, while Total 10 and Total 30 maintain larger margins. EIR plays a limited role, with generally low cleared volumes that increase during tighter system conditions. Despite rising participation, some capability remains unoffered due to commercial, operational, and risk considerations. Overall, participation has not raised concerns about physical withholding, though it remains an important driver of outcomes particularly during stressed system conditions.

[66] The IMM found that day-ahead energy market exhibited competitive outcomes in 2025. For more information, see its 2025 Annual Markets Report, available here:https://www.iso-ne.com/static-assets/documents/100035/2025-annual-markets-report.pdf.

DA A/S markets exhibit moderate levels of structural concentration, which increase when capability is measured on an ex-post basis due to market clearing effects (e.g., when demand for energy is considered). Concentration is highest for TMSR, reflecting the more limited set of resources capable of providing fast-response reserves, while Total 10 and Total 30 markets are less concentrated.

Despite this structural concentration, DA A/S offer behavior appears broadly consistent with competitive, risk-adjusted benchmarks. Simulations using both Sharpe-based and CVaR-based risk premia produce cost outcomes that are close to, or modestly above, those observed with participant offers. The Sharpe-based framework yields results very similar to observed outcomes, suggesting that participants are embedding risk premiums consistent with managing overall profit variability. The CVaR framework, which places greater weight on tail-risk exposure, results in somewhat higher costs, particularly under stressed conditions. On balance, observed outcomes indicate that participant offers incorporate reasonable, but not excessive, compensation for risk.

6.1 Market Participation

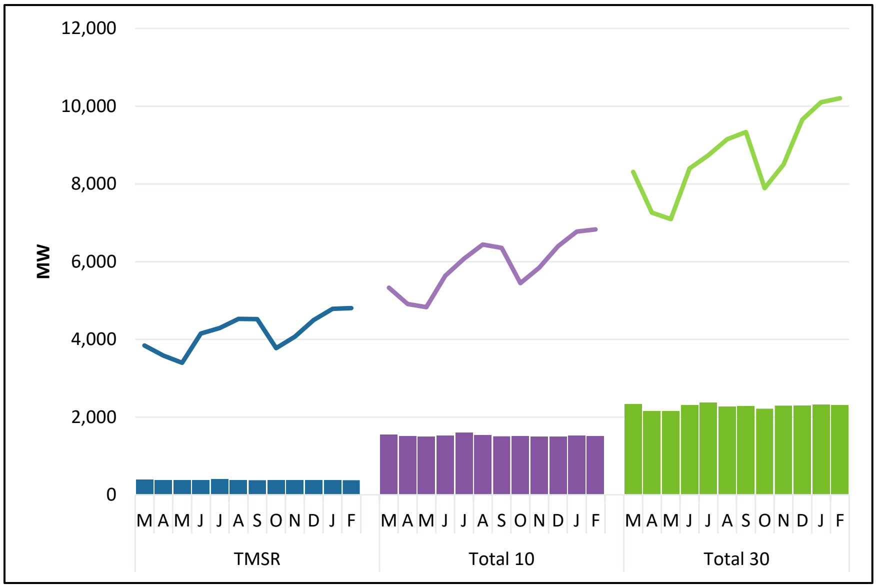
The first section examines the level of participation in the FRS markets over the first year of DA A/S, the second section examines EIR participation, and the last section discusses observations related to unoffered capability.

6.1.1 Flexible Response Services

The offered FRS capability was typically several times larger than the corresponding requirement, and this offered capability generally increased over the first year of the program. This can be seen in Figure 6-1, which shows the average hourly FRS requirements (as bars) and offered capability (as lines) by month.[67]

[67] Offered capabilities reflect participant-submitted DA A/S offer quantities limited by physical resource characteristics (e.g., ramp rate, EcoMax). Importantly, this figure does not account for the use of Maximum Daily Award Limit (MDAL) parameter by resources as a way to manage the amount DA A/S awards they can clear over the 24-hour day-ahead market clearing. We have seen this parameter commonly used by resources such as limited energy generators (e.g., oil, pondage hydro, pumped storage, and battery storage), which marks an important difference relative to the assumptions used in the Impact Assessment discussed in Section 5.1.

Figure 6-1: Offered FRS Capability relative to Requirements, Ex-ante



Between March 2025 and February 2026, offered TMSR capability rose by roughly 1,000 MW (from 3,800 MW to 4,800 MW), offered Total 10 capability rose by roughly 1,500 MW (from 5,300 MW to 6,300 MW), and offered Total 30 capability rose by roughly 1,900 MW (from 8,300 MW to 10,200 MW). However, the offered capability displayed a seasonality, with participation declining in the spring and fall (when resources tend to undertake planned outages) and then rising in the summer and winter. Meanwhile, the average FRS requirements did not change much by month. The average TMSR requirement was 380 MW, the average Total 10 requirement was 1,521 MW, and the average Total 30 reserve requirement was 2,278 MW.

Several elements of the co-optimized day-ahead market clearing process can limit the DA A/S capability that can be used to satisfy the FRS requirements. Overlooking these limits may lead to an incomplete understanding of the DA A/S market structure. For example, some offered DA A/S capability may be: (1) more valuable to the system when cleared as energy, (2) accessible only from an online state (and the resource may not receive a day-ahead commitment), or (3) limited due to binding transmission constraints.

Consequently, throughout this assessment we use two definitions of supply: *ex-ante* capability (i.e., offered capability) and *ex-post* capability (i.e., offered capability that has been adjusted to account for the factors noted above).[68]

- *Ex-ante* capability is calculated from the resource's offered DA A/S quantity and physical parameters before market clearing. For online capability, the measure reflects the lesser of (1) headroom between EcoMax and EcoMin and the (2) relevant ramp capability over the

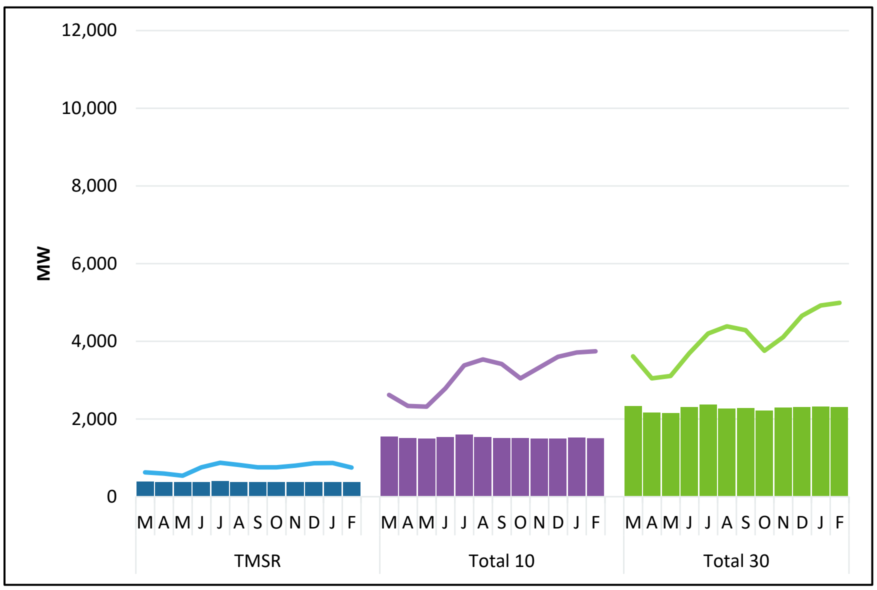
[68] Specifically, we adjust the offered DA A/S capability downward by the amount of capability that (1) cleared for energy, (2) was offered by non-fast start resources that did not receive a DA commitment, and (3) was behind a binding transmission constraint.

response period. For offline fast-start capability, it reflects the lesser of EcoMax and the applicable Claim10 or Claim30 value.

- *Ex-post* capability starts from the same offered capability but reduces it for capacity that clears for energy, capacity that is not available because the resource was not committed, and capacity limited by binding transmission constraints.[69]

Ex-ante measures can overstate supply because they ignore these clearing effects, while ex-post measures can understate supply because they evaluate capability after the day-ahead market has produced an efficient day-ahead schedule. However, when viewed together, these measures can provide a more complete supply picture. The ex-post perspective of offered FRS capability is illustrated in Figure 6-2 below. Similar to the chart above, this figure shows the average hourly offered FRS capability (as lines) and FRS requirements (as bars) by month.[70]

Figure 6-2: Offered FRS Capability relative to Requirements, Ex-post



As can be seen above, FRS capability becomes more constrained when viewed from a post market clearing perspective. Ex-post TMSR capability tracked tightly with the TMSR requirement over the first year of DA A/S, with an average margin of about ~370 MW per hour. This makes intuitive sense when we consider TMSR procurement in the context of the cost-minimization objective of the day-ahead market. Given that spinning reserve is mostly provided by resources that must be committed

[69] This ex-post supply assessment is further utilized in the market structure assessment in section 6.2 below.

[70] Offered capabilities reflect participant-submitted DA A/S offer quantities limited by physical resource characteristics (e.g., ramp rate, EcoMax). Importantly, this figure does not account for the use of Maximum Daily Award Limit (MDAL) parameter by resources as a way to manage the amount DA A/S awards they can clear over the 24-hour day-ahead market clearing. We have seen this parameter commonly used by resources such as limited energy generators (e.g., oil, pondage hydro, pumped storage, and battery storage), which marks an important difference relative to the assumptions used in the Impact Assessment discussed in Section 5.1.

at a cost to provide energy (i.e., have non-zero startup commitment costs), one would not expect an excess of this capability when the market is viewed from a post-clearing perspective.

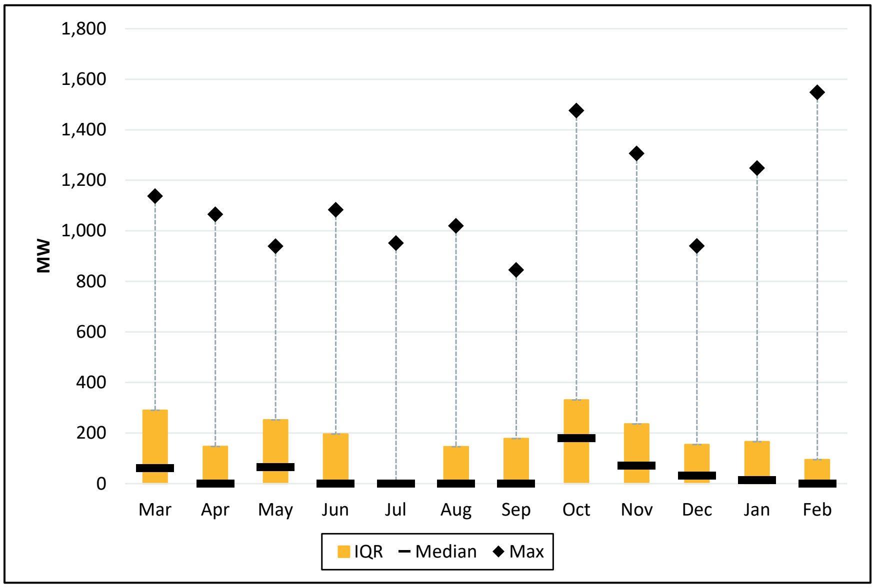
In contrast, ex-post Total 10 and Total 30 capabilities generally had larger margins relative to their respective requirements and these margins are more reflective of the seasonal effects described earlier. Additionally, these ex-post capabilities display clearer upward movement over time as additional resource capability entered the market. The ex-post Total 10 and Total 30 margins tend to be larger than the TMSR margin given that these requirements can be met by both online and *offline* resources.

6.1.2 Energy Imbalance Reserves

There is no strict requirement on the level of EIR that must clear per hour. Instead, the market clearing engine will determine the level of cleared EIR in tandem with its determination of the level of cleared day-ahead energy awards on physical resources, ensuring that, collectively, the two values satisfy the FER. Meanwhile, the supply side of the market is the largest for all the DA A/S products as EIR capability reflects the increase in energy output that resources can achieve in 60 minutes.[71]

In general, only small amounts of EIR are cleared to satisfy the FER, but clearing does vary by hour. This can be seen in Figure 6-3, which shows the hourly distributions of cleared EIR MW by month over the first year of DA A/S, highlighting the interquartile range (IQR), median, and maximum values.

Figure 6-3: Cleared EIR MW



[71] Given that there is no strict requirement for EIR and that the supply pool is the largest of all the DA A/S products, the FRS products receive the majority of the focus in our assessment of DA A/S market competitiveness.

Across the year, median cleared EIR volumes were relatively low (generally under ~100 MW) and, in many months, the median value was 0 MW. However, there was a modest uptick in the fall when generators took winter readiness outages and the level of imports generally decreased. Maximum values (black markers) exhibit greater volatility, with pronounced spikes in October, November, January, and February.

6.1.3 Unoffered Capability

It is important to note that some capability chooses not to participate in the voluntary DA A/S market.[72] In fact, while offered capability has far exceeded the FRS requirements, and participation has trended upwards, participation rates have peaked around an estimated 70% for 60-minute (i.e., EIR) capability, although participation has varied by resource type and fuel. Participants that choose not to participate, or to participate at reduced levels, in the DA A/S market have generally provided three reasons: commercial strategy, physical/operational constraints, and risk considerations. Each of these is discussed briefly below.

- Some participants indicated commercial strategy considerations influenced their decision not to participate in the DA A/S market. A few of these participants cited a focus on alternative, non-market-based revenue streams, most notably those attainable through Massachusetts Clean Peak Energy program. Power Purchase Agreements (PPAs) are likely influencing DA A/S offer behavior as well by prioritizing energy market participation.
- Physical and operational constraints also impacted certain resources decisions to limit their participation in the DA A/S market. Some participants described limitations related to fuel management, making reserve provision impractical. Other participants, particularly those with hydroelectric resources, cited that generation decisions can affect downstream operations and water management schedules.
- Finally, some participants indicated that risk considerations played a role. These participants generally cited the view that a DA A/S award can expose certain resources to additional financial risk because these resources cannot rely on inframarginal real-time energy market revenues to offset potential losses.[73] This reasoning applied both to broad classes of resources as well as certain energy segments, such as upper block or duct firing ranges, which tend to have significantly higher marginal costs.

The IMM has consulted with participants regarding their participation levels in the DA A/S market, particularly around periods of stressed system conditions such the five-day period from January 25, 2026, to January 29, 2026, that coincided with Winter Storm Fern. Participation levels have generally not raised physical withholding concerns that would impact overall competitive cost

[72] There is no must-offer rule in the DA A/S market. For discussion on this topic, please see pages 111-113 of the testimony of Dr. Matthew White in support of DA A/S contained within the ISO's filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

[73] For a discussion of this risk, see Section 6.3.

estimates. We will continue to monitor participation levels on an ongoing basis and require legitimate justification when lack of participation exceeds the Tariff-defined thresholds.[74]

6.2 Market Structure

Market structure refers to the organization of a market, including the number and relative size of participating firms offering their ancillary services capability into the day-head market. Given that the capabilities needed to satisfy the various requirements are different, the natural lanes for this analysis are the requirements: ten-minute spinning reserve (TMSR), total 10-minute reserve (Total 10), and total 30-minute reserve (Total 30).[75]

As mentioned in Section 3.1, the day-ahead market formulation includes nested FRS demand quantities (TMSR, Total 10, and Total 30). TMSR awards can satisfy each of the three FRS requirements; TMNSR can satisfy the Total 10 and Total 30 requirements; and TMOR awards can satisfy only the Total 30 requirement. In the text, we refer to TMSR, Total 10, and Total 30 as shorthand for these nested requirements.

As discussed earlier, ex-ante measures can overstate supply and therefore underestimate market power because they ignore the co-optimization effects, while ex-post measures can understate supply and overstate market power because the day-ahead market can re-optimize commitment and reserve awards in response to offers.

Concentration Ratios

A concentration ratio measures the percentage of total capability accounted for by a set of the largest participants. Lower concentration ratios are indicative of more structurally competitive markets, while higher concentration ratios are indicative of less structurally competitive markets that are more susceptible to exercise or market power. In this analysis, CR4 refers to the share of total capability accounted for by the four largest participants, and CR8 refers to the share accounted for by the eight largest participants.

The DA A/S markets exhibit moderate levels of concentration, and these concentration levels increase across all markets when capability is measured on an ex-post basis. This can be seen below in Table 6-1, which shows the average CR4 and CR8 over the study period.

[74] See Section III.A.4 of the ISO-NE Tariff for more information on physical withholding.

[75] This assessment does not consider Energy Imbalance Reserve (EIR), which has no explicit requirement and has the largest supply of the DA A/S products given its 60-minute definition.

Table 6-1: DA A/S Market Concentration Ratios

Requirement	CR4		CR8	
	Ex-ante	Ex-post	Ex-ante	Ex-post
TMSR	61%	75%	79%	94%
Total 10	56%	60%	75%	82%
Total 30	50%	54%	72%	79%

On an ex-ante basis, the top four participants accounted for over 50% of the offered supply for all DA A/S requirements. Intuitively, the levels of concentration decreased as the response period increased (i.e., the concentration ratios for 30-minute capability are lower than those for 10-minute capability). Concentration levels increased across all requirements when capability is measured on an ex-post basis, reflecting the effects of joint optimization in day-ahead energy and ancillary services market. This pattern is most pronounced in the TMSR requirement, where CR4 rose from 61% percent under ex-ante capability to 75% under ex-post capability. When considering the eight largest participants, the concentration ratios for all three markets ranged between 72%-79% on an ex-ante basis and between 79%-94% on an ex-post basis.

It is important to recognize that the structure of supply for the DA A/S requirements differs from that in the energy market because only a subset of resources possesses the fast-start (i.e., Claim10 or Claim30) or fast-ramp capability needed to provide the requisite ancillary service. As a result, the supply of reserve capability is inherently more limited than the supply of energy, increasing the potential for concentration.[76, 77]

Herfindahl-Hirschman Index

The Herfindahl-Hirschman Index (HHI) is a measure of market concentration that gives more weight to larger participants and considers the market shares of all participants.[78] Similar to concentration ratios, lower values are indicative of more competitive markets and higher values are indicative of less competitive markets.[79]

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[76] The IMM estimates that the real-time energy market had an annual average C4 during the on-peak hours that ranged between 40%-45% over the five-year period between 2020-2024. For more information, see Section 2.1.1in our 2024 Annual Markets Report (AMR) (https://www.iso-ne.com/static-assets/documents/100023/2024-annual-markets-report.pdf). Please note that the C4 for energy reported in the 2024 AMR is based on *cleared* energy awards and the concentration ratios for DA A/S presented in this assessment are based on *offered* MWs.

[77] This comparison is intended only as a directional reference. Energy-market concentration measures are often based on cleared energy MW, while DA A/S concentration measures are based on offered or available reserve capability. The two measures therefore answer different questions, but the comparison is useful for illustrating that reserve-capability supply is inherently narrower than the broader energy supply base.

[78] The HHI is calculated as follows: $HHI = \sum_{i=1}^{n}(C_i)^2$; where C_i is the market share of the *i*-th largest participant (e.g., 25%) and *n* is the number of all participants that offer their capability.

[79] The highest possible HHI value is 10,000, which would occur when one firm accounted for 100% of the market.

The HHI values were consistent with the CR4 and CR8 values, indicating a range of concentration from low to moderate.[80] This can be seen below in Table 6-2, which shows the average HHI values over the study period.

Table 6-2: DA A/S Market Herfindahl-Hirschman Indices

Requirement	HHI	
	Ex-ante	Ex-post
TMSR	1,560	2,203
Total 10	1,320	1,368
Total 30	943	1,111

The HHI values reveal much of the same insight as the concentration ratios above. According to the Antitrust Division of the U.S. Department of Justice, the ex-ante TMSR and Total 10 markets are moderately concentrated while Total 30 is unconcentrated. Of specific note is the HHI for TMSR, which increased from an ex-ante value of 1,560 (moderately concentrated) to an ex-post value of 2,203 (highly concentrated). Ex-post Total 10 and Total 30 are both moderately concentrated according to those standards.

The concentration ratio and HHI measures provide useful summaries of structural concentration by describing how offered (or ex-post) capability is distributed across suppliers. However, these measures do not, by themselves, indicate whether concentration is competitively consequential in each hour, i.e., whether the DA A/S requirement could be met using capability outside a particular supplier or small set of suppliers, especially after accounting for the capability that is available. To evaluate when concentration can translate into potential market power, we therefore apply more insightful and dynamic metrics, the pivotal-supplier tests (PST) and the residual supply index (RSI), which explicitly compare residual (non-supplier) capability to the requirement on an hour-by-hour basis and identify periods when one or more suppliers are necessary to satisfy the requirements.

Pivotal Suppliers and Residual Supply Index

A pivotal supplier is a participant without whose offered capability a requirement could not be met. Periods when a market has a pivotal supplier are noteworthy because they can provide a useful screen identifying that a participant may have the ability to increase clearing prices. A related concept is the residual supply index (RSI), which is the proportion of a requirement that can be satisfied without the capability of the largest supplier.

[80] The Antitrust Division of the U.S. Department of Justice generally considers markets with HHI values below 1,000 as unconcentrated markets, HHI values between 1,000 and 1,800 as moderately concentrated market and HHI values >1,800 as highly concentrated markets. https://www.justice.gov/atr/herfindahl-hirschman-index

Statistics related to pivotal suppliers and the RSI are presented by requirement in Table 6-3 below.

Table 6-3: DA A/S Market Pivotal Supplier and RSI Statistics

Requirement	% of Hours with at least one Pivotal Supplier		RSI[81]	
	Ex-ante	Ex-post	Ex-ante	Ex-post
TMSR	0%	38%	729	124
Total 10	0%	1%	271	147
Total 30	0%	3%	303	136

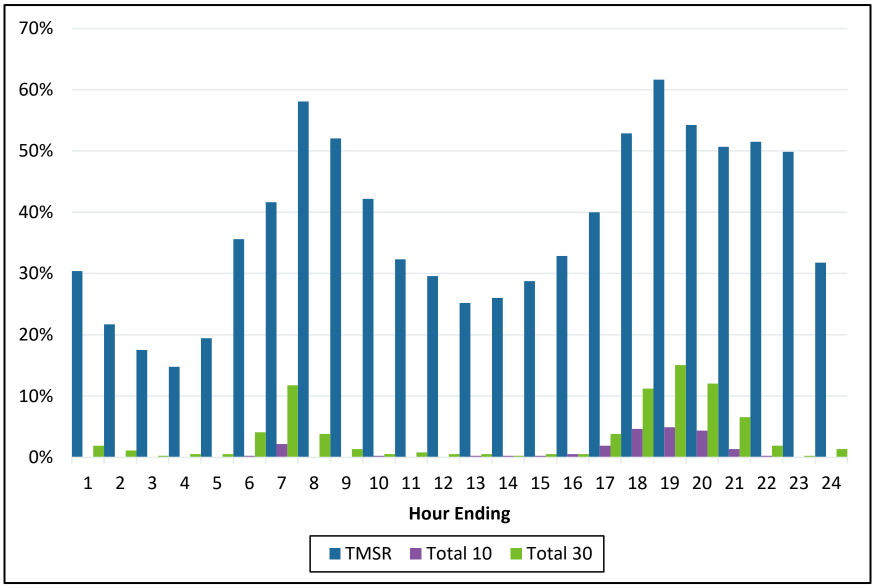
There were no hours with a pivotal supplier for any reserve market when capability is defined on ex-ante basis. By contrast, when ex-post capability is considered, at least one pivotal supplier is present in 38% of the hours in the TMSR market, while pivotal supplier occurrences remain infrequent in the 10- and 30-minute markets.

Consistent with the pivotal supplier results, average RSI values under the ex-ante capability definition suggest a generally robust supply picture with the values across all markets coming in well above 100. However, when capability is measured on an ex-post basis, RSI values decline across all markets. The decline is most significant for the TMSR requirement, which fell from over 700 to 124.

On an ex-post basis, the share of hours with at least one pivotal supplier varies significantly, rising during the morning and evening peak periods when reserve capability is converted to energy to satisfy higher loads. This can be seen in Figure 6-4 below, which shows the percentage of hours with at least one pivotal supplier by hour and market.

[81] The residual supply index (RSI) represents the amount of demand and reserves that the system could satisfy without the largest supplier's available energy and reserves. If the value is less than 100, the largest supplier would be needed to meet demand and could exercise market power if permitted. Further, if the RSI is less than 100, there is one or more pivotal suppliers.

Figure 6-4: Percentage of Hours with at least One Pivotal Supplier (Ex-post) in the DA A/S Market



The percentage of hours with at least one pivotal supplier for the TMSR market rises from as low as 15% in hour ending (HE) 4 to 58% in HE 8 and 62% in HE 19. The pattern is similar, although more muted, for the Total 10 and Total 30 requirements; the share for Total 10 peaks at 5% in HE 19 while the share for Total 30 peaks at 15% during the same hour.

It is important to consider the TMSR market results in the context of the cost-minimization objective of the day-ahead market. Given that spinning reserve is mostly provided by resources that must be committed at a cost to provide energy (i.e., have non-zero startup commitment costs), one would not expect an excess of this capability when the market is viewed from an ex-post perspective. This effect is likely to raise the appearance of pivotality, especially to the extent that the resources that commonly clear TMSR awards have the same owner. Meanwhile, the Total 10 and Total 30 requirements can be met by both online and offline resources, which do not incur commitment costs, and therefore their ex-post market structure metrics tend to appear lower.

Further, the results above should also be considered in the context of FRS price formation. As noted in Section 5.2.1, in the majority of hours the TMSR clearing price is determined by the marginal offer for the Total 30-minute reserve constraint, which binds in every hour and whose price cascades up to influence the TMSR clearing price.[82] This means that TMSR is generally competing with all 30-minute capability to set price. [83] Put differently, TMSR structural tightness

[82] The ten-minute spinning reserve constraint bound in only 20% of hours during the first year of DA A/S.

[83] Additionally, the relatively low Reserve Constraint Penalty Factor (RCPF) for the TMSR ($50/MWh) provides a form of safeguard against the exercise of market power in this market (when only the TMSR requirement is binding). This does not mean TMSR clearing prices are capped at $50/MWh. Because FRS requirements are nested, TMSR awards can also satisfy Total 10 and Total 30 requirements, and the TMSR price can include the shadow prices of those broader constraints. The RCPF is therefore a useful safeguard against TMSR-specific market power, but it does not eliminate the need to monitor broader reserve scarcity and ex-post pivotal conditions.

does not necessarily imply that TMSR clearing prices are not determined by competitive market forces.

6.3 Offer Behavior

To assess whether market outcomes are consistent with competitive offer behavior, we conduct two simulations in which DA A/S offers are set at IMM benchmark levels, differing only in how the risk premium is defined. Together, these risk methodologies provide a range of competitive outcomes: one based on a return-per-unit-of-risk metric (Sharpe) and one based on a more conservative tail-risk measure (conditional Value at Risk).

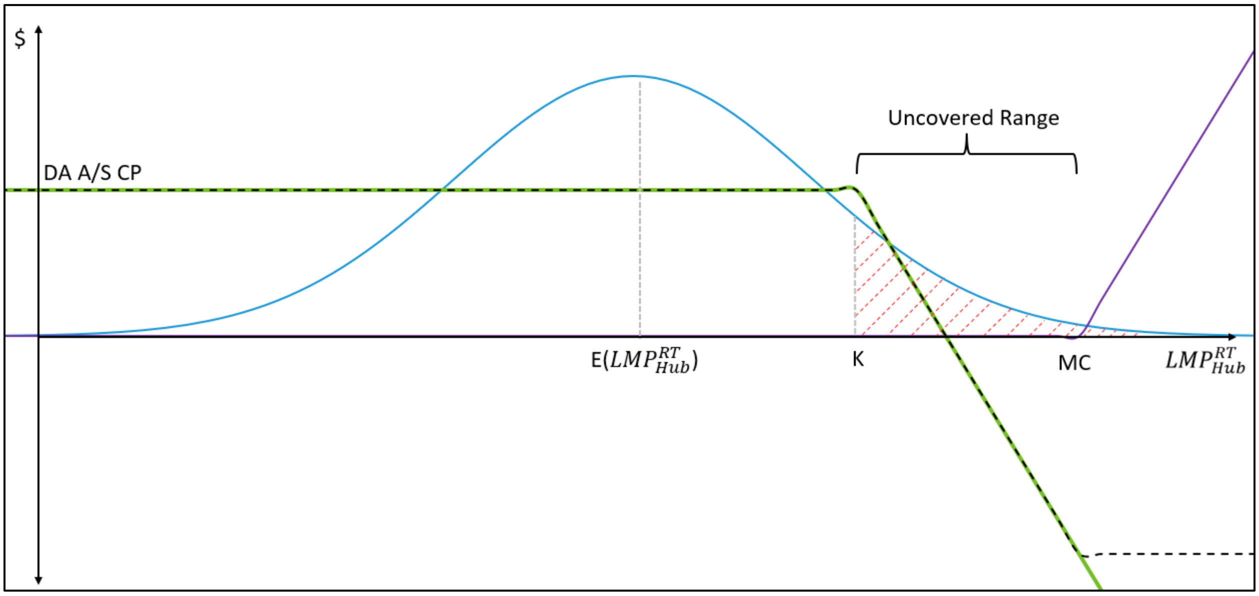
Indeed, both approaches are somewhat conservative in that they treat risk as something participants evaluate asset-by-asset and over short horizons. In practice, resource owners manage risk at the portfolio level and over longer horizons, so diversification and intertemporal balancing can reduce the risk that must be priced into any single asset's DA A/S offer in any given hour. While participant risk tolerance and hedging capability are heterogenous and not directly observable, we use these two transparent benchmark frameworks to bound plausible risk-premium levels and to evaluate whether risk premiums can materially impact market outcomes.

We start by laying out the underlying cost components of a DA A/S award, before turning to how the Sharpe and CVaR frameworks translate risk exposure into a premium. Recall from Section 3.1.3 that the primary cost associated with a DA A/S award is the expected closeout, which represents the probability-weighted charge that a resource could otherwise avoid by not taking on a DA A/S award. Other costs include the fuel-related costs incurred by a subset of DA A/S providers (gas and energy storage); under this design, these are referred to as avoidable input costs.[84]

Risk arises for resources with DA A/S awards because these obligations exchange a fixed premium (the DA A/S clearing price) for exposure to uncertain (and potentially severe) real-time closeout charges. An illustrative example that describes some of the important factors related to this risk is presented in Figure 6-5 below. In this figure, the x-axis represents possible values of the real-time LMP and the y-axis represents payoff in dollars.

[84] For more information about the various components of a DA A/S offer, see Section 3.1.3.

Figure 6-5: Payoff Diagram



The payoff associated with the DA A/S award is shown by the green line; the resource receives the DA A/S clearing price until the real-time LMP exceeds the strike price, K, at which point it decreases one-for-one with the real-time LMP. This figure also incorporates the resource's payoff from producing energy in real time (purple line); there is no payoff until the real-time LMP exceeds the asset's short-run marginal cost, denoted MC, at which point it increases in value one-for-one with the real-time LMP. [85] Finally, the figure also shows the combined payoff of a DA A/S award *and* producing energy in real time (black dashed line). The combined payoff matches the DA A/S payoff until the real-time LMP exceeds the asset's marginal cost; once the unit is in merit, incremental real-time energy margins offset the increasing closeout exposure if the unit can run (i.e., is not on outage), so the combined payoff becomes approximately flat over that range.[86]

While the payoff will vary by resource depending on its marginal cost and its performance, the resource depicted in the figure above is one whose short-run marginal cost exceeds the strike price and so is not able to offset the closeout charge with real-time energy production through a wide range of possible real-time LMPs (labeled as "Uncovered Range" in the figure). In fact, this resource begins incurring a loss at some value of the real-time LMP above the strike price, and even when the resource produces energy, it does not eliminate the loss but instead only prevents it from increasing. More generally, the figure highlights that DA A/S exposure is most acute in states where

[85] The dollar-for-dollar increase in the real-time margin holds when the resource is available to run once prices exceed short-run marginal cost.

[86] For exactly the reason outlined in footnote 85, the apparent hedge in combined payoffs holds when the resource is available to run once prices exceed short-run marginal cost. Because outages occur with nonzero probability, there are high-price states in which the unit cannot produce and therefore cannot offset closeout exposure; these states drive residual downside risk and contribute to both overall profit volatility and tail outcomes.

real-time prices are high, but the resource cannot (or does not) provide offsetting real-time energy—whether because it remains out of merit or because it is unavailable.

The risk calculation that a resource owner makes in relation to taking on a DA A/S award depends on numerous factors captured in the illustrative example above (e.g., the expected DA A/S clearing price, the strike price, the resource's marginal cost, the distribution of real-time LMPs) as well as other considerations not shown (e.g., portfolio-level risk tolerances and resource outage risk).

Different methodologies formalize the tradeoff between risk and return in different ways. In this section we utilize two common methodologies—the Sharpe ratio, which is based on overall profit variability, and CVaR, which focuses on tail losses (extreme downside exposure)—to estimate benchmark measures of risk associated with a DA A/S award.[87] We then perform market simulations that make use of these risk estimates and compare the results from these simulations to the one based on actual participant offers. This comparison allows us to assess the extent to which market outcomes may reflect competitive offers that incorporate benchmark risk premiums.[88]

Sharpe Ratio

Under the Sharpe ratio approach, the risk premium for selling DA A/S is determined by comparing risk-adjusted expected profits from two alternatives: (i) selling both DA A/S and real-time energy, and (ii) selling real-time energy only. Risk is summarized by the *standard deviation of net revenues*, and the guiding condition is that the Sharpe ratio (expected profit divided by standard deviation) from DA A/S participation must be at least as large as that of the next-best alternative. We compute expected net revenues and profit volatility under each alternative using simulated real-time price distributions (derived from ISO-NE's Gaussian Mixture Model), along with resource-specific outputs such as marginal costs and outage rates. The DA A/S offer price is then solved as the minimum offer that equalizes these risk-adjusted returns.[89]

Within this framework, the Sharpe-based risk premium is the increment above fair value, defined as expected closeout costs plus any avoidable input costs (AIC), required to satisfy the Sharpe condition. This framework yields a clear decomposition of competitive offers. All suppliers must recover expected DA A/S closeout costs (and any avoidable fuel or storage costs), while a positive risk premium appears only if DA A/S participation *increases* profit volatility relative to real-time-only operation.

Importantly, low volatility does not necessarily imply low downside exposure. A resource with a very high short-run marginal cost, for example, may have stable profits simply because it is rarely in merit and seldom operates. Under a Sharpe metric, DA A/S participation may appear to add little incremental variance. Yet such a resource still faces large closeout charges in high-price states

[87] The distinction matters most in periods of scarcity, where non-linear price behavior drives economic risk.

[88] Our risk premium metrics are intended to capture certain salient features of the exposure faced by DA A/S suppliers. These approaches do not capture the likely wide range of risk tolerances across market participants.

[89] We follow the approach developed during the DASI stakeholder process: https://www.iso-ne.com/static-assets/documents/2023/06/a03a_mc_2023_06_06__dasi_competitive_offer_formulations_memo.pdf

and has little operational ability to profitably offset them through real-time production. Conversely, flexible gas or storage resources may exhibit higher gross variability but also stronger natural hedges—profits from real-time operation that rise exactly when closeouts are large—so that DA A/S participation can leave their overall volatility unchanged or even lower, satisfying the Sharpe condition with little or no additional premium.

In Sharpe-ratio terms, the key question is therefore whether adding the DA A/S position increases the overall dispersion of profits relative to real-time-only operation; that increase can be material even if the Uncovered Region in Figure 6-5 is narrow, depending on how frequently the unit is out of merit in tight hours and how often outages prevent the unit from running when prices are high.

As mentioned above, we performed the following simulation:

- **Sharpe**: a scenario in which all DA A/S constraints are 'turned on' but DA A/S offers are based on expected closeout, any avoidable input costs, and a resource-specific risk premium derived using the Sharpe methodology outlined above.

Table 6-4 below provides a high-level comparison of this Sharpe scenario to the DA A/S scenario (initially presented in Section 4.2).

Table 6-4: Comparison to Outcomes with Competitive Offers plus Sharpe Ratio Risk Premia

Category	DA A/S ($M)	Sharpe ($M)	Delta ($M)	Delta (%)
DA Energy	**$11,153**	**$11,194**	**$40**	**0.4%**
LMP	$10,127	$10,081	-$47	-0.5%
FER Price	$1,026	$1,113	$87	8.5%
DA A/S	**$261**	**$259**	**-$2**	**-0.9%**
Credits	$453	$450	-$4	-0.8%
Closeouts	-$192	-$191	$1	-0.7%
Total Charges/Credits	**$11,415**	**$11,453**	**$38**	**0.3%**
Cost of Incremental RT Energy	$136	$138	$1	0.9%
Total Cost/Revenue Change	**$11,551**	**$11,590**	**$39**	**0.3%**

The simulation results using the Sharpe approach for calculating risk show modest cost increases relative to the simulation based on participant offers. The cost increases are most notable for the FER-related credits (labeled 'FER Price' in Table 6-4), which increases by $87 million. However, these increases are partially offset by a decrease in LMP-based payments of $47 million, resulting in a modest increase in total day-ahead energy market payments ($40 million). Payments in the DA A/S market and the real-time energy market were largely unchanged, and the result was an overall increase in costs of $39 million.

As an additional diagnostic, we isolate the **12 highest-cost days** (largely clustered in multi-day stress events) that together account for roughly half of the incremental first-year DA A/S costs. In this subset, costs under the participant-offer baseline (the DA A/S scenario) amount to $1,900 million ($158 million per day) compared to $2,017 million ($168 million per day) under Sharpe-based competitive offers, implying that costs on these 12 days were 5.8% below what they would have been had active participants offered according to our Sharpe-based competitive benchmarks. By contrast, across the remaining days of the year, DA A/S costs were $9,651 million ($27.50

million per day) versus $9,573 million ($27.27 million per day) under the Sharpe-based competitive benchmark, indicating that in normal conditions, participants are broadly consistent with Sharpe-implied premia.

CVaR

A CVaR (Expected Shortfall) approach reframes the same problem in explicitly *tail-risk* terms. Instead of focusing on overall revenue volatility, risk is defined as the average loss in the worst 5 percent of outcomes. For DA A/S positions, these tail losses arise in scenarios where real-time prices exceed the strike price and the resource is unable to offset the resulting closeout charge through real-time operation, leading to losses. This can occur either because the unit is economically out-of-merit (e.g., due to high short-run marginal cost) or because it is physically unavailable (e.g., on outage). In both cases, the defining feature of tail risk is the lack of an effective operational hedge precisely in the states where closeout charges are largest.

Under this approach, tail losses are computed directly from simulated profit distributions, and the risk premium is set as the incremental compensation required to cover the incremental economic capital needed to absorb those losses. A fixed capital charge rate converts required tail-risk capital into a $/MWh premium. Relative to a Sharpe-ratio method, CVaR places much greater weight on asymmetric downside exposure, focusing on states where high RT LMPs coincide with an inability to hedge closeout charges through real-time production. These states arise not only from physical outages, but also from high short-run marginal costs that keep units out of merit. By explicitly conditioning on such stress scenarios, CVaR captures economically relevant risk that variance-based measures tend to smooth over, making it well suited for participants whose binding constraints are liquidity, collateral, or internal risk limits defined by severe but infrequent losses, rather than by average profit volatility.[90]

In CVaR terms, the Uncovered Region in Figure 6-5 matters disproportionately (especially when coincident with resource outages) because it determines the worst-tail outcomes—high-price intervals in which the closeout exposure is large, and the operational hedge is ineffective.

As mentioned above, we performed the following simulation:

- **CVaR**: a scenario in which all DA A/S constraints are ‘turned on’ but DA A/S offers are based on expected closeout, any avoidable input costs, and a risk premium derived using the CVaR methodology outlined above.

Table 6-5 below provides a high-level comparison of this CVaR scenario to the DA A/S scenario (initially presented in Section 4.2).

[90] The tradeoff is complexity: CVaR requires careful specification of tail thresholds, capital charges, and, for resources with avoidable input costs, a specification of the dependence between various profit components like RT LMP and input prices.

Table 6-5: Comparison to Outcomes with Competitive Offers plus CVaR Risk Premia

Category	DA A/S ($M)	CVaR ($M)	Delta ($M)	Delta (%)
DA Energy	**$11,153**	**$11,247**	**$94**	**0.8%**
LMP	$10,127	$10,059	-$69	-0.7%
FER Price	$1,026	$1,188	$162	15.8%
DA A/S	**$261**	**$287**	**$26**	**9.9%**
Credits	$453	$477	$24	5.3%
Closeouts	-$192	-$190	$2	-0.9%
Total Charges/Credits	**$11,415**	**$11,534**	**$119**	**1.0%**
Cost of Incremental RT Energy	$136	$137	$1	0.5%
Total Cost/Revenue Change	**$11,551**	**$11,671**	**$120**	**1.0%**

Compared to the DA A/S scenario, the simulation results based on the CVaR approach depict overall cost increases. The largest cost increase occurs in the FERP-based payments (labelled 'FER Price' in Table 6-5), which rose by $162 million. However, these cost increases were partially offset by a reduction in LMP-based payments of $69 million. The combined impact was an increase in day-ahead energy market payments of $94 million relative to the DA A/S scenario. Unlike the Sharpe scenario, costs also increased in the DA A/S market under this approach, rising by $26 million. With the minor increase in real-time energy payments ($1 million), the overall increase in costs amounts to $120 million.

We also perform the same **high-risk-day breakout** under the CVaR framework, which by construction places greater weight on the severe but infrequent outcomes that characterize stressed system conditions. On the 12 highest-incremental-cost days, costs under the participant-offer baseline (the DA A/S scenario) amount to $1,900 million ($158 million per day) compared to $2,051 million ($170.95 million per day) under CVaR-based competitive offers, implying that costs on these 12 days were 7.4% below what they would have been had active participants offered according to our CVaR-based competitive benchmarks. On the remaining days of the year, DA A/S costs were $9,651 million ($27.50 million per day) compared to $9,619 million ($27.41 million per day) under the CVaR-based competitive benchmark, again suggesting close alignment in normal periods but a materially larger gap during system stress.

Over the full year, simulated costs fall slightly below the costs produced by the Sharpe- and CVaR-based competitive benchmarks. That full-year comparison, however, is driven primarily by a small number of high-cost stress days: on the 12 highest-incremental cost days, participant-offer outcomes were 5.8% below the Sharpe benchmark and 7.4% below the CVaR benchmark, while on the remaining days, participant-offer outcomes were closely aligned with both benchmarks. This pattern suggests that observed offers were broadly consistent with competitive, risk-adjusted behavior in normal conditions, and somewhat below these benchmark levels during stressed conditions. At the same time, both the Sharpe and CVaR frameworks are conservative benchmarks because they evaluate risk largely on a unit-by-unit basis and over relatively short horizons and therefore do not fully reflect the benefits of diversification across assets or intertemporal risk management within participant portfolios. Accordingly, the fact that participant-offer outcomes fall at or below these benchmarks is consistent with offers reflecting "reasonable" risk premia.

Section 7
Mitigation Performance

This section evaluates whether observed mitigation outcomes during the first year of DA A/S market operations are consistent with the intended two competing objectives: limiting the risk that uncompetitive offers materially affect market outcomes, while avoiding unnecessary intervention of offers based on a resource's legitimate competitive costs; with particular attention to the frequency, context, and system conditions under which mitigation occurred.

Key Takeaways

Overall, mitigation outcomes observed during the first year of DA A/S market operations are largely consistent with the stated objectives of the mitigation framework. Mitigation occurred infrequently, was generally limited to circumstances where offers both materially exceeded benchmark expectations and had a measurable effect on clearing prices, and did not appear to constrain competitive offer behavior during periods of heightened system stress.

One notable exception arises when price impact thresholds fell below $3/MWh, which occurs during times when system conditions are generally unstressed and market power is not a concern. Almost thirty-percent of mitigations occurred under these conditions. The ISO plans to address as part of their DA A/S market enhancements work in 2026 by incorporating a $3/MWh price impact floor, a sensible measure which will address these observed instances of over-mitigation.

As described in the ISO's filing, the mitigation framework is explicitly designed to intervene only in clear and impactful instances of uncompetitive behavior.[91] To achieve this balance, the DA A/S mitigation framework applies a sequenced evaluation consisting of a conduct test to identify offers that materially exceed benchmark levels, a price impact test to assess whether such offers meaningfully affect market clearing prices, and mitigation that is limited to offers failing conduct test thresholds. This structure reflects a deliberate design choice to preserve pricing flexibility under most conditions while providing targeted safeguards when competitive outcomes may otherwise be distorted.

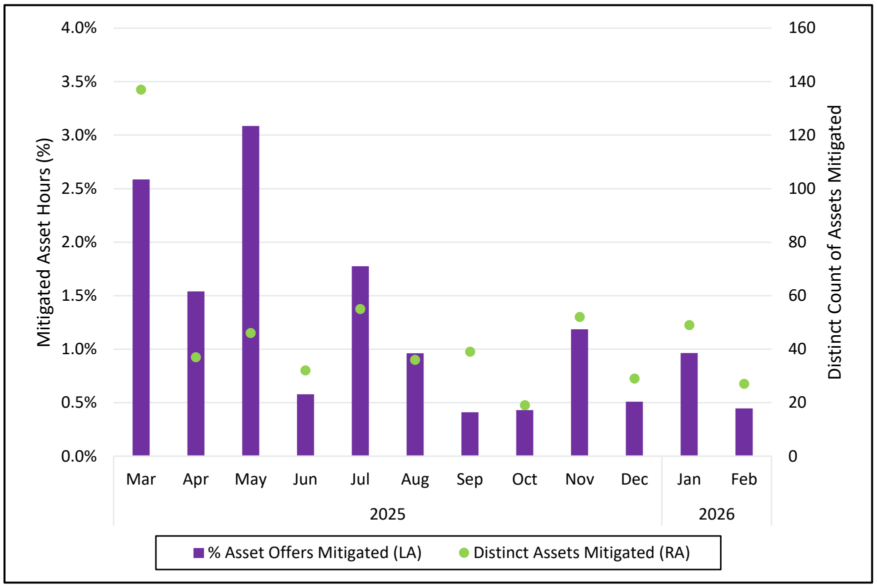
Frequency of Mitigation

In general, there has been a low frequency of DA A/S mitigation indicating that mitigation has not played a prominent role in determining market outcomes. The occurrence of DA A/S mitigation can

[91] See Dr. Alivand's testimony in https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf

be seen in Figure 7-1 below, which shows the percentage of DA A/S offers that were mitigated on the left axis (LA) and the count of the distinct assets that were mitigated on the right axis (RA).[92]

Figure 7-1: DA A/S Mitigations



Over the course of the first year, 1.2% of all asset-product-hours were mitigated. The count of distinct assets that were mitigated in any month ranged from 19 in October 2025 to 137 in March 2025.[93] It is likely that a growing familiarity with the market design reduced both the frequency of mitigation and the number of assets that were mitigated.

Mitigation Performance During Periods of System Stress

The IMM has found that, in general, participants do not increase their offers beyond the conduct test threshold more frequently when the system is stressed, and, if anything appear more likely to remain within conduct test thresholds during these periods. This can be seen in Figure 7-2 below, which compares conduct test failure rates during periods of stressed system conditions and unstressed periods.[94]

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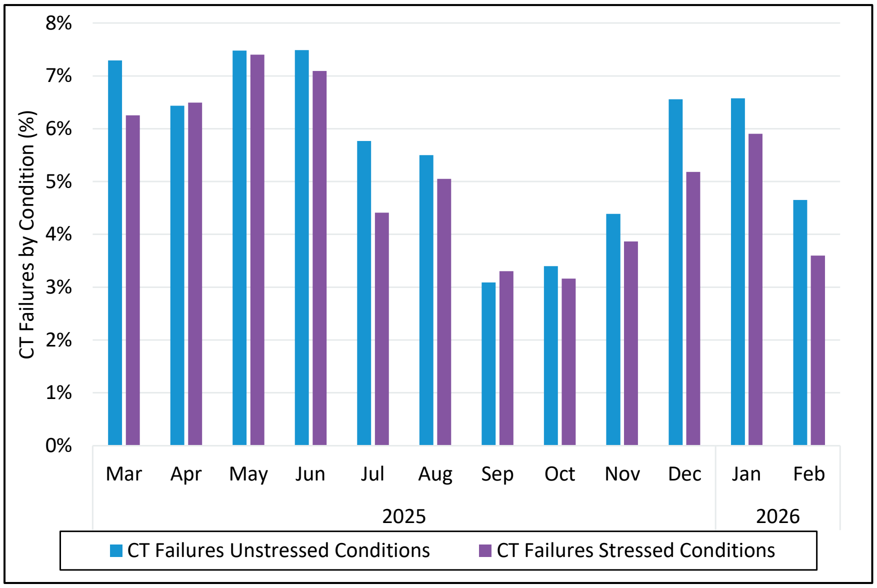
[92] Given that one asset can make offers on up to four DA A/S products per hour, this percentage represents the count of mitigated asset-product-hours relative to the total count of asset-product-hours in the period.

[93] For example, in October, the 19 distinct assets could have been mitigated on different days or the same day, and in different hours or the same hour. Using the combination of the percent of all asset-offers, along with the distinct number of assets mitigated in a month, explains the market-wide impact of mitigation.

[94] Hourly reserve margins are defined as the difference between ex-post capability and the associated FRS requirement. If any of the three reserve margins was in the bottom 10th percentile for the month, that hour was flagged as a stressed condition hour. Otherwise it is considered unstressed.

Figure 7-2: Conduct Test Failures Across FRS Products

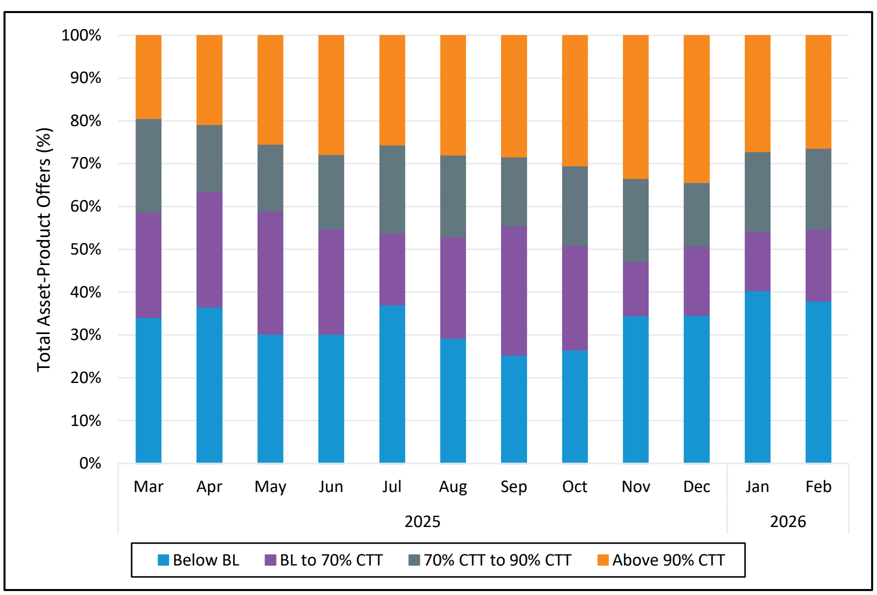


The results indicate that conduct test failure rates exhibit little change—and in several months are modestly lower—during stressed system conditions. One plausible explanation is that the conduct test threshold prices do a reasonable job defining the upper limit for competitive price ranges. Another plausible explanation is that participants adjust their offers to avoid failing the conduct test. As a result, participants may limit conduct test exposure rather than risk mitigation.

Participant Offers Relative to Mitigation Values

Figure 7-3 below represents participant offer bands across all products relative to benchmark levels and the conduct test threshold.

Figure 7-3: Offers Relative to Mitigation Values



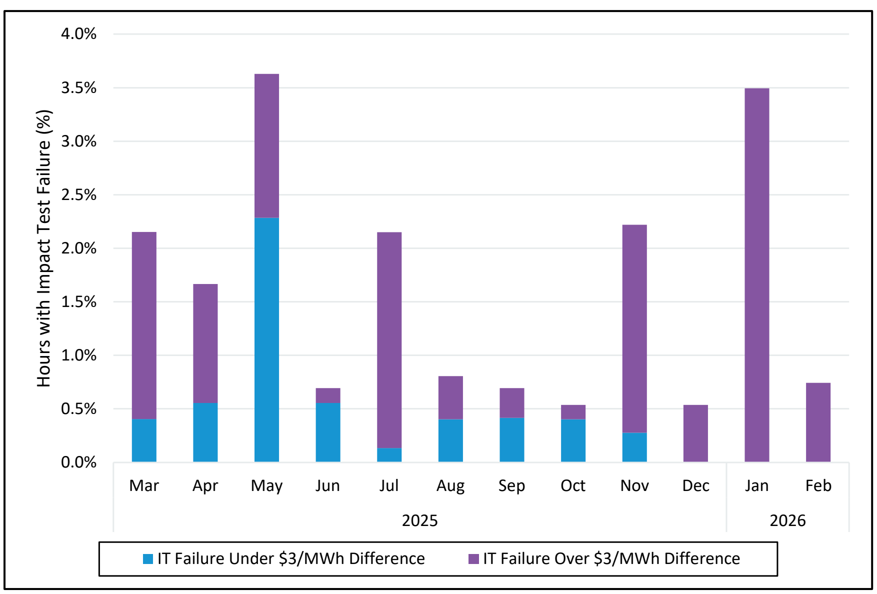
The blue and purple categories, representing offers below the benchmark level or only modestly above it, account for 55% of offers. The gray category, representing offers between 70% and 90% of the conduct test threshold, accounts for 18% of offers. These offers approach the conduct test threshold without exceeding it and may reflect situations in which participants incorporate their own assessment of system conditions or operational risk into pricing decisions, resulting in offers that move meaningfully above benchmark levels while remaining below the conduct test threshold. This behavior is consistent with the intended design of conduct test threshold multipliers, which allow some upward pricing flexibility while discouraging excessive departures from benchmark levels.

The remaining 27% of offers fall at or above 90% of the conduct test threshold, including approximately 6% of offers that fail the conduct test. Offers above the conduct test threshold that occur on days with impact test failures are subject to mitigation and are reduced to benchmark levels when mitigation occurs. Participants whose offers fall into these higher bands may have legitimate concerns that existing conduct test thresholds do not fully reflect their operational or business conditions. In such circumstances, participants are encouraged to engage with the IMM to discuss potential adjustments, including benchmark overrides, as described in Appendix A of the ISO-NE Tariff.

Over-mitigation

One area where the mitigation design shows fault arises when price impact thresholds fell below $3/MWh. In these instances, mitigation tended to occur under relatively benign system conditions when market power is typically not a concern, suggesting a risk of over-mitigation that does not advance the core objectives of the framework. These outcomes indicate that very low impact thresholds are less effective at distinguishing between competitively meaningful and inconsequential price effects. Instances of impact test failures at impact prices below $3/MWh (blue) and above $3/MWh (purple) are shown in Figure 7-4.

Figure 7-4: Percent of Hours with Impact Test Failure



During the first year, there were impact test failures in 1.6% of hours, leading to mitigation on 63 days. Of those hours, 28% occurred when the impact test threshold and evaluated price difference were below $3/MWh. Hours with price impact violations occurring at thresholds of $3/MWh or less were associated with expected real-time LMPs below $29/MWh.[95] This pattern suggests these conduct/impact violations occurred during relatively benign system conditions, when the exercise of market power was less likely to raise concerns. For reference, in hours where the violations occurred at thresholds greater than $3/MWh, the expected real-time LMP averaged $111/MWh.

[95] The ISO started producing an expected real-time LMP as part of the implementation of the DA A/S market.

Section 8
GMM Performance

This section assesses the performance of the ISO's statistical model that is used to estimate several key values associated with the DA A/S market.

> ***Key Takeaways***
>
> Over the first year of DA A/S, the GMM understated real-time LMPs on average. Model performance reflected systematic under forecasting bias, with observed values frequently falling in the upper percentiles of the predictive distributions. This bias carried through to expected closeout values, which were also understated relative to realized outcomes.
>
> We encourage the ISO to continue to invest in its modeling tools and processes to ensure that expected real-time energy prices and closeout costs better track prevailing market conditions.

8.1 Expected Real-time LMP

To calculate key DA A/S market values, the ISO developed a statistical model of real-time LMPs that depends on a set of explanatory variables known in advance of the day-ahead market (e.g., load forecast, gas price).[96] The statistical model is a Gaussian Mixture Model (GMM), which produces a set of normal (i.e., Gaussian) distributions whose means and variances change depending on the values of these explanatory variables.

The GMM distributions are used to compute both the expected real-time LMP, which is used to set the Strike Price, and the expected closeout charge, which forms a key part of a resource's benchmark level that is used in DA A/S mitigation. These values represent means that are determined by integrating over the full range of price outcomes. Therefore, these values are not expected to match realized outcomes on an hour-by-hour basis. However, for a well-calibrated model, the *average* expected values should converge to the *average* realized values over a sufficiently large sample period.

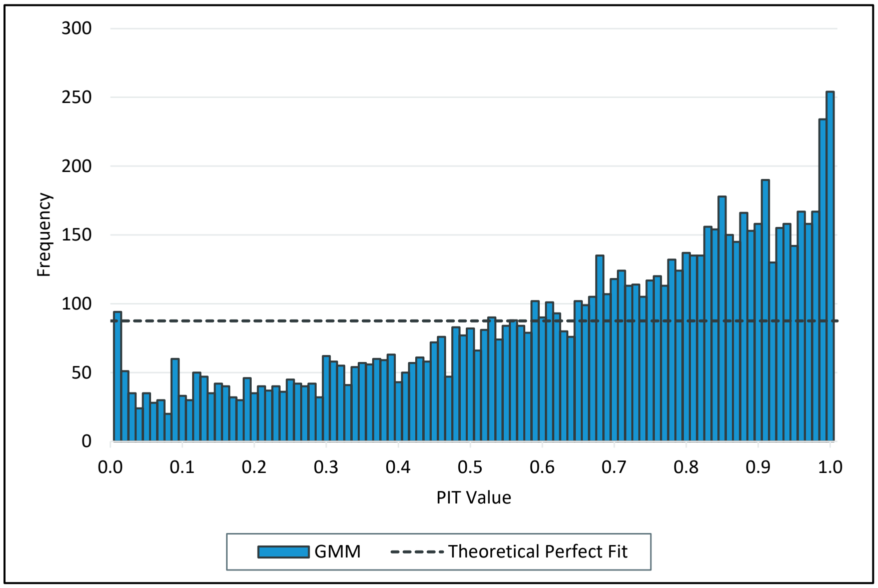
Over the first year of the DA A/S market, we found that the GMM tended to underestimate the real-time LMP. Over this period, the average expected real-time LMP from the GMM was $60.06/MWh, while the average realized real-time LMP was $67.63/MWh, indicating a $7.57/MWh average underprediction bias.

This bias is consistent with evidence that the GMM underestimated the right tail of the real-time LMP distribution. To evaluate the fit of the GMM distributions (which produce the expected real-time LMP) to the true distribution of observed pricing outcomes (realized real-time LMP), we use a probability integral transform (PIT) histogram. The PIT value is defined as the percentile of the

[96] More information about the model that the ISO uses to forecast the real-time LMP can be found in the ISO's Day-Ahead Ancillary Services Monthly Real-Time LMP Modeling Memo, available at https://www.iso-ne.com/isoexpress/web/reports/pricing/-/tree/DA A/S-monthly-memo.

realized outcome under the GMM forecast distribution.[97] Figure 8-1 shows the histogram of PIT values for all hours during the first year of DA A/S.

Figure 8-1: Probability Integral Transform (PIT) Histogram, All Hours



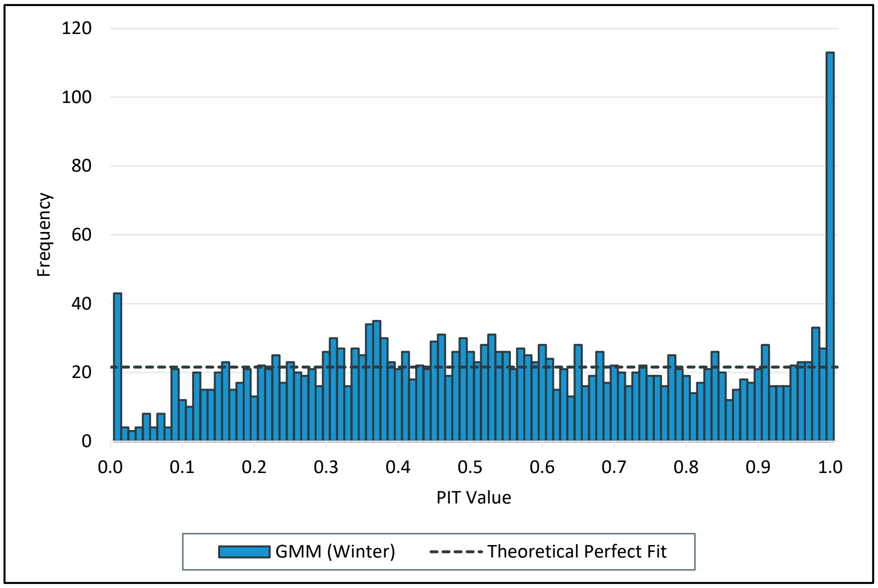
The empirical distribution of PIT values in Figure 8-1 provides a visual assessment of the model fit. The dashed line represents the uniform expected height of the histogram bars for a theoretical model that is perfectly well-calibrated at every percentile.[98] In contrast, the GMM distribution exhibits a pronounced right skew, with the bulk of the histogram mass falling in the higher percentiles. In particular, approximately 250 hours fell above the 99th percentile of the GMM distribution, over twice as many as expected under a model that perfectly captures the likelihood of observed outcomes. This heavy concentration of prices at high PIT values (and corresponding deficiency of observations at low PIT values) suggests that the GMM understated the probability of high-price outcomes.

Seasonal analysis shows similar patterns throughout most of the year, except for winter. Figure 8-2 shows that winter PIT values were more consistent with a uniform distribution in the middle percentiles but exhibited pronounced spikes in both tails. This increased frequency of observations at PIT ~ 1 (n=113) and PIT ~ 0 (n=43) indicates that, during winter, the model produced distributions that were too narrow to capture the actual variability in real-time LMPs. As a result, the model frequently underpredicted extreme high-price outcomes. It also occasionally produced severe overpredictions of low-price outcomes. Of these 156 extreme percentile outcomes, 51% occurred during Winter Storm Fern.

[97] For example, if an observed real-time LMP falls at the 50th percentile of the hour's GMM distribution, its PIT value is 0.5.

[98] A model is well-calibrated if, for any predicted probability, p, the empirical probability of the event actually occurring matches p. In the language of PIT values, a model is well-calibrated at the 50th percentile if 50% of observations have PIT values less than or equal to 0.5 over a sufficiently large sample, i.e., if 50% of the histogram mass falls below PIT 0.5.

Figure 8-2: PIT Histogram, Winter Hours



8.2 Expected Closeouts

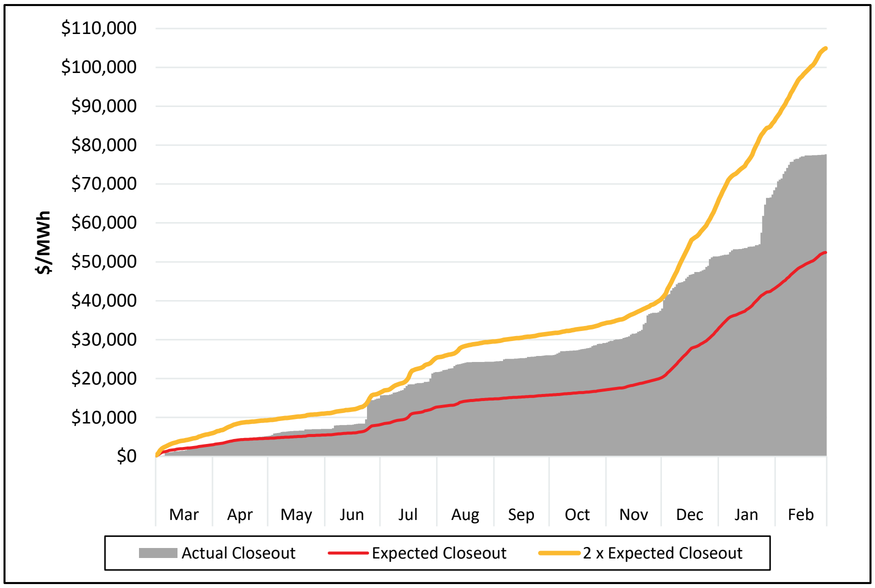
The ISO computes expected closeout charges as the probability-weighted average of potential closeout outcomes, with these probabilities derived from the GMM. Given the model's tendency to underestimate the upper tail of real-time prices, this bias is expected to be carried through to underestimate expected closeouts as well.

Consistent with this expectation, we found that the GMM underestimated the expected closeouts relative to realized values when viewed on a cumulative basis. This is shown in Figure 8-3 below, which shows the cumulative actual closeout with gray bars and the cumulative expected closeout value produced by the GMM as a red line.[99] The figure also depicts, in orange, a value that is twice the expected closeout (labeled as '2 x Expected Closeout'); this represents the expected closeout portion of the conduct test threshold price that is used in mitigation.[100]

[99] In order to illustrate GMM performance, this expected closeout series does not include any IMM overrides.

[100] For more information about the conduct test threshold price and mitigation, see Section 3.1.4.

Figure 8-3: Actual and Expected Closeouts, Cumulative



We can see that the cumulative actual closeouts, which tend to be more volatile, exceeded the cumulative ISO-produced expected closeouts by a significant margin at the end of the first year of the DA A/S market. Actual closeouts totaled $78,000/MWh while expected closeouts totaled only $52,000/MWh. This means that a hypothetical asset that cleared one MWh of DA A/S awards in every hour would have incurred a loss of over $25,000 if DA A/S clearing prices had been exactly equal to the expected closeouts from the ISO's model.[101]

To account for estimation error, as well as for reasonable variation in participant expectations of real-time outcomes and in risk premiums, the DA A/S offer mitigation design allows participants to offer up to twice the expected closeout without triggering mitigation. We can see that the cumulative twice expected closeout series does exceed the cumulative actual closeout series at the end of the first year, reaching a year-end total of $105,000/MWh.

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These findings have two important implications. First, when the model produces Strike Prices below prevailing market expectations, the resulting expected closeout values will also be lower, which may prompt the IMM to adjust mitigation values to correct this misalignment, potentially increasing offer prices and day-ahead market costs.[102] Indeed, the IMM performed such adjustments during many high-stress days. Second, implementing a Strike Price floor—consistent with our recommendation to better align the strike price with the short-run marginal costs of

[101] It is worth noting that DA A/S clearing prices are not expected to equal the expected closeout for a variety of reasons, one significant cost driver to date being that clearing prices reflect significant opportunity costs.

[102] The relationship between strike price levels and market outcomes is nuanced and requires further study. In particular, while lower strike prices relative to prevailing market conditions increase expected closeout costs and likely increases overall day-ahead costs, however this effect is at least partially offset by higher realized closeout costs.

resources providing ancillary services—offers a meaningful secondary benefit by eliminating forecasting errors below the marginal cost of a combustion turbine.

Even with this change, we continue to encourage the ISO to invest in its modeling tools and processes so that expected real-time energy prices and closeout costs more closely reflect prevailing market conditions. When the expected real-time LMP (plus the $10/MWh adder) exceeds the proposed floor and determines the Strike Price, it is important that these inputs to option pricing remain aligned with current market conditions.

Section 9
Market Performance Metrics

While previous sections evaluated market costs and competitiveness, this section assesses market performance. Specifically, this section focuses on how well the day-ahead market is preparing the system for what is needed in real time. Consequently, focus in this section is given to price convergence (as an indicator of market efficiency), out-of-market actions, and Net Commitment Period (NCPC) costs. We conclude with an assessment of how DA A/S impacts wholesale revenues streams and potential implications for cost recovery allocation between the E&AS and capacity markets.

Key Takeaways

The first year of DA A/S was associated with a modest increase in the average day-ahead price premium, rising to \$3.81/MWh from \$1.18/MWh, while the median remained largely unchanged, indicating that a small number of high-price events, particularly during stressed periods like July 2025 and January 2026, drove the increase.

Out-of-market commitments have been infrequent in recent years, even before DA A/S, and in the past year have further declined slightly and remained rare.

DASI did not lead to a clear reduction in day-ahead NCPC, as higher revenues from FER and reserves were offset by lower energy prices and ongoing cost recovery needs for marginal units. While DASI may reduce NCPC by avoiding some manual RAA commitments, these potential savings are highly uncertain and likely modest relative to an upper-bound estimate of approximately \$35 million annually. Real-time NCPC declined in categories associated with out-of-merit actions, suggesting improved system preparedness, but the overall impact is relatively small.

Over time, DA A/S revenues may therefore reduce the "missing money" that some resources seek to recover through the capacity market. This is particularly the case for combustion turbine resources. As a result, these revenues are expected to influence capacity-market offer behavior and, ultimately, capacity-market outcomes. Future estimates of energy and ancillary services revenues should also affect Net CONE estimates and the setting of the capacity market's administrative demand curve. These longer-run effects are not measured in our first-year incremental-cost estimates but are important to understanding the design's broader economic implications.

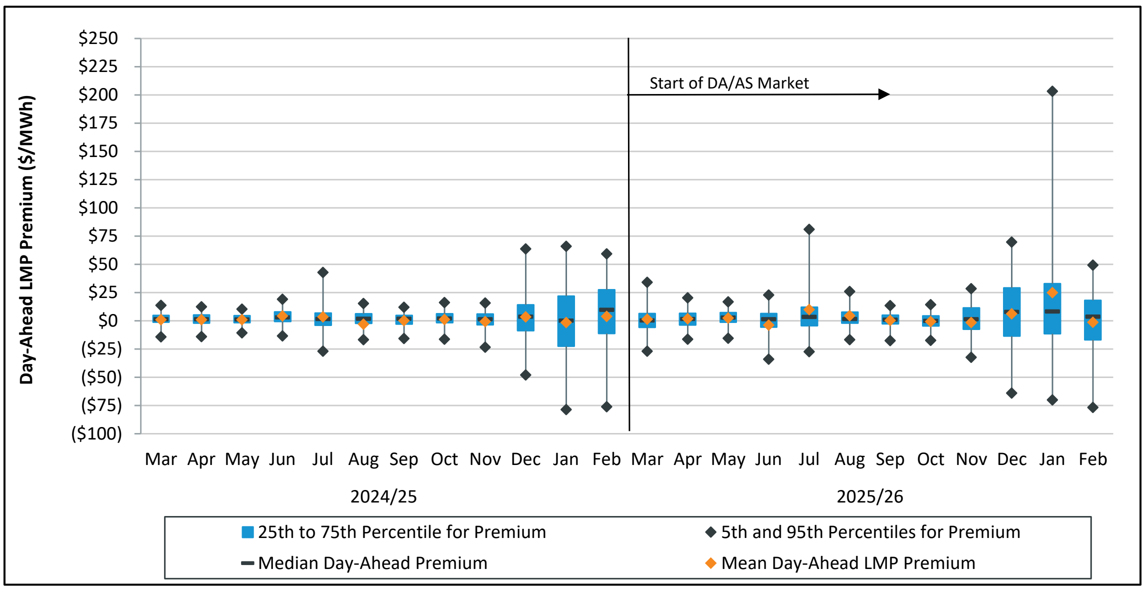
9.1 Price Convergence

Price convergence describes the degree to which prices in the day-ahead and real-time markets align. It is commonly used as an indicator of market efficiency, defined here as achieving the necessary real-time resource commitments at the lowest possible cost. Strong price convergence can indicate that the day-ahead market is effectively anticipating real-time conditions to facilitate efficient and reliable scheduling outcomes.

While both the day-ahead and real-time markets are now co-optimized markets that procure energy and operating reserves, they differ in important ways that can impact price convergence. Reserve procurement in the day-ahead market is based on voluntarily-submitted ancillary services offers, while procurement in the real-time market considers all reserve-capable resources (i.e., is not strictly voluntary) and determines reserve clearing prices solely based on opportunity costs (i.e., there are no reserve offers). Additionally, the incorporation of the Forecast Energy Requirement Price (FERP) as a second price for (physical) energy adds complexity to what had previously been a comparison simply between LMPs.[103]

LMP convergence can be seen in Figure 9-1, which shows the distribution of the day-ahead price premium (i.e., day-ahead LMP minus real-time LMP) at the Hub by month between March 2024 and February 2026 using a box-and-whiskers diagram. This figure also shows the average monthly day-ahead LMP premium (orange marker).

Figure 9-1: Day-Ahead vs. Real-Time LMP Convergence



The day-ahead premium averaged $3.81/MWh over the first year of DA A/S, up from $1.18/MWh in the year prior. However, the median day-ahead premium remained similar, increasing from $1.84/MWh to $1.93/MWh over the same period. The difference between the average and median highlights that the day-ahead premium was right-skewed, with some high observations pulling the mean up. This can be seen in the figure above; in fact, the average day-ahead premiums in July 2025 and January 2026 were the two months with the highest premiums since the beginning of the Standard Market Design.

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[103] ISO-NE expected that, over time, the day-ahead and real-time LMP would converge under this new market design as load-serving entities cleared more demand in the day-ahead market to take advantage of lower day-ahead LMPs when the FER bound. See pages 54-56 of the testimony of Ben Ewing in support of DASI contained within the ISO's filing to FERC, which is available here: https://www.iso-ne.com/static-assets/documents/100004/rev_to_est_jointly_optimized_day-ahead_mkt_for_energy_and_ancillary_services.pdf.

While the day-ahead premium increased in the year following the implementation of DA A/S, it is important to consider the factors that contribute to a day-ahead premium:

- Under DA A/S, the day-ahead market produces a more robust and flexible operating plan for real time than with the previous market construct. The cost of procuring this additional flexibility is reflected in day-ahead energy and ancillary service prices.
- Because not all operating reserve capability is offered into the day-ahead market, there can be less economic capacity available to meet load and reserve requirements than in real time. Co-optimization can further raise day-ahead LMPs when efficient generators are used to satisfy reserve requirements rather than energy, resulting in higher-cost resources setting the price. This effect becomes more pronounced under stressed conditions, when the energy supply curve is steeper.
- Renewable resources often offer in a way that results in only a portion of expected real-time output clearing day-ahead. As a result, higher-cost generation may be dispatched in the day-ahead market to meet the FER (also impacting the LMP) and later displaced by lower-cost renewable generation in real time.
- Increased long-lead time commitments and stronger performance incentives under DA A/S place downward pressure on real-time LMPs, reducing reliance on higher-cost real-time-only generation.

9.2 Out-of-Market Actions

Out-of-market actions can reflect both market performance and reliability. If DA A/S improves the day-ahead operating plan, one expected benefit is fewer supplemental commitments through the reserve adequacy analysis (RAA) process or manual operator actions.[104] Because these actions are infrequent, annual averages can obscure the magnitude of actions taken on stressed days. We therefore report a time series, highlighting commitments on the top 12 highest cost DA A/S days[105], all of which occurred during Winter Storm Fern.

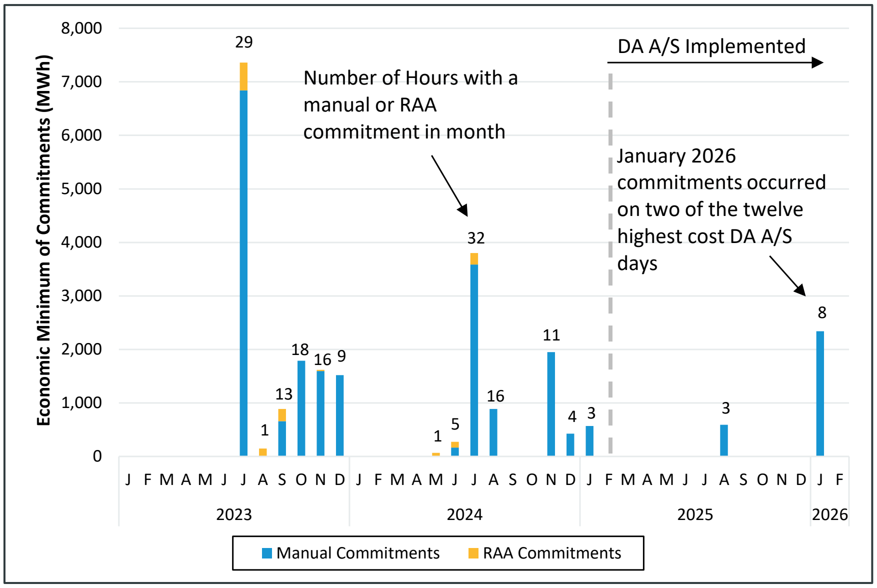
Our evaluation indicates that DA A/S has potentially reduced manual commitments and RAA commitments, although the impact is slight due to the low quantity of these committed MWs pre-DA A/S.[106]

[104] RAA commitments include commitments made post-day-ahead clearing to ensure adequate reserves. These commitments can happen during the operating day or the previous day after the day-ahead market is run. For more information, see ISO-NE operating procedure titled *Perform Reserve Adequacy Analysis*, available here: https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/sysop/rt_mkts/sop_rtmkts_0050_0010.pdf

[105] Twelve days, most of which were associated with multi-day periods of stressed system conditions, accounted for approximately 50% of incremental costs of DA A/S in its first year. See Section 4.2.

[106] Manual commitments for capacity and locational support are included in this analysis. Excluded commitments include manual commitments for auditing, special constraint resources that are requested by transmission owners or distribution companies, and manually-initiated economic commitments.

Figure 9-2: RAA and Manual Capacity and Locational Commitments



Manual and RAA commitments to provide capacity or local reliability support remained rare in both the pre- DA A/S and DA A/S periods. Despite the small number of manual and RAA commitments, there was a decrease when DA A/S was implemented. Since then, manual commitments have occurred in only 11 total hours, adding up to only 2,900 total MWh of committed energy (at EcoMin). About 2,300 MWh of those commitments occurred during two of the twelve highest cost DA A/S days, both in January of 2026. In 2024, there were 7,400 MWh of energy at EcoMin committed either manually (7,000 MWh) or in the RAA process (400 MWh). As a result, while DA A/S appears directionally consistent with fewer out-of-market commitments, the effect is relatively small in the context of prior years' performance.

9.3 Impact on NCPC (Uplift)

This section evaluates the impact of DA A/S on Net Commitment Period Compensation (NCPC) through both direct day-ahead effects and indirect real-time effects. The analysis yields three key takeaways:

- **No clear reduction in day-ahead NCPC from increased revenues:** Higher FER payments did not translate into lower day-ahead uplift, as they were largely offset by lower day-ahead LMPs and ongoing cost recovery needs for marginal units; day-ahead NCPC increased modestly in nominal terms following the implementation of DA A/S.
- **Potential reductions from avoided manual commitments are limited and uncertain:** While DA A/S may reduce NCPC by limiting reliance on RAA commitments, estimated reductions are highly sensitive to assumptions and are bounded at approximately $35 million annually, with more realistic outcomes likely significantly lower (e.g., roughly $11 million if limited to peak conditions).
- **Real-time NCPC declined in plausibly affected categories:** Payments associated with out-of-merit actions fell following DA A/S implementation, consistent with improved system preparedness; simple counterfactual estimates suggest roughly $3 million in real-

time NCPC reductions over the first year, although these results are based on correlations rather than a true counterfactual.

Together, these findings indicate a shift in how system costs are recovered—from out-of-market uplift, as well as Forward Reserve payments, to market-based mechanisms—with total NCPC reductions estimated to be no more than approximately $38 million in the first year.

Day-Ahead NCPC Impacts

In theory, DA A/S affects day-ahead NCPC through two related channels: increased generator revenue streams and changes in commitment patterns.

First, DA A/S introduces additional compensation through the Forecast Energy Requirement price (FERP) and FRS revenues, which increase total day-ahead revenues to generators. To the extent that compensation under the combined DA LMP, FERP, and FRS revenue exceeds what generators would have earned under DA LMP alone, DA A/S may reduce the need for economic uplift payments.

Second, the FER constraint modifies commitment outcomes in the day-ahead market. When the market clears with insufficient physical supply to meet forecast load, the FER constraint induces additional generator commitments. These commitments can improve system preparedness and reduce the need for manual commitments through the Reserve Adequacy Analysis (RAA) process. In principle, this mechanism can reduce NCPC by shifting compensation from uplift to market-based revenues (DA LMP + FERP).

In practice, observed outcomes do not show an immediate reduction in day-ahead NCPC following the implementation of DA A/S. In the year prior to implementation, day-ahead economic NCPC payments totaled approximately $4.4 million (0.06% of energy market payments), compared to approximately $5.4 million (0.07%) in the first year of DA A/S. While this is not a full counterfactual analysis of what DA NCPC would have been absent DA A/S, the nominal increase in NCPC indicates that any moderating effects from enhanced revenue streams were offset by other factors.

Several factors help explain the lack of an immediate decline in day-ahead NCPC. First, generator operating costs were generally higher after DA A/S than before due to higher fuel prices in 2025, pushing up NCPC payments for reasons unrelated to DA A/S. Second, economic NCPC payments are often driven by units that are only marginal for part of their commitment periods. These units require uplift to recover startup costs, no-load costs, and unrecovered costs during non-marginal intervals. While DA A/S changes pricing and commitment decisions, it does not eliminate these cost recovery dynamics.

In addition, DA A/S -induced commitments may increase exposure to uplift in some cases. Incremental commitments driven by the FER constraint tend to involve relatively higher-cost units. If these units do not fully recover their costs through energy and reserve revenues, they may require larger NCPC payments. As a result, DA A/S may simultaneously reduce and increase uplift through different mechanisms, leading to ambiguous net effects on day-ahead NCPC.

Averted RAA Commitments

A second potential source of day-ahead NCPC reductions arises from the avoidance of manual commitments through the RAA process. To evaluate this effect, we identify incremental DA A/S commitments—defined as commitments present in the "DA A/S" simulation that do not occur in a counterfactual "No DA A/S" simulation[107] —and estimate their total cost based on startup, no-load, and energy-to-EcoMin costs.[108]

To translate these costs into potential NCPC reductions, we assume that all incremental DA A/S commitments would otherwise have been manually committed through the RAA process. Under this assumption, the relevant comparison is between (1) their realized compensation under day-ahead markets and real-time energy revenues, and (2) the uplift that would have been required if these commitments had been made manually.

This approach yields an upper bound on the NCPC reductions attributable to DA A/S. Importantly, the underlying assumption is likely generous. The FER constraint tends to understate expected real-time renewable generation and may therefore induce more commitments than operators would have implemented manually. In addition, historical RAA commitment levels have been low even prior to DA A/S, suggesting that not all incremental commitments would have been necessary in practice.

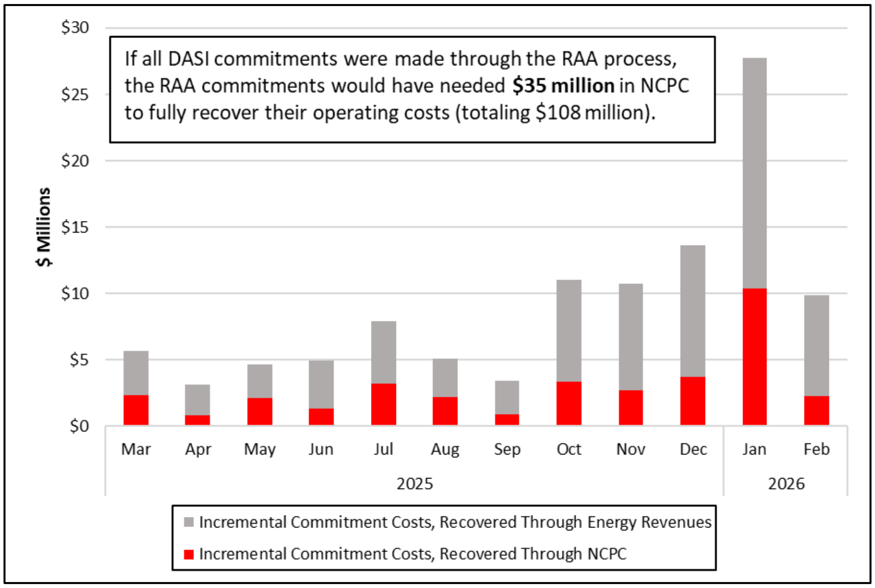
Under this bounding assumption, the total cost of incremental DA A/S commitments was approximately $108 million in the first year. After accounting for roughly $72 million in real-time energy revenues, the implied NCPC that would have been incurred under manual commitments is approximately $35 million. This represents the maximum potential real-time NCPC reductions from avoiding RAA-based commitments.

In Figure 9-3 below, we show the estimated reductions in RAA commitment-driven NCPC. A large share of these estimated reductions is concentrated in a limited number of high-cost days, particularly during Winter 2026 when generator operating costs were elevated. The twelve most expensive DA A/S days account for approximately 30% of total estimated NCPC reductions under this framework. If operators would only have undertaken manual commitments during such high-stress conditions, then the realized NCPC reductions would be substantially lower—on the order of approximately $11 million.

[107] See Section 4.2 for more information about these simulations.

[108] Note that the DA A/S influence on the commitment mix is not simple – it is not generally true that, for every generator committed under DA A/S, the same generator would have been committed without DA A/S. This analysis identifies the incremental manual commitments that would have been needed without DA A/S to ensure that *at least* the same DA A/S -driven generator mix was online in every hour.

Figure 9-3: Estimated NCPC Cost of Averted RAA Commitments



Taken together, these results suggest that while DA A/S has the potential to reduce NCPC through avoided manual commitments, the magnitude of these reductions is highly sensitive to assumptions about operator behavior. Given historically low levels of RAA commitments, the realized reductions are likely significantly smaller than the upper-bound estimate.

Other Real-Time NCPC Impacts

DA A/S may also affect NCPC outcomes indirectly through changes in real-time system conditions. By increasing day-ahead commitments, DA A/S can improve system preparedness and reduce the likelihood of tight operating conditions that require out-of-market interventions.

The categories of real-time NCPC most likely to be affected include: (1) out-of-merit fast-start commitments, (2) manual dispatches to create "eco surplus,"[109] and (3) real-time manual commitments of long lead-time units. These actions are typically undertaken to maintain sufficient operating reserves or manage system reliability during periods of tight supply-demand balance.

Following DA A/S implementation, NCPC payments and associated out-of-merit generation in these categories declined. Average seasonal NCPC payments across these categories fell from approximately $3.8 million before DA A/S to $2.9 million after implementation, corresponding to a 34% reduction. This decline coincided with a reduction in out-of-merit generation, from approximately 42 MW per hour to 33 MW per hour on average.

[109] When system reserves are tight, operators may manually dispatch long lead-time units up in advance of peak load hours to create additional reserve capability; this is referred to as creating "Eco Surplus." Such out-of-merit dispatches incur significant NCPC credits but are less likely to occur when DA A/S clears such long-lead time units at higher levels in the day-ahead market.

Although these changes are consistent with expected DA A/S outcomes, they reflect correlation rather than causation. Real-time NCPC outcomes depend on a wide range of factors, including load realizations, generator outages, fuel prices, and system conditions more broadly. In the absence of a true real-time counterfactual, it is not possible to attribute these changes solely to DA A/S.

Nevertheless, a simple counterfactual framework can be used to estimate the potential magnitude of real-time impacts. Assuming that out-of-merit generation would have continued at pre- DA A/S levels in the absence of DA A/S, and holding NCPC rates ($/MWh) constant, estimated NCPC payments for these categories would have been approximately $14.4 million over the first year, compared to $11.5 million of actual payments. This implies a roughly $3.0 million reduction in NCPC attributable to changes in commitment patterns associated with DA A/S.

Summary

Overall, the impact of DA A/S on NCPC payments is mixed and reflects the interaction of several offsetting mechanisms. There is no clear evidence that DA A/S reduced day-ahead NCPC through increased revenue streams alone, as higher FER payments were partially offset by lower day-ahead LMPs and continued cost-recovery needs for marginal units. While DA A/S may not have substantially reduced aggregate NCPC, it changes how costs are recovered by shifting compensation from out-of-market uplift to market-based pricing mechanisms, which represents an important economic benefit of the design.

Notably, other RTOs experienced significant uplift during Winter 2026, while uplift declined in New England during the same period—coinciding with the first winter of DA A/S implementation.[110] However, differences in uplift rules, operating conditions, and market structures across regions limit direct comparisons. This analysis suggests that New England could have achieved a similar commitment mix through manual interventions at an estimated annual cost of approximately $35 million in NCPC (including roughly $10 million in January 2026). At the same time, given historically low levels of manual commitments and relatively stable system conditions, it is unlikely that New England would have experienced the more extreme uplift outcomes observed in other RTOs even in the absence of DA A/S.

9.4 Revenues Source Mix and Implications

The introduction of the DA A/S market provides explicit compensation for reserve capability, with implications for longer-term resource incentives. While it is too early to observe direct impacts on long-term resource economics (entry, exit, retention), IMM analysis indicates that DA A/S revenues represent a meaningful share of total revenues for fast-start resources, improving the economics of such resources by explicitly rewarding flexibility.

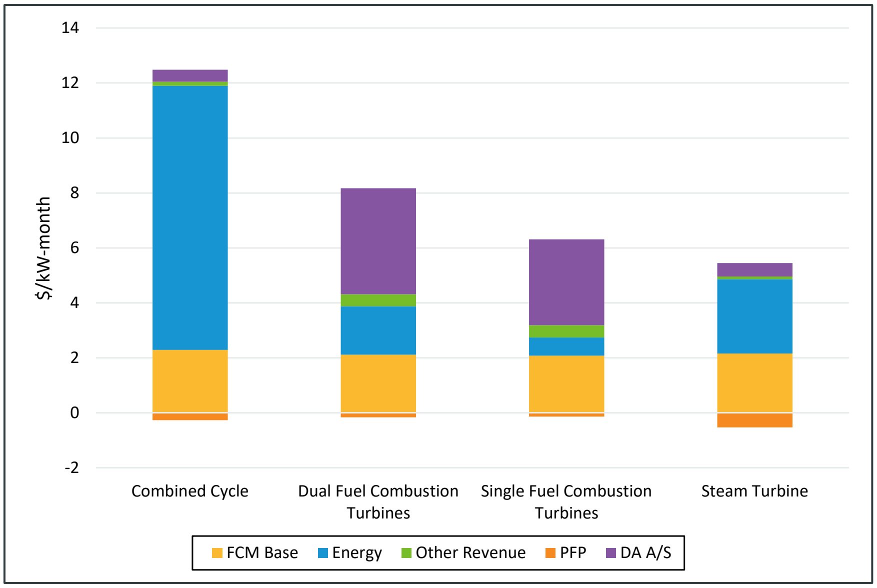
Over time, DA A/S revenues may therefore reduce the “missing money” that some resources seek to recover through the capacity market. As a result, these revenues are expected to influence

[110] For example, PJM had over $750 million in uplift in January 2026 alone. See the PJM markets report for January 2026, available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2026/20260219/20260219-item-07a---1-pjm-market-operations-report---presentation.pdf.

capacity-market offer behavior and, ultimately, capacity-market outcomes. Future estimates of energy and ancillary services revenues should also affect Net CONE estimates and the setting of the capacity market's administrative demand curve. These longer-run effects are not measured in our first-year incremental-cost estimates but are important to understanding the design's broader economic implications.

Figure 9-4 below shows the net revenue for different technology types categorized by the following revenue sources: base capacity from the Forward Capacity Market, PFP, energy, DA A/S, and other revenue.

Figure 9-4: Net Revenue by Technology Type



DA A/S did not contribute significantly to combined-cycle profitability given that they primarily earn revenues by providing energy rather than reserves. Steam turbines also did not have significant DA A/S revenue because they are non-fast-start and cannot provide reserves from an offline state. Combustion turbines received about half of their revenues from DA A/S during the year (combined, \$3.53/kW-mo of a total of \$7.19/kW-mo). DA A/S payments exceed revenues from the now defunct Forward Reserve Market, which averaged about \$1.30/kW-month in 2023 and 2024.

Section 10
Reliability Outcomes

The evaluation of reliability outcomes during the first year of DA A/S is based on a structured set of metrics designed to assess whether the design has led to improved system preparedness and performance. Because reliability outcomes are influenced by system conditions, fuel and energy prices, and a broad range of market-based incentives (e.g., energy prices, Pay-for-Performance), it is difficult to assign causality to DA A/S incentives. This analysis focuses on behavioral and operational indicators that are consistent with the design objectives, including resource availability, day-ahead plan flexibility, and gas scheduling. These indicators are designed to provide a framework for evaluating reliability value over time.

Key Takeaways

Although it is difficult to assign causality to DA A/S given the broad range of market incentives at play over the first year, certain reliability-based metrics for DA A/S resources appear promising.

Additional revenue sources to combustion turbines providing day-ahead reserve products has coincided with improvements to availability. Additionally, more fast-starts are allocated DA A/S obligations, rather than energy, resulting in a day-ahead schedule that has more longer-lead-time units, and fast-start units ready to respond to unexpected events.

Finally, we did not observe any strong gas scheduling behavioral response to DA A/S incentives, although the majority of participants who responded to our survey indicated that DA A/S has influenced their fuel procurement decisions across several fuel types.

10.1 Commitment Differences

The commitment and dispatch outcomes in the day-ahead market may not always reflect expected physical real-time conditions. For example, load-serving entities may clear less demand than the ISO's load forecast, resulting in less physical energy supply clearing in the day-ahead market than is expected to be needed in real time. When this happens, there is a day-ahead "energy gap," which we define here as (1) the expected real-time load less (2) the amount of day-ahead energy awards on physical resources (i.e., excluding virtual supply).[111]

A key design change under DA A/S was the explicit incorporation of the ISO's load forecast into the day ahead market clearing process. The Forecast Energy Requirement (FER) constraint ensures that sufficient physical capability is procured in the day ahead market to meet forecasted load. This requirement may be satisfied through day-ahead energy awards from physical supply resources as

[111] Under this definition, a negative "energy gap" value indicates that the quantity of cleared physical energy *exceeded* the load forecast.

well as awards of Energy Imbalance Reserve (EIR). Consequently, “the energy gap is closed by procurement of additional energy and EIR.

Day-Ahead Energy Gap

Our evaluation indicates that DA A/S has likely decreased the energy gap, especially at the tail end of the distribution (i.e., DA A/S appears to reduce the incidence of extreme energy gaps). The following table shows energy gap statistics comparing pre-DA A/S times (March 1, 2023-February 28, 2025) with Post-DA A/S implementation (March 1, 2025-February 28, 2026).

Table 10-1: Energy gap statistics pre- and post-DA A/S implementation, in MW

Time Period	Mean	75th Percentile	90th Percentile	95th Percentile	99th Percentile
DA A/S	(94)	198	395	540	800
Pre-DA A/S	(132)	234	542	721	1,079
Difference	**38**	**(36)**	**(147)**	**(181)**	**(278)**

Consistent with expectations, DA A/S has reduced the frequency of extreme energy gaps. Pre-DA A/S, the 90th percentile was about 540 MW – a level corresponding to the 95th percentile post-DA A/S implementation. This outcome is expected because the FER constraint enforces a physical supply constraint that ensures physical supply cleared plus EIR in the day-ahead market is adequate to deliver forecasted real-time energy. The enforcement of the additional constraint results in lower energy gaps since DA A/S was implemented.

Fast-Start Commitment in the Day-Ahead Energy Mix

We find that fast-start units made up a smaller portion of the day-ahead generation mix, in favor of longer-lead-time generators, since DA A/S was implemented. The shift indicates that fast-start units are being held for reserves more often after DA A/S implementation, an outcome that is also evident in our simulation studies.[112] The following table shows the percentage of day-ahead cleared MWs for energy by startup + notification time, comparing pre- DA A/S times (March 1, 2023-February 28, 2025) with post- DA A/S implementation (March 1, 2025-February 28, 2026).

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[112] Fixed generation mix is estimated using the percentage of the total Economic Minimums of units committed in the day-ahead market. Calculations using Economic Maximum were similar.

Table 10-2: Day-Ahead Generation by Startup plus Notification Time

	All Hours			Top 3% Load Hours			Top 12 Days
Startup plus Notification Time	**Pre- DA A/S**	**DA A/S**	**Delta (% Points)**	**Pre- DA A/S**	**DA A/S**	**Delta (% Points)**	
Less Than 30 Minutes	30%	19%	-11	25%	18%	-7	16%
Between 30 Minutes and 1 Hour	2%	1%	-1	2%	2%	0	1%
Between 1 and 2 Hours	1%	1%	0	1%	1%	0	1%
Between 2 and 4 Hours	0%	0%	0	0%	0%	0	0%
Between 4 and 8 Hours	44%	52%	8	46%	49%	4	51%
Between 8 and 16 Hours	10%	12%	1	16%	19%	3	19%
Longer than 16 Hours	12%	15%	3	10%	11%	0	12%

Since DA A/S was implemented, the percentage of fixed (i.e., up-to EcoMin) generation from fast-start units has decreased by about 11 percentage points across all hours as some generators now clear DA A/S awards. The fast-start fixed MWs have been offset by longer-lead time generation, with startup + notification time greater than 4 hours. In the highest load hours, as well as the twelve days with the highest DA A/S costs, fast-start generation makes up a smaller percentage of fixed generation, with the longer-lead time generation increasing, when compared with all hours. This indicates that, post- DA A/S, the day-ahead schedule may be more flexible, with more flexible units held in reserve to help respond to unexpected real-time events.

Long Lead-Time Commitment Differences in Simulated Outcomes

Simulated day-ahead market clearing results without DA A/S constraints can directly show the impacts of DA A/S on the day-ahead supply mix. In particular, this can be used to show how DA A/S increased the commitment and dispatch of long-lead time units in the day-ahead market to create reserve availability. Table 10-2 below shows the commitment of economic, long-lead-time units between DA A/S outcomes and simulated non-DA A/S counterfactuals.[113,114]

Table 10-3: Economic Long Lead-Time Commitments With and Without DA A/S

	Average Long Lead-Time Generator MWh		
Time	**Non-DA A/S**	**DA A/S**	**Difference**
All Hours	5,283	5,359	**+ 76 (1%)**
Top 12 Days	6,766	6,865	**+ 99 (1%)**

[113] For this table, we define long lead time units as any generator that offered a combined startup and notification time greater than 4 hours. We include only economic generation, excluding self-schedules or other must-run generation.

[114] While the table uses the terms "Non-DA A/S" and "DA A/S" to denote scenarios, note that the "DA A/S" scenario does not reflect the actual DA A/S outcomes, but rather reflects the benchmark scenario in our simulation software. Using this scenario as a comparison rules out any outcomes that are driven by differences in market clearing software. However, note that the DA A/S benchmark scenario performs well and accurately reflects true DA A/S outcomes.

DA A/S increased the amount of long lead-time generation that cleared the day-ahead market, with an average increase of 76 MW (1%) relative to day-ahead market results without DA A/S constraints. Notably, while this table shows *all* cleared long lead-time energy, this result holds even when considering only *commitment* energy up to generators' economic minimum limits. Therefore, DA A/S materially increased committed long lead-time generation ahead of real-time operating conditions.

The impacts of DA A/S on the commitment and dispatch of long lead-time generation were relatively high on the Top 12 days. On average across these days, DA A/S resulted in a 99 MW increase in economic long lead-time generation that cleared the day-ahead market.

10.2 Fuel Scheduling and Management

The DA A/S market strengthens preparedness incentives in the period between day-ahead clearing and real-time operations with an expectation that resource owners are more likely to ensure fuel is available when needed to cover their DA A/S obligation. For gas-fired resources, DA A/S positions can increase the value of securing fuel in advance.[115]

This analysis focuses on:

- gas nominations pre- and post-DA A/S implementation,
- the share of gas nominated day-ahead, and
- energy preservation for batteries and pump storage units.

The empirical results suggest that, at a system level, resources have not altered their approach to securing fuel based on DA A/S positions. The following table shows scheduled gas generation, estimated expected gas consumption associated with the day-ahead cleared energy offer, and DA A/S positions, across all seasons, and in the top 12 days with the highest DA A/S costs.[116]

[115] Specifically, a resource has an incentive to procure fuel in advance when the expected reduction in closeout exposure exceeds the incremental cost of arranging fuel, including the risk that the gas is not needed and must be resold or otherwise managed.

[116] Gas required to deliver day-ahead energy awards is estimated using generator input-output curves and startup gas estimates associated with the day-ahead schedules. Scheduled gas represents timely and evening gas nomination estimates from an external vendor. Both the estimated gas required to deliver day-ahead energy and the hourly scheduled gas are estimates based on the best available data.

Table 10-4: Gas scheduling pre- and post-DA A/S implementation

Time Period	DA A/S Status	Hourly Day-Ahead Cleared Gas Generation (MW/hour)	Hourly DA A/S Position (MW/hour)	Hourly Estimate Gas Required to Deliver Day-Ahead Energy (MMBtu)	Hourly Scheduled Gas (MMBtu)	(Scheduled Gas) / Gas Required to Deliver Day-Ahead Energy
Spring	**Pre-DA A/S**	5,324		39,852	43,274	109%
	DA A/S	5,416	834	40,649	43,868	108%
Summer	**Pre-DA A/S**	8,258		62,363	62,296	100%
	DA A/S	8,741	989	65,949	67,799	103%
Fall	**Pre-DA A/S**	6,968		52,399	53,251	102%
	DA A/S	7,139	1,052	53,384	49,954	94%
Winter	**Pre-DA A/S**	5,474		40,617	40,308	99%
	DA A/S	6,993	788	50,867	48,056	94%
All Seasons	**Pre-DA A/S**	**6,510**		**48,831**	**49,806**	**102%**
	DA A/S	**7,072**	**916**	**52,720**	**52,443**	**99%**
Top 12 Days		**8,611**	**1,117**	**64,903**	**66,115**	**102%**

In the two years before DA A/S, gas generators scheduled 2% more gas than estimated gas consumption of their day-ahead schedules (All Seasons, Pre-DA A/S, rightmost column). This number declined slightly, to 99% of estimated gas in the first year of DA A/S despite DA A/S positions that amounted to about 13% of day-ahead energy positions. Summer was the only season in which gas generator scheduled more per MMBtu of estimated day-ahead gas consumption after DA A/S implementation than in pre-DA A/S periods.

In the top 12 days, gas generators scheduled 2% more fuel than was necessary to cover their day-ahead energy position. DA A/S did not necessarily cause the subtle shifts in gas scheduling we observed; it is likely that changes in gas costs, OFOs, gas constraints and overall increases in demand in all of the seasons led to the shift. However, we did not find strong evidence that gas generators scheduled additional gas to cover their DA A/S positions, with similar amounts of scheduled gas per day-ahead cleared generation MW pre- and post-DA A/S implementation.

As a counter point to the above empirical analysis, we note that in response to our survey, six out of 16 respondents with gas generators in their portfolios indicated that they procured fuel in response to a DA A/S positions.

For **stored-fuel resources**, including batteries and pumped storage resources, the design may impact both generation timing and fuel preservation incentives. Resources may be incentivized to defer generation in earlier hours to maintain flexibility for periods when DA A/S-related obligations introduce risk of fuel-related outages. During its first year, the impact of DA A/S on overall storage generation profiles appears small given that about 89% of storage generation is produced by assets that do not have a DA A/S obligation during the day and another 5% is produced on days in which the DA A/S obligation occurs earlier in the day (so generators are available to cover if needed without altering their optimal schedule).

Despite these data limitations, the average storage generator without a DA A/S obligation ran more often during the morning ramp in hours ending 7-9 (13% of generation) than those with a late-day DA A/S obligation (3%).[117] On the twelve highest-cost DA A/S days, the difference was more pronounced; storage generators with late-day DA A/S obligations produced zero MWs in hours ending 7-9, compared with 8% of generation for resources without a DA A/S obligation.

10.3 Resource Availability and Performance

Our evaluation of resource availability and performance focuses on outages rates across different technology types. The following table shows the total percentage of seasonal claimed capability out-of-service. The outages include planned and forced outages. The column on the far right shows estimated capacity out of service due to oil or gas availability during the Top 12 days with the highest incremental cost from DA A/S.[118]

Table 10-5: Total Percentage of Accredited Capacity Out-of-Service

Technology	Pre-DA A/S	DA A/S	Difference (% Points)	Top 12 Days	Top 12 Days – Due to Fuel Availability
Steam Turbines	21%	25%	4	20%	0%
Combustion Turbines	18%	11%	-7	11%	3%
Combined Cycles	12%	14%	2	9%	2%
Total: Above Technology Types	**14%**	**15%**	**1**	**11%**	**2%**

The combined outage rates of steam turbines, combustion turbines, and combined cycles across all hours was similar pre- and post-DA A/S, from 14% of claimed capability to 15% of claimed capability.

Outage rates decreased substantially for combustion turbines (an average of 18% of capacity out-of-service vs. 11% post DA A/S implementation). While it is difficult to isolate the incremental effect of DA A/S from other market incentives, it is likely that DA A/S revenues played a part in the reduction for combustion turbines, which receive over half of their net revenue from DA A/S between (discussed in the next section). The availability incentives could also have been influenced by higher energy prices; however, energy price incentives are shared by combined cycles and steam turbines, which did not see an increase in availability.

The design provides incentives for timely return to service by providing a revenue stream for units that are less often called upon for energy but are willing to provide reserves. Despite the additional incentives to procure fuel, about 3% of combustion turbine capacity was out of service during the

[117] Late day in this context is a generator that has a DA A/S obligation in hour ending 17 or later.

[118] The IMM estimated out of service MWs using outage data reported to the ISO. The values represent estimates due to the nature of the data.

12 highest cost DA A/S days due to depleted oil inventories, and 2% of combined cycle capacity was unavailable due to gas availability. Due to the energy dynamics in this especially-tight winter it is not possible for us to conclude at this time that DA A/S improved fuel procurement or fuel retention.

While the reduction in combustion turbine outage rates is directionally consistent with DA A/S incentives and revenues, the evidence is insufficient to attribute causality. One hypothesis is that higher DA A/S revenues may have led some fast-start resources to defer maintenance, improving short-run availability. Continued monitoring is needed to distinguish such maintenance timing effects from other drivers, e.g., weather, dispatch patterns, etc.

Section 11
Survey Results

The IMM conducted an online survey of market participants in February 2026 to better understand how the market reforms under DA A/S were being experienced by participants firsthand. The survey covered topics including participant understanding of the market, offer behavior, risk perceptions, and views on market performance. In total, 42 respondents completed the survey, yielding a 36% response rate. Of those, 76% indicated they were active in the DA A/S market. The survey therefore includes the perceptions of some participants not offering into the DA A/S market but primarily reflects the experience of those actively engaged in the market.

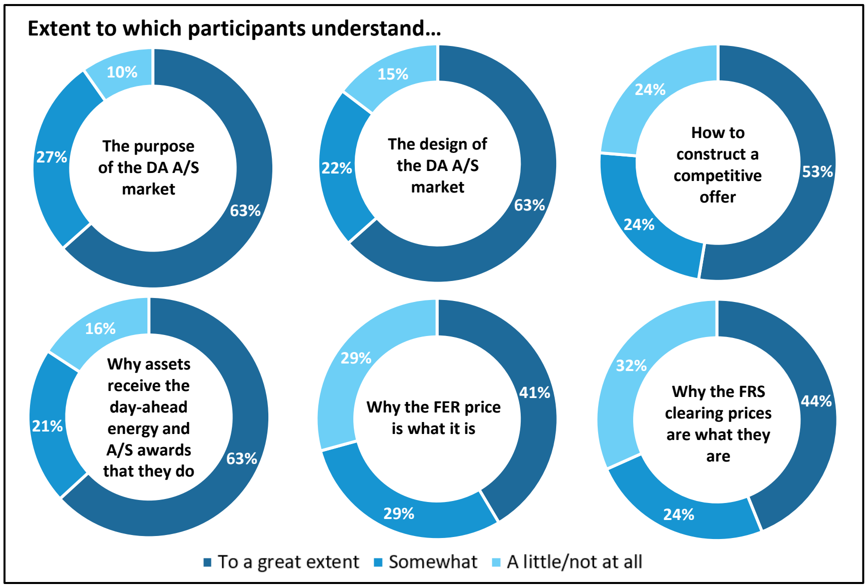
> ***Key Takeaways***
>
> The survey results suggest that many participants are responding to the incentives embedded in the design, particularly with respect to fuel procurement and operational readiness. However, market complexity and uncertainty continue to influence behavior. Some participants have adjusted their offer behavior over time as they've become more familiar with the market, but many indicated that they want additional training to enhance their understanding and comfort with specific market features. These findings are consistent with the broader analysis in this report, which shows that risk, uncertainty, and market design features play a significant role in shaping offer behavior and market outcomes.

Below, we provide a high-level summary of the survey results.

Market Understanding

Participants generally understand the purpose and high-level design of the DA A/S market but have less confidence in constructing offers and understanding clearing prices, as shown in Figure 11-1.

Figure 11-1: Participant Understanding of the Market (Survey)



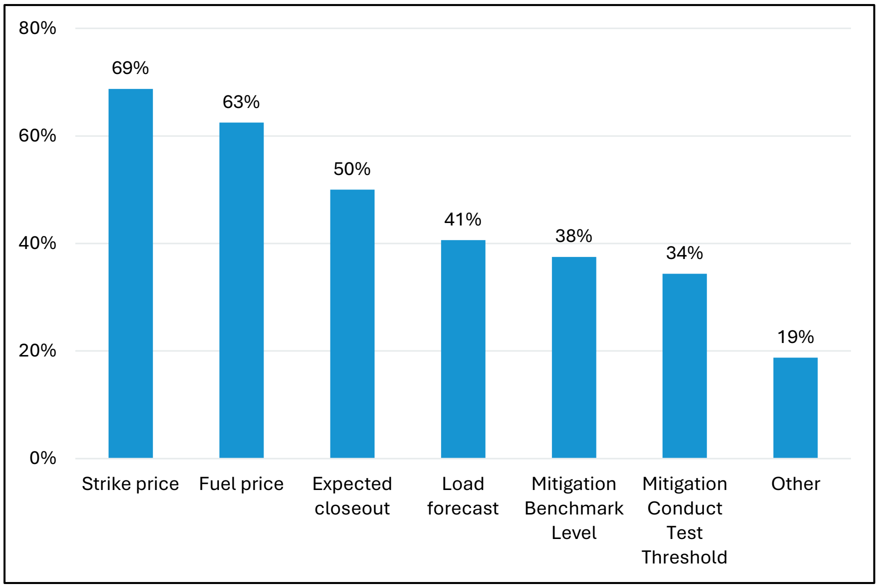
Approximately two-thirds of respondents reported a strong understanding of the market's purpose and design. However, only about 41–44% reported a strong understanding of FRS and FER price formation, and just over half reported confidence in their ability to construct competitive offers. About 16% reported no confidence in constructing offers. These results suggest that while the design is understood conceptually, translating that understanding into effective participation remains challenging. Additionally, over two thirds of respondents indicated that additional training, particularly on offer formulation, would be beneficial.

Market Participation and Offer Behavior

Some participants indicated that they have changed the frequency or quantity of their offers over time, citing changes in commercial strategy, improved understanding of the market, and changes in fuel prices and asset availability as the main reasons for varying offer behavior.

Participants who do participate in the DA A/S market generally incorporate multiple inputs into their offers, including strike prices, fuel costs, and expected close-outs, as shown in Figure 11-2.

Figure 11-2: Inputs to DA A/S Offers (Survey)



Note: Sample size = 32. Excludes "prefer not to respond" and "not applicable" responses.

A notable share of respondents (31%) reported that they do not explicitly incorporate strike prices in their offers, relying instead on fuel prices, expected closeouts, and/or load forecasts. At the same time, multiple respondents cited uncertainty related to strike prices, expected close-outs, and real-time exposure. These concerns are consistent with the broader finding that risk and uncertainty contribute to higher offer prices and variability in offer strategies.

Operational Impact

Survey results also indicate that DA A/S awards influence operational decisions. Approximately 71% of respondents reported taking actions in response to awards, most commonly procuring fuel.

Risk Perceptions

Participants were evenly split in their ability to account for risk in offers. One-third agree to a great/very great extent that they can sufficiently account for risk, one-third agree to some extent, and one-third agree a little or not at all. Despite this, approximately 75 percent indicated that DA A/S revenues generally cover the costs of providing reserves.

Mitigation and Benchmarking

Participants are generally aware of the mitigation design and many engage with the IMM to revise their benchmark levels. Most respondents who have revised their benchmark level with the IMM agree that the new level accurately reflects costs. However, some highlighted the administrative burden of frequently updating their benchmark level. These results underscore the importance of maintaining a mitigation framework that is both effective and operationally workable.

Perceived Benefits and Challenges

Participants most frequently cited increased revenue and improved compensation for reserve capability as key benefits of the DA A/S market. Other benefits include improved fuel planning and more transparent reserve pricing.

The most commonly cited challenges include:

- market complexity and difficulty forecasting outcomes,
- uncertainty in strike prices and closeout charges, particularly during stressed periods,
- challenges in constructing offers and managing risk, and
- administrative burden associated with mitigation.