2022 Annual Markets Report

Internal Market Monitor

JUNE 5, 2023

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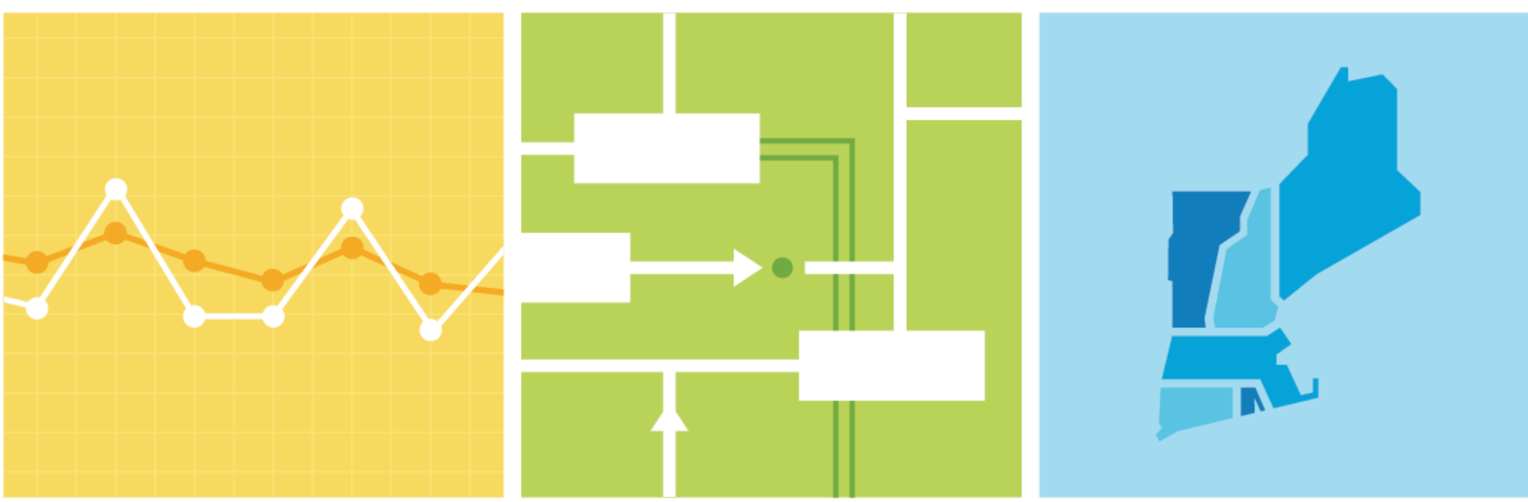

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Preface/Disclaimer

The Internal Market Monitor (IMM) of ISO New England (ISO) publishes an Annual Markets Report (AMR) that assesses the state of competition in the wholesale electricity markets operated by the ISO. The *2022 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2022. The report addresses the development, operation, and performance of the wholesale electricity markets administered by the ISO and presents an assessment of each market based on market data, performance criteria, and independent studies.

This report fulfills the requirement of *Market Rule 1*, Appendix A, Section III.A.17.2.4, *Market Monitoring, Reporting, and Market Power Mitigation*:

> *The Internal Market Monitor will prepare an annual state of the market report on market trends and the performance of the New England Markets and will present an annual review of the operations of the New England Markets. The annual report and review will include an evaluation of the procedures for the determination of energy, reserve and regulation clearing prices, Net Commitment-Period Compensation costs and the performance of the Forward Capacity Market and Financial Transmission Rights Auctions. The review will include a public forum to discuss the performance of the New England Markets, the state of competition, and the ISO's priorities for the coming year. In addition, the Internal Market Monitor will arrange a non-public meeting open to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general, and others with jurisdiction over the competitive operation of electric power markets, subject to the confidentiality protections of the ISO New England Information Policy, to the greatest extent permitted by law.*[1]

This report is being submitted simultaneously to the ISO and the Federal Energy Regulatory Commission (FERC) per FERC order:

> *The Commission has the statutory responsibility to ensure that public utilities selling in competitive bulk power markets do not engage in market power abuse and also to ensure that markets within the Commission's jurisdiction are free of design flaws and market power abuse. To that end, the Commission will expect to receive the reports and analyses of a Regional Transmission Organization's market monitor at the same time they are submitted to the RTO.*[2]

This report presents the most important findings, market outcomes, and market design changes of New England's wholesale electricity markets for 2022. The executive summary gives an overview of the region's wholesale electricity market outcomes, the important market issues and our recommendations for addressing these issues. It also addresses the overall competitiveness of the markets, and market mitigation and market reform activities. Sections 1 through Section 8 include more detailed discussions of each of the markets, market results, analysis and recommendations. A list of acronyms and abbreviations is included at the back of the report.

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[1] *ISO New England Inc. Transmission, Markets, and Services Tariff* (ISO tariff), Section III.A.17.2.4, *Market Rule 1*, Appendix A, "Market Monitoring, Reporting, and Market Power Mitigation", http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_append_a.pdf.

[2] FERC, PJM Interconnection, L.L.C. et al., *Order Provisionally Granting RTO Status*, Docket No. RT01-2-000, 96 FERC ¶ 61, 061 (July 12, 2001).

A number of external and internal audits are also conducted each year to ensure that the ISO followed the approved market rules and procedures and to provide transparency to New England stakeholders. Further details of these audits can be found on the ISO website.[3]

All information and data presented are the most recent as of the time of writing. The data presented in this report are not intended to be of settlement quality and some of the underlying data used are subject to resettlement.

In case of a discrepancy between this report and the ISO New England Tariff or Procedures, the meaning of the Tariff and Procedures shall govern.

Underlying natural gas data are furnished by the Intercontinental Exchange (ICE):

Underlying oil and coal pricing data are furnished by Argus Media.

[3] See https://www.iso-ne.com/about/corporate-governance/financial-performance

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Executive Summary

The 2022 Annual Markets Report by the Internal Market Monitor (IMM) at ISO New England (ISO) addresses the development, operation, and performance of the wholesale electricity markets. The report presents an assessment of each market based on market data and performance criteria. In addition to buying and selling wholesale electricity day-ahead and in real time, the participants in the forward and real-time markets buy and sell operating reserve products, regulation service, financial transmission rights, and capacity. These markets are designed to ensure the competitive and efficient supply of electricity to meet the energy needs of the New England region and secure adequate resources required for the reliable operation of the power system.

To provide readers with additional background on our markets, this year, we have published a supporting document, "An Overview of New England's Wholesale Electricity Markets: A Market Primer". We expect that this document will be a useful in helping readers understand the fundamental concepts and mechanics of our markets.

In this executive summary, we provide an overview and assessment of key market trends, performance, and issues. We follow this with a consolidated list of recommended enhancements to the market design and rules from this and prior IMM reports.

The capacity, energy, and ancillary service markets performed well and exhibited competitive outcomes in 2022. The day-ahead and real-time energy prices reflected changes in underlying primary fuel prices, electricity demand and the region's supply mix.

We saw record high energy prices in 2022; the annual average day-ahead price of $86/MWh was almost 90% higher than last year, and was the highest since the market was implemented in 2003. We need to go back to the 2005 and 2008 to find comparable pricing levels, before the shale gas boom in the United States. Energy prices continued to be driven by the market price of natural gas, which at $9.32/MMBtu was more than double last year's price, and was the highest average price since 2008.

Natural gas prices were driven by a combination of market conditions and events at an international and national level, in addition to regional New England winter issues. The Russian-Ukrainian conflict exacerbated global uncertainty in natural gas inventories and prices, and caused a significant uptick in international demand for Liquefied Natural Gas (LNG). Prices at major trading hubs in the United States were higher due to international LNG demand and higher US demand. In New England, periods of sustained cold weather led to increased demand on a constrained pipeline system, and along with reduced injections from LNG terminals, resulted in very high gas and electricity prices during the first quarter of the year. Oil-fired generation made a more significant contribution to meeting the region's energy demand than recent years, by displacing natural gas generation and mitigating some of the energy price impacts on days with extremely high gas prices.

While no major reliability issues occurred in 2022, in late December, the region experienced only its second capacity scarcity condition in five years. This was due to lower imported energy and generator outages during bitterly cold weather conditions at the tail end of Winter Storm Elliott, which had a greater impact on other regions and markets, notably PJM. In this instance, the region was short of meeting its reserve requirement for about 1½ hours, but there was sufficient supply to meet system load. High real-time energy and reserve scarcity prices and capacity performance credits (peaking at over $6,300/MWh, combined) provided strong market signals and incentives for supply resources to respond and correct the deficit.

High–level market statistics for the five-year period covered in this report are presented below.

At a Glance: High-level Market Statistics

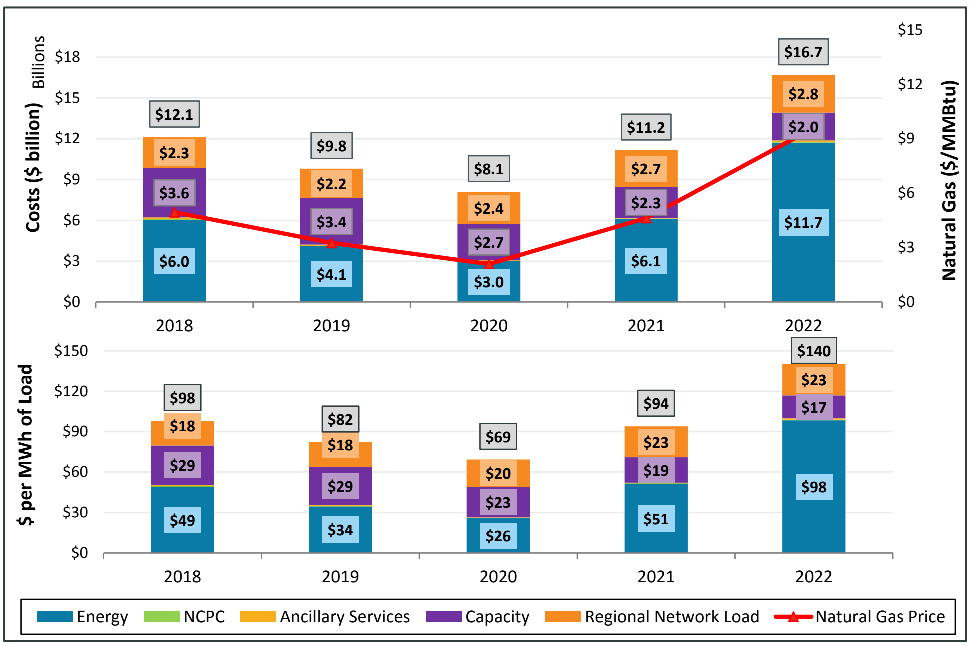
Demand (MW)	2018	2019	2020	2021	2022	% Change '22 to '21	Sparkline
Load (avg. hourly)	14,095	13,614	13,309	13,566	13,576	0%	
Weather-normalized load (avg. hourly)	13,725	13,558	13,279	13,419	13,472	0%	
Peak load (MW)	26,024	24,361	25,121	25,801	24,780	-4%	
Generation Fuel Costs ($/MWh) [b]							
Natural Gas	38.72	25.48	16.34	36.07	72.57	101%	
Coal	54.52	40.58	37.82	67.77	144.87	114%	
No.6 Oil	127.73	130.89	89.42	138.21	221.17	60%	
Diesel	187.55	173.55	112.07	184.50	331.99	80%	
Hub Electricity Prices: LMPs ($/MWh)							
Day-ahead (simple avg.)	44.14	31.22	23.31	45.92	85.56	86%	
Real-time (simple avg.)	43.54	30.67	23.37	44.84	84.92	89%	
Day-ahead (load-weighted avg.)	46.88	32.82	24.57	48.30	91.36	89%	
Real-time (load-weighted avg.)	46.85	32.32	24.79	47.34	91.07	92%	
Estimated Wholesale Costs ($ billions)							
Energy	6.0	4.1	3.0	6.1	11.7	92%	
Capacity	3.6	3.4	2.7	2.3	2.0	-11%	
Uplift (NCPC)	0.07	0.03	0.03	0.04	0.05	49%	
Ancillary Services	0.1	0.1	0.1	0.1	0.1	127%	
Regional Network Load Costs	2.3	2.2	2.4	2.7	2.8	2%	
Total Wholesale Costs	**12.1**	**9.8**	**8.1**	**11.2**	**16.7**	**49%**	
Supply Mix [c]							
Natural Gas	40%	39%	42%	45%	45%	0%	
Nuclear	25%	25%	22%	22%	23%	0%	
Imports	17%	19%	20%	16%	14%	-2%	
Hydro	7%	7%	7%	6%	6%	0%	
Other[d]	5%	5%	5%	5%	4%	-1%	
Wind	3%	3%	3%	3%	3%	0%	
Solar	1%	1%	2%	2%	3%	0.8%	
Coal	1%	0%	0%	0%	0.3%	-0.20%	
Oil	1%	0%	0%	0%	1.5%	1.34%	

[a] Weather-normalized results are those that would have been observed if the weather were the same as the long-term average. [b] Generation costs are calculated by multiplying the daily fuel price ($/MMBtu) by the average standard efficiency of generators for each fuel (MMBtu/MWh) [c] Capacity cost in 2022 includes the Mystic cost-of-service costs of $0.17 billion. [d] Provides a breakdown of total supply, which includes net imports. Note that section 2 provides a breakdown of native supply only. [e] The "Other" fuel category includes landfill gas, methane, refuse and steam ⇨ denotes change is within a band of +/- 1% Sparkline: Green = High Point, Red - Low Points

Energy costs drove an overall increase in wholesale costs due to high natural gas prices, comprising over two thirds of total costs

The total wholesale cost of electricity in 2022 was $16.7 billion, the equivalent of $140 per MWh of load served.[4] These costs were at their highest level over the last five years and were considerably higher than the 2021 total of $11.2 billion. This 50% increase (or $5.5 billion) was driven by higher energy costs. Also, with the exception of capacity costs (down by $0.22 billion), every other component of the wholesale cost of electricity increased in 2022.

Wholesale Costs ($ billions and $/MWh) and Average Natural Gas Prices



Energy costs continued to comprise the largest share of wholesale costs, at 70%, a significant jump from a 55% share in 2021. At their highest level since 2008, energy costs totaled $11.7 billion, up 92% (or $5.6 billion) on 2021 costs. With natural gas prices increasing by over 100% year-over-year, day-ahead LMPs averaged $86.56/MWh, up 86% (or by $40.64/MWh) on 2021. In addition, while there were increases in energy costs in each quarter, Quarter 1 (Q1) accounted for 32% of the total annual change. Q1 2022 saw the highest natural gas prices since Q1 2014, with gas generation costs exceeding $100/MWh on average. This resulted in an

[4] The wholesale cost of electricity comprises energy, uplift, ancillary services and transmission costs.

average day-ahead LMP of $115.23/MWh, also the highest since Q1 2014. This upward pressure on LMPs from natural gas prices was attenuated by more frequent in-merit oil generation than prior years.

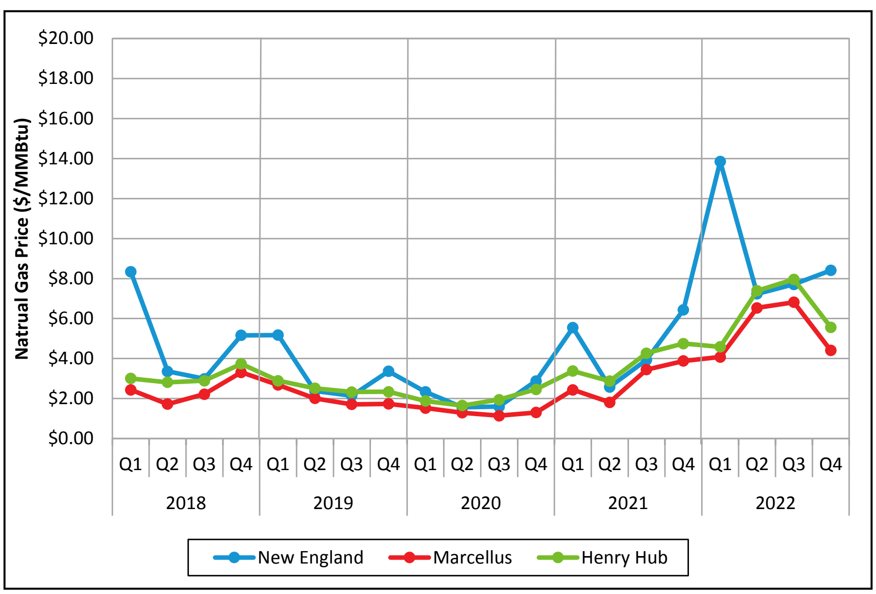
Net Commitment Period Compensation (NCPC), or uplift, costs remained relatively low at just $53 million, or 0.5% of total energy payments. There were few out-of-market commitments or dispatch decisions impacting NCPC. In fact, the vast majority of uplift (95%) uplift was paid to resources committed and dispatched in economic merit order, with the remaining 5% (just $1.1 million) required to meet the costs of out-of-merit reliability commitments. There were significantly fewer out-of-merit local reliability commitments needed to address impactful transmission outages.

Capacity, which comprised just 12% of total wholesale costs, continued to decline as the market maintains surplus capacity over the system's capacity requirement. Costs totaled $2 billion and were down by 10% (or $0.22 billion) on 2021. The costs were a function of lower combined clearing prices in the twelfth and thirteenth Forward Capacity Auctions (FCAs 12 and 13). When compared against 2021 capacity costs, lower auction clearing prices more than offset supplemental payments under the Cost of Service (CoS) agreement during 2022 for the Mystic 8 and 9 generators ($166 million in 2022) that began in summer 2022.

Natural gas prices drive high wholesale energy prices in New England

Natural gas prices in New England increased significantly in 2022, with an average price of $9.32/MMBtu, up from $4.62/MMBtu in 2021. This price increase was driven by local market conditions, New England's reliance on a constrained natural gas transmission system, and events at a national and international level, particularly the Russian-Ukrainian conflict.

New England vs. Henry Hub and Marcellus Natural Gas Prices



Prices at supply basins also increased, with Henry Hub averaging $6.38/MMBtu and Marcellus averaging $5.46/MMBtu. New England's natural gas traded at a premium of $2.94/MMBtu and $3.86MMBtu compared to Henry Hub and Marcellus, respectively. During Q1 2022, New England's natural gas price reached its highest quarterly price since 2014, at $13.86/MMBtu, due to decreased LNG injections and increased reliance on interstate pipeline gas. However, the highest daily natural gas prices of the year were in Q4. While the quarterly natural gas price averaged $8.41/MMBtu, a cold snap from December 24 to December 27 drove the average daily natural gas price to $35.37/MMBtu over the four days. These were the highest daily averages since Q4 2018.

The trend of decreasing load may have reached an inflection point

Net Energy for Load (NEL) averaged 13,576 MW per hour in 2022, which was comparable to 2021. On a weather-adjusted basis, load has been declining, which reflects the long-term trend of increased energy efficiency (EE) and, more recently, the adoption of behind-the-meter (BTM) solar generation. However, weather-normalized load increased slightly over the past two years. While it is difficult to attribute this directly to any particular driver, this change is consistent with the ISO forecast that average load will increase each year with the continued adoption of electricity-fueled transportation and electric heating.

In 2022, EE reduced weather-normalized annual average load by an estimated 2,538 MW (by 16%), which was a 2% decrease (40 MW) compared to 2021. This is in line with the ISO's expectation that EE will decline over time due to rising costs of eligible EE measures and the associated baselines used to calculate claimable savings. By contrast, BTM solar generation reduced weather-normalized load by 426 MW (by ~3%) which was a 15% increase (57 MW) compared to 2021, and is expected to continue this upward trend in future years.

Net interchange with neighboring control areas continued to decrease

In 2022, net interchange (or net imports) averaged 1,914 MWs per hour, an 11% (or 231 MW) decrease compared to 2021, and the lowest amount over the past five years. Net imports met just 14% of New England's electric demand, compared to up to 19% during the 2018-2020 period.

Net imports fell at the New York North and New Brunswick interfaces. At New York North, average net interchange decreased by 189 MW per hour compared to 2021 (401 MW vs. 590 MW). The retirement of the Indian Point nuclear generator in New York in April 2021 and increased planned transmission outages in New York led to increased congestion and higher energy prices relative to New England prices. At the New Brunswick interface, average net interchange decreased by 68 MW (228 MW vs. 296 MW) compared to 2021 due to the extended outage of a nuclear generator in New Brunswick, which has since returned to service.

Price formation is generally robust but we recommend a review of reserve pricing under the fast start pricing rules

Large volumes of unpriced (or fixed) supply can have important implications for pricing outcomes because it increases the likelihood of low or negative prices. We expect this impact to become more prevalent as additional capacity from renewable generation (e.g., wind, solar) with low marginal costs enter the energy markets. At present, we generally find that energy price formation is robust under current levels of unpriced supply. Further, as more low marginal cost generation participates in the wholesale market, we would expect to see a market response in terms of more price-responsive supply, particularly with more energy storage devices joining the market; otherwise, there is a higher risk of energy prices not covering short-run production costs.

The Fast Start Pricing rules in the real-time energy market are working as intended by better reflecting the production cost of fast-start generators in LMPs, and reducing uplift costs. However, we have observed frequent non-zero reserve pricing in scenarios when resources' dispatch instructions were not impacted by the reserve constraint and the system had a surplus of reserves.

Due to tradeoffs presented by the separation of the dispatch and pricing software, the ISO chose a pricing optimization methodology that minimizes false negatives (i.e., no reserve pricing when there is a physical reserve constraint binding) but allows false positives (i.e., reserve pricing when there is not a physical reserve constraint binding). This was an intentional decision when fast-start pricing was implemented, however, the frequency in which we have observed reserve pricing when there is not a physical reserve constraint binding has exceeded our expectations. In 2022 alone, $13.7 million in reserve payments were made when there was a reserve surplus (over half of the $26.9 million in total reserve payments during the year), despite dispatch being unaffected by the reserve constraint.

We recommend that the ISO revisits reserve pricing mechanics under fast-start pricing to address the frequency of non-zero reserve pricing when there is a physical reserve surplus.

Low levels of structural market power and mitigations in the energy market, but not in the Forward Reserve Auction

In 2022, the market concentration among the four largest firms controlling *supply* in the real-time market was in line with the values of the last five years, at 44%. There was an increase in the amount of time when structural market power was evident in real-time because of less reserve supply, leading to slightly lower total operating reserve margins. There was at least one pivotal supplier in a quarter of all hours. However, operating reserve margins remained relatively high on average compared to the underlying requirement, and mitigation remained relatively infrequent, which tempers any significant concerns regarding the exercise of market power.

Markups, which estimate the impact of above-cost bidding on clearing prices, were close to zero or negative in the real-time and day-ahead markets. In 2022, the quantity of withheld economic capacity was relatively low (below ~ 2%) and generally in line with levels seen in past years.

While the mitigation process for the energy markets has functioned reasonably well in recent years, we have identified a number of potential issues with the current rules that we recommend the ISO and stakeholders consider. For example, the current thresholds allow for considerable latitude in supply offer levels over competitive benchmarks (300% and 50%); these thresholds have been in place for many years with little empirical support. With the benefit today of a rich history of supply offer data and robust simulation tools to measure impact and incentives, an assessment should consider whether the current thresholds adequately limit the exercise of market power under a plausible set of system scenarios.

Another area of concern is with the structural competitiveness of the Forward Reserve Auction (FRA). Forward Reserve Market (FRM) auction prices for Ten Minute Non-Spinning Reserve (TMNSR) have frequently been below $2,000/MW-month over the last few years. However, the most recent auctions (Summer 2022 and Winter 2022-23) have seen increasing price levels and have not been structurally competitive. The Summer 2022 auction, in particular, had TMNSR prices of $7,386/MW-month, reflecting a significant increase in participant offer prices. While we reviewed participant offers in the Summer 2022 auction and did not find evidence of the exercise of market power, we remain concerned about the structural competitiveness of this auction and the lack of market power mitigation measures. We note, and support, the ISO's plans to sunset this market, coinciding with the implementation of day-ahead ancillary service in early 2025.

Low capacity costs continue as older fossil-fueled generators are replaced with renewable resources

Capacity market outcomes remained relatively constant in the past two auctions, driven by an unchanged FCA 16 and 17 (rest-of-pool) clearing price of $2.59/kW-month. Since FCA 10, capacity prices have decreased 63% ($4.44/kW-month) and Net ICR has decreased 11% (3,846 MW), resulting in a record low $0.9 billion in projected capacity payments for CCP 2026-2027. Prices are reflective of continued surplus supply conditions and recent reductions in the capacity requirement.

The capacity market has been structurally competitive at the system level over the past five auctions and competitiveness indices have further improved in the past two auctions due to reductions in NICR, along with the absence of major retirements. In FCA 17, Southeast New England (SENE) was not modelled as an import constrained zone due to a decrease in the zonal load forecast and an increase in the import capability limit into the zone. This also enhanced the overall structural competitiveness of the capacity market.

New entrants to New England have varied over the past seven auctions, with gas and energy efficiency resources making up a majority of new capacity additions from FCA 10-13. Since FCA 13, renewable technologies, typically sponsored-policy resources, have made up 56% of all new generator additions. Major retirements have comprised nuclear, oil-, and gas-fired resources, and an additional 1,100 MW of new gas-fired resources have been terminated since FCA 10 for failing to meet critical development milestones.

From FCA 10-16, the volume of cleared import capacity has fluctuated between 1,000 MW to 1,500 MW across the four external ties in the auction, with most capacity at the New York AC lines (50%) and Phase II (30%). However, cleared import capacity was down significantly in the most recent auction, FCA 17, at just 567 MW, comprising 390 MW at New York and 177 MW at New Brunswick. In FCA 17, we observed the largest percentage of import capacity de-listing (85%). Despite an import limit of 1,600 MW, import resources cleared at the lowest level over the five-year period; a key factor driving reduced import capacity is the expected value of capacity in the neighboring control area.

December 2022 saw the first Pay-for-Performance event since 2018. The December 2022 event lasted for 17 five-minute intervals and resulted in the transfer of $35.9 million from under-performing resources to over-performing resources. Import and nuclear resources received the most performance credits. While cold weather led to forced outages for some of the gas fleet, the leading cause of gas resource under-performance was high gas prices. Spot natural gas prices climbed to over $30/MMBtu, resulting in gas generation being pushed out of economic merit order and, instead, relatively cheaper oil generation was scheduled in the day-ahead energy market.[5] Once system conditions tightened in real-time and system-wide LMPs

[5] More information on fuel prices in Q4 2022 can be found in Section 1.2.2.

increased significantly, operating limitations prevented many gas-fired resources from coming online in time to contribute to meeting the load and reserve requirement.

IMM Market Enhancement Recommendations

One of the IMM's key functions is to recommend rule changes to enhance the performance of the markets. In practice, we communicate our recommendations through our reports, particularly our quarterly markets performance reports, and through comments filed with FERC on proposed rules changes.

The table below summarizes the IMM's recommended market enhancements, first showing issues with an "open" status, followed by recently closed issues. Recommendations included in this report for the first time are identified as "*NEW*". A hyperlink is provided to the document in which the recommendation was first put forward, along with the IMM's priority ranking of each recommendation.

The priority ranking (High, Medium or Low) considers the potential market efficiency gains, as well as the potential complexity and cost of implementing each recommendation. High priority recommendations may deliver significant market efficiency gains, with the benefit outweighing the cost of implementing them. At the other end of the scale, low priority recommendations are not intended to indicate low importance, but rather issues which may not have as significant long-term efficiency gains (compared to high priority recommendations) and/or may be very costly to implement.

ID	Recommendation	When made	Status	Priority Ranking
2023-1	****NEW* Review energy mitigation thresholds and reference level methodologies, eliminate mitigation exemptions for non-capacity resources, and extend mitigation to export-constrained area.*** Market power mitigation rules need to strike a reasonable balance between producer and consumer interests, and in turn prescribe adequate threshold tests to determine when market monitors override generators supply offers. The IMM has identified a number of potential rule improvements to better serve the mitigation function. 1. Review of the current energy mitigation thresholds that apply to instances of system-wide and local market power. The current thresholds allow for considerable latitude in supply offers levels over competitive benchmarks (300% and 50%) and have been in place for many years with little empirical support. 2. Eliminate the energy offer mitigation exemption for non-capacity resources in the day-ahead energy market. 3. Extend the scope of offer mitigation to cover the potential exercise of market power in export-constrained areas. 4. Review the methodologies for determining reference levels, which are used to evaluate if	2022 AMR	New Recommendation – the IMM will work with the ISO to assess the implementation requirements for this project.	Medium

ID	Recommendation	When made	Status	Priority Ranking
	an offer is competitive (the "conduct test"). Currently, reference levels can be based on marginal cost, or historical fuel-adjusted accepted supply offers or LMPs. We have observed instances in which the latter two methodologies produce unreasonably high reference levels.			
2023-2	****NEW* Review reserve pricing mechanics under fast-start pricing.*** Under current fast-start pricing rules, we have observed frequent non-zero reserve pricing in scenarios when resources' dispatch instructions were not impacted by the reserve constraint and the system had a surplus of reserves. Due to tradeoffs presented by the separation of the dispatch and pricing software, the ISO chose a pricing optimization methodology that minimizes false negatives (no reserve pricing when there is a physical reserve constraint binding) but allows false positives (reserve pricing when there is not a physical reserve constraint binding). This was an intentional decision when fast-start pricing was implemented, however, the frequency in which we have observed reserve pricing when there is not a physical reserve constraint binding has exceeded the frequency in which we expected these scenarios to occur, and the cost of reserve payments in these intervals warrants additional consideration of other solutions.	2022 AMR	IMM and ISO to assess the implementation requirements for this project.	Medium
2022-1	***Incentive rebuttal component of proposed Buyer-side Mitigation Rules.*** The ISO's proposed buyer-side mitigation rules will allow a Project Sponsor to demonstrate a lack of incentive through a Net Benefits Test to avoid mitigation of a below-cost supply offer from certain resources. The IMM has recommended that removing the incentive rebuttal provision from the proposal would make the buyer-side mitigation review more predictable and capable of being administered more reliably and with less subjectivity.	Filed Comments with FERC on MOPR Elimination and Buyer-side Mitigation Rules (Apr 2022)	The ISO /NEPOOL proposal was approved by FERC. The IMM will keep this recommendation under review, which will be informed by implementation experience.	Medium
2021-1	**Develop Offer Review Trigger Price (ORTP) for co-located solar/battery facilities** Under the current rules, the ORTP for a co-located battery and solar project is based on the weighted average of the individual technologies. This results in a value that is below the true "missing money" for the combined resource, allowing such resources to offer in at prices below competitive levels	Filed Comments with FERC on ORTP Recalculation (Apr 2021	The value of this recommendation is low in the context of the elimination of MOPR in FCA 19. The IMM will reassess this recommendation pending the outcome of the MOPR elimination proposal.	Low

ID	Recommendation	When made	Status	Priority Ranking
	without review and mitigation, and undermining the protections put in place by the minimum offer price rule (MOPR). In our opinion, a bottom-up calculation is preferable because it accurately represents the constraints that co-located solar/battery facilities face and results in a more precise cost estimate.			
2020-1	***Reference level flexibility for multi-stage generation*** Given that recommendation 2017-1 below is not part of the ISO's work plan, and is unlikely to be developed for some time, we recommend related changes that could be made to the market power mitigation function in the meantime. We believe these changes will be less resource-intensive and complex to adopt, compared to incorporating multi-stage generation modeling into the day-ahead and real-time market and systems software. However, it is not a replacement of the above recommendation. The recommendation is to provide generators with the ability to dynamically select their active or planned configuration and to adjust reference levels to be consistent with their operating costs and their supply offers. This will address the current risk of false positive and negative errors in mitigation, given the potentially high costs differences between configurations. It may also eliminate a potential deterrent to generators from offering configurations to avoid the risk of mitigation, which may ultimately be more cost effective to consumers.	Winter 2020 QMR (May 2020)	Not in the scope of the ISO's current work plan.	Medium
2018-1	***Unoffered Winter Capacity in the FCM*** The IMM is concerned that generators may be contracting at, or close to, their maximum capacity (i.e., their winter qualified capacity), as determined by the ISO, even though that capacity is not deliverable in certain months given expected ambient temperatures. The IMM recommends that the ISO review its existing qualification rules to address the disconnect between the determination of qualified capacity for two broad time horizons (summer and winter), the ability of the generators to transact on a monthly basis, and the fluctuations in output capability based on ambient conditions. A possible solution would be for the ISO to develop more granular (e.g., monthly) ambient temperature-adjusted qualified capacity values, based on forecasted temperatures and the existing output/temperature curves that the ISO currently has for each generator.	Fall 2018 QMR (Mar 2019)	While this recommendation remains open it may need to be reviewed by the IMM in the context of the design effort to revise the methodology for calculating qualified capacity (the resource capacity accreditation project).	Medium

ID	Recommendation	When made	Status	Priority Ranking
2017-1	***Treatment of multi-stage generation*** Due to the ISO's current modeling limitations, multi-stage generator commitments can result in additional NCPC payments and suppressed energy prices. This issue was first raised by the external market monitor, Potomac Economics. [1]The IMM recommends that the ISO consider improvements to its current approach to multi-stage generator modeling. Two possible options are: a. Expanding the current pseudo-combined cycle (PCC) rules- Consider whether to make PCC rules a mandatory requirement for multi-stage generators through proposed rule changes, or b. Adopt multi-configuration resource modeling capability- More dynamic approach to modeling operational constraints and costs of multiple configurations.	Fall 2017 QMR (Feb 2018)	Not in the scope of the ISO's current work plan.	Medium
2016-1	***Improving price forecasting for Coordinated Transaction Scheduling (CTS):*** There is a consistent bias in the ISO's internal price forecast at the New York North interface, which may reduce the effectiveness of CTS. To date, biases in ISO-NE and NYISO forecasts have been in opposite directions, which increase the price spread between the markets relative to actual spreads, and may produce inefficient tie schedules. ISO-NE should assess the causes of biases in the price forecast and assess how the accuracy of the forecast can be improved. ISO-NE should periodically report on the accuracy of its price forecast at the NYISO interface, as well as the differences between the ISO-NE and NYISO price forecasts.	2016 AMR (May 2017)	The IMM will continue to assess and report on the price forecasting issue. The ISO is also periodically reporting on the forecast accuracy. Future improvements are not in the scope of the ISO's current work plan.	High
2016-2	***Analyzing the effectiveness of Coordinated Transaction Scheduling***: ISO-NE should implement a process to routinely access the NYISO internal supply curve data that is used in the CTS scheduling process. This data is an important input into the assessment of the cost of under-utilization and counterintuitive flows across the CTS interface.	2016 AMR (May 2017)	Related to the item above (Improving price forecasting for CTS). Not in the scope of the ISO's current work plan.	Medium
2015-1	***Corporate relationships among market participants:*** The ISO develop and maintain a database of corporate relationships and asset control that allows for accurate portfolio construction for the purpose of identifying uncompetitive participation, including the potential exercise of market power and market manipulation.	Q2 2015 QMR (Oct 2015)	The project is not in the scope of the ISO's current work plan. The IMM will continue to rely on a combination of internal data and its own market research to satisfy its monitoring needs.	Medium
2015-3	***Pivotal supplier test calculations:*** The ISO, working in conjunction with the IMM, enhance the real-time energy market mitigation pivotal supplier test to include (1) ramp-based accounting of supply recognizing the differences between energy and reserve products and (2) participant affiliations.	2015 AMR (May 2016)	IMM and ISO to assess the implementation requirements for this project.	Medium

ID	Recommendation	When made	Status	Priority Ranking
2015-2	***Forward reserve market and energy market mitigation:*** The ISO develop and implement processes and mechanisms to resolve the market power concerns associated with exempting all or a portion of a forward reserve resource's energy supply offer from energy market mitigation.	Q2 2015 QMR (Oct 2015)	The IMM will evaluate revising or eliminating mitigation exemptions for FRM resources to resolve the market power issues. [The ISO is proposing to sunset the FRM with the implementation of DASI in Q1 2025]	Low
2013-1	***Limited energy generator rules:*** The ISO modify the market rules as necessary to ensure that the use of the limited-energy generator (LEG) provisions in both the day-ahead and real-time markets are restricted to instances when the availability of fuel is physically limited.	2013 AMR (May 2014)	Further analysis required by the ISO to assess whether specific rule or procedure improvements are appropriate. The IMM will continue to monitor the use of the limited-energy generation provision and address any inappropriate use on a case-by-case basis.	Low
2010-1	***NCPC charges to virtual transactions:*** The ISO develop and implement processes and mechanisms to reduce NCPC charges to virtual transactions (to better reflect the NCPC cost causation principle) in response to the historical decline in virtual trading activity. A reduction in NCPC charges to virtual transactions will likely improve day-ahead scheduling by adjusting expectations of real-time conditions.	2010 AMR (Jun 2011)	The ISO had planned to review this issue as part of the conforming changes related to the Energy Security Improvements Project.	Medium

Section 1
Overall Market Conditions

This section provides an overview of the key trends in the wholesale markets. It covers the underlying supply and demand conditions behind those trends, and provides important context to the market outcomes discussed in more detail in subsequent sections of this report.

1.1 Wholesale Cost of Electricity

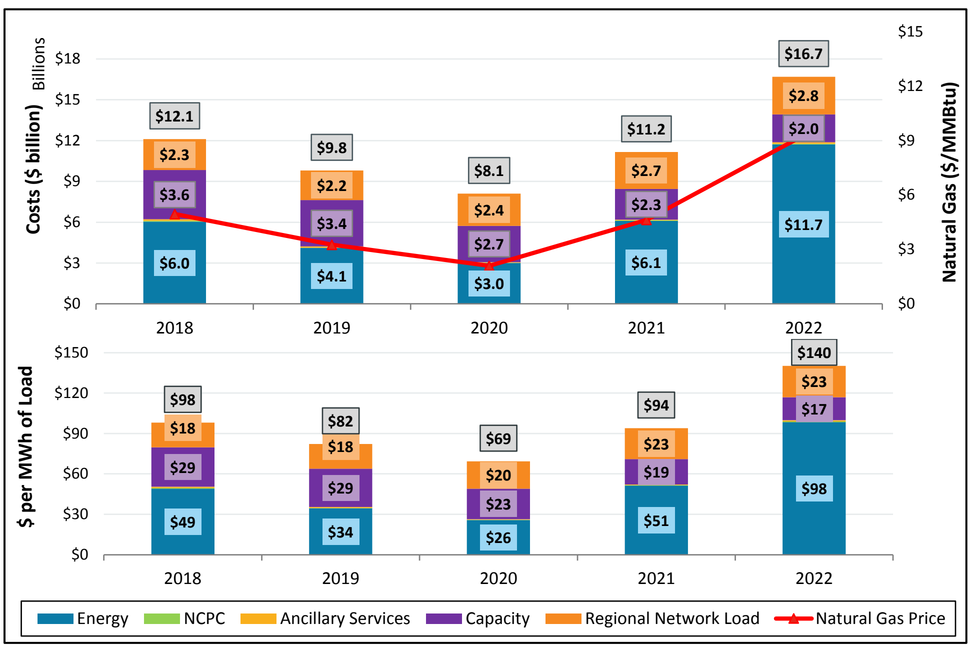
This section provides a high-level overview of wholesale electricity costs over the past five years, focusing on the significant factors that influenced changes in different cost categories, particularly the fluctuations in the natural gas prices.

Key Takeaways

In 2022, the wholesale market cost of electricity totaled $16.7 billion, an increase of $5.5 billion (or 50%) compared to 2021 costs ($11.2 billion). The increase was largely due to higher energy costs, which were close to record levels, driven by higher natural gas prices. Natural gas prices rose by about 100% between 2021 ($4.62/MMBtu) and 2022 ($9.28/MMBtu). Natural gas-fired generators continued to be the single largest resource type in terms of installed capacity and energy output, making up 52% of total native generation. As such, natural gas prices continued to be the primary driver of energy, ancillary services and NCPC costs.

The relationship between wholesale electricity costs and the price of natural gas is evident in Figure 1-1 below. This figure shows the breakdown of the wholesale costs of electricity over the past five years, along with average natural gas prices.

Figure 1-1: Wholesale Costs ($ billions and $/MWh) and Average Natural Gas Prices



Energy costs are incurred by market participants with load obligations (typically Load Serving Entities or LSEs) in the day-ahead and real-time energy markets. This component accounted for the largest share of wholesale electricity costs in each of the past five years. It comprised more than 70% of total costs in 2022, its highest share over this time.

Energy costs totaled $11.7 billion, the highest total since 2008 ($12.0 billion). Energy costs increased substantially, by $5.6 billion, or 92%, compared to the 2021 total of $6.1 billion. Natural gas prices more than doubled, rising to $9.28/MMBtu (up by 101%) and were the primary driver of the change in energy costs.[6] However, the upward pressure of natural gas on energy costs was attenuated by relatively cheaper oil prices during winter cold spells, particularly at the end of the year. This is the primary reason that the energy cost increase was slightly lower than the gas price change. Oil-fired generators set price for a larger share of electricity demand in 2022 compared to 2021 (4% vs. 1%).[7]

Regional network load (RNL) costs, or transmission costs, includes transmission owners' recovery of infrastructure investments, maintenance, operating, and reliability costs. This accounted for a large share (17%) of total costs in 2022. Transmission and reliability costs were $2.8 billion in 2022, $46 million (2%) more than 2021 costs. The change was due to a slight increase in infrastructure costs, which make up the majority (around 95%) of RNL costs.[8]

Capacity costs comprise payments to supply resources in the Forward Capacity Market, and accounted for 12% of wholesale costs in 2022, decreasing by 10%, or $0.22 billion.[9] Lower auction clearing prices in FCA 12 (2021/22) and FCA 13 (2022/23) more than offset supplemental payments under the Cost of Service (CoS) agreement for the Mystic 8 and 9 generators ($166 million in 2022) that began in Summer 2022. Capacity clearing prices peaked in FCA 9 (2018/19) at $9.55/kW-month, and have since declined in each subsequent auction through FCA 14 (2023/24). Clearing prices in FCA 12 ($4.63/kW-month) reflected lower installed capacity requirements and increased surplus due to new entry. In FCA 13, the clearing price ($3.80/kW-month) decreased further due to a large influx of lower-priced, new capacity displacing higher-priced existing capacity.

Ancillary service costs include payment to supply resources for providing operating reserves and regulation services, and totaled $123 million in 2022, $69 million more than 2021 costs.

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[6] Unless otherwise stated, the natural gas prices shown in this report are based on the weighted average of the Intercontinental Exchange next-day index values for the following trading hubs: Algonquin Citygates, Algonquin Non-G, Portland, Tennessee gas pipeline Z6-200L, Tennessee North gas, Tennessee South gas, and Maritimes and Northeast. Next-day implies trading today (D) for delivery during tomorrow's gas day (D+1). The gas day runs from hour ending 11 on D+1 through hour ending 10 on D+2.

[7] The highest daily average natural gas prices of 2022 occurred at the end of the year, and oil-fired generators were frequently in merit from December 23 to December 29. If we exclude these dates from the annual gas price average, we see a 93% increase in gas prices, which is in line with the 92% increase in energy prices.

[8] The annual figure is the sum of the monthly Total RNL Costs as reported in the ISO's Monthly Regional Network Load Cost Reports, available at: https://www.iso-ne.com/markets-operations/market-performance/load-costs/

[9] In 2022, capacity costs also include supplemental payments under the Cost of Service Agreement to the Mystic 8 and 9 generators, which were retained for their fuel security attributed for power years 2022/23 and 2023/24. Supplemental payments are in addition to base FCM payments at the auction clearing prices.

Both reserve and regulation costs increased in 2022 primarily due to the increase in energy prices (which, in general, increased the opportunity costs of providing these products).[10]

Net Commitment Period Compensation (NCPC costs, or uplift, covers supply resource productions costs not recovered through energy prices. NCPC totaled $53 million in 2022, an increase of 49% compared to $35 million in 2021. NCPC costs comprised a small component of total energy costs at just 0.5%. Higher payments to resources committed in economic merit (up $23.2 million) were offset by fewer local reliability commitments and payments (down by $5.7 million). The increase in economic payments was in-line with higher production costs associated with higher gas prices.

1.2 Supply Conditions

This section provides a macro-level view of supply conditions across the wholesale electricity markets and describes how conditions have changed over the past five years. The first subsection (1.2.1) covers the New England generation mix, the second subsection (1.2.2) covers fuel and emissions market prices, and the third subsection (1.2.3) provides estimates of generator profitability.

Key Takeaways

Natural gas generation continued to account for the largest share (52%) of native electricity generation, twice as much as the second largest fuel type (nuclear). In 2022, natural gas prices averaged $9.32/MMBtu, moving upward from the record lows in 2021. A large factor for this increase was the start of the conflict between Russia and Ukraine, which exacerbated global uncertainty in natural gas inventories and prices.

These higher natural gas prices led to larger spark spreads, which drove a significant increase in gas-fired generators' net revenues in 2022. While oil prices also saw year-over-year increases, oil generation increased in 2022 as it displaced some gas generation during times of elevated gas prices (e.g., Winter 2022). Emissions costs were relatively low compared to fuel costs in 2022 (less than 10%), but these costs have grown in recent years.

1.2.1 Generation and Capacity Mix

An overview of New England's *native* generation and capacity mix by fuel type, location, and age, is presented below.[11] The composition of the system supply portfolio provides context to the relationship between fuel and wholesale prices, as well as emerging operational challenges.

In 2022, there was slightly more wholesale solar (increased installed capacity) and oil generation (generation during the winter and peak summer hours) compared to 2021. Nuclear

[10] The ancillary services total presented here does not include blackstart and voltage costs. Those costs are included in the RNL category. The costs of the winter reliability program are included in the 2018 total; this program ended in February 2018.

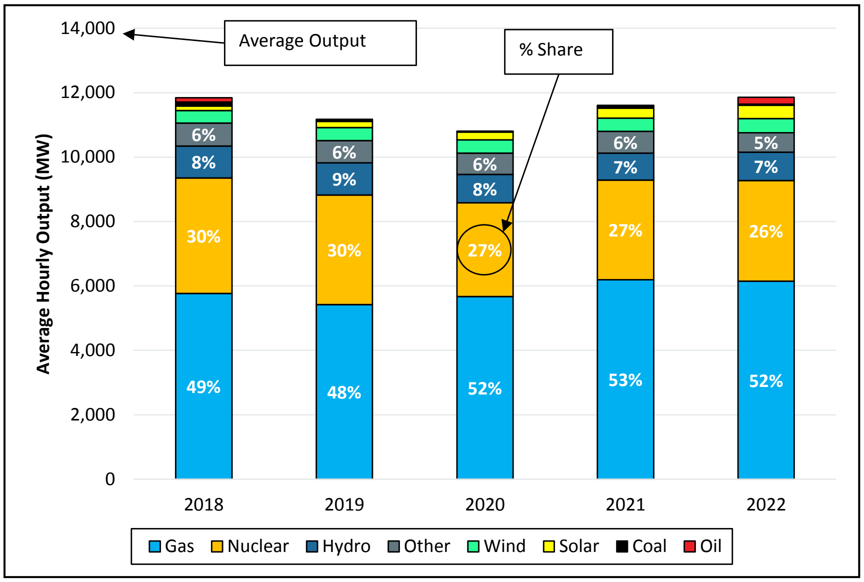
[11] Section 1.2.1 focuses on native generation. Section 5 provides an explanation of interchange between New England and the bordering control areas.

and gas-fired generation displayed the highest capacity factors in 2022, emphasizing the region's high utilization of, and dependence on, these two fuels for electricity production.

Average Generator Output by Fuel Type

Energy production by fuel type has exhibited minor changes on average as illustrated in Figure 1-2 below. The chart shows a breakdown of hourly average native generation (in MW per hour) by fuel type, along with percent share of each fuel.

Figure 1-2: Average Output and Share of Native Electricity Generation by Fuel Type



Native generation increased slightly in 2022 (by 249 MW compared to 2021), balancing out a reduction in net imports, which decreased by 231 MW, primarily at the New York North interface (see Section 1.4 for more detail). Natural gas generation continued to account for the largest share (52%) of native electricity generation, twice as much as the second largest fuel type (nuclear).

There was a relatively significant increase in oil generation in 2022 compared to prior years, producing 211 MW per hour compared to 26 MW per hour in 2021. The largest increase occurred during cold winter days, when higher gas prices meant oil-fired generators (including dual-fuel generators) were more frequently in economic merit relative to gas-fired generators. To a lesser extent, fast-start oil generators operated more often on summer days in 2022 with high loads and tight system conditions.

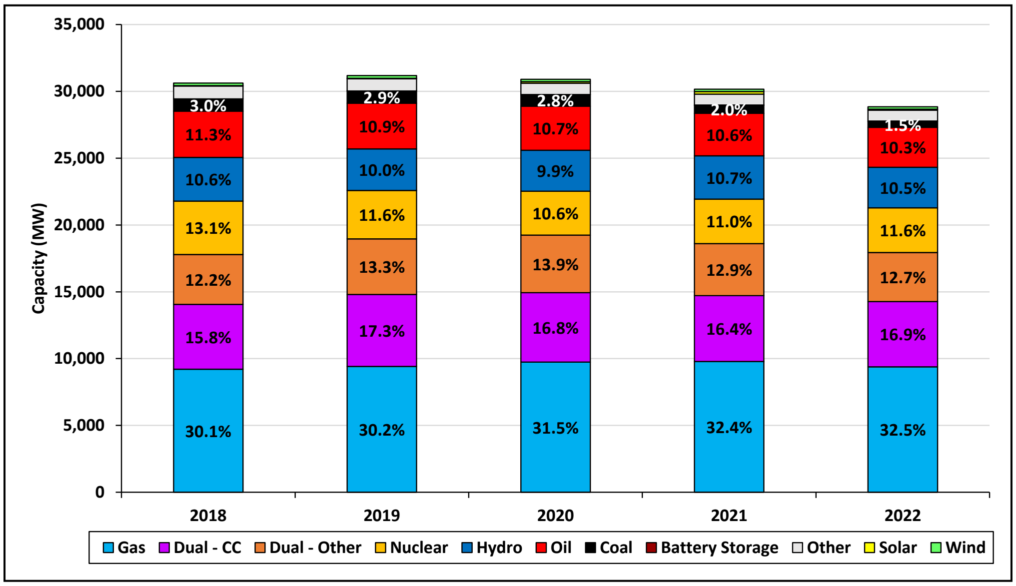
While the share of native generation is small (roughly equivalent to hydro generation), solar and wind production remain a key focus of energy policies impacting New England's energy footprint. State and federal policies have driven additional wholesale (front-of the-meter) solar energy production and wind energy production.[12] Solar and wind accounted for 4% of native generation in 2018 and increased each year, up to 7% in 2022.

[12] Section 1.3.1 discusses the impact of solar generation on load from both behind- and front-of-the-meter solar.

Capacity by Fuel Type

Capacity by generator fuel type in Figure 1-3 below shows the breakdown of total capacity under contract in the FCM. Total capacity is significantly higher than actual generation and demand due to the need to have sufficient operating reserves to account for uncertainty in supply availability.[13,14]

Figure 1-3: Average Capacity by Fuel Type



In total, average capacity in New England decreased 4% year-over-year, from 30,200 MW in 2021 to 28,900 MW in 2022, driven by steady decreases in the demand for capacity; the net installed capacity requirement (Net ICR).

No single fuel type saw a significant change in capacity share in 2022. Natural gas generation continues to make up the most capacity of any fuel source. Combined, gas-fired and dual-fuel (oil/gas-fired) generators accounted for over 62% (about 18,000 MW) of total average generator capacity in 2022. Coal resources have seen a steady decline in capacity share due to the retirement of Bridgeport Harbor 3 in June 2021 (383 MW).

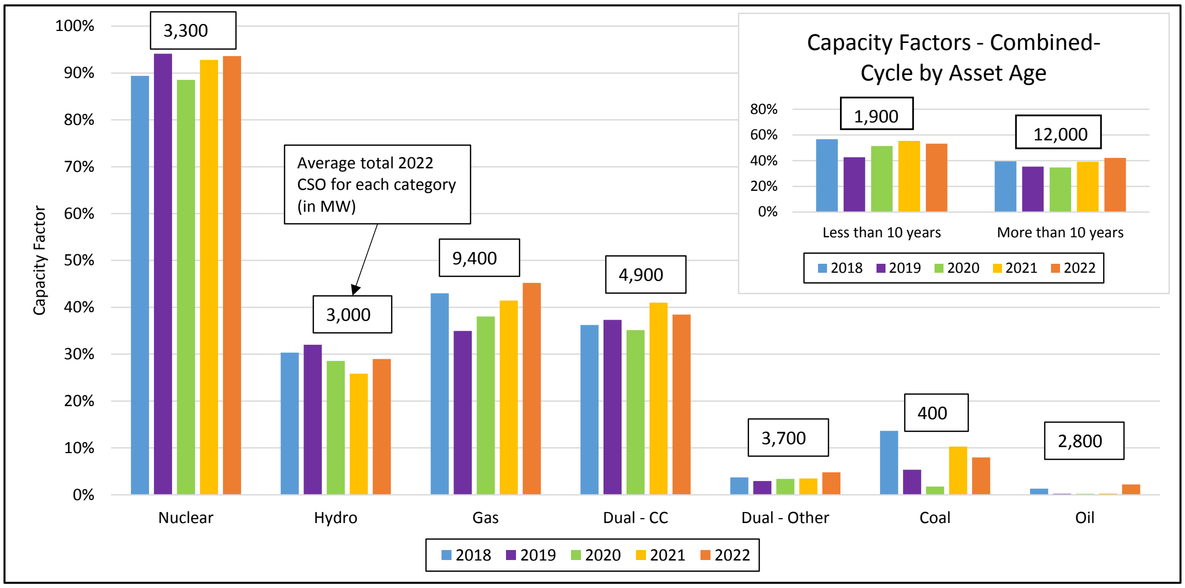
[13] The underlying data to determine resource fuel type changed in the 2019 AMR. The change was reflected across all five years. With this change, more resources were identified as dual-fuel. This shifted resources out of the gas category into the dual-fuel category. Additional, this AMR introduced two new categories for dual-fuel generators: combined-cycle (CC) and other.

[14] Coal category includes generators capable of burning coal and dual-fuel generators capable of burning coal and oil. "Other" category includes active capacity demand response, landfill gas, methane, refuse, solar, battery storage, steam, and wood.

Capacity Factors

A capacity factor is the percentage of a generator's capacity being utilized and is calculated as the ratio of a resource type's average hourly output over their total capacity supply obligation (CSO).[15] The individual capacity factors are aggregated by fuel type and shown in Figure 1-4 below.

Figure 1-4: Capacity Factor by Fuel Type



In 2022, nuclear generators and gas-fired generators saw modest increases to their capacity factors. Nuclear generation capacity continued to be the most utilized generation source, generally producing at their maximum output when available. Gas-only generators saw the largest increase in capacity factors year-over-year, up from 41% in 2021 to 45% in 2022, making up for flower net imports.[16] The inset graph shows capacity factors for combined-cycle (CC) gas-fired generators categorized by age tranche. As expected, newer and more efficient CCs have a higher capacity factor. Most system capacity is in the 10+ year category, which saw a slight increase in overall utilization in 2022.

Since 2020, increases in the average natural gas price has made oil and coal generation more economic in New England. While coal-fired generator capacity comprises a very small proportion of total system capacity, there was a modest increase in their capacity factors in 2022, up from 1% in 2020 to 8% in 2021 and 2022. Oil-fired generators provided the lowest capacity factor at 2%, but their production increased significantly year-over-year, from an hourly average of 8 MW in 2021 to 65 MW in 2022.

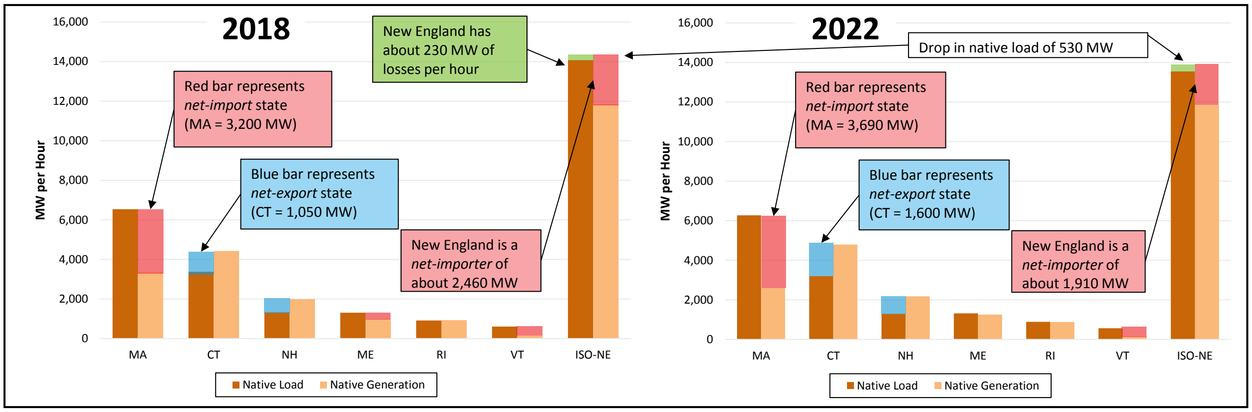
[15] The methodology for capacity factor calculation changed for this AMR. The capacity factor is now calculated as the ratio of average hourly MW production over the average hourly CSO, aggregated by fuel type. For example, if there was an hourly average of 5,000 MW of gas generation for a given year with an average gas resource CSO of 10,000 MW, the yearly capacity factor for the fuel type would equal 50%. The new methodology includes production MWs from resources without an active CSO.

[16] More information on net import trends in New England can be found in Section 1.4.

Generation by State

A breakdown of energy production and consumption within each state and aggregated across the ISO-NE market is shown in Figure 1-5 below.[17] Darker shaded bars show state load, while lighter shaded bars show state generation. The red and blue bars simply show the difference between production and consumption; the red bars illustrate net imports into each state, and the blue bars net exports out of the state.[18,19]

Figure 1-5: Average Native Electricity Generation and Load by State[20]



Given their larger populations, Massachusetts and Connecticut are the largest consumers and producers of electricity within the six-state footprint. *Massachusetts*, the state with the most load, consumed an average of 3,690 MW per hour more than it generated in 2022, up from 3,200 MW per hour in 2018. The gap between load and generation was driven by a decrease in generation from two existing combined-cycle generators due to relatively expensive fuel input costs. *Connecticut* generated an average of 1,600 MW per hour more than it consumed in 2022, up from 1,050 MW per hour in 2018. New gas-fired generators built in Connecticut over the past five years accounted for the majority of new generation in the state.

The total ISO-NE bar summarizes two key trends. First, average native load in New England fell by 530 MW per hour compared to 2018. This is largely due to the impact of energy efficiency and behind-the-meter solar generation, which are discussed in Section 1.3.1 below. Second, New England continues to be a net importer of power, although its reliance on imports fell. In 2022, 14% (or 1,910 MW per hour) of New England's electricity demand was met by energy imported from neighboring jurisdictions. This was the lowest level of net imports over the five-year period; more detail on this trend is provided in Section 1.4 below.

[17] The state breakdown shows native energy production and consumption within each state; it does not include imports into the state from neighboring jurisdictions

[18] The green bar for ISO-NE illustrates losses as energy flows through the system.

[19] Net imports in this context are not necessarily from neighboring jurisdictions outside of New England (New York or Canada), but refer to any imports from outside the state.

[20] Note: MW values are rounded to the nearest 10 MW.

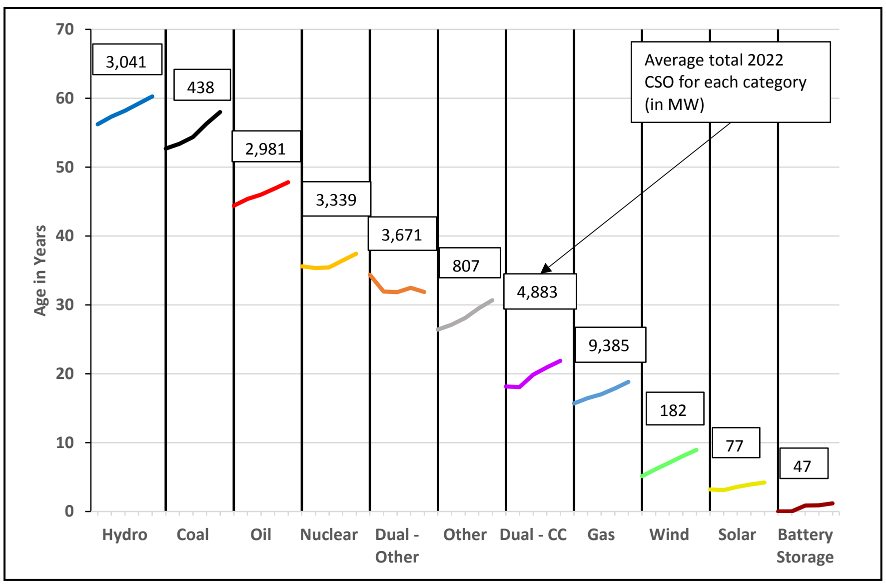
Average Age of Generators by Fuel Type

The age profile of the generation fleet in New England captures how the supply mix is evolving and can be indicative of potential changes in the future. As generators age, they require increased maintenance and upgrades to remain operational, thereby increasing costs. Older coal- and oil-fired generators in New England also face other market dynamics, including higher compliance costs associated with public policies intended to reduce greenhouse gas emissions.

Compared with coal- and oil-fired generators, new natural gas-fired generators are cleaner, more efficient, and generally have lower fuel and emission costs. As a result, recent investments have been in new natural gas-fired generators, wind turbines, and solar panels. Most retirements include older nuclear, coal- and oil-fired generators.

The average age, in years, of New England's generation fleet is illustrated in Figure 1-6 below.[21] If there were no retirements or new generation, we would expect each colored line to increase by one year as generators age. Either an influx of new generators or a retirement of old generators can cause a decline in average age. Data labels above the bars show average total FCM capacity in 2022 by fuel type.

Figure 1-6: Average Age of New England Generator Capacity by Fuel Type (2018 - 2022)[22]



The average age of New England's generators in 2022 ranged from one and a half years (battery storage) to 60 years (hydro), with a weighted-average total system age of 37 years. Oil generation comprises most capacity considered by the ISO to be "at risk of retirement", with an average age approaching 50 years.[23] Oil generation plays an important role in the supply mix during winter cold spells when natural gas is priced high and pipeline capacity is limited.

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[21] Age is determined based on the generator's first day of commercial operation. The values are weighted by the max net output for each generator within the fuel type.

[22] The "Other" category includes landfill gas, methane, refuse, steam, and wood.

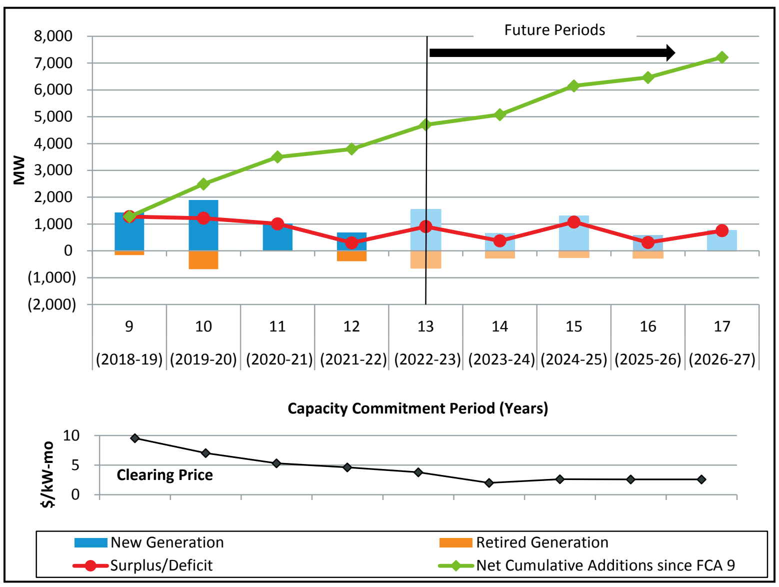
[23] For an overview of generator retirements see https://www.iso-ne.com/about/what-we-do/in-depth/power-plant-retirements#:~:text=More%20than%205%2C200%20MW%20of,be%20retiring%20in%20coming%20years.

Wind, solar, and battery storage remain the newest generation fuel types; all three groups of generators had an average age below 10 years. These technology or fuel categories will comprise an increasing share of supply over the coming years, playing a big part in meeting the states' decarbonization goals.

Generation Additions and Retirements

Generator additions and retirements in each Forward Capacity Auction (FCA), beginning with Capacity Commitment Period 9 (CCP 9, 2018/19) are shown in Figure 1-7 below. Future periods are years for which the FCA has taken place, but the capacity has yet to be delivered or retired. The FCA clearing prices (for existing rest-of-system resources) are also shown for further context.

Figure 1-7: Generator Additions, Retirements, and FCM Outcomes



In the past eight primary auctions, capacity additions from new generation (9,906 MW) have significantly outpaced capacity withdrawals (2,690 MW) from retiring generation. Cumulative net additions to capacity have reached 7,215 MW since FCA 9.

While the surplus amounts (red line) fluctuate between commitment periods, the additions of cheaper, more efficient new capacity, as well as limited retirements continue, to drive down clearing prices. In FCA 17, new generation increased significantly year-over-year; the largest types of new capacity consisted of battery storage projects (400 MW) and solar projects (124 MW).

Existing generation nearing the end of their economic life, and facing high environmental costs, is incentivized to retire when the capacity price (and associated revenue) falls below their net going forward costs. However, retirements were quite low in the recent auction, FCA 17, totaling just 22 MW, a 244 MW (91%) decrease from FCA 16.

It is important to note that a significant amount of existing and new gas capacity was removed from the capacity market, which is not reflected in the above graph. This totaled over 2,500 MW, effectively reducing the actual net capacity additions since FCA 9 to 4,685 MW. First, the retirement of Mystic 8 and 9 (1,413 MW) was suspended in FCA 13 as the ISO retained the units for reliability for two years.[24] Second, two large gas resources, Burrillville Energy Center (485 MW) and Killingly Energy Center (632 MW), had their capacity supply obligations (CSOs) terminated in FCA 10 and 13, respectively.[25]

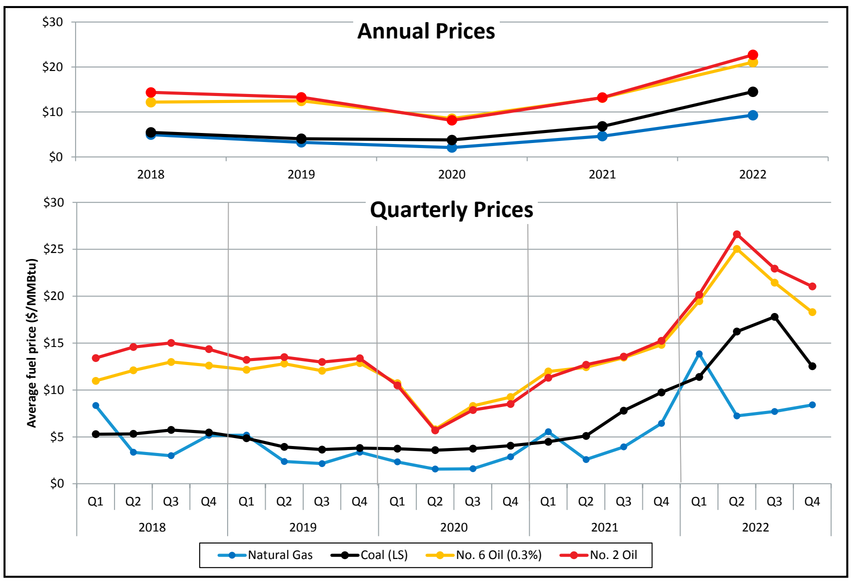
1.2.2 Generation Fuel and Emissions Costs

Input fuel costs and combustion engines' operating efficiencies are major drivers of electricity prices. In 2022, average prices increased for all major fossil fuels as follows:

- Natural gas: $9.28/MMBtu (up 101%)
- No. 2 oil: $22.69/MMBtu (up 72%)
- No. 6 oil: $21.06/MMBtu (up 60%)
- Coal: $14.50/MMBtu (up 113%).

The annual (top) and quarterly (bottom) trends in fuel prices are shown in Figure 1-8 below.

Figure 1-8: Average Fuel Prices by Quarter and Year



[24] The delayed retirement of the two resources was not captured in FCA 15 retirement data as the resources never entered the auction. More information on the Mystic 8 and 9 retention can be found in Section 6.2.1.

[25] The terminated resources appeared as new capacity in the FCAs they clear in, but did not appear as FCA retirements post-termination as they were not qualified to participate in any more primary auctions. More information on the Burrillville Energy Center and Killingly Energy Center terminations can be found in Section 6.2.2.

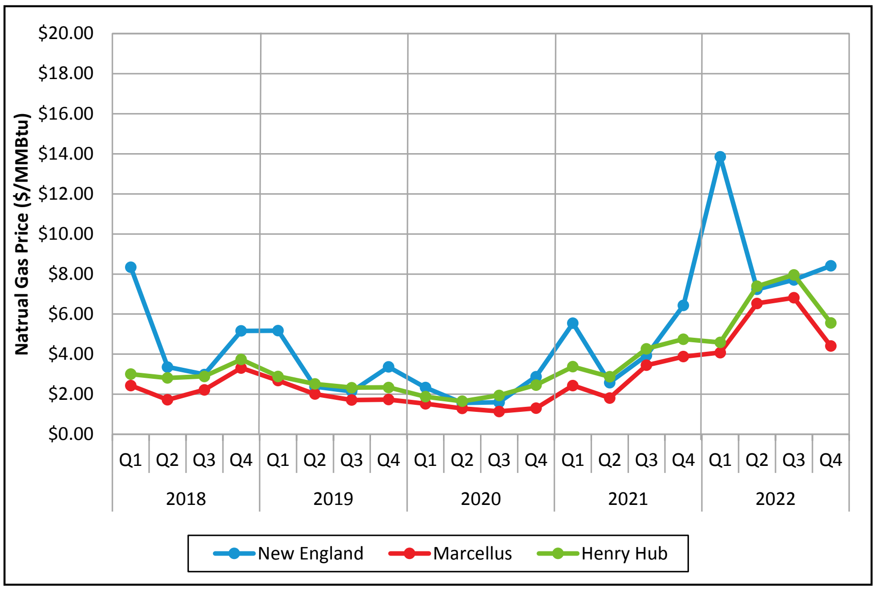
Natural Gas

In 2022, natural gas prices averaged $9.32/MMBtu, continuing an upward trend in prices from record lows in 2020.[26] Prices increased by $4.70/MMBtu, or 102%, compared to 2021 ($4.62/MMBtu). The significant year-over-year increase was due to a combination of market conditions and events at a national and international level, as well as high New England winter gas prices due to a constrained natural gas transmission system.

Higher nationwide prices due to international LNG demand and higher US demand

Given the region's lack of native production, New England's gas prices are influenced by gas prices at supply basins. Figure 1-9 below compares annual average prices in New England to prices at Henry Hub and the Marcellus trading hub.[27]

Figure 1-9: New England vs. Henry Hub and Marcellus Natural Gas Prices



For the second year in a row, prices increased significantly at the two major supply basins due to increased domestic natural gas demand and LNG export demand. There was a 6% increase in US demand for natural gas along with increased international demand for LNG exports in all quarters of 2022.[28] Prices at Henry Hub averaged $6.38/ MMBtu, up by $2.56/MMBtu (67%)

[26] New England natural gas prices averaged $2.10/MMBtu in 2020, the lowest natural gas prices since at least 1999.

[27] While Henry Hub is the predominant pricing benchmark in the United States, over the last several years, prices in the Marcellus region have often traded below the Henry Hub price due to the prevalence of cheap shale gas. Additionally, the geographical proximity between New England and the Marcellus region provides a stronger relationship between prices, particularly during times when New England pipelines are unconstrained.

[28] Average daily natural gas consumption for energy increased from 84 billion cubic feet per day in 2021 to 89 billion cubic feet per day in 2022, per Table 1 of EIA's Short Term Energy Outlook data.

year-over-year, and $5.46/MMBtu at Marcellus, up by $2.56/MMBtu (88%), with the Henry Hub price reaching its highest quarterly price since 2008.[29]

The Russian-Ukrainian conflict exacerbated global uncertainty in natural gas inventories and prices. With the start of the conflict in late February 2022, US exports of liquefied natural gas (LNG) rose to a record high of 11.9 Bcf in March 2022, with the quarterly LNG exports up 24% year-over-year (up from 9.27 Bcf in Q1 2021 to 11.51 Bcf in Q1 2022).[30] The significant increase in LNG exports was primarily driven by the Northwestern Europe LNG prices increasing substantially to $30.08/MMBtu in Q1 2022 (compared to $9.67/MMBtu in Q1 2021).[31]

In 2022, the price spread between New England and the two supply basins increased markedly and was at its highest level, in dollar terms, over the five-year period. New England natural gas traded at a premium of $2.94/MMBtu (or 46%) and $3.86/MMBtu (or 71%) compared to Henry Hub and Marcellus, respectively. The premium in New England prices was far more pronounced during the winter months (in Q1 and Q4 2022), when constrained natural gas pipelines during cold periods, leads to elevated prices. The price premium during Q2 and Q3 were relatively small and in line with prior year ranges.

Larger increase in New England natural gas prices due to interstate pipeline constraints

During the colder winter months, New England typically relies on LNG imports to fulfill the additional residential heating demand for natural gas. In Q1 2022, LNG injection into New England pipelines decreased 46% year-over-year as global LNG prices outpaced New England interstate pipeline prices.[32] Without as much pipeline sendout from New England's LNG terminals, generators relied heavily on interstate pipeline gas, which drove up the Q1 spot market price significantly. New England's Q1 average natural gas price increased 150% year-over-year, from $5.55/MMBtu in Q1 2021 to $13.86/MMBtu in Q1 2022, the highest quarterly natural gas price since 2014.

In the warmer months of Q2 and Q3 2022, residential natural gas demand decreased significantly and the spot price for natural gas in New England remained in line with US hub prices. The average natural gas price in New England increased 181% ($2.58/MMBtu to $7.24/MMBtu) year-over-year in Q2 and 96% ($3.93/MMBtu to $7.71/MMBtu) year-over-year in Q3, in line with price increases seen at the Marcellus and Henry hubs.[33]

As New England temperatures dropped in Q4, residential heating demand placed upward pressure on the spot natural gas price. The quarterly natural gas price averaged $8.41/MMBtu in Q4 2022, a $1.97/MMBtu (31%) increase from Q4 2021. A cold snap affected New England from December 24 to December 27 and led to an average daily natural gas price of $35.37/MMBtu over the four days, the highest daily averages since Q4 2018.

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[29] Historical Henry Hub spot prices can be found in Table 5b of EIA's Short Term Energy Outlook data.

[30] More information on March LNG exports can be found in the April 2022 Short Term Energy Outlook by EIA.

[31] In-depth analysis on LNG prices can be found in the gas market review in the Winter 2023 Quarterly Markets Report.

[32] The average forward price for the Algonquin pipeline was $18.73/MMBtu in winter 2022, much less than Northwest Europe's price of $30.08/MMBtu. More information on the quarterly comparison of pipeline and LNG forward prices can be found in the gas market review in the Winter 2023 Quarterly Markets Report.

[33] In Q2, the Marcellus and Henry hubs saw a 260% and 157% year-over-year increase in price, respectively. In Q3, the Marcellus and Henry hubs saw a 97% and 87% year-over-year increase in price, respectively.

Oil

In 2022, No. 2 Oil increased 72% year-over-year ($13.21/MMBtu to $22.69/MMBtu) and No. 6 Oil prices increased 60% year-over-year ($13.17/MMBtu to 21.06/MMBtu). The significant increases in price were primarily driven by higher demand Q1 leading to decreased oil storage levels entering the colder Q4 months.[34] The larger increase in gas prices in 2022 led to greater displacement of gas generation with lower-priced oil generation, with oil generators providing almost 2% of total native electricity generation, up from 0.2% in 2021.

Coal

In 2022, coal prices increased by 113% year-over-year ($6.69/MMBtu to $14.50/MMBtu) due in part to increased worldwide coal generation.[35] Coal generation remains the least active thermal generation source in New England, however, providing only 0.3% of total native generation in 2022.

Emission Prices

Emissions allowances are secondary drivers of electricity production costs for fossil fuel-fired generators, but have been trending up. State regulations require some generators to purchase emissions allowances, which are incorporated into generator offers and their mitigation reference levels.

New England has two carbon-reducing cap-and-trade programs that influence electricity prices:[36]

1. The Regional Greenhouse Gas Initiative (RGGI), covering generators in all New England states, and
2. The Electricity Generator Emissions Limits (EGEL) under the Global Warming Solutions Act (referred to as the MA GWSA program below), covering only Massachusetts generators.[37]

These programs aim to make the environmental cost of CO_2 explicit in dollar terms so that energy producers consider it in their production decisions. Market prices for CO_2 credits affect the total energy costs of fossil fuel-fired generators and, in turn, energy market prices. Consequently, existing fossil fuel-fired generators are incentivized to maintain or improve their operating efficiency while newly constructed generation facilities are incentivized to construct high efficiency generators to minimize generator production/operating costs.

The average cost of emissions by generator fuel type for each program in the context of short-run fuel costs is illustrated in Figure 1-10.

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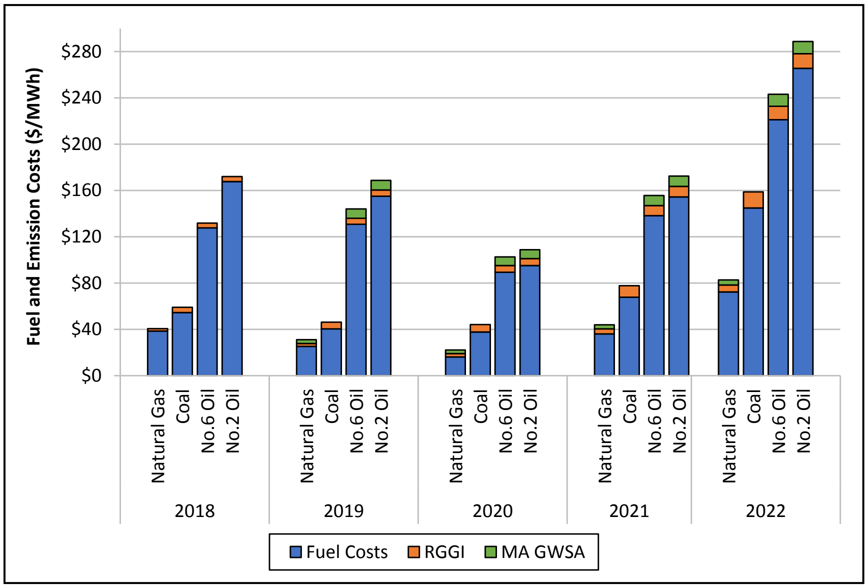
[34] More information on Q1 oil price trends can be found on EIA's website here. More information on Q4 oil price trends can be found on EIA's website here.

[35] More information on 2022 international coal trends can be found in Coal 2022 Report by the International Energy Agency.

[36] Both of these programs are discussed in more detail in Section 3.2.1.

[37] 310 CMR 7.74: Reducing CO_2 Emissions from Electricity Generating Facilities (https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774)

Figure 1-10: Annual Estimated Average Costs of Generation and Emissions[38]



The cost of emissions is still relatively low compared to fuel costs (less than 10%), but has grown in recent years and is increasingly impactful on energy prices. In 2022, the average estimated costs of the *RGGI* program increased 41% for most fossil fuel-fired generators year-over-year: natural gas ($4.36/MWh to $6.15/MWh), coal ($9.85/MWh to $13.89/MWh), No. 6 oil ($8.73/MWh to $11.69/MWh), and No. 2 oil ($9/MWh to $12.70/MWh).[39] Since natural gas generators set price for most of load (~80% in 2022), one would expect that the impact on energy prices will be most closely related to their CO_2 cost.

The average estimated costs of the *Massachusetts GWSA* program increased 19% from 2021 to $4.23/MWh for the average natural gas combined cycle. This was largely due to expectations of tighter conditions in future years. Therefore, in 2022, a typical combined cycle gas generator located in Massachusetts incurred CO_2 costs of over $10/MWh ($6.15 + $4.23)/MWh and would be expected to incorporate this cost into its energy market supply offer (along with fuel costs of approximately $72/MWh and other operating and maintenance costs). The impact of this program on New England energy prices is more challenging to determine, given that it applies to one state only.

1.2.3 Generator Profitability

With high natural gas prices leading to large spark spreads in 2022, gas-fired generators' net revenues increased significantly. As a result, our estimates of the average energy and ancillary revenues for gas-fired generators over the past five years increased to levels that exceed the capacity market benchmarks for new entry.

[38] IMM standard generator heat rates and fuel emission rates are used to convert $/ton CO_2 prices to $/MWh generation costs. The Massachusetts EGEL program began in 2018, but 2018 costs are excluded due to limited available market information regarding the value of allowances resulting in varied bid prices. The MA GWSA costs are a trade-weighted average of auction clearing prices and secondary trades for a given year. MA GWSA was removed for coal because there are currently no coal generators affected by the EGEL program.

[39] This was due to a variety of factors discussed in Section 3.2.1.

New generator owners rely on a combination of net revenue from energy and ancillary service markets and forward capacity payments to cover their fixed costs. Revenue from the Forward Capacity Market (FCM) is a critical factor considered when moving forward with the development of a new project. Developer expectations for minimum capacity revenues are based on the cost of the project (CONE, or cost of new entry) and their expectations for net revenue from the energy and ancillary services markets.

This section presents estimates of the net revenues that hypothetical new gas-fired generators (combined cycle (CC) and combustion turbine (CT)) could have earned in the energy and ancillary services markets in each of the previous five years. In addition to providing a basis for the amount of revenue required from the capacity market to build a new generator, this section also highlights the incremental revenue that could be earned from dual-fuel capability and evaluates participation in the Forward Reserve Market (FRM) for a combustion turbine generator.

The analysis is based on simulations of generator scheduling under an objective that maximizes net revenue while enforcing operational constraints, i.e., ramp rates, minimum run and down times, and economic limits.[40] The simulation model also includes a Regional Greenhouse Gas Initiative (RGGI) cost for every short ton of CO_2 emitted.[41]

Figure 1-11 shows the result of the simulations.[42] Each stacked bar represents revenue components for a generator type and year. A combined cycle generator is shown in green and a combustion turbine generator that participates in the FRM market is shown in blue. The simulation produces base revenue (energy and ancillary services (AS)) and incremental dual-fuel revenue numbers for 2018-2022.[43] Estimates of future year's base revenue, dual-fuel revenue, and FRM revenue are simple averages of these numbers. For all years, the FCA revenue numbers shown are calculated using the actual payment rates applied to calendar years.

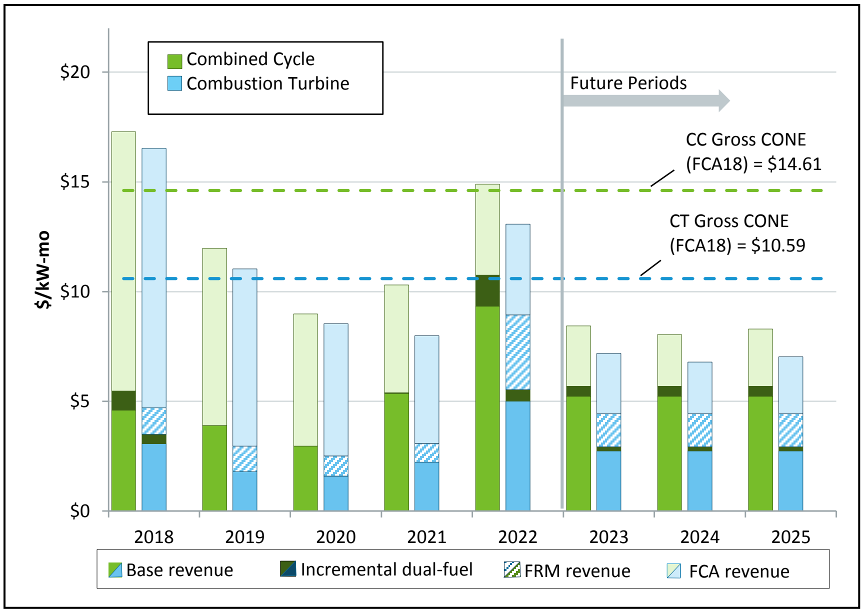
[40] The simulation uses historical market prices, which implies that the generator's dispatch decisions do not have an impact on day-ahead or real-time energy prices. Results should be considered in the high range for potential revenue estimates because this analysis does not account for forced outages (which should be infrequent for a new generator).

[41] In the model, the RGGI cost for each year is the average auction clearing price for RGGI allowances in that year. RGGI Auction data is available at https://www.rggi.org/auctions/auction-results/prices-volumes.

[42] The Gross CONE figures for the CC and CT gas-fired generators reflect Net CONE values of \$10.50/kW-month and \$6.33/kW-month with the difference between gross and net figures attributed to net revenue from energy and ancillary service sales.

[43] Incremental dual-fuel energy revenue is earned by the generator when running on its second fuel type.

Figure 1-11: Estimated Net Revenue for New Gas-fired Generators



When compared with 2021, the simulation results show 2022 net energy revenues increased by approximately 100% for the combined cycle generator and approximately 190% for the combustion turbine that participates in the FRM. These large year-over-year increases were driven by a moderate increase in capacity utilization and significantly higher spark spreads, which increased by 87% from the prior year.[44] Unlike 2020 and 2021, dual-fuel capability added significant revenue to both technology types with CT generators earning an additional $0.66/kW-month and CC generators adding $1.42/kW-month to net revenue this year. This was driven by relatively colder temperatures in January and February than in the previous two winters, which resulted in more frequent oil-fired generation.[45] In addition, a very high clearing price for TMNSR in the Summer 2022 Forward Reserve Market (FRM) Auction resulted in a 300% increase in FRM revenue when compared with the prior year.[46]

Overall, the results show that if future market conditions remain similar to the previous five years, owners of new gas-fired combined cycle generators could expect net revenues (not including capacity payments) to average $5.23/kW-month, which increases to $5.69/kW-month for generators with dual-fuel capability. Under the same conditions, new combustion turbines could expect net revenue earnings from $3.43/kW-month for single-fuel generators to $3.67/kW-month for generators with dual-fuel flexibility. With higher capacity factors, combined cycle generators can benefit more often from dual-fuel capability than peaking CT generators, but both technologies can expect significant revenue gains during periods when high demand for natural gas pushes its price above the oil price.

A combustion turbine generator can also participate in the FRM where off-line reserves are procured prior to the reserve season. A forward reserve resource receives revenue from the forward reserve auction, but it foregoes real-time reserve payments and, in most hours where

44 Section 3.2.1 of this report discusses spark spreads in more detail.

45 See: https://www.iso-ne.com/static-assets/documents/2022/05/2022-winter-quarterly-markets-report.pdf

46 See: https://www.iso-ne.com/static-assets/documents/2022/11/2022-summer-quarterly-markets-report.pdf

the energy price is within a normal range, also foregoes energy revenue since it will be held in reserve. When the energy price is very high, as in the case of a scarcity event, the forward reserve resource may be dispatched for energy and would then receive net revenue (above variable cost) for those high-priced periods. Taking the average of FRM payment rates over the past five years, a new combustion turbine that is designated as an FRM resource could earn $0.81/kW-month more net revenue than the same resource might accumulate in the real-time market alone. Overall, participation in the FRM results in greater net revenue than non-participation in all five years where these revenues have been observed.

For the next Forward Capacity Auction (FCA 18), the most recent CONE revisions approved by FERC establish net revenue components of $4.12/kW-month and $4.27/kW-month for combined cycle and combustion turbine generators respectively.[47] When compared with these benchmark estimates, the simulations show that average revenues for both the CC generator and the CT generator that participates in the FRM are sufficient to meet these expectations. Regardless, these revenue numbers are clearly insufficient to support new entry without the addition of capacity payments to cover the fixed costs of a new gas-fired generator.

In recent years, capacity prices have remained low reflecting a system that is long on capacity. Consequently, total revenues from the energy and capacity markets appear insufficient to incent either type of gas-fired generator to enter the region's energy market. In fact, New England has not added a new gas-fired generator since 2019 (FCA 13).[48]

[47] These revenue components include "Pay-for-Performance" (PFP) revenue which this study does not.

[48] Note that CONE benchmarks are produced from financial and engineering studies that estimate the cost of adding green-field generators. In practice, the cost of new entry for a generator may be lower than the current CONE benchmarks for a number of reasons. In particular, when new generating units are built on existing generation sites or when there are material additions to the capacity of an existing operational plant, the presence of existing infrastructure tends to lower fixed costs.

1.3 Demand Conditions

This section presents trends and assesses underlying drivers of demand for the primary wholesale market products: energy, operating reserve and capacity. The first subsection (1.3.1) reviews changes in energy demand, and quantifies the impact of weather, energy efficiency, and behind-the-meter solar generation. The second subsection (1.3.2) provides an overview of system and local reserve requirements. The final subsection (1.3.3) reviews the amount of capacity needed to meet the region's reliability standard.

> ***Key Takeaways***
>
> Similar average weather conditions between 2021 and 2022 resulted in comparable average *wholesale energy demand* (13,576 MW in 2022 vs 13,566 MW in 2021). In general, however, wholesale load continued to trend downward due to increases in energy efficiency and behind-the-meter solar generation. In 2022, energy efficiency reduced annual average load by an estimated 2,538 MW (by 15%) and behind-the-meter solar generation reduced annual average load by 426 MW (by 3%).
>
> The average *system reserve requirements* in 2022 were similar to prior years. The one exception was the 10-minute spinning reserve requirement, which declined modestly from previous years as a result of an operational decision by the ISO due to improved resource performance.
>
> *Capacity* (Net ICR) needed to meet the system's reliability objective has generally declined over recent capacity auctions, primarily due to lower projected peak load forecasts. The Net ICR for FCA 17 (2016/17 delivery) was 30,305 MW, representing a 4% decrease from the Net ICR for FCA 16 (31,645 MW).

1.3.1 Energy Demand

New England wholesale electricity demand, otherwise known as Net Energy Load (NEL) [49], has exhibited a downward trend in recent years, largely due to the impact of state policies promoting the installation of energy efficiency measures, as well as the increase in the behind-the-meter generation. However, load levels are projected to increase significantly over the next decade due to the electrification of the heating and transportation sectors. Loads are projected to average over 16,000 MW per hour by 2031, almost 20% above 2022 levels.[50]

Wholesale electricity demand in 2022 similar to 2021

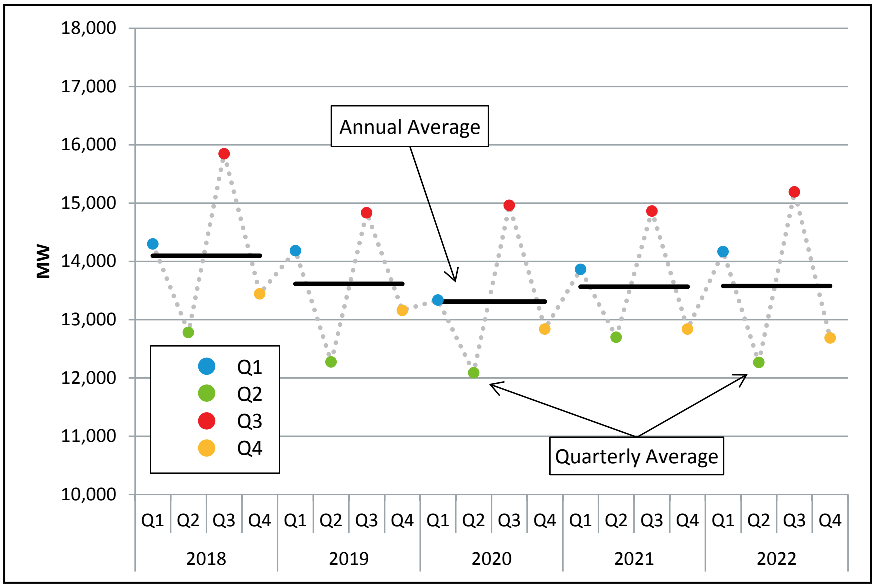
In 2022, load was within 0.1% of 2021 wholesale electricity demand (13,576 MW in 2022 vs 13,566 MW in 2021), largely due to similar weather conditions. Annual and quarterly average loads from 2018 to 2022 are shown in Figure 1-12 below.

---

[49] NEL is net of (excludes) electricity demand that it met by "behind-the-meter" generation, including photovoltaic generation, not participating in the wholesale market. It also excludes pumped-storage demand since pumped-storage facilities are energy neutral.

[50] See ISO-NE's 2022 CELT Report, section 1.5.2, at https://www.iso-ne.com/system-planning/system-plans-studies/celt

Figure 1-12: Average Hourly Load by Quarter and Year



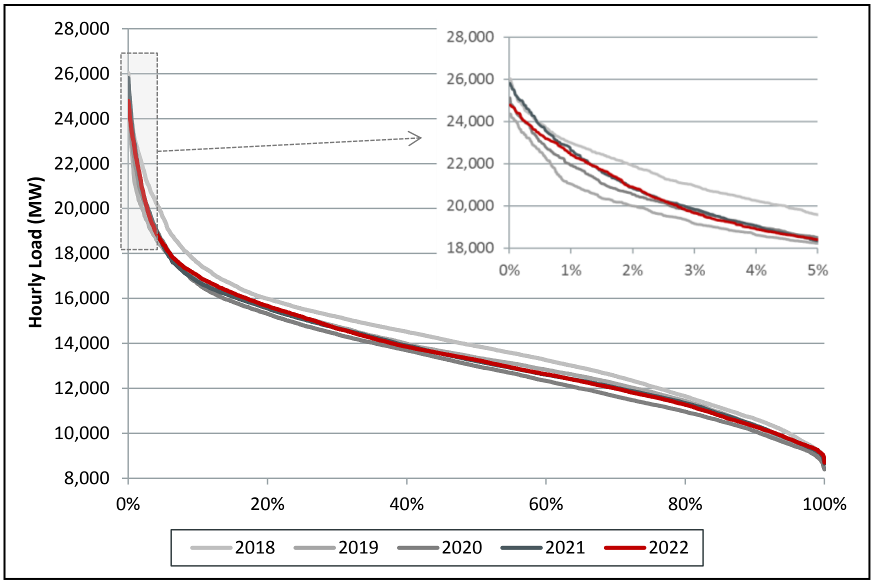
With the exception of 2020, when load was diminished due to the COVID-19 pandemic in Q1 and Q2, 2022 annual load was lower than previous years, reflecting annual variations in weather and the continued growth in energy efficiency and behind-the-meter solar generation.[51] At a quarterly level, load in each quarter of 2022 was within a narrow (4%) range of 2021 quarterly load levels. Higher winter loads in Q1 were offset by lower loads during spring (Q2) and fall (Q4) driven partially be an increase in behind-the-meter solar electric production.

Distribution of load levels in-line with prior years

New England's system load over the last five years is shown as load duration curves in Figure 1-13 below. A load duration curve depicts the relationship between load levels and the frequency that load levels occur. The inset graph highlights the 5% of hours with the highest load levels for each year.

[51] The comparatively high average load in 2018 was driven by cold temperatures in Q1 and warmer temperatures in Q3.

Figure 1-13: Load Duration Curves



The 2022 load duration curve has a similar overall profile to prior years (with the exception of 2018), showing no significant differences between the frequencies of various load levels. Looking at periods of high load, and typically tighter supply/demand conditions, the inset graph focuses on the top 5% of hourly load. Peak load continues to be concentrated during summer months due to increased air-conditioning demand. Therefore, weather differences tend to explain annual variations during the top 5% of hours. The highest peak loads, especially in the top 1% of all hours, occurred due to hot weather at the end of July and beginning of August 2022. On August 4, load peaked at 24,780 MW with a temperature of 92°F.

Controlling for weather effects, wholesale demand continued to decrease due to energy efficiency and behind-the-meter solar generation[52]

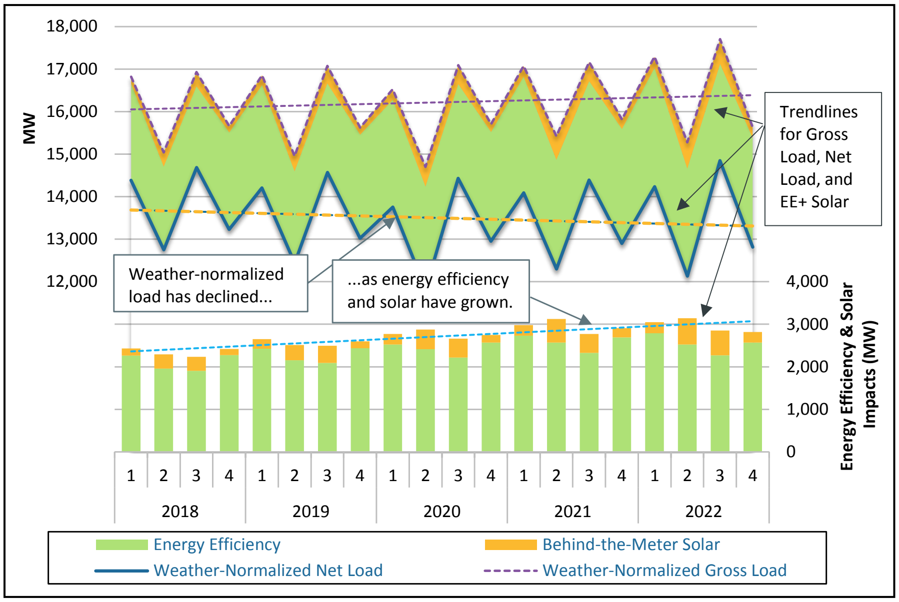
The trend in estimated gross energy demand, wholesale market demand and the contribution of energy efficiency and behind-the meter solar is presented below.[53,54] In addition to the trend lines, Figure 1-14 also shows the average quarterly breakdown of each category

[52] Weather-normalized load adjusts observed load for the effects of weather, leap year and non-holiday weekdays.

[53] Energy Efficiency is based on aggregated performance of installed measures on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment. Energy Efficiency and Demand Response Distributed Generation (DG) measures are aggregated to On-Peak and Seasonal-Peak resources. Performance of DG accounts for only 5% of energy efficiency performance.

[54] Behind-the-meter solar production estimates provided by ISO New England's system planning department.

Figure 1-14: Average Quarterly Weather-Normalized Load with Energy Efficiency and Solar Impacts



Weather-normalized *gross* load (dashed purple line), which shows load without the effects of energy efficiency (EE) and behind-the-meter solar, has continued to grow. Weather-normalized net load (solid blue line), the remaining demand satisfied through the wholesale energy market, trended downward over the past five years.

The gap between gross and net load is the combined impact of energy efficiency (green bar area) and behind-the-meter solar generation (gold bar area). Greater energy efficiency and behind-the-meter solar generation have typically helped offset increases in gross load, causing weather-normalized wholesale load to fall. Energy efficiency has a greater effect during Q1 and Q4, while behind-the-meter solar generation has a greater impact during Q2 and Q3.

In 2022, energy efficiency reduced weather-normalized annual average load by an estimated 2,538 MW, a 2% decrease (40 MW) compared to 2021. This is in line with the ISO's expectation that EE will decline over time due to rising costs of eligible EE measures and the associated EE baselines used to calculate claimable savings. Behind-the-meter solar generation reduced weather-normalized annual average load by 426 MW (by ~3%) or nearly 14% of estimated installed capacity (3,170 MW). The 426 MW average load reduction was a 15% increase (57 MW) compared to 2021.

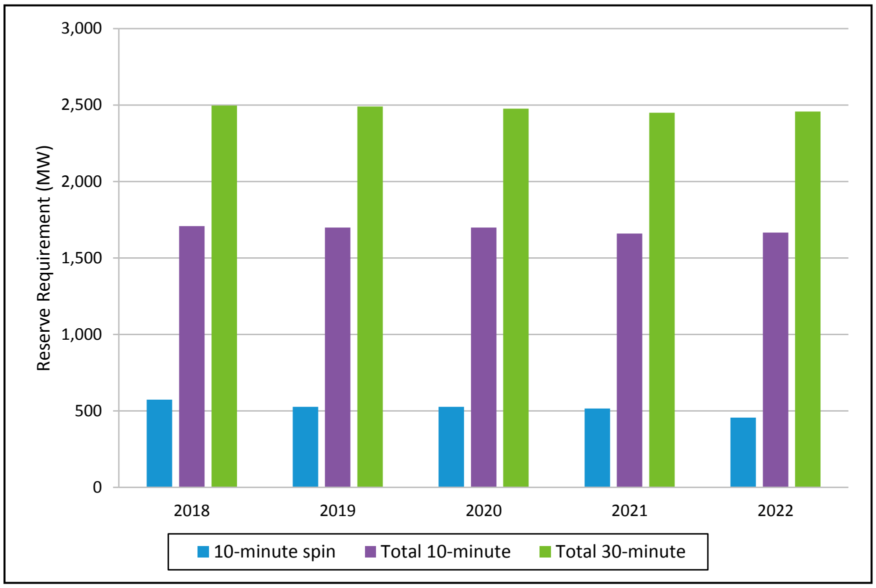
1.3.2 Reserve Requirement and Margin

In New England, there are three distinct reserve requirements determined by the North American Electric Reliability Corporation (NERC) and Northeast Power Coordinating Council Inc. (NPCC). Figure 1-15 shows the system total 10-minute requirement (purple), which includes both system 10-minute spin (blue) and non-spin reserves.[55] The system total 30-minute requirement (green) contains the total 10-minute and 30-minute requirements. Requirements are based on the two largest contingencies on the system (commonly known as

[55] There are also 30-minute local reserve requirements that are not shown or discussed below. These requirements bind infrequently, and showed no discernable trends during the reporting period.

first- and second-contingencies). The size of the contingencies, and therefore requirements, have not varied significantly on an annual average basis.

Figure 1-15: Average System Reserve Requirements



The average 10-minute spin requirement was 456 MW in 2022, down 12% from 2021 (515 MW). The requirement was notably lower due to an operational change that reduced the percentage of the ten-minute reserve requirement that must be spinning from 31% to 25% on May 31, 2022.[56] The total 10-minute (1,667 MW) and total 30-minute requirements (2,458 MW) were similar to prior years reflecting changes to the largest system contingency. In particular, Phase II, a 2,000 MW direct current tie line connecting the Hydro-Quebec control area to New England, was the largest contingency in 87% of hours of the past two years. Planned reductions in 2021 and 2022 reduced the average size of Phase II as the largest contingency, which reduced total 10-minute and 30-minute requirements.

The reserve margin measures additional available capacity over the load and reserve requirements.[57] On average, there has been a healthy surplus of reserves capability on the system compared to the requirements, and relatively few instances where the system experienced a deficiency of capacity or reserves. These instances are included in the discussion of interesting system events in section 3.2.8.

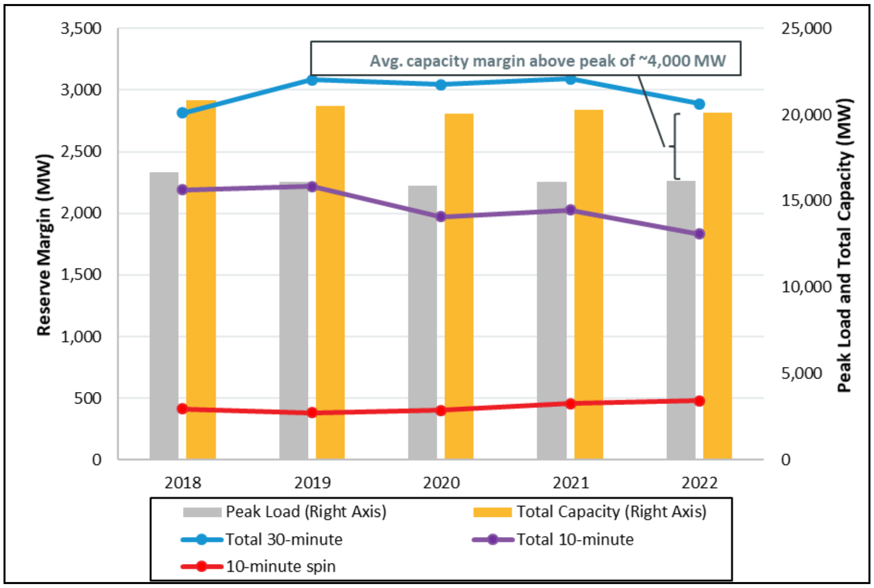
The annual average margins for 10-minute spin reserves (red line), total 10-minute reserves (purple line), and total 30-minute reserves (blue line) are shown in Figure 1-16 below. The margins are equal to the amount of reserves provided in excess of the corresponding reserve requirement. The bars represent annual average load (gray bar) and available capacity (orange

[56] The operational decision to change this percentage stemmed partly from an enhancement of the Energy Management System (EMS) that led to more accurate accounting of reserves.

[57] The reserve margin is the difference between available capacity and demand. The equations below illustrate this relationship: i. $Gen_{Energy} + Gen_{Reserves} + [Imports - Exports] = Demand + [Reserve\ Requirement]$. Equation i. is equivalent to: $Supply + Gen_{Reserves} - [Reserve\ Requirement] = Demand$ or $Supply + Reserve\ Margin = Demand$

bar) during the peak hour of each day.[58] Combined, these bars show the difference between load and available capacity, which is when reserve margins are typically at their lowest.

Figure 1-16: System Reserve Margin, Peak Load, and Available Capacity



Slightly lower year-over-year total 30-minute and total 10-minute reserve margins reflect changes in the generation mix over the course of 2022. Both margins fell by about 200 MW, primarily due to the decline in the total 10-minute reserve margin.[59] The lower margin was an outcome of the dynamics between lower net interchange (231 MW less) and the corresponding increase in native generation. More native energy generation reduced reserve capability and contributed to lower margins. The 10-minute spin margin increased by 22 MW (15%) in 2022 because the reserve requirement declined after operational tool enhancements.

1.3.3 Capacity Market Requirements

The Installed Capacity Requirement (ICR) is the amount of capacity needed to meet the region's 1-in-10 year reliability standard.[60] When developing the target capacity to be procured in the Forward Capacity Auction (FCA), the ISO utilizes a Net ICR, which is the amount of necessary capacity after accounting for tie benefits with Hydro-Quebec. Due to transmission limitations, there are also local sourcing requirements (LSR) for import constrained areas and maximum capacity limits (MCL) for export-constrained areas.

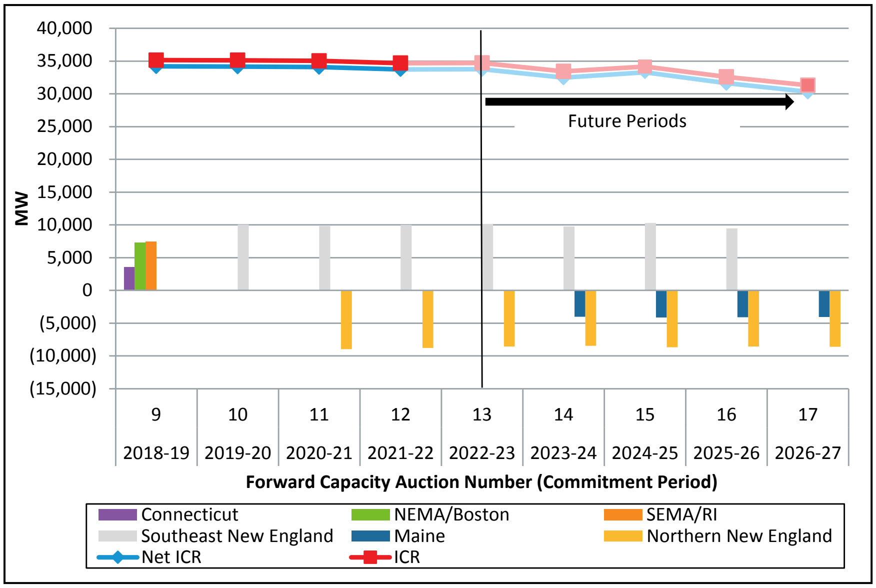
Trends in system capacity requirements, ICR and Net ICR, between 2018 and 2027 are shown in Figure 1-17 below. The system ICR and Net ICR are represented as line series. LSRs (positive bars) and MCLs (negative bars) are also shown.

[58] Available capacity is the generation capacity that can be delivered within a 30 minute period: $Gen_{Energy} + Gen_{Reserves} + [Imports - Exports]$

[59] The decline of the total 10-minute requirement is reflected in the total 30-minute margin, since the total 30-minute requirement is inclusive of the 10-minute requirement.

[60] The ICR requirements are designed such that non-interruptible customers can expect to have their load curtailed not more than one day every ten years.

Figure 1-17: ICR, NICR, Local Sourcing Requirements, and Maximum Capacity Limits



The Net ICR for FCA 17 (2026/27) was 30,305 MW, down by 1,340 MW (4%) from FCA 16. Since FCA 13, Net ICR has steadily declined due in part to decreases in the ISO's expected load forecast and increases in external tie benefits.[61] Specifically in FCA 16, the load forecast decreased over 1,000 MW due to a revision in the reconstitution process of passive demand response resources.[62]

At a local level, Southeast New England (SENE) was the only import-constrained zone from FCA 10 to 16.[63] In FCA 17, SENE was not modelled as an import-constrained zone due to improvements to the local transmission network and decreases in the zonal load forecast. The Maine and Northern New England (NNE) capacity zones were modeled as separate export-constrained capacity zones in recent auctions with similar MCL values year-over-year.

[61] The ISO publishes Net ICR amounts and related values for all auctions here.

[62] More information on the FCA 15 demand response reconstitution changes can be found in ISO filing to FERC in September 2020.

[63] Southeast New England consists of the NEMA/Boston, Southeastern Massachusetts, and Rhode Island load zones.

1.4 Imports and Exports (External Transactions)

This section summarizes the level of external transactions with neighboring control areas in Canada and New York over the last five years. External transactions are covered in more detail in Section 5.

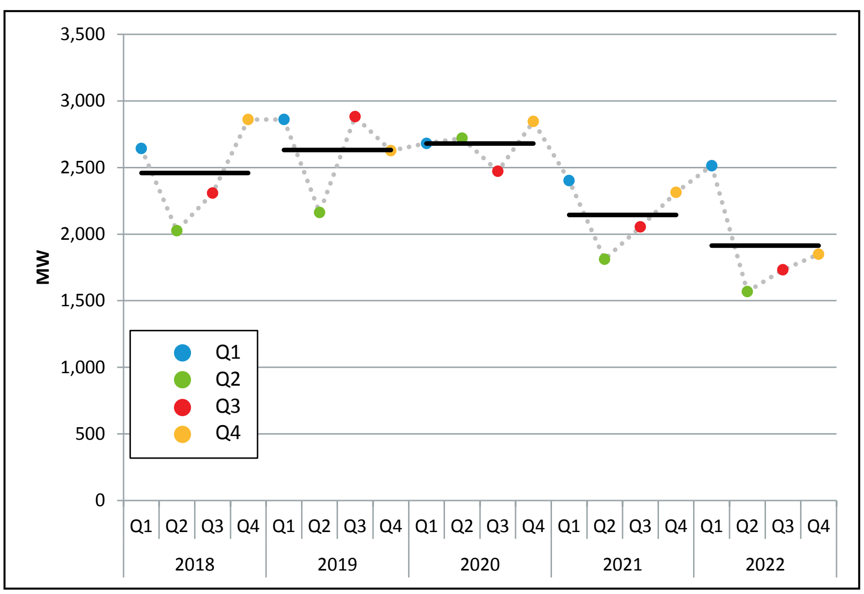
Key Takeaways

Net interchange (imports minus exports) from Canada and New York averaged about 1,900 MW per hour, meeting 14% of New England demand. Like last year, the level of net interchange continued to decline. The significant driver for this decline was an increase in exports to the New York market, particularly over the New York North interface.

The retirement of the Indian Point nuclear generator in New York in April 2021 and increased planned transmission outages in New York led to increased congestion and higher energy prices relative to New England prices. These system and market dynamics have resulted in an increase in export transactions over the New York North interface, approaching 400 MW over the last two years. With the reduction in net interchange from New York, imports from the Canadian provinces comprised a higher share (over 90%) of total net interchange in 2022.

New England tends to import high volumes of power from its neighboring regions, particularly during the colder winter months when energy prices in the region can be elevated as a result of constrained natural gas supplies. Seasonal variations in net interchange can be seen in Figure 1-18 below which shows the hourly average real-time system-wide net interchange value by quarter and year. The black line series illustrates each year's hourly average net interchange, while the colored circles show the average net interchange for each specific quarter.

Figure 1-18: Average Hourly Real-Time Pool Net Interchange by Quarter and Year



Net interchange from Canada and New York averaged about 1,900 MW in 2022, representing its lowest level over the five-year period. This marks the second year in a row that average annual net interchange decreased, and the 2022 value is nearly 30% less than the value observed in 2020 (2,680 MW). The primary driver for the reduction in net interchange in recent years is the increase in exports over the New York North interface, which went from 487 MW per hour on average in 2020 to 874 MW per hour on average in 2022. One factor behind this increase in exports to New York is the retirement of the Indian Point nuclear generator in New York in April 2021, which was followed by planned transmission work in the region during 2022. As a result of this decline in net interchange with New York, a significantly higher share of New England's net interchange came from the Canadian provinces in 2022 (93%) than from New York (7%).

From a seasonal perspective, Q1 2022 was the only quarter that saw a year-over-year increase in net interchange. This was due to increased imports from New Brunswick and decreased exports over Northport-Norwalk and Cross Sound Cable, the two interfaces connecting Long Island and New England. Meanwhile, from Q2 2022 through Q4 2022, net interchange decreased year-over-year due to generator outages or retirements and increased transmission work. In Q2 2022, net interchange decreased by 13% (or 242 MW) due to decreased net interchange from New Brunswick. In April 2022, a 660 MW nuclear generator in New Brunswick began an extended planned outage. The generator's outage led to reduced imports as it typically accounts for over 40% of New Brunswick's native generation. This outage continued into July, and additionally contributed to the year-over year decrease in net interchange during Q3 2022.

In Q3 2022, net interchange averaged 273 MW at New York North, a 55% (or 339 MW) decrease compared to Q3 2021. This was the lowest level of net interchange at New York North for any Q3 over the prior five years. Transmission work and congestion continued to impact net interchange in Q4 2022. In Q4 2022, average net interchange at New York North decreased by 280 MW year-over-year (412 MW vs. 692 MW). New York prices averaged $4.86/MWh higher than New England compared to $3.01/MWh higher in Q4 2021. The increased price was due to increased congestion in New York, with the congestion component of the New York LMP at New York North increasing from $16.53/MWh to $34.97/MWh year-over-year.

Section 2
Market Structure and Competitiveness Assessment

This section assesses the level of competition in the wholesale electricity markets in New England. Competition is important because it ensures that the prices consumers pay and that producers receive for the products are the result of competitive forces and not unduly influenced by the exercise of market power. In situations where the electricity markets are unable to achieve competitive outcomes, market power mitigation controls may be necessary. The IMM performs reviews across various ISO electricity markets to identify these situations and limits their impact through the mitigation process.[64]

This section is organized in the following order:

- (2.1) Energy market
- (2.2) Energy market mitigation
- (2.3) Forward capacity market (FCM)
- (2.4) Forward capacity market mitigation
- (2.5) Financial transmission rights (FTR) market
- (2.6) Ancillary services markets, which includes the forward reserve market (FRM) and the regulation market

In general, we find that ISO New England capacity, energy, and ancillary service markets exhibited competitive outcomes in 2022. Across the majority of these markets, metrics indicated that levels of competition were generally sufficient to limit opportunities where market power could be exercised. However, this was not the case for the Summer 2022 FRM auction, which was found to be structurally uncompetitive.[65] The IMM reviewed conduct in this auction in some detail and we were unable to conclude that the exercise of market power had occurred. Additionally, market concentrations across the different markets generally remained in historical ranges and mitigation was relatively infrequent.

To further strengthen market safeguards, the IMM recommends that the ISO consider a number of changes related to energy market mitigation. These changes include (1) reviewing the current thresholds for system-wide and local market power in the energy market; (2) eliminating the energy offer mitigation exemption for non-capacity resources in the day-ahead energy market; (3) extending mitigation to include resources in export-constrained areas; and (4) reviewing the reference level calculation methodology for energy offers. These recommendations are discussed in more detail in Section 2.2.2.

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[64] Importantly, the IMM does not have defined mitigation authority for certain markets, including the regulation and Forward Reserve Markets.

[65] See Section 2.6.1 for further discussion of the Summer 2022 auction competitiveness.

2.1 Energy Market

This section presents a number of metrics on the structure and competitiveness of the energy markets. Specifically, we present and interpret the following:

- high-level market concentration measures for the supply side (2.1.1) and demand side (2.1.2) of the real-time market,
- supply-side structural market power tests in the real-time market (2.1.3): pivotal supplier test (PST) and the residual supply index (RSI),
- supply offer cost mark-up metrics in the day-ahead (2.1.4) and real-time(2.1.5) markets, and
- degree of economic withholding in the real-time market (2.1.6).

Key Takeaways

In 2022, the market concentration among the four largest firms controlling supply in the real-time market was in line with the values of the last five years, at 44%. The four largest load-serving entities served 53% of total load in real time, the lowest share of electricity purchased over the five-year reporting period.

There were more instances of structural market power in real-time because of slightly lower total operating reserve margins due to less supply. However, operating reserve margins (surplus) remained relatively high on average compared to the underlying requirement. There were more five-minute intervals with pivotal suppliers in 2022 than in 2019-2021. Additionally, the average RSI in the real-time energy market fell from 106.0 in 2022 to 104.6 in 2021. Despite the lower RSI and higher frequency of pivotal suppliers in 2022, mitigation was still relatively infrequent and did not indicate any significant concerns.

Markups in the real-time and day-ahead markets were close to zero or negative during all years of the reporting period. In 2022, withheld economic capacity was relatively low (below ~ 2%) and generally in line with levels seen in past years.

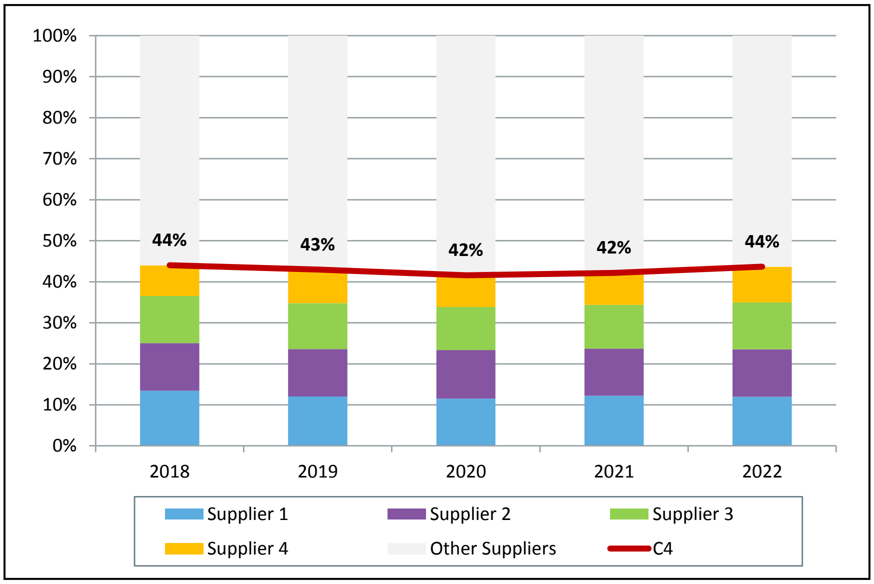
2.1.1 C4 Concentration Ratio for Generation

This subsection presents an analysis of supplier market concentration among the four largest firms controlling generation and scheduled import transactions in the real-time energy market. The measure, termed the "C4," is useful in understanding the general trend in supply concentration as companies enter, exit, or consolidate control of supply serving the New England region over time.[66, 67] As shown in Figure 2-1 below, the C4 value for 2022 increased slightly from the prior year, to 44%.

[66] The C4 is the simple sum of the percentages of system-wide market supply provided by the four largest firms in on-peak hours of the year and accounts for affiliate relationships among suppliers.

[67] This C4 analyses for both supply and demand does not account for market participants with both load and generation positions. These firms generally have less incentive to exercise market power. Any spot market actions that would tend to

Figure 2-1: Real-time System-wide Supply Shares of the Four Largest Firms



The C4 values of the last five years range between 42-44%, indicating low levels of system-wide market concentration, particularly because the market shares are not highly concentrated in any one company. In 2022, the total on-peak supply of generation and imports was about 66,400 GWh, of which about 29,000 GWh (44%) came from the four largest suppliers.[68] The C4 line indicates a tight range over the past five years, and one company maintained a dominant share of on-peak supply, with the split among the top four suppliers remaining stable.

2.1.2 C4 Concentration Ratio for Load

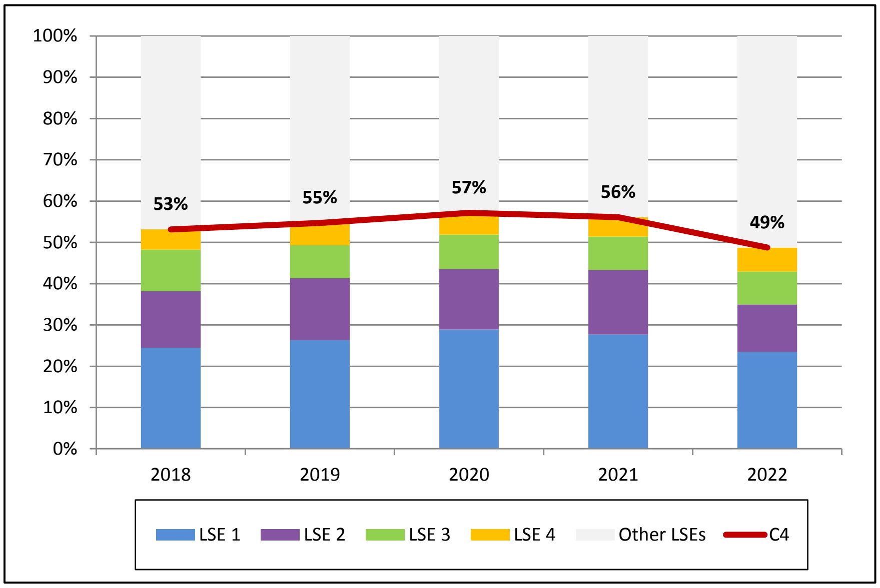
The C4 for load measures the market concentration among the four largest load-serving entities (LSEs) in the real-time energy market and is presented in Figure 2-2 below.[69]

raise prices to benefit their generation would come at a cost to their load position. Any actions that would suppress prices to benefit their load would come at a cost to their generation position.

[68] On-peak hours last from HE 8 to HE 23 on Monday to Friday.

[69] The C4 load metric also accounts for any affiliations among different LSE and includes on-peak hours only.

Figure 2-2: Real-time System-wide Demand Shares of the Four Largest Firms[70]



In 2022, the real-time load obligation (RTLO), or the amount of electricity purchased, was 65,479 GWh.[71] Overall, the four largest LSEs served 49% (31,913 GWh) of total load, the lowest share of electricity purchased over the five-year period. The red C4 line shows that the total load share of the four largest LSEs decreased in 2022 and falls 4% lower than 2018 levels. The decrease was largely due to one participant divesting a large share of its generation and load into an independent company.

The observed C4 values presented above indicate relatively low levels of system-wide market concentration. The above figure shows that individual shares are not highly concentrated in any one company. Additionally, there is no evidence to suggest that LSEs exhibit energy market bidding behavior that would suppress prices. On average over 100% of demand clears in the day-ahead market and the aggregate demand curve is relatively price-insensitive around expected LMPs (see Section 3.2.5 on Demand Bidding).

2.1.3 Residual Supply Index and the Pivotal Supplier Test

This section examines opportunities for participants to exercise market power in the real-time market using two metrics: the pivotal supplier test (PST) and the residual supply index (RSI).[72] Both of these widely used metrics identify instances when the largest supplier has market power.[73] The RSI represents the amount of demand that the system can satisfy without the largest supplier's available energy and reserves. If the value is less than 100, the largest supplier is needed to meet demand, and could potentially exercise market power (if permitted).

[70] The firms labeled "LSE 1", "LSE 2" and so on are not necessarily the same LSE across all years; these are generic labels for the top four firms during a given year.

[71] Real-time load obligation is measured as all end-use wholesale load in the ISO New England region, along with all exports. The difference between this number and the real-time generation obligation should equate to energy losses.

[72] In this report, the RSI and pivotal supplier tests are calculated using supply, load, and reserve requirement data from the ISO's real-time market software. This differs from the calculation methodology of previous AMRs, which used the results and inputs of the real-time pivotal supplier test conducted by the mitigation software process.

[73] When the RSI exceeds 100, there is sufficient supply available to meet demand without any generation from the largest supplier. In this case, no individual supplier is pivotal and sufficient competition exists in the market.

Further, if the RSI is less than 100, there is at least one pivotal supplier. Conversely, when the RSI exceeds 100, there is enough supply available to meet demand without any generation from the largest supplier. In this case, no individual supplier is pivotal and sufficient competition exists in the market.

The data used to calculate the RSI come from the ISO's real-time market software (the Unit Dispatch System, or UDS). Based on these data, the RSI for an interval t is calculated as follows:

$$RSI_t = \frac{Total\ Available\ Supply_t - Largest\ Supplier's\ Supply_t}{Load_t + Reserve\ Requirements_t}$$

Pivotal suppliers are identified for every five-minute pricing interval by comparing the real-time supply margin[74] to the sum of each participant's total supply that is available within 30 minutes.[75] When a participant's available supply exceeds the supply margin, they are considered pivotal. The number of five-minute intervals with at least one pivotal supplier are divided by the total number of five-minute intervals in each year to obtain the percentage of intervals with pivotal suppliers.

The average RSI for all five-minute real-time pricing intervals and the percentage of five-minute intervals with pivotal suppliers are presented in Table 2-1 below.

Table 2-1: Residual Supply Index and Intervals with Pivotal Suppliers (Real-time)

Year	% of Intervals With At Least 1 Pivotal Supplier	RSI
2018	30.7%	103.6
2019	14.7%	106.4
2020	16.6%	106.9
2021	18.0%	106.0
2022	24.9%	104.6

There were more five-minute intervals with pivotal suppliers in 2022 than in 2019-2021, but fewer than in 2018. By this measure, this indicates that suppliers faced relatively less competition in 2022 than during the three previous years. The increase in the number of intervals with at least one pivotal supplier was driven by lower total 30-minute reserve margins in 2022.

Reserve margins have fluctuated throughout the reporting period for several reasons, including generator outages, resource additions or retirements, and changes in the reserve requirement. In 2022, the average total 30-minute reserve surplus was 2,888 MW, down by about 200 MW from 3,091 MW in 2021. The decrease was primarily driven by changes in net imports. In 2022,

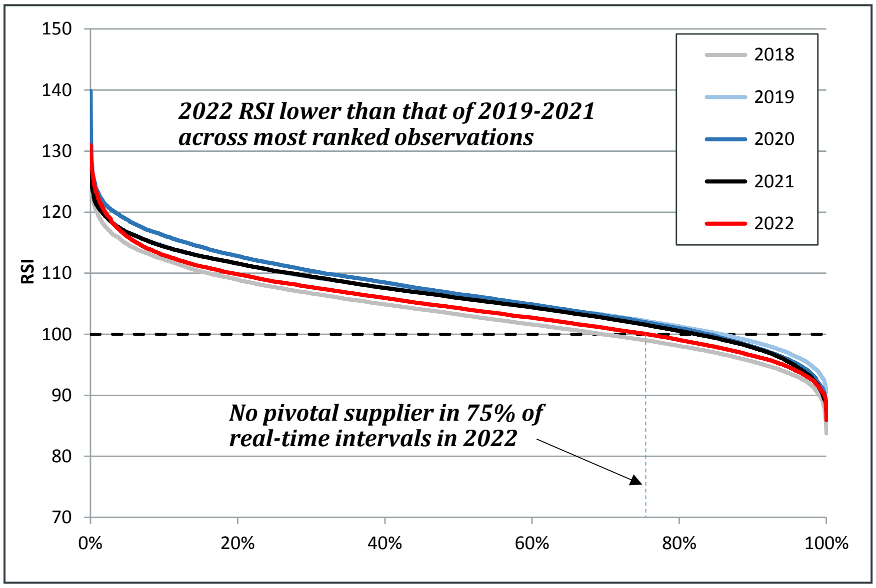
[74] The real-time supply margin measures the amount of available supply on the system after load and the reserve requirement are satisfied. It accounts for ramp constraints and is equal to the Total30 reserve margin: Gen_{Energy} + $Gen_{Reserves}$ + [*Net Interchange*] -*Demand* - [*Reserve Requirement*]

[75] This is different from the pivotal supplier test performed by the mitigation software, which does not consider ramp constraints when calculating available supply for each participant. Additionally, the mitigation software determines pivotal suppliers at the hourly level.

average hourly net imports decreased by 231 MW compared to 2021. As a result, native generation provided more energy and fewer reserves.[76]

Duration curves that rank the average hourly RSI over each year in descending order are illustrated in Figure 2-3 below. The figure shows the percent of hours when the RSI was above or below 100 for each year. An RSI below 100 indicates the presence of at least one pivotal supplier.

Figure 2-3: System-wide Residual Supply Index Duration Curves



Like the pivotal supplier statistics, Figure 2-3 shows that there was a lower availability of competitive supply in 2022 and 2018 compared to 2019-2021. The RSI was above 100 in 75% of real-time pricing intervals in 2022, which was lower than the 2021 result (82%). Despite the lower RSI and higher frequency of pivotal suppliers in 2022, mitigation was still relatively infrequent and did not indicate any significant concerns.

2.1.4 Day-Ahead Price-Cost Markup

In a perfectly competitive market, all market participants' energy supply offers would equal their marginal costs. The energy component of the LMP would then be set by the supply offer or demand bid on the margin. However, in practice, participants can raise their supply offers above marginal costs. Uncompetitive offers priced above marginal cost can distort prices and impact generator commitment decisions, leading to inefficient market outcomes. Though the IMM administers mitigation rules in the energy market to prevent the exercise of market power, participants are allowed to increase their offers within a certain threshold before mitigation is applied.

The price-cost markup estimates the divergence of the observed market outcomes from the ideal scenario in which all energy supply is offered at marginal cost. The results provide insight on how uncompetitive offer behavior impacts the day-ahead energy market.

[76] Additionally, there was a 43 MW reduction in offline reserves from two generators that shed their CSOs for FCA 13 (June 2022 – May 2023). Section 1.3.2 provides additional information on reserve margin trends.

To calculate price-cost markup, the IMM simulated the day-ahead market clearing using two scenarios:[77]

- Scenario 1 is an *offer case* that uses actual day-ahead energy market supply offers submitted by market participants.
- Scenario 2 is a *marginal cost case* that assumes all market participants offered at an estimate of their short-run marginal cost.[78]

The price-cost markup is then calculated as the percentage difference between the annual generation-weighted LMPs for the offer case and the marginal cost case simulations:

$$PCM = \frac{LMP_O - LMP_{MC}}{LMP_O} \times 100$$

- LMP_O is the annual generation-weighted LMP that results from actual generator offers, and
- LMP_{MC} is the annual generation-weighted LMP that would occur if generator offers were replaced with their respective marginal costs.

A larger price-cost markup means that a larger component of the LMP is the result of inflated supply offers.

The annual day-ahead price-cost markup values from the simulation are shown in Table 2-2 below.

Table 2-2: Day-Ahead Price-Cost Markup, %[79]

Year	Price-Cost Markup
2018	-4.0%
2019	-2.4%
2020	0.9%
2021	-0.6%
2022	-1.8%

[77] The IMM uses the PROBE, or "Portfolio Ownership and Bid Evaluation," simulation model for this analysis. The software simulates the day-ahead LMP-based market clearing. See http://www.power-gem.com/PROBE.html. This is a more dynamic approach than calculating the difference between a static offer price and marginal cost. Rather, this approach re-runs the market optimization process with both as-offered and competitive (marginal cost) supply curves, and calculates the difference in the resulting LMPs.

[78] The marginal costs estimates are based on underlying variable cost data and generator heat rate parameters used in the calculation of IMM reference levels. Reference levels are calculated pursuant to Appendix A to Market Rule 1 of the ISO tariff and are used in market power mitigation analyses to represent a competitive offer. Where a good estimate of marginal cost does not exist the marginal cost is set equal to the supply offer. Some differences between estimated and actual marginal costs are to be expected.

[79] Prior to this report, this metric used a different methodology to estimate marginal costs. This is why the values in this report are lower than values for the same years in previous reports.

In 2022, the price-cost markup for the day-ahead energy market remained low (below the strictest mitigation threshold of 10%) at -1.8%. This indicates that the average marginal resource offered below its marginal costs, and that offers deviating from marginal cost decreased the generation-weighted day-ahead energy market price by approximately 1.8%. This result is similar to that of prior years, and is consistent with normal year-to-year variation given modeling and estimation error.[80] This indicates that competition among suppliers in the day-ahead market limited their ability to inflate LMPs by submitting offers above marginal cost.

In this assessment, we reviewed price-cost markup values at an hourly level and compared the peak load hour price-cost markup with the forecasted supply margin at peak. Comparing these attributes provides insight into whether participants take advantage of tight system conditions, when market power tends to be more of a concern, by increasing offer markups during those times. There was no meaningful correlation between the price-cost markup and the supply margin in 2022, indicating that the day-ahead market remained competitive even when the ISO expected supply margins to be low and market power was present.

2.1.5 Real-Time Price-Cost Markup (Lerner Index)

This analysis used different methods for the day-ahead and real-time price cost markup calculations. Recall that the day-ahead analysis above was performed by calculating generation-weighted LMPs for each scenario using simulation software. The real-time analysis calculated (load-weighted) LMPs by creating supply curves for 1) available generation[81] by offer price and 2) available generation by marginal cost estimate, and then intersecting real-time demand with each. The real-time price cost markup is presented in Table 2-3 below.

Table 2-3: Real-Time Price Cost Markup, %

Year	Price-Cost Markup
2018	-8.9%
2019	-7.4%
2020	-3.1%
2021	0.2%
2022	-1.7%

Annual load-weighted markups were close to zero or negative during all years of the reporting period. Consequently, average generator offers were close to or below marginal costs, indicating that competition limited participants' abilities to inflate real-time prices.

Gas-fired generator offer behavior had the largest impact on annual markup values. Gas-fired generators may offer at values lower than their estimated marginal costs for multiple reasons,

[80] Note that the IMM's estimates of marginal cost are an approximation of actual marginal costs, and the simulations used to calculate the price-cost markup are subject to modeling differences when compared to the market model the ISO runs for the day-ahead market.

[81] Available generation is equal to on-line generation plus generation capacity that can come on-line within 30 minutes. It comes from on-line generators (both long lead-time and fast-start) and off-line fast-start generators.

including managing gas burn to nominations or offering lower output levels below their fuel price adjusted reference level.[82] Renewable generator offer behavior also tend to reduce markups, but to a lesser extent. Though it is common for renewable generators to offer below marginal cost, these generators are typically smaller and/or export-constrained.

Differences between the real-time and day-ahead price cost markups values are due to several factors, including: 1) differences in the methodologies used to calculate the price cost markup in each respective market; 2) modeling differences between the day-ahead and real-time energy markets; and 3) real-time events that the day-ahead market did not anticipate.

2.1.6 Real-Time Economic Withholding

Economic withholding occurs when suppliers offer above marginal cost in order to prevent some generation that would otherwise be economic from clearing, which in turn raises the market price. The quantity that does not clear as result of suppliers offering above cost is considered economically withheld.

We estimate the economically withheld MWs for each generator in every real-time interval as the difference between:

a) the quantity that was economic (i.e., the sum of MWs where marginal cost ≤ LMP) and,
b) the actual quantity offered (i.e., the sum of MWs where offer price ≤ LMP).[83]

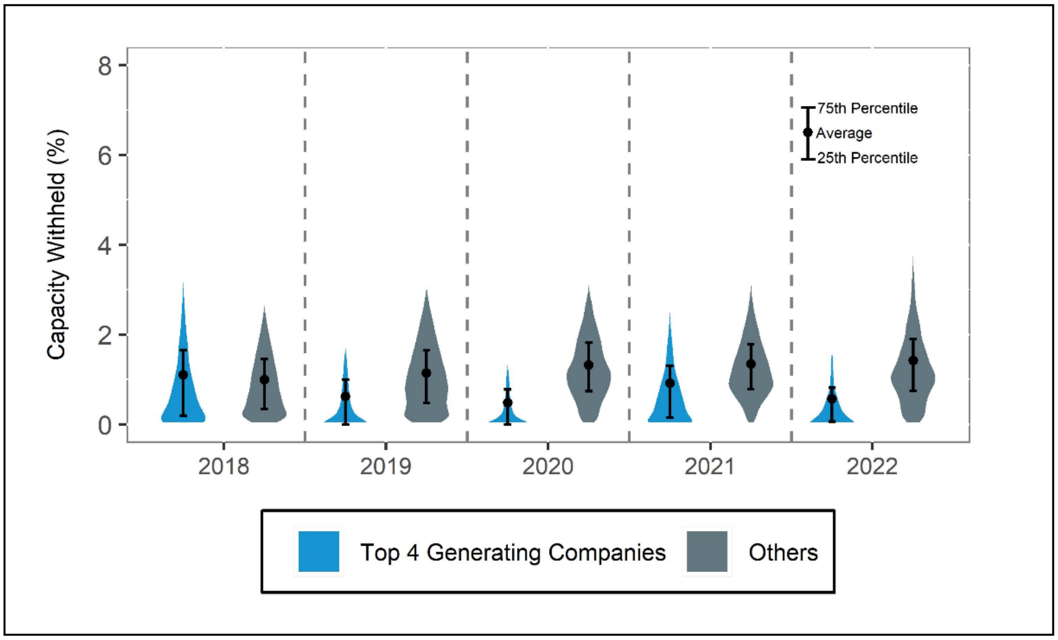
In cases where the quantity offered exceeds the quantity that was economic, the withheld MWs are set to zero (i.e., withheld MWs cannot be negative). This analysis considers only non-fast-start generators that are online and all fast-start generators (online or offline), and it does not assess potential withholding by offline, non-fast-start generators.

Hourly economic withholding (as a percent of capacity) during on-peak hours in each of the past five years is summarized in Figure 2-4 below. Note the curves depict the distribution of hourly withholding, where the widest sections of each curve represent the most-frequently observed levels of withholding. Results are broken down for two groups: combined withholding by the top four generating companies (those with the largest share of generation) versus all others.

[82] The most extreme negative markup values occurred during the winter months, when generators are more likely to have fuel price adjustments (FPAs) in place. FPAs are applied to the entire output curve and replace the default gas index value, but gas-fired generators often use FPAs to reflect the price of incremental gas needed at higher output levels, which might be higher than the market value of liquidating gas that they have already purchased.

[83] For example, if the LMP is $30/MWh and a participant offered 50 MW at $45/MWh but had a $20/MWh marginal cost, then those 50 MW would be considered economically withheld. The IMM cost-based reference level is used as the generator's marginal cost. The calculation accounts for ramp rate limitations and fast-start generators' startup and no-load costs.

Figure 2-4: Hourly Real-time Economic Withholding During On-Peak Hours



In 2022, economic withholding was relatively low across both groups (generally below 2%) and generally in line with levels seen in past years. Although not presented in the figure, levels of economic withholding did not increase when reserve margins where low, suggesting that suppliers were largely unable or did not attempt to take advantage of tight system conditions by economically withholding.

2.2 Energy Market Mitigation

The IMM reviews energy market supply offers for generators in both the day-ahead and real-time energy markets. This review minimizes opportunities for participants to exercise market power.[84] Under certain conditions, the IMM will mitigate generator supply offers. Mitigation results in a participant's financial parameters for a generator supply offer (i.e., start-up, no load, and segment energy offer prices) being replaced with "reference" values. The reference values are estimated and maintained by the IMM; these values are used in mitigation to reduce impacts on energy market pricing (LMPs) and uplift payments (NCPC) from participant offers that appear to overstate a generator's operating costs.[85]

In this section, we review the frequency and underlying drivers of the various forms of energy market mitigation in the day-ahead and real-time energy markets (2.2.1). We also provide an overview of a number of issues we identified through our ongoing assessment of mitigation rule performance, and we make a number of recommendations on design enhancements (2.2.2).

[84] This review of supply offers is automated (along with the offer mitigation process), and occurs within the ISO's energy market software.

[85] Seven mitigation types utilize mitigation tests and are used in ex-ante supply offer mitigation. An eighth mitigation type for dual-fuel generators is performed after-the-fact, when a dual-fuel generator burns a low-priced fuel but submits supply offers based on a higher-cost fuel.

Key Takeaways

Energy market mitigation is an infrequent occurrence. In 2022, only 930 asset hours of mitigation occurred, compared to 1.3 million asset hours of generator operation that were subject to potential mitigation. Over the past five years, mitigation instances have been relatively stable, fluctuating between 874 and 990 asset hours per year. Mitigation frequencies are low because: (1) energy market mitigation requires that up to three tests (structure, conduct, impact) be failed, prior to the imposition of offer mitigation; and (2) the tests typically have relatively tolerant thresholds for triggering a test failure. Note that the summary data for mitigation outcomes in Figure 2-5 below utilizes data that have been scaled relative to asset hours subject to mitigation.

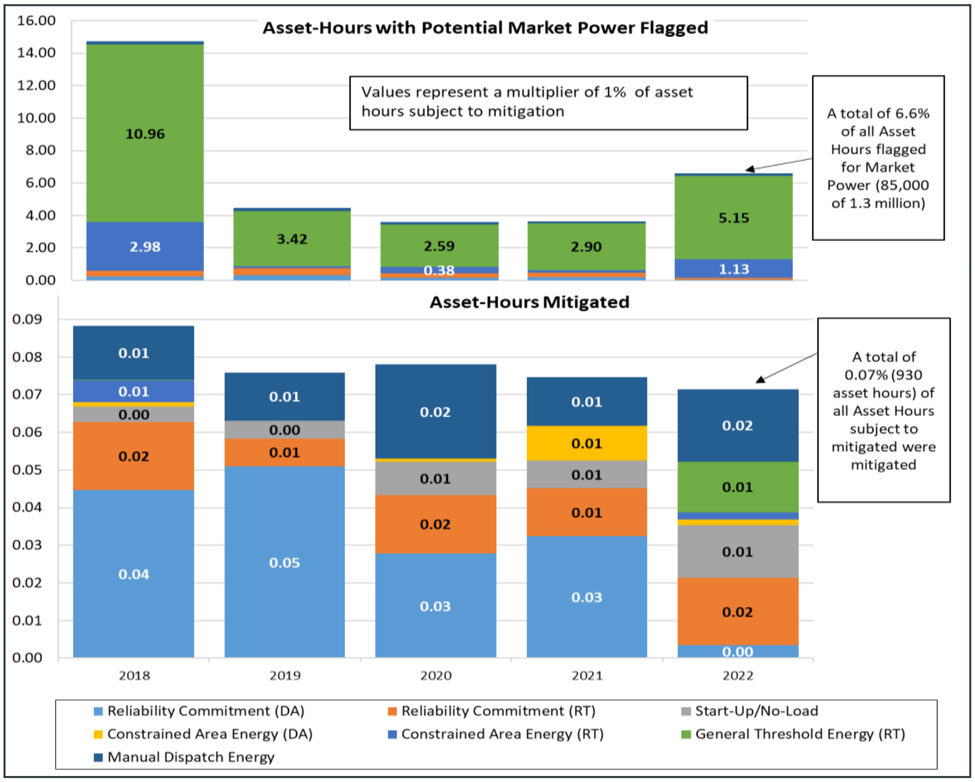
2.2.1 Mitigation Outcomes and Drivers

An indication of mitigation frequency, relative to opportunities to mitigate generators, is illustrated in Figure 2-5 below.[86, 87] It compares asset hours of structural test failures for dispatch and commitment (depending on mitigation type) to asset hours of mitigations. To provide additional context, the values in the figure represent multiples of one percent of total asset hours subject to potential mitigation.

[86] Asset hours refer to the commitment and operation hours of a generator. For example, a generator (asset) committed for reliability for a 12-hour period would represent 12 asset hours of commitment. If that asset were mitigated upon commitment, then 12 asset hours of mitigation would occur. For constrained areas, if 10 assets were located in an import-constrained area for two hours, then 20 asset hours of structural test failures would have occurred. If a pivotal supplier has seven assets and is pivotal for a single hour, then seven hours of structural test failures would have occurred for that supplier; however, more than one supplier may be pivotal during the same period (especially during tighter system conditions), leading to a larger numbers of structural test failures than for other mitigation types. Manual dispatch energy commitment data indicate asset hours of manual dispatch (i.e., the asset hours when these generators are subject to commitment). Finally, Start-up and no-load commitment hours are not shown because mitigation hours equal commitment hours.

[87] Because the general threshold commitment and constrained area commitment conduct tests resulted in only two instances of mitigation during the review period, those mitigation types have been omitted from the figure. The structural test failures associated with each mitigation type are the same as for the respective general threshold energy and constrained area energy structural test failures. Ex-post, dual-fuel mitigation also is not summarized in the graphs, since the process for applying that mitigation does not involve conduct, structural and market impact tests. However, we do provide results for this mitigation type in the discussion provided below.

Figure 2-5: Energy Market Mitigation



On average, approximately 1.2 million asset hours of ISO-committed generation are subject to the IMM's mitigation rules each year.[88] In 2022, the total asset hours reached 1.3 million asset hours, with approximately 85,000 asset hours (6.6%) failing structural tests. Mitigation asset hours represented a very small fraction of potential asset hours subject to mitigation. For example, real-time reliability commitment mitigation totaled just 231 asset hours for 2022, equaling 0.02 of asset hours scaled to 1% in the figure.

Overall, mitigation occurs very infrequently relative to the initial triggers for potential mitigation. The highest frequency of mitigation occurs for reliability commitments (0.02% in 2022, light blue and orange shading) driven by the frequency of local reliability commitments and the relatively tight conduct test thresholds (10% supply offer/reference level threshold). General threshold (pivotal supplier) mitigation and constrained area mitigation (green, dark blue, and yellow shading) have had the lowest mitigation frequency, just 0.01% of asset hours in 2022. Both of these mitigation types have relatively tolerant conduct test and market impact test thresholds, reducing the likelihood of mitigation given a structural test failure.

Reliability commitment mitigation: Reliability commitments primarily occur to satisfy local reliability needs, and are generally due to routine transmission line outages, outages facilitating

[88] The asset hours subject to mitigation are estimated as on-line generators with a dispatchable range above eco min. Each such on-line generator during a clock hour represents one asset hour of generation potentially subject to energy market mitigation.

upgrade projects, or localized distribution system support.[89] While real-time reliability commitments declined in 2022, mitigation asset hours increased (from 164 to 231), compared to 2021, as a result of two generators that were needed for localized transmission needs being frequently mitigated. Overall, reliability mitigations in the day-ahead market have declined significantly since 2019 (from 587 asset hours to 46 asset hours in 2022).[90] This decrease resulted from both a decline in reliability commitment asset hours (decline from 3,765 to 522 asset hours) and of mitigated offers in Maine and SEMA-RI (decline of 540 to 30 asset hours), the two areas with the highest frequency of reliability upgrades.

Start-up and no-load (SUNL) commitment mitigation: This mitigation type addresses grossly over-stated commitment costs (relative to reference values), which could otherwise result in very high uplift.[91] SUNL mitigations occur very infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate – particularly natural gas. Generators associated with just three participants accounted for 84% of these mitigations. There were just 183 asset hours of SUNL mitigation in 2022.

Constrained area energy (CAE) mitigation: With relatively tolerant conduct and market impact test thresholds, the frequency of this mitigation is low relative to the frequency of structural test failures. Over the five-year period, only 91 asset hours occurred in the real-time energy market and only 162 asset hours in the day-ahead energy market. The frequency of structural test failures follows the incidence of transmission congestion and import-constrained areas within New England.[92] The 2022 structural test failures totaled 15,000 asset hours. In fall 2022, a constraint in Connecticut resulted in a large number of structural test failures during the month of November (i.e., 10,000 asset hours). Both planned and unplanned transmission outages caused this constraint. Although this constraint caused an 11-fold increase in structural test failures (compared to summer 2022), only a total of 23 asset hours of mitigation occurred during fall 2022.

General threshold energy (GTE) mitigation: This mitigation type has the lowest frequency of any mitigation type, and has the most tolerant conduct test and market impact thresholds. GTE mitigation occurred for only 175 asset hours in 2022. This happened despite of the highest frequency of structural test failures (i.e., pivotal supplier asset hours) for any mitigation type. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators. Five participants accounted for 74% of the structural test failures over the review period.

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[89] This mitigation category applies to most types of "out-of-merit" commitments, including local first contingency, local second contingency, voltage, distribution, dual-fuel resource auditing, and any manual commitment needed for a reason other than meeting system load and operating reserve constraints. See Market Rule 1, Appendix A, Section III.A.5.5.6.1.

[90] Reliability commitments are typically made in the day-ahead energy market and carry over to the real-time energy market. Hence, day-ahead reliability commitments account for approximately 69% of the reliability commitment asset hours in the real-time energy market.

[91] The conduct test for this mitigation type compares a participant's offers for no-load, start-up and incremental energy cost up to economic minimum to the IMM's reference values for those same parameters. It uses a very high conduct test threshold (200% applied to the start-up, no-load, and offer segment financial parameters).

[92] Day-ahead energy market structural test failures are not being reported at this time. This results from questions about some of the source data for these failures. We expect to report on these structural test failures in future reporting.

Manual dispatch energy (MDE) mitigation: Manual dispatch energy mitigation can occur when a generator is manually dispatched by the ISO in the real-time market. Like reliability commitment mitigation, manual dispatch energy mitigation has a relatively tight conduct test threshold (10%), and had comparable mitigation hours in 2022. There were 1,780 asset hours of manual dispatch and 251 asset hours of mitigation. Manual dispatch is relatively infrequent in the real-time energy market, with typically fewer than 2,000 asset hours occurring each year and primarily (85%) involving combined-cycle generators.[93]

Dual-fuel ex-post mitigation: Dual-fuel mitigations occur relatively infrequently, typically fewer than 100 asset hours of mitigation per year. In 2022, only five asset hours of dual-fuel mitigation occurred; this happens when a dual-fuel generator's reference level is set to the highest-cost fuel but the generator actually operates using its lower cost fuel.

[93] This is consistent with manual dispatch frequently occurring in the context of (1) regulation service provided to the real-time energy market and (2) the need for relatively flexible generators to be positioned away from the market software-determined dispatch to address short-term issues on the transmission grid.

2.2.2 Energy Market Mitigation Assessment

The IMM routinely assesses how the energy market mitigation rules and processes are functioning.[94] This is done with the perspective of relying on competition to drive efficient prices and incentives, and intervening only when markets are structurally uncompetitive and participants may have the ability and incentive to exercise market power and inflate prices above competitive levels. The market power mitigation rules need to strike a reasonable balance between producer and consumer interests, and in turn prescribe adequate threshold tests to determine when market monitors override generators supply offers.

Recommendation

We have identified a number of areas of potential improvement to the current rules and we recommend for ISO and stakeholder consideration. In particular, IMM recommends that the following four issues be addressed:

1. Review of the current mitigation thresholds that apply to instances of system-wide and local market power. The current thresholds allow for considerable latitude in supply offers levels over competitive benchmarks (300% and 50%) and have been in place for many years with little empirical support. With the benefit today of a rich history of supply offer data and robust simulation tools to measure impact and incentives of withholding, the assessment would consider whether the current thresholds adequately limit the exercise of market power under a plausible set of system scenarios.
2. Eliminate the energy offer mitigation exemption for non-capacity resources in the day-ahead energy market.
3. Extend the scope of offer mitigation to cover the potential exercise of market power in export-constrained areas.
4. Review the methodologies for determining reference levels, which are used to evaluate if an offer is competitive (the "conduct test"). Currently, reference levels can be based on marginal cost, or historical fuel-adjusted accepted supply offers or LMPs. We have observed instances in which the latter two methodologies produce unreasonably high reference levels. In particular, we recommend that only marginal cost-based reference levels be relied on for generators that have robust cost estimates with the IMM.

Mitigation Thresholds

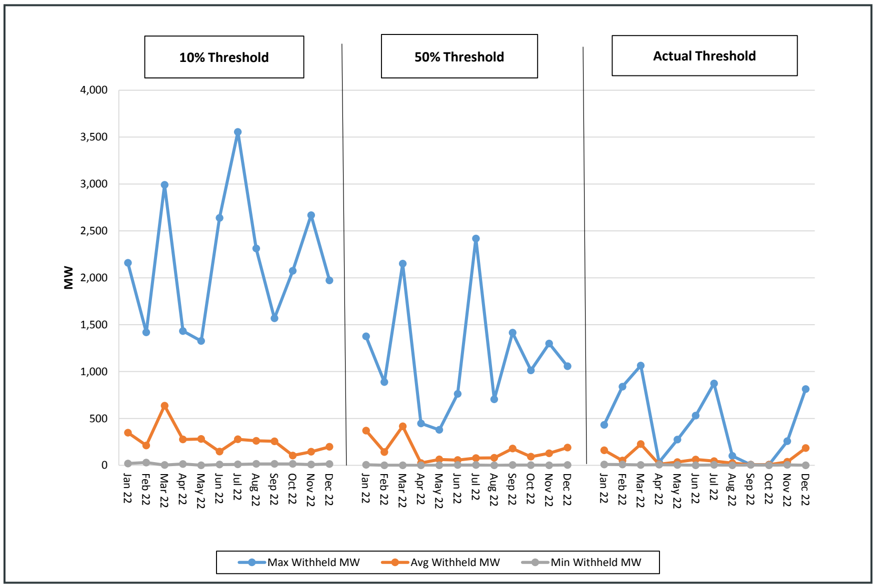
The current mitigation rules potentially allow for economic withholding in the ISO's energy markets because of relatively generous mitigation thresholds. The current mitigation rules rely on up to three tests, before mitigation is applied to a generator's energy market supply offer: a structural test, a conduct test and an impact test.[95]

[94] The External Market Monitor also has responsibility for assessing the quality and appropriateness of the ISO's supply offer mitigation activities. See Market Rule 1, Appendix A, Section 2.2.(d).

[95] The IMM believes that a review of the threshold levels for both the conduct and impact tests would be appropriate, to ensure that opportunities for uncompetitive behavior have been minimized.

As an example of our concern with the current thresholds, we have summarized instances of potential economic withholding for "general threshold energy" (GTE) in the real-time energy market. Figure 2-6 provides summary statistics for pricing intervals during 2022, when at least one supplier was pivotal (i.e., failed the mitigation structural test) and pivotal supply was offered at three different conduct test threshold levels: 10% above the marginal cost of supply, 50% above the marginal cost of supply, and the current conduct test threshold (i.e., the minimum of 300% or $100 above the marginal cost of supply).

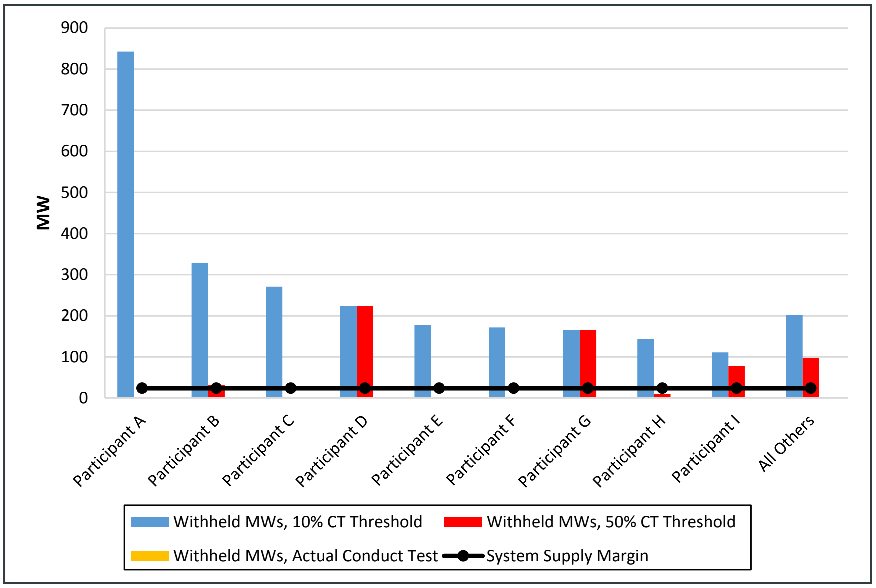
Figure 2-6: Potential Economic Withholding, General Threshold Energy



In 2022, the potentially-withheld capacity during these intervals averaged between 100 and 600 MW, depending on the month. The potential withholding exceeded 1,000 MW during at least one 5-minute interval in every month. At the increased conduct test threshold levels, conduct test failures declined significantly. At the 50% conduct test threshold, potentially-withheld megawatt levels decline by 40-50% in most months. At the current conduct threshold level, average potential withholding is quite low, ranging from approximately 10 MW to 200 MW.

Further, we highlight a pricing interval in June 2022, when potential economic withholding under the GTE mitigation rules exceeded 2,000 MWs in the real-time energy market. During this interval, the system supply margin was 24 MW (indicating an extremely constrained supply position, relative to demand, in the real-time energy market). Figure 2-7 summarizes the capacity offered by pivotal suppliers that was priced at more than 10%, 50% and 300% in excess of the supply's marginal cost.

Figure 2-7: Supply Controlled by Pivotal Suppliers on June 13, 2022, During HE 18 (Interval 2)



More than 10 pivotal suppliers had energy market offers that were in excess of 10% above marginal cost. Nine of these suppliers had more than 100 MW of supply priced in excess of this level, with one pivotal supplier offering more than 800 MWs priced above this level. These offers on a weighted average basis exceeded marginal cost by 43%. At the 50% threshold, seven suppliers had energy market offers more than 50% above marginal cost, constituting 600 MW of supply. At the 300% threshold, no supplier failed the conduct test threshold. Given these results, we are concerned that the current mitigation thresholds may not provide adequate safeguards against the exercise of market power in the ISO's energy markets.

Supply Offers Not Associated with a Capacity Supply Obligation

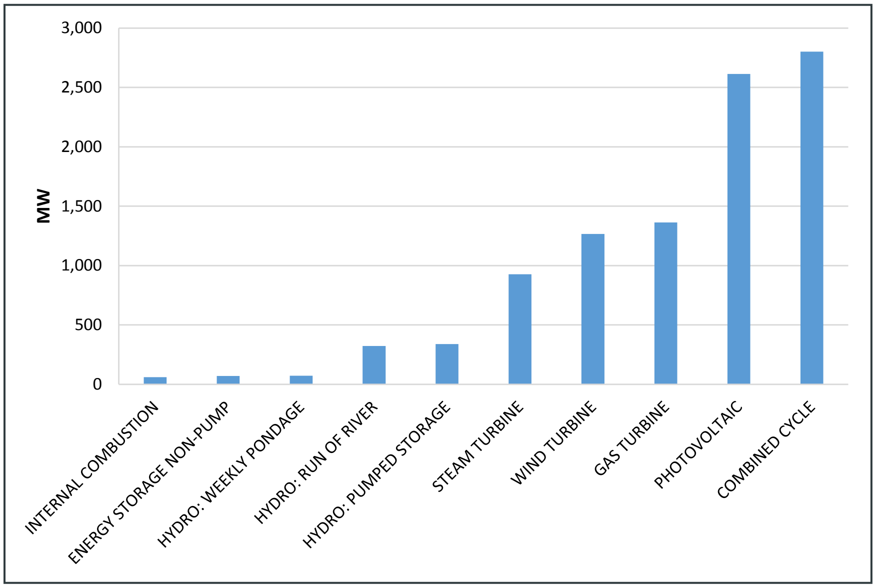
Under the economic withholding rules, offer mitigation does not apply to non-capacity resources in the day-ahead energy market, and only applies up to (and including) the energy segment corresponding to the capacity supply obligation (CSO) for resources with partial capacity obligations. All components of the supply offer are evaluated for economic withholding in the real-time market. We are concerned that the omission of mitigation rules in the day-ahead market for resource capacity lacking a CSO creates an opportunity for economic withholding. In November 2022, we outlined the rationale for ensuring reasonably comprehensive mitigation rules:

> Under FERC's market-based rate approach, prices resulting from market-based rates are just and reasonable if they are a result of competitive markets among participants that lack market power and/or are mitigated. In other words, market prices must be competitive in order to be just and reasonable. Because electricity markets are more susceptible to the exercise of market power from suppliers than many other markets due to the relative inelasticity of demand, mitigation measures are relied upon to limit the exercise of market power. Effective rules that mitigate or deter the exercise of

market power are critical to assuring competitive outcomes and just and reasonable rates.[96]

Currently, almost 10 thousand MWs of active capacity (as measured by winter claimed capability) does not have a CSO associated with it. Figure 2-8 summarizes this capacity by asset type.

Figure 2-8: Generator Capacity Lacking a CSO by Asset Type



With the exception of photovoltaic capacity which currently is non-dispatchable, these capacity types (totaling approximately 7,200 MW) use supply offer pricing to determine dispatch in the ISO's energy markets. These supply offers can be used by participants with market power to economically withhold capacity, irrespective of whether the capacity is associated with a CSO. The successful exercise of market power (for capacity with or without a CSO) would result in uncompetitive market outcomes that result in market prices that are not just and reasonable.

Export Constrained Mitigation

Constrained area energy (CAE) mitigation only applies to import-constrained areas. CAE mitigation does not address the potential for economic withholding within *export-constrained* areas. There may be instances when export-constrained areas allow for the exercise of market power by a participant. These instances occur when there is insufficient competition behind the export constraint to result in participant supply offers reflecting competitive pricing levels; instead, offer pricing may reflect an estimate of higher price levels (LMPs) available outside of the export-constrained area, resulting in elevated pricing behind the export constraint. This behavior is uncompetitive, undermines locational pricing signals, and raises costs to consumers above the level expected in a competitive market.

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[96] See IMM's memorandum re ["Current Market Rules on Physical Witholding"](#) November 30, 2022. The memorandum was provided to the NEPOOL Markets Committee.

Reference Pricing Methodology

The ISO's current methodology for setting reference prices for incremental energy offers can result in values that do not reasonably approximate a competitive offer. The current reference price methodology uses three methods for estimating reference prices: accepted offer, LMP, and marginal cost.[97] The reference level is biased upward by the methodology providing a preference for accepted offer and LMP-based reference values, as long as they are greater than the marginal cost reference value. The accepted offer and LMP pricing methodologies utilize historical data for setting reference prices, based either on a generator's accepted offers during the prior 90 days or LMPs during operating hours over the prior 90 days. For generators that may be called on-line during periods with high energy market prices and otherwise operate very infrequently, the current reference pricing methodology can result in significant distortions in reference pricing over the subsequent 90 days after operation.

Figure 2-9 provides an example of distorted reference pricing after the December 24, 2022 system event. The figure shows the actual reference prices used for a generator on March 11, 2023 in the real-time energy market, relative to its marginal cost pricing level for that day.

Figure 2-9: LMP-Based and Marginal Cost Reference Prices

As indicated in the figure, the reference prices (blue bars) are equal to the marginal cost reference levels (orange line) in most hours. However, in hours 17-19, the reference levels are based on the LMP methodology. The LMP-based reference prices continue to reflect the very high LMPs that occurred during the system event from almost three months prior, and range from $500 to $1,000/MWh. The LMP-based reference prices are not reflective of the generator's marginal cost of operation or other measures of potential opportunity costs of operation for March 11. Such distortions in reference levels create opportunities for participants to economically withhold capacity, whenever high energy market prices or high fuel prices from prior periods result in overstated accepted-offer and LMP-based reference levels.

[97] See Market Rule 1, Appendix A, Section 7.2.

2.3 Forward Capacity Market

In this section, we review the structural competitiveness of the Forward Capacity Market (FCM) using two metrics: the Residual Supply Index (RSI) and Pivotal Supplier Test (PST).

Key Takeaways

The results of two complementary competitiveness metrics - the residual supply index and the pivotal supplier test - indicate that, over the past five auctions, the New England capacity market has been structurally competitive at the system level. The capacity market was most competitive entering FCAs 14, 16, and 17, with an RSI of over 100% (no pivotal suppliers).

Reductions in the Net Installed Capacity Requirement due to lower peak forecasts and higher tie benefits, along with the absence of major retirements over the past two FCAs, has resulted in a higher capacity margins heading into the auction. Consequently, structural competitive indices have improved. Further, in FCA 17 SENE was not modelled as an import constrained zone due to a decrease in the zonal load forecast and an increase in the import capability limit into the zone. This enhanced the overall competitiveness of the capacity market.

In FCA 17, there were no pivotal suppliers and the residual supplier index was 102%. A supplier would have needed a portfolio of over 3,600 MWs to be pivotal.

Similar to the PST and RSI calculated for the energy market, we account for affiliations between suppliers to reflect all capacity under a supplier's control.[98] For each Forward Capacity Auction (FCA), we consider the qualified capacity of existing resources prior to the auction given the difficultly of predicting intra-auction new supply behavior. Both metrics are calculated for the import-constrained zone (Southeastern New England or SENE), in addition to the larger system.

For the purposes of market power mitigation, de-list bids from a pivotal supplier above the dynamic de-list bid threshold may be subject to mitigation.[99] This process ensures that suppliers do not withdraw capacity from the auction at uncompetitive prices to raise the FCA clearing price in a way that may benefit the remainder of their portfolio.

The PST the RSI rely on the following inputs:

- *Capacity requirements* – both at the system level (Net Installed Capacity requirement, or Net ICR) and the import-constrained area level (Local Sourcing Requirement, or LSR). The Net ICR and LSR change from year to year.
- *Capacity zone modelling* – different capacity zones are modelled for different FCAs depending on the quantity of capacity in the zone and transmission constraints.

[98] As defined in Section III.A.23.4 of the Tariff, for the purposes of this test, "the FCA Qualified Capacity of a supplier includes the capacity of Existing Generating Capacity Resources, Existing Demand Resources, Existing Import Capacity Resources, and New Import Capacity Resources (other than (i) a New Import Capacity Resource that is backed by a single new External Resource and that is associated with an investment in transmission that increases New England's import capability; and (ii) a New Import Capacity Resource associated with an Elective Transmission Upgrade)."

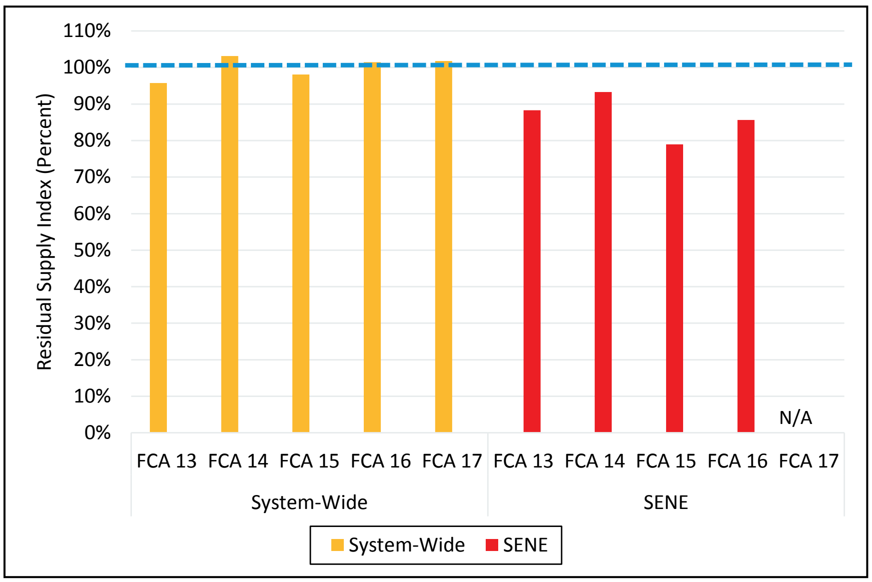
[99] Note that there are certain conditions under which capacity is treated as non-pivotal. These conditions are described in Section III.A.23.2 of the Tariff.

- *The total quantity of existing capacity* – a value driven by retirements from existing resources and additions from new resources (which become existing resources in subsequent years.
- *Supplier-specific portfolios of existing capacity* – values that can change year-over-year as a result of mergers, acquisitions, divestitures, affiliations, resource performance, etc. To avoid providing supplier-specific data, these are not described in any detail in this document, but should be taken into account when considering the analysis.

Residual Supply Index Results

The RSIs for the system and for each import-constrained zone over the past five FCAs are shown in Figure 2-10 below.

Figure 2-10: Capacity Market Residual Supply Index, by FCA and Zone



The primary outcomes from FCA 17 were: 1) the system-wide RSI was above 100% for the second auction in a row; and 2) the SENE zone was not modelled.

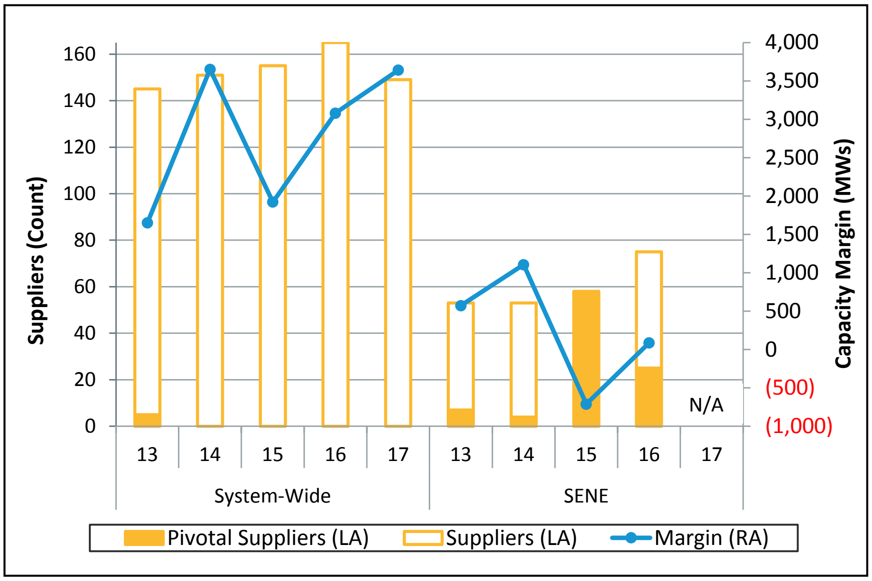
The RSI in FCA 17 was 102%, which indicates that Net Installed Capacity requirement (Net ICR) could still be satisfied without the largest supplier. There was no pivotal supplier at the system level. Existing capacity remained relatively stable between FCA 16 and FCA 17, while Net ICR decreased from 31,645 MW in FCA 16 to 30,305 MW in FCA 17. The decrease was driven by lower peak load forecasts as well as greater net tie benefits from transmission across the New York interface, which had the effect of reducing reliance on capacity resources to meet load. There were also no significant retirements in FCA 16 and 17. The larger system margins meant the suppliers would have to be much larger in FCA 17 than in FCA 16, which was not the case.

There were no zonal RSI values (red) in FCA 17. The Southeastern New England zone was removed mainly due to a decrease in the zonal load forecast and an increase in the import capability limit into the zone.

Pivotal Supplier Test Results

The number of suppliers and pivotal suppliers within each zone over the past five FCAs are presented in Figure 2-11 below. To provide additional insight into the approximate portfolio size needed to be pivotal, the figure also presents the margin by which capacity exceeded or fell below the relevant capacity requirement. For example, consider the SENE capacity zone in FCA 14. The amount of existing capacity exceeded the local sourcing requirement (LSR), resulting in a capacity margin of 1,105 MW (right axis – blue marker). Consequently, only suppliers with a portfolio greater than 1,105 MWs in this zone were pivotal in FCA 14. Of the 53 suppliers in SENE in FCA 14 (left axis – yellow bar), only four (highlighted in yellow) were pivotal.

Figure 2-11: Overview of Suppliers, Pivotal Supplier, and Capacity Margin, by Zone



At the system level, the capacity margin remained high over the past five FCAs. In FCA 17, a supplier needed a portfolio of over 3,600 MWs to be pivotal, resulting in no pivotal suppliers. The increase in the system capacity margin from roughly 1,900 MWs in FCA 15 to over 3,600 MWs in FCA 17 was driven largely by a significant decrease in net ICR. For FCA 15, in SENE, the amount of capacity was less than the LSR, resulting in a capacity margin of approximately -711 MWs. Consequently, every supplier located in SENE of every portfolio size was pivotal. As covered above, the SENE did not need to be modelled in FCA 17 as an import-constrained zone, which improved the overall structural competitiveness of the FCM.

When the market is not structurally competitive, buyer- and supplier-side mitigation rules are in place to prevent the potential exercise of market power. While a pivotal designation may indicate the ability to influence clearing prices, a de-list bid is necessary to exercise it. In FCA 17, there were 25 MWs of de-list capacity subject to the pivotal supplier test.[100] Since there

[100] Static and retirement de-list bid capacity that is 1) below the FCA starting price and 2) had not been withdrawn prior to the auction, is shown here. A static de-list bid is entered in the auction as a sealed bid and indicates the minimum price at which an existing capacity resources seeks to retain a capacity supply obligation. Static de-list bids belonging to a pivotal suppler are subject to IMM mitigation if the bid is deemed uncompetitive. Dynamic de-list bids are entered during the auction below a given threshold and are not subject to Tariff prescribed market power tests and mitigation. Retirement

were no pivotal suppliers in FCA 17, none of the de-list bids were part of a pivotal portfolio. Therefore, participant-submitted de-list bid prices were used in the FCA. This is discussed in the next section.

2.4 Forward Capacity Market Mitigation

In this section, we provide a summary of the mitigation measures employed in the FCM between FCA 13 and FCA 17. The first subsection (2.4.1) looks at supplier-side mitigation for existing resources. The second subsection (2.4.2) covers buyer-side mitigation, namely the Minimum Offer Price Rules (MOPR) for new resources.[101]

Key Takeaways

There were no significant retirement or permanent de-list bid reviews by the IMM in FCAs 16 or 17. However, older fossil-fueled resources used dynamic de-lists to exit the FCAs for one year at a time. There was a significant retirement in FCA 15, when Mystic 8 and 9 were allowed to retire after a two-year reliability retention for fuel security.

There have been a notable number of static de-list bids (85% of a capacity) denied by the IMM over the past five years. There were no pivotal suppliers in FCA 17, therefore no de-list bids were mitigated.

There were no Offer Review Trigger Price (ORTP) challenges in FCA 17 from renewable resources. We attribute this to lower ORTP values for batteries and solar resources and the re-introduction of the renewable technology resource (RTR) exemption that allowed new renewable resources to qualify for the FCA irrespective of their ORTP.

2.4.1 Supplier-Side Market Power

The IMM reviews certain de-list bids to determine if they are consistent with a resource's avoidable costs of a capacity supply obligation; i.e., its net going forward operating and capital costs, including expected capacity performance payments, risk premium, and opportunity costs. While there are a variety of de-list bid types, only a few require review by the IMM prior to the auction. Those include: general static de-list bids, import and export bids, retirement de-list bids and permanent de-list bids.[102]

Retirement and permanent de-list bids

Retirements and permanent de-list bids are removed from the capacity market – permanently – when the FCA clearing prices falls below the bid value. All bids for capacity exceeding 20 MW are subject to an IMM cost review and potential mitigation. For the past two auctions, FCA 16 and 17, there has not been any significant retired or permanently delisted capacity, despite low

and permanent de-list bids (>20 MW) are subject to a net benefits test, whereby the potential impact on clearing prices and the overall portfolio position is assessed.

[101] For more information on changes to the MOPR rule, see Section 8.

[102] The term "general" is used to differentiate between other types of static de-list bids, including ambient air static de-list bids and ISO low winter static de-list bids, which are not subject to IMM review.

capacity clearing prices. Resource owners may be waiting to assess how future market rules changes (removal of MOPR, Resource Capacity Accreditation (RCA), and Day-Ahead Ancillary Services(DASI)) will impact qualified capacity, going forward costs, and ultimately future FCA prices.

A substantial amount of capacity was retired in FCA 15 and reviewed by the IMM. The Mystic 8 and 9 resources (1,400 MW) will retire after a two-year reliability retention for fuel security for periods covering FCA 13 and 14 (up to June 2024). The IMM reviewed the retirement bids for these resources for FCA 13, which were mitigated down; however, they were subsequently compensated under the terms of a Cost of Service agreement, rather than at their mitigated retirement bid. Two other smaller retirements did take place (CDECCA and West Springfield 3), accounting for approximately 160 MW.

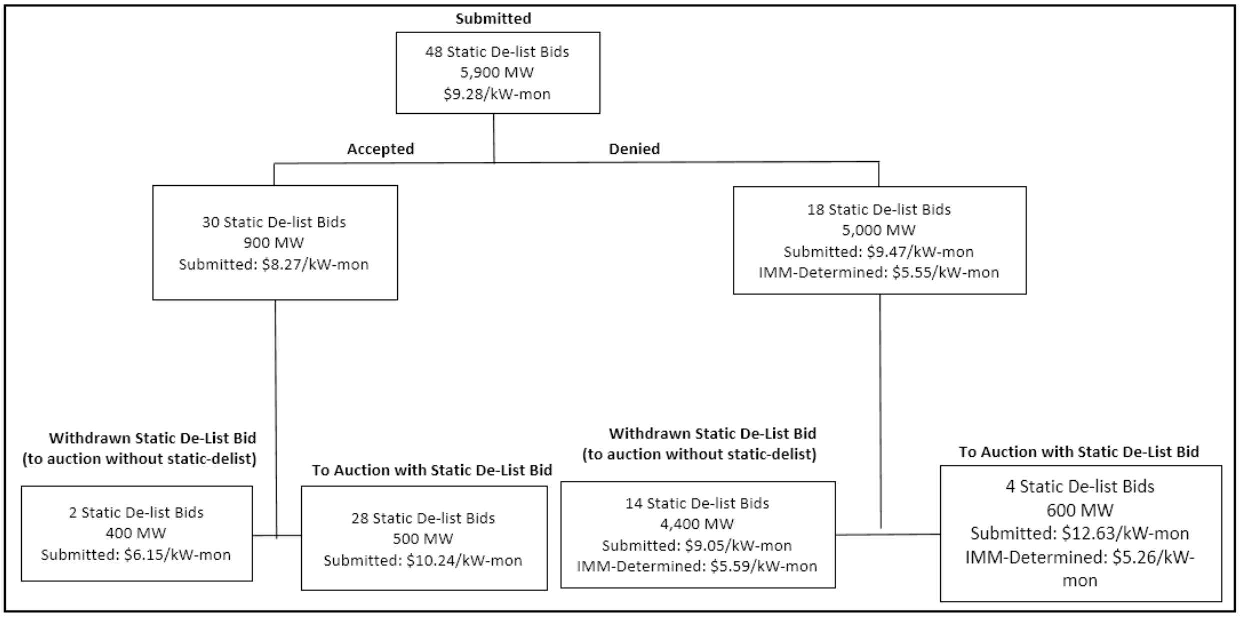
Static de-list bids

The IMM reviews all static de-list bids during the FCA qualification process, and issues a determination denying or accepting the bid value. Participant can take various actions after the IMM determination, including accepting the bid price, reducing or withdrawing the bid. Ultimately, only denied bids of pivotal suppliers are mitigated; the pivotal supplier test is performed closer to the auction date.

Summary statistics for static de-list bids from FCA 13 through FCA 17 as well as the path the bids took from the time of initial submittal to the auction are provided in Figure 2-12 below. Note that all de-list bid prices are megawatt-weighted averages.[103]

[103] Price calculations are not presented for new import capacity resources because, depending on the circumstances, the direction of the price difference can vary for price-quantity pairs within the same supply offer. Consequently, the resulting price difference summary statistics are less meaningful.

Figure 2-12: General Static De-list Bid Summary Statistics, by Key Milestone Action (FCAs 13 – 17)[104]



For FCA 13 through FCA 17, the IMM reviewed 48 general static de-list bids from 11 different lead participants, totaling roughly 5,900 MW of capacity (an average of 1,200 MW per auction).[105] Generation resources accounted for 99% of the total capacity and 44 of the 48 general static de-list bid submissions. Four demand response resources made up the remaining 44 MW of the total capacity. The IMM denied approximately 38% of the general static de-list bids (18 bids or 85% of de-list MW capacity), generally finding that the submitted bids were either inconsistent with the resource's net going forward costs or were not sufficiently supported.[106]

Roughly 60% of bids were accepted by the IMM without any changes (left box, second level). Of the static de-list bids that were denied, many were voluntarily withdrawn or the bid price further reduced prior to the auction. For resources that were denied and went to the auction (box furthest to the right, third level), the weighted-average price of denied static de-list bids was $7.36/kW-month less than the market participant's originally submitted price.

The number of static delist bids has decreased significantly in previous years. In 2013, the IMM received over 3,200 MWs of static de-list bids; since then, we have not received over 1,000 MWs in any year (and less than 500 MWs in FCA 17). Concurrently, the FCA rest-of-pool clearing prices have fallen below the dynamic de-list bid threshold in each year. When this occurs, existing resources are allowed to submit dynamic de-list bids without a review by the IMM. With high levels of surplus capacity, resource owners may: 1) deem the cost of review by the

[104] All MW values are rounded to the nearest hundred.

[105] A resource with a static de-list bid in each of the three auctions would be counted three times in the MW total; however, the associated lead participant is only counted once.

[106] If a supplier is pivotal, the IMM-determined value is entered into the auction; if not, the participant-submitted bid is entered. The mitigation only takes effect if the supplier is deemed pivotal, an evaluation that is done some months after the cost review process in completed.

IMM greater than the risk of not being able to dynamically de-list; and 2) see an opportunity to leave the auction without an IMM review.

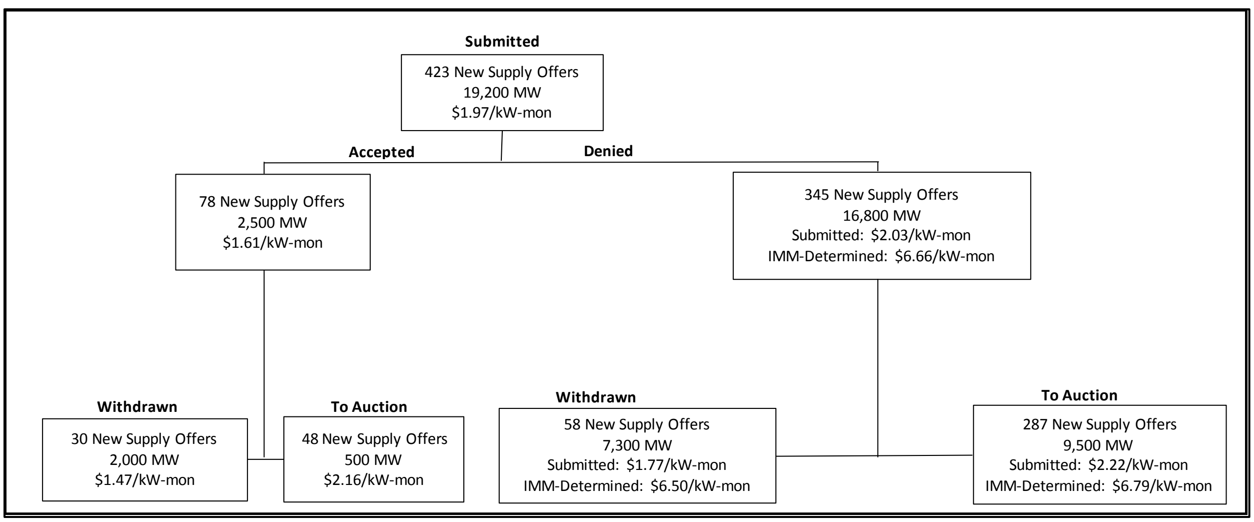
As discussed above, only de-list bids belonging to pivotal suppliers are mitigated. There were active de-list bids from pivotal suppliers in FCA 13 only; the four other auctions did not have any de-list bids from pivotal suppliers. In FCA 13, the denied de-list bids for three resources (628 MW) were mitigated in the auction. There were no pivotal suppliers in FCA 17, therefore no de-list bids were mitigated.

2.4.2 Buyer-side Market Power (Minimum Offer Price Rule)

For FCAs 13 through 17, the IMM reviewed 423 new supply offers[107] from participants requesting to offer below the offer review trigger price (ORTP).[108] These offers came from 59 different participants and totaled 19,200 MWs of qualified capacity, of which about 10,000 MW (~52%) entered the auction.[109] Non-emitting resources inclusive of battery storage, solar and wind made up 71% (11,200 MWs) of 19,200 MWs. Demand response resources accounted for 5% (1,200 MW) of total capacity reviewed and import resources accounted for 12% (2,400 MW).

Summary statistics for resources requesting to offer below their respective ORTP in FCAs 13 through 17 are provided in Figure 2-13 below.[110] Note that all offer prices are megawatt-weighted averages.

Figure 2-13: Reviewable Offer Request Summary Statistics, by Key Milestone Action (FCAs 13 – 17)



[107] Note that the count does not capture all unique resources. If a resource was mitigated in FCA 11 and did not clear, it could return in FCA 12 and would be captured twice in the count.

[108] Note that this total does not include supply offers from new import capacity resources without transmission investments, which are discussed in the supplier-side market power section.

[109] A resource with a new supply offer in each of the three auctions would be counted three times in the MW total. In addition, where FCA qualified capacity does not exist for a resource (e.g., the proposal was withdrawn or denied), the summer capacity from the resource's show-of-interest is used instead. Consequently, the presented total overstates the actual capacity.

[110] All MW values are rounded to the nearest hundred.

The IMM mitigated approximately 82% (345) of new supply offers it reviewed, or approximately 87% (16,800 MW) of new supply capacity.[111] Similar to supplier-side mitigation, the degree of MOPR mitigation can be measured by the relative increase in the offer floor price imposed by the IMM. The mitigation process (box furthest to the right, second level) resulted in an average increase in offer price of $4.57/kW-month (from a submitted price of $2.22/kW-month to an IMM-determined price of $6.79/kW-month).

In FCA 17, the IMM did not receive Offer Review Trigger Price (ORTP) challenges from any solar or battery resources. The ORTPs for solar declined from $1.381/kW-month in FCA 16 to $0/kW-month, due to updated renewable energy credit prices that reduced reliance on FCM payments. Battery storage fell from $2.601/kW-month to $0.79/kW-month due to reduced capital costs year-over-year, and high expected revenues based on higher energy futures than previously assumed. In addition to lower ORTP's for renewables, the ISO reintroduced the renewable technology resource (RTR) exemption in FCA 17. Total new qualified capacity under the RTR exemption reached the maximum allowance of 300 MW in FCA 17. RTR exempt resources may not have challenged their ORTP, since they cleared irrespective of the auction price.[112]

2.5 Financial Transmission Rights Market

In this section, we look at the concentration of Financial Transmission Rights (FTRs). In this context, market concentration refers to the extent to which FTR MWs are concentrated among participants.

Key Takeaways

The ownership of FTRs continued to be relatively highly concentrated in 2022 with the top four participants holding 66% of FTR MWs in the on-peak period and 69% in the off-peak period. There were 34 unique FTR holders in both the on-peak and off-peak periods in 2022, which marked the lowest levels of participation in the previous five years.

Anticipating what a competitive level of FTR ownership looks like is complex as it is unlikely to match system-level load-serving or generation ownership percentages. This is because there are not clear commercial reasons for all market participants to hold FTR positions (e.g., participants that serve load or own generation in unconstrained areas). Even those participants that could benefit may have risk preferences that favor exposure to day-ahead congestion over managing that exposure with the purchase of a financial instrument. Further, FTR market design permits the purchase of FTRs for financial speculation, so many FTR holders may have no load or generation position at all.

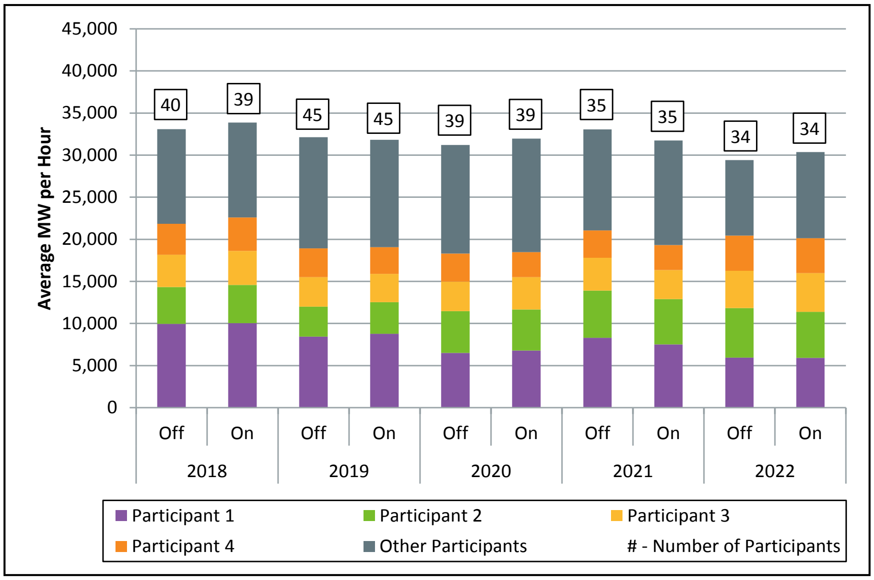
The concentration of FTR MWs among market participants in 2022 was similar to prior years. The average amount of FTRs held per hour by the top four participants with the most MWs each

[111] Note that the value does not capture all unique capacity. In other words, if a 100 MW photovoltaic (PV) resource was mitigated in FCA 16 and did not clear, it could return in FCA 17 and would be captured as 200 MW.

[112] See Section 6 of the AMR for more information.

year is shown in Figure 2-14 below.[113] This figure also shows the number of different participants that held FTRs each year (indicated by the number above each stacked column). This information is broken down separately for the on-peak and off-peak periods.

Figure 2-14: Average FTR MWs Held per Hour by Top Four FTR Holders by Year and Period



The top four participants held 66% of on-peak FTR MWs and 69% of off-peak FTR MWs in 2022. The concentration ratio of the top four FTR holders has stayed fairly stable over the reporting period, ranging between 58%-69%. However, the percentage of FTRs held by the largest FTR holder has trended downward over the reporting period. The largest FTR holder held 30% of on-peak and off-peak FTR MWs in 2018, but held only 20% of on-peak and off-peak FTR MWs in 2022. The total number of unique FTR holders fell to its lowest level of the reporting period in 2022 with only 34 unique participants in both the on-peak and off-peak periods. This is down modestly from the range of 35-45 different participants in the previous four years.

[113] The firms labeled "Participant 1," "Participant 2" and so on are not necessarily the same companies across all years; these are generic labels for the top four firms during a given year.

2.6 Ancillary Services

In this section, we review the competitiveness of the Forward Reserve Market (FRM) auctions and the regulation market. The first subsection (2.6.1) provides RSI results for the last 10 FRM auctions. The second subsection (2.6.2) reviews available regulation capacity relative to the regulation requirement and indicates the RSI for 2022.

Key Takeaways

Four FRM auctions during the review period were structurally uncompetitive at the system-level for TMNSR; three auctions were structurally uncompetitive for total thirty reserves. In all cases, variations in requirements and offered supply for each product resulted in RSI values below 100 (a structurally competitive result). In one instance, TMNSR supply in the Summer 2022 auction, the RSI declined significantly with a large reduction in offered supply.

At the zonal level, FRM TMOR auctions in the NEMA zone were structurally uncompetitive in 2018. After 2018, none of the modeled zones in the FRM auctions needed to procure supply.

The regulation market was structurally competitive in 2022, with available supply significantly exceeding the regulation requirement and with no supplier controlling enough supply to potentially have market power.

2.6.1 Forward Reserve Market

The competitiveness of the FRM is assessed using the Residual Supply Index (RSI) and is based on FRM offer quantities by participant and the operating reserve requirements in each auction.[114] The heat map provided in Table 2-4 below shows the offer RSI for TMNSR at a system level and for TMOR at a zonal level. The colors indicate the degree to which structural market power was present; red is associated with low RSIs, white with moderate RSIs, and green with high RSIs. Dark red indicates that structural market power was present, while dark green indicates that there was ample offered supply without the largest supplier.

[114] The RSI for TMNSR is computed at a system-level based on the total quantity of TMNSR offers across all reserve zones, excluding the largest TMNSR offer quantity by a single market participant. The RSI for TMOR is computed similarly for each reserve zone with a non-zero TMOR local reserve requirement. Given that the TMNSR quantity also satisfies the TMOR requirement, the TMNSR offer quantity in a zone is included in the total TMOR offer quantity within that zone.

Table 2-4: Offer RSI in the FRM for TMNSR (system-wide) and TMOR (zones)

Procurement Period	Offer RSI TMNSR (System-wide)	Offer RSI Total Thirty (System-Wide))	Offer RSI TMOR (SWCT)	Offer RSI TMOR (CT)	Offer RSI TMOR (NEMA)
Summer 2018	112	108	438	N/A	34
Winter 2018-19	127	127	N/A	N/A	21
Summer 2019	90	97	N/A	N/A	N/A
Winter 2019-20	120	118	N/A	N/A	N/A
Summer 2020	84	97	N/A	N/A	N/A
Winter 2020-21	102	115	N/A	N/A	N/A
Summer 2021	92	108	N/A	N/A	N/A
Winter 2021-22	110	116	N/A	N/A	N/A
Summer 2022	78	90	N/A	N/A	N/A
Winter 2022-23	109	112	N/A	N/A	N/A

At the system level, four (out of the ten) auctions had RSI values below the structurally-competitive level for TMNSR, TMOR or both.

TMNSR RSI values were below structurally-competitive levels in four of the five summer periods. In Summer 2019, the decline in TMNSR RSI resulted from a slightly increased requirement and a medium-sized supplier not participating in that auction. The Summer 2020 TMNSR results likewise had an increased requirement (up an additional 4% compared to Summer 2019), coupled with a small net reduction in supply offers (approximately 2% compared to the prior summer). The Summer 2021 RSI improved somewhat compared to the Summer 2020 RSI, with a small increase in supply and a small reduction in the requirement. In Summer 2022, the requirement did not change significantly from the prior summer auction, but supply in the auction declined by approximately 800 MW; the change in supply resulted in the decline in the RSI.

System-wide total thirty RSI values were not structurally-competitive for the Summer 2019, 2020 and 2022 auctions. In the 2019 and 2020 auctions, the RSI estimates were only slightly below the competitive level, reflecting slightly reduced supply and slightly increased reserve requirements in those auctions (relative to the other system-wide total thirty auctions). In Summer 2022, a small increase in the requirement and an approximately 200 MW reduction in supply offers compared to Summer 2021 resulted in the RSI decline. The decline in total thirty supply in Summer 2022 was the result of numerous supply offer changes (both increases and reductions in supply) compared to the prior summer auction.

Considering the *TMOR RSI at the zonal level*, only the NEMA/Boston zone had an RSI less than the structurally-competitive level. For the Summer 2018 and Winter 2018-19 auctions, every participant that offered forward reserve supply in NEMA/Boston was needed to meet the local requirement; in these auctions, every supplier for that zone had market power.

A Further Discussion of Summer 2022 Auction Competitiveness

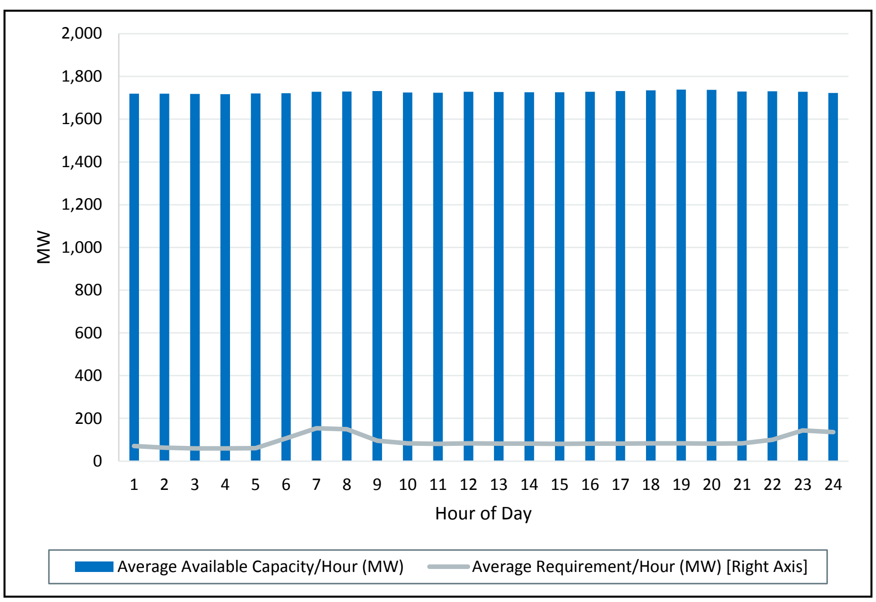
As noted earlier in this subsection, the Summer 2022 auction for the TMNSR product was not structurally competitive. The FRM is not subject to offer price mitigation and it is often structurally uncompetitive, i.e., demand is fixed and supply is limited. However, the IMM reviews each auction to assess whether the auction results are consistent with the results we would expect from a competitive process, i.e., did participants that had market power make competitive offers that reflected their anticipated costs? In evaluating the competitiveness of the Summer 2022 auction, we reviewed potential physical and economic withholding and found no evidence of the exercise of market power.

- Bid in supply was consistent with prior auctions including auctions when there was no pivotal supplier.
- Offer prices appeared to reflect a plausible range of anticipated costs of providing the service. Note, offer prices can vary significantly depending on the participant generation portfolio and expectation of market conditions. The FRM auction offer cap (set at $9,000/MW-month) suggests that a large range of auction offers may fall within a reasonable range. The reasonableness of auction offers depends on factors such as expectations about reserve revenue (which is sensitive to the likelihood of incurring reserve constraint penalty factor reserve pricing), foregone energy market net revenue, and the likelihood of incurring FRM failure-to-reserve and failure-to-activate penalties.

2.6.2 Regulation Market

We reviewed the competitiveness of the regulation market by examining market structure and resource abundance. The abundance of regulation resources, and relatively unconcentrated control of that supply, implies that market participants had little opportunity to engage in economic or physical withholding in 2022. For these reasons, we find that the regulation market was competitive in 2022. Figure 2-15 below indicates the regulation requirement relative to available supply.

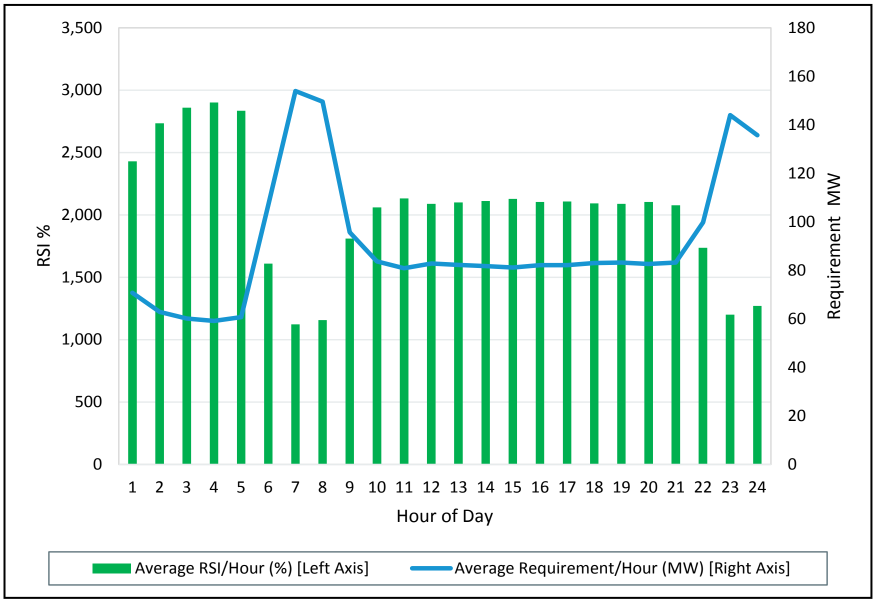
Figure 2-15: Average Regulation Market Requirement and Available Capacity, 2022



On average, during every hour of the day, available supply far exceeds the regulation requirements. However, an abundance of available supply alone is not a dispositive indicator of market competitiveness, as one - or a small number of suppliers - could control the available supply and seek to exercise market power.

The RSI provides a better indicator of the structural competitiveness of the regulation market. As shown in Figure 2-16, the regulation requirement (right axis) and RSI (left axis) are inversely correlated (the lower the requirement the higher the RSI).

Figure 2-16: Average Regulation Requirement and Residual Supply Index



In 2022, the lowest hourly average RSI did not fall below 1,000%, implying that, on average, the system had the capability to serve ten times the regulation requirement without the largest regulation supplier, even in the hours with the greatest regulation requirements.

Section 3
Day-Ahead and Real-Time Energy Market

This section covers key trends in energy market outcomes. In the first section (3.1), energy prices are analyzed across a number of dimensions. The second section (3.2) dives into the major factors behind recent energy market outcomes, looking at such factors as input costs, load and weather conditions, and notable system events. The subsequent section (3.3) looks at net commitment period compensation (NCPC) payments, which are the payments that resources receive when energy prices are too low to cover their production costs. The final section (3.4) summarizes demand response resource (DRR) participation in the energy markets.

Day-ahead and real-time energy prices increased significantly from 2021 levels. This reflected a large increase in underlying primary fuel prices, most notably natural gas. The average Hub price was $85.56/MWh in the day-ahead market, up by 86% on 2021. This increase was consistent with the 101% increase in natural gas prices that occurred as a result of the conflict between Russia and Ukraine, in addition to local pipeline limitations that New England often experienced during the winter months.

In addition to generation costs, numerous other factors played roles in determining the energy market outcomes in 2022. While weather conditions in 2022 were generally comparable to those observed in 2021, several notable events had outsized impacts. Chief among them was Winter Storm Elliot, which moved through New England on December 24, 2022, and led to a system capacity shortage. Transmission congestion and out-of-market actions taken to maintain system reliability only slightly impacted energy market outcomes in 2022, as incidence of both were relatively low. Meanwhile, DRRs continued to be infrequently dispatched in 2022 as a result of high offers prices.

NCPC payments totaled $52.9 million in 2022, an increase of $17.0 million (48%) compared to 2021. However, payments as a percentage of total energy payments remained low, and decreased from 0.6% in 2021 to 0.5% in 2022, the lowest percentage level over the past five years. One notable NCPC outcome was the reduction in payments for resources committed for local reliability (i.e., LSCPR NCPC payments); these payments decreased from $6.8 million in 2021 to $1.1 million in 2022.

Importantly, one area that we recommend the ISO assess further is related to the fast-start pricing rules that were implemented in the real-time energy market in March 2017. We found that there were significant periods of non-zero pricing (and payments) during times when there were physical surpluses of reserves. This topic is discussed in more detail in Section 3.1.2.

3.1 Energy Prices

This section evaluates and discusses energy prices across a number of dimensions, including by energy market (i.e., day-ahead and real-time), time-of-day, and location. These dimensions provide useful context for understanding differences in energy prices (LMPs) over the review period. The first subsection (3.1.1) summarizes energy market pricing over a five-year period, reviews price separation for 2022 for load zones, and examines load-weighted LMPs, which provide an indication of the effective prices that load-serving entities pay for energy. The second subsection (3.1.2) estimates the impacts of fast-start pricing rules on LMPs and other market outcomes. Finally, the third subsection (3.1.3) examines the extent to which prices converged across the day-ahead and real-time energy markets, which is a useful barometer of market efficiency.

Key Takeaways

Energy market prices increased significantly in 2022, primarily as a result of increased natural gas prices. Average LMPs in 2022 were $85.56/MWh in the day-ahead energy market and $84.92/MWh in the real-time energy market; this compares to day-ahead and real-time average LMPs in 2021 of $45.92/MWh and $44.84/MWh, respectively.

Zonal prices in 2022 exhibited modest degrees of separation in the real-time and day-ahead energy markets. Comparing Hub and zone LMPs, the average absolute differences were $0.68/MWh in the day-ahead energy market and $0.70/MWh in the real-time energy market, a difference of less than 1.0% in each market. This reflects relatively low levels of both transmission losses and congestion on average throughout ISO New England's control area.

Load-weighted LMPs, which reflect effective prices paid by load-serving entities, tend to follow seasonal patterns reflecting high-load and high fuel price periods. The impacts were evident in 2022 as the summer period (with higher loads) and the winter periods (with elevated fuel prices) exhibited the highest prices. The day-ahead energy price at the Hub exceeded the real-time price by an average of $0.64/MWh in 2022. However, this difference was consistently larger on average during the middle part of the day.

3.1.1 Day-Ahead and Real-Time Energy Prices

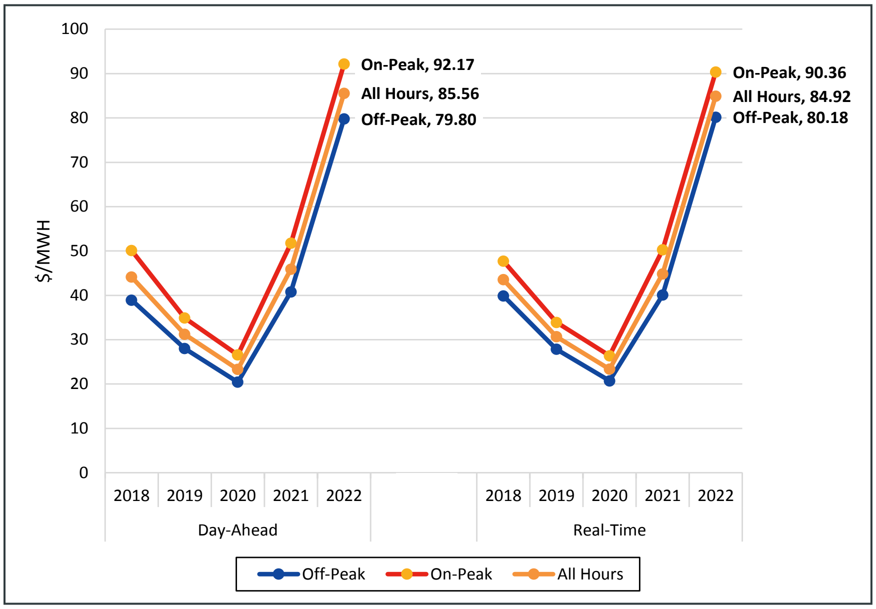
Energy prices at the *Hub* and the eight New England load zones are presented below, with an assessment of price levels and differences across a number of dimensions: time-of-use (e.g., peak, off-peak hours), market, location and load-weighted compared to simple average prices.

Hub prices by time-of-use and market

First, Figure 3-1 shows simple average Hub prices in the day-ahead and real-time market for three time tranches: all hours, peak and off-peak hours.[115]

[115] On-peak periods are weekday hours ending 8 to 23 (i.e., Monday through Friday, excluding North American Electric Reliability Corporation (NERC) holidays); the off-peak period encompasses all other hours.

Figure 3-1: Annual Simple Average Hub Price



Prices in 2022 were at their highest level since Standard Market Design was implemented 19 years ago in 2003 – price levels exceeded $80/MWh in only one other year (2008). In 2022, the simple annual average Hub price (in *all hours*) was $85.56/MWh in the day-ahead market and $84.92/MWh in the real-time market, a significant increase compared to 2021; up 86% in the day-ahead market and by 89% in the real-time market.

These price changes are consistent with observed market conditions, including input fuel costs, load levels, and generator operations. The primary driver of energy prices, natural gas prices, increased significantly in 2022, by over 100%, and gas generators set price for almost 80% of load in the real-time energy market.

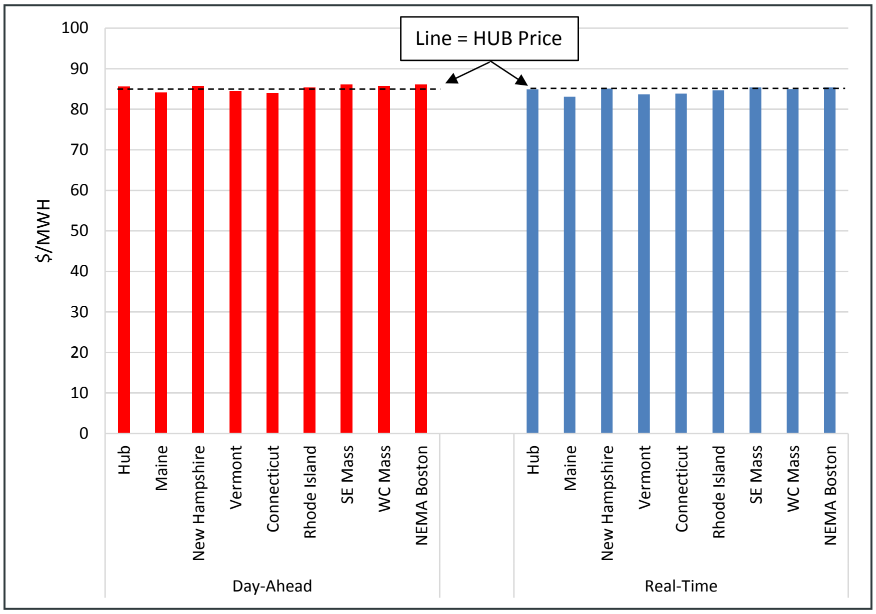
Pricing by time-of-day (i.e., *on-peak and off-peak*) in 2022 exhibited the same trend; on-peak prices increased by 78% in the day-ahead market and 80% in the real-time market, while average off-peak prices increased by 96% in the day-ahead market and 100% in the real-time market, respectively.

On average, day-ahead and real-time Hub prices were comparable indicating that the day-ahead market performed reasonably well in reflecting expected real-time outcomes. Differences ranged from $0.38/MWh (0.5%) for the off-peak period to $1.81/MWh (2.0%) for the on-peak period.

Prices by load zone and market

At the *zonal* level, locational price differences were relatively small in 2022 in both the day-ahead and real-time energy market, as shown in Figure 3-2.

Figure 3-2: Simple-Average Hub and Load Zone Prices, 2022



The relatively small price differences among the load zones and with the Hub were the result of modest levels of both marginal losses and congestion. The average absolute difference between the Hub price and load zone prices was $0.68/MWh in the day-ahead energy market and $0.70/MWh in the real-time energy market, a difference of less than 1% in each market.

The Connecticut and Maine load zones had the lowest overall average prices in the region in 2022. Connecticut's prices averaged $1.50/MWh (1.8%) lower than the Hub price in the day-ahead market and Maine's prices averaged $1.85/MWh (2.2%) lower than the Hub price in the real-time market. Most of the difference in average prices between load zones and the Hub resulted from the imputed cost for transmission losses that is included in the LMP; losses represented about 74% of the price difference in the day-ahead market and 91% in the real-time market.

Conversely, the NEMA pricing zone had the highest average prices in the day-ahead and real-time markets. NEMA's average day-ahead and real-time prices were slightly higher than the Hub, by $0.52/MWh and $0.50/MWh, respectively. While NEMA is import-constrained at times, with the transmission network limiting the ability to import relatively less expensive power into the load zone, losses represented the bulk of the price difference between the Hub and NEMA: 100% in both the day-ahead and real-time markets, respectively. The average congestion component in NEMA was quite low in both markets for 2022.

Consumer prices: load-weighted prices

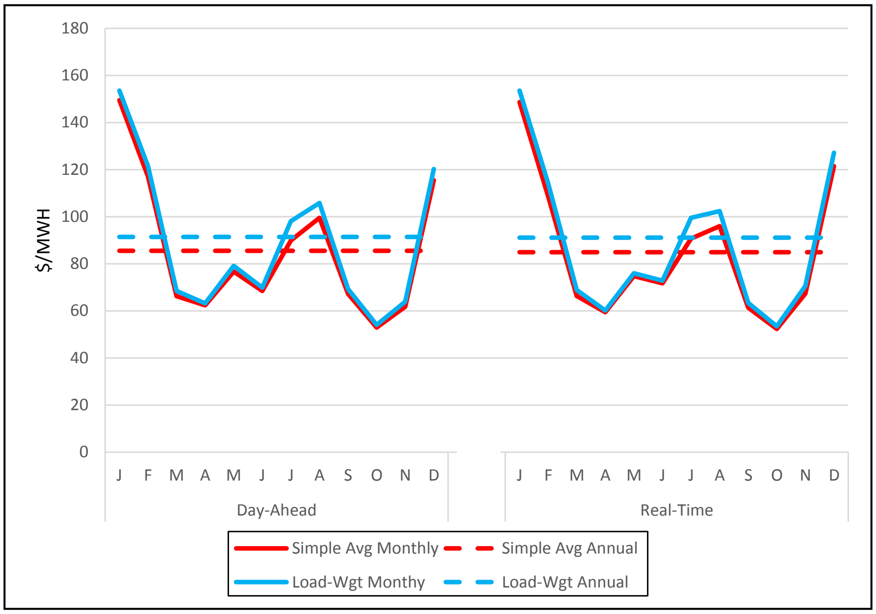
Compared to simple-average prices presented above, load-weighted prices are a better indicator of average prices that load-serving entities (LSEs) pay for energy.[116] The amount of energy consumed in the markets can vary significantly by hour. Load-weighted prices reflect

[116] While a simple-average price weights each energy market price equally across the day, load-weighting reflects the proportion of energy consumed in each hour: load-weighted prices give greater weight to high-load consumption hours than to low-load consumption hours, with each hour being weighted in proportion to total consumption for the entire day.

the increasing cost of satisfying demand during peak consumption periods when higher demand necessitates the commitment and dispatch of more expensive generators. Because of this, load-weighted prices tend to be higher than simple average prices.

The average load-weighted prices were $91.36 and $91.07/MWh in the day-ahead and real-time markets in 2022, respectively. Monthly load-weighted and simple average prices for 2022 are provided in Figure 3-3.

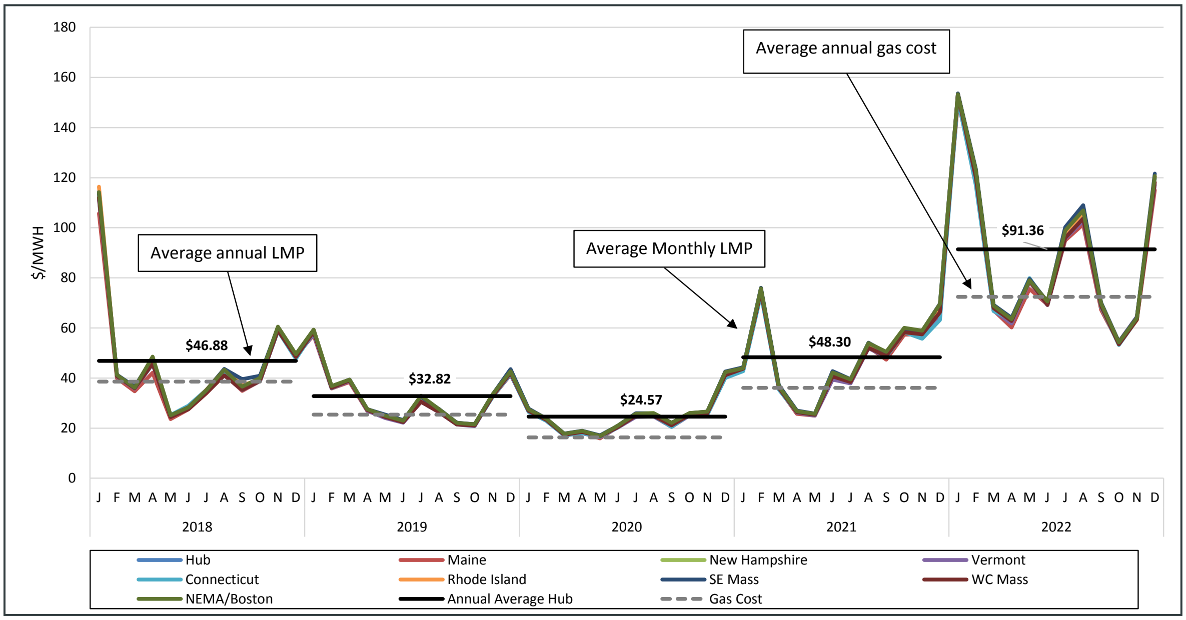
Figure 3-3: Load-Weighted and Simple Average Hub Prices, 2022



As expected, load-weighted average prices were higher than simple-average prices in 2022. The differences range from approximately 1% to 9%, depending on the month and energy market (day-ahead or real-time). These price differences reflect the variability in load over the course of a day, which is typically a function of temperature and business/residential consumption patterns. For example, hours with low electricity consumption tend to occur overnight, when business and residential activity is low and summer cooling needs are minimal. We are also observing relatively low wholesale loads during some mid-day periods, as the result of increased behind-the-meter solar generation reducing retail loads.

Monthly day-ahead load-weighted prices across load zones over the past five years are shown in Figure 3-4 below. The figure illustrates significant monthly variability in LMPs, particularly during winter months with fuel price volatility.

Figure 3-4: Day-Ahead Load-Weighted Prices



Load-weighted energy prices by load zone from 2018 to 2022 indicate a pattern that varies considerably by year and by month, but typically not by load zone. Very high pricing occurred in January 2022, consistent with colder temperatures and high natural gas prices. Winter periods with high fuel prices and summer months with elevated load variability typically have the highest load-weighted prices; a similar trend applies to the real-time market. Notably in 2021, high winter gas prices and relatively high fall gas prices resulted in those periods having the highest energy prices during the year.

3.1.2 Fast-Start Pricing: Impact on Real-Time Outcomes

This section details the impacts of fast-start pricing rules on market outcomes in 2022. We found that fast-start pricing impacts were similar to prior analyses, and is generally meeting the design's key objective of improving real-time price formation by better reflecting the production costs of flexible, fast-start resources in energy prices.[117] However, our assessment of the impact on reserve pricing shows that there are significant periods of non-zero pricing (and payments) during times when the reserve constraint is not impacting the physical dispatch of resources and there is a physical surplus of reserves. We recommend that the ISO assess this issue.

The following table compares a number of actual and estimated counterfactual market outcomes. The column labeled *Fast-Start Pricing* details actual pricing and settlement outcomes. The column labeled *Non-Fast-Start Pricing* provides estimates of counter-factual outcomes if fast-start pricing had not been implemented.

[117] See Section 5.5 of the Summer 2017 Quarterly Markets report for detail on fast-start pricing: https://www.iso-ne.com/static-assets/documents/2017/12/2017-summer-quarterly-markets-report.pdf

Table 3-1: Fast-Start Pricing Outcome Summary, 2022

Market Outcome	Fast-Start Pricing (Actual Outcomes)	Non Fast-Start Pricing (Counterfactual Outcomes)	Difference
System LMP ($/MWh)[118]	$84.52	$78.84	**$5.68 (7%)**
Real-Time Energy Payments ($, Millions)[119]	$208.3	$181.7	**$26.5 (15%)**
NCPC Payments ($, Millions)[120]	$29.9	$44.5	**-$14.6 (-33%)**
Reserve Prices ($/MWh)[121]	$2.54	$1.08	**$1.47 (136%)**
Reserve Payments ($, Millions)[122]	$26.9	$9.0	**$17.9 (199%)**
Percent of Intervals with Reserve Pricing (%)	13.5%	7.5%	**6.0% (81%)**
Intervals Fast-Start Resource Marginal[123]	26.4%	10.0%	**16.4% (165%)**

To summarize the key takeaways, the fast-start pricing approach:

- resulted in a higher frequency of fast-start resources setting price,
- increased the average annual system LMP by 7% and real-time energy payments from load by 15% over the course of 2022,
- decreased real-time NCPC paid to generators and ARDs by 33%[124], and
- had a substantial impact on reserve pricing and payments, with non-zero pricing occurring in 81% more intervals. Overall, average reserve prices were 136% higher in the fast-start-pricing case than in the non-fast-start-pricing case and payments were 200% higher.

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118 The system LMP shown here is the energy component of the LMP in each interval.

119 The estimation of energy payments is calculated using generation-weighted zonal LMPs, as opposed to load-weighted, due to data limitations. Additionally, generation that do not set price for any load are removed and real-time load deviations are only considered for locations and customers with physical load (i.e., exports and day-ahead demand that does not correspond to physical load are excluded). The actual value of real-time payments to these locations and customers is $210.6 million.

120 NCPC payments included in this analysis are Commitment-Out-Of-Merit (COOM), Dispatch-Out-Of-Merit (DOOM), and Rapid Response Pricing Opportunity Cost (RRPOC) payments for generators and asset-related demand resources (ARDs). Due to data limitations, LMPs were not available during each generator's full ramp time so estimated payments are slightly higher than actual payments. Actual payments (i.e., not based on IMM estimates like the data shown in the table) in 2022 were $29.8 million.

121 These reserve prices represent the average reserve price in every interval – including $0/MWh reserve price intervals.

122 The netting of real-time payments for a participant's forward reserve market obligations is not accounted for in the reported reserve payments. For more information on the impact of fast-start pricing on reserves, see Section 7.1.

123 This metric represents the percentage of intervals in which at least one fast-start generator that was marginal (i.e., set price).

124 Breaking down the reduction further, fast-start pricing reduced commitment-out-of-merit and dispatch-out-of-merit NCPC to generators that did not recover their costs when following ISO dispatch instructions by 50%. The decrease was offset by an increase in Rapid Response Pricing Opportunity Cost (RRPOC) NCPC.

Reserve Pricing under Fast-Start Pricing

Reserve prices are intended to:

- offset lost opportunity costs *when a resource is selected to serve as reserve capacity instead of producing electricity in real-time*,[125] and
- compensate market participants with on-line and fast-start generators for the increased value of their product *when the reserve constraint is binding* (economically, when reserves become scarce).

Since fast-start pricing was implemented in 2017, we have observed frequent non-zero reserve pricing in scenarios when resources' dispatch instructions were not impacted by the reserve constraint and the system had a surplus of reserves. In 2022,

- there was a TMSR surplus 45% of the time there was a positive TMSR price (about 516/1,151 hours),
- there was a TMNSR surplus 65% of the time there was a positive TMNSR price (about 11/16 hours), and
- there was a TMOR surplus 86% of the time there was a positive TMOR price (about 18/21 hours).[126]

In 2022 alone, $13.7 million in reserve payments were made when there was a reserve surplus (over half of the $26.9 million in total reserve payments during the year), despite dispatch being unaffected by the reserve constraint.

The separation of pricing and dispatch under fast-start pricing rules introduced reserve pricing challenges. Physically (i.e., in the dispatch software), generation up to EcoMin must be producing energy and generators cannot be dispatched below EcoMin to provide reserves; these reserves are unattainable. Fast-start pricing rules relax fast-start units' EcoMin in the pricing software to give the appearance of a larger dispatchable range, which allows fast-start units to set price more often. However, the ISO's fast-start pricing design does not allow the expanded dispatchable range (i.e., the range between 0 MW and EcoMin) to provide reserves

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[125] Because the pricing software frequently generates LMPs that are higher than the dispatch software, there are often cases in which resources are incentivized to increase their output in the presence of the higher prices but no units have been impacted by the reserve constraint. The IMM does not believe these units have been "*selected to serve as reserve capacity instead of producing electricity*" because physically their dispatch has not been impacted by the reserve constraint. In principle, RRPOC NCPC, not reserve pricing, is the mechanism through which the market should compensate these resources. RRPOC NCPC is designed to compensate units when faced with higher fast-start pricing-driven prices, while reserve prices are designed to compensate units for foregoing the energy price when the reserve constraint is binding.

[126] Throughout this section, reserve prices represent incremental reserve prices for each individual product. Because reserve prices are cascaded (TMSR MWs are paid the TMOR price + the incremental TMNSR price + the incremental TMSR price), we first separated each price into their components. When there was a physical reserve surplus for a given product, we set that component =$0. More complex methodologies, taking into account different permutations of pricing and physical outcomes yielded similar results. The number of hours reported here are the number of 5-minute intervals divided by 12. Percentages do not match number of hours for all three products due to rounding error.

for pricing purposes because these reserves are physically unattainable.[127] This methodology produces tradeoffs:

- Pro: It ensures the system does not appear to have more reserves than are physically attainable and reserve prices are always produced when the reserve constraint is impacting physical dispatch.
- Con: Under certain circumstances, the system can appear to have less reserves than are physically available at no cost to the system, thus it over-values reserves in many scenarios when the reserve constraint is *not* impacting physical dispatch and the system is operating with a reserve surplus. This is explained in the following paragraph.

When there is $0/MWh reserve pricing, dispatchable offers that are priced higher than the LMP are not dispatched because they are not "in-the-money" and provide reserves without additional compensation—they are essentially providing reserves 'for free.' Often, in pricing, when fast-start units' EcoMins are relaxed the energy between 0 MW and EcoMin is relatively expensive compared to other units on the system and the energy moves towards the top of the supply stack. The ISO's methodology dictates that for pricing purposes this available energy cannot provide reserves "for free" because these reserves are physically unattainable. In some cases, the pricing model must take reserves from lower-cost asset offers that are permitted to provide reserves to meet the modeled reserve requirement, and take energy from these higher-priced fast-start unit offers that are not permitted to provide reserves because they are physically unattainable. This dynamic gives the appearance of a *reserve* opportunity cost (the pricing model is producing a result where the lower-cost assets would like to be producing energy at the higher LMP but are designated for reserves) and, in turn, produces reserve prices, although physically the reserve constraint is not impacting physical dispatch and there is a physical reserve surplus.

To summarize, due to tradeoffs presented by the separation of the dispatch and pricing software, the ISO chose a methodology that minimizes false negatives (no reserve pricing when there is a physical reserve constraint binding) but allows false positives (reserve pricing when there is not a physical reserve constraint binding). This was an intentional decision when fast-start pricing was implemented, however, the frequency in which we have observed reserve pricing when there is not a physical reserve constraint binding has exceeded the frequency in which we expected these scenarios to occur, and the cost of reserve payments in these intervals warrants additional consideration of other solutions.

As an example, Figure 3-5 below, shows reserve clearing prices from the pricing and dispatch software on December 12, 2022.[128] On this day, the ten-minute-spinning-reserve (TMSR) reserve constraint penalty factor (RCPF) bound for 85 minutes despite a TMSR surplus. The pricing software (top orange bars) represents the fast-start pricing (actual) case. The dispatch software (bottom blue bars) represents the non-fast-start pricing (counterfactual) case.

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[127] The ISO considered different reserve accounting methodologies for pricing when fast-start pricing was implemented and chose not to allow physically unattainable reserves between 0 MW and EcoMin to contribute reserves for pricing.

[128] Reserve clearing prices from the dispatch software are not used in market settlement.

Figure 3-5: Reserve Prices in the Pricing vs. Dispatch Software on December 12, 2022

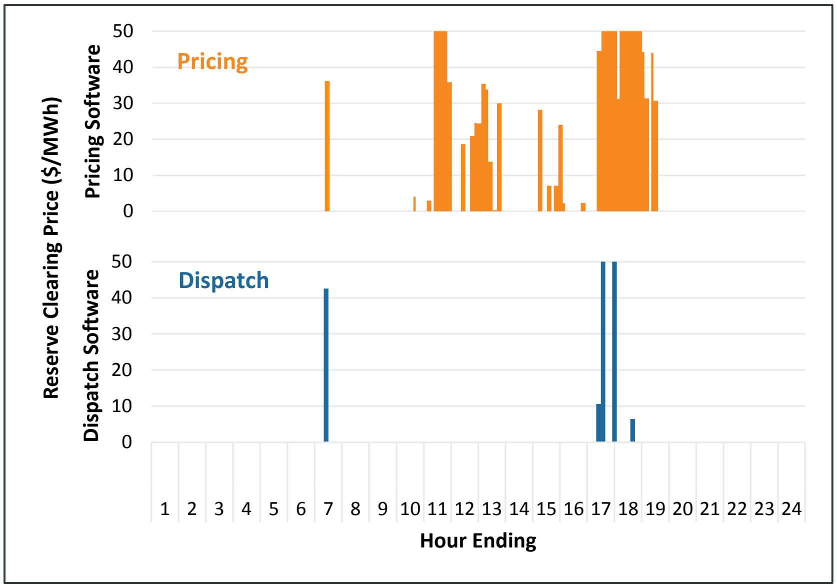


Figure 3-5 shows that fast-start pricing can have a substantial impact on the frequency of non-zero reserve prices. On December 12, fast-start pricing generated TMSR RCPF pricing for 85 minutes, despite the RCPF binding for only 20 minutes in the counterfactual case. Additionally, there was non-zero reserve pricing, designed to signal that the optimal dispatch had to be adjusted to meet the reserve requirement, in five and a half hours, although the physical dispatch was only adjusted in less than one hour.

> ***Recommendation***
>
> We recommend that the ISO revisits reserve pricing mechanics under fast-start pricing to address the frequency of non-zero reserve pricing when there is a physical reserve surplus.

3.1.3 Energy Price Convergence

Price convergence refers to the extent to which prices are equal across the day-ahead and real-time energy markets. Price convergence can serve as a signal of market efficiency – which, in this case, means achieving the necessary real-time generator commitments at the lowest possible cost. In an efficient market, day-ahead (forward) prices should generally reflect expected real-time (spot) prices.

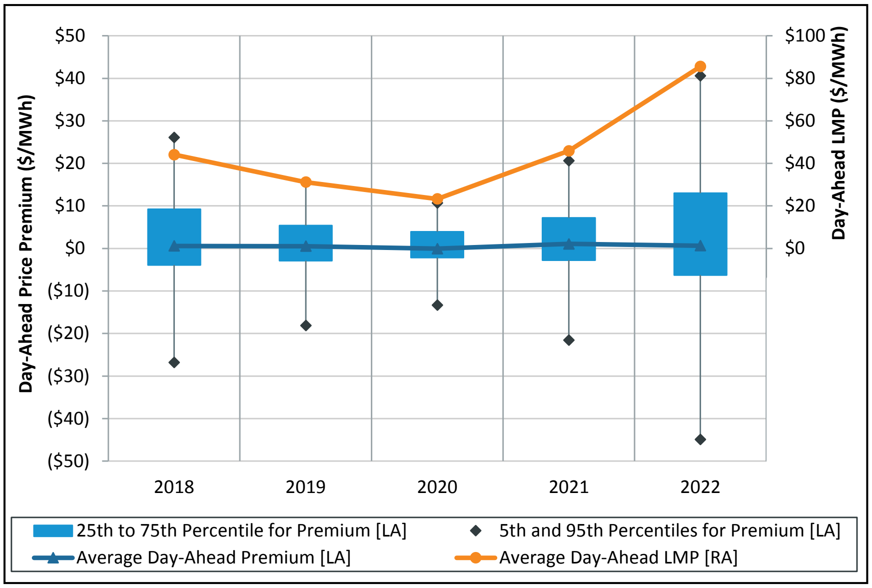
While day-ahead prices will almost never perfectly match real-time prices in any given hour (because real-time conditions will usually differ from expectations), one might expect to see similar average prices between the two markets over a longer period. Consequently, one way to assess price convergence is to look at the average annual difference between day-ahead and real-time prices (i.e., the day-ahead price premium).[129]

[129] The day-ahead price premium is defined as the day-ahead energy price *minus* the real-time energy price.

Convergence across all hours

The average day-ahead price premium at the Hub in 2022 remained in line with recent historic values, although there was an increasing amount of volatility. This can be seen in Figure 3-6 which shows the distribution of the day-ahead price premium at the Hub using a box-and-whiskers diagram.[130] This figure also shows the average annual day-ahead Hub LMP (orange line) for 2018–2022.

Figure 3-6: Average Annual Day-Ahead Price Premium at the Hub and Average Day-Ahead Hub LMP



The day-ahead premium at the Hub averaged $0.64/MWh in 2022, a moderate decrease from 2021 when the premium was $1.08/MWh. In percentage terms, the 2022 price premium (0.7%) was the second lowest in the reporting period. Between 2018 and 2022, the average price premium was as low as -$0.06/MWh (in 2020) and as high as $1.08/MWh (in 2021).

An increased amount of variability in the day-ahead price premium in 2022 is evident in Figure 3-6. While the widening price ranges might suggest worsening price convergence, it is important to note that, over time, these percentiles generally track the average day-ahead Hub LMP (orange series, right axis) and natural gas prices. Since natural gas prices are the primary drivers of LMPs in New England, average LMPs tend to be higher when natural gas prices in New England are higher. The average price of natural gas in New England was $9.28/MMBtu in 2022, compared to $4.62/MMBtu in 2021. Similarly, differences between day-ahead and real-time prices tend to be larger when gas prices are higher. This is because the cost difference

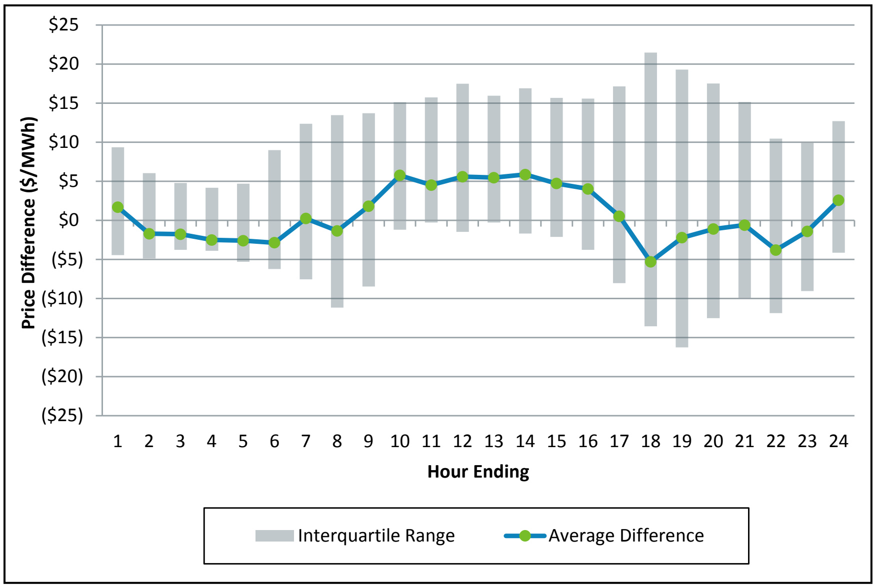
[130] The day-ahead price premium is measured on the left axis ("LA"), while the average annual day-ahead Hub LMP is measured on the right axis ("RA").

between two gas-fired generators with different heat rates is greater when gas prices are higher.[131]

Convergence by time of day

Although the annual average day-ahead price premium in 2022 was small, there were notably higher day-ahead price premiums, on average, during the middle part of the day. This can be seen in Figure 3-7 below, which shows, by hour, the average day-ahead price premium at the Hub (blue line). The gray bars show the interquartile range (i.e., the middle 50 percent) of the day-ahead price premium.

Figure 3-7: Average Hourly Day-Ahead to Real-Time Hub Price Differences, 2022



The average day-ahead price at the Hub exceeded the average real-time price during nine consecutive hours in 2022 (HE9 to HE17), by as much as $5.85/MWh. One potential factor behind this daytime premium is the price-suppressing impact of increased solar generation on real-time load.[132] Much of New England's solar capacity is "behind-the-meter," meaning that it appears in real time in the form of load reduction. To the extent that more solar generation shows up in real time than anticipated in the day-ahead market, prices in the real-time energy

[131] For example, consider two gas-fired generators: Gen A, which is marginal in the day-ahead market, has a heat rate of 10 MMBtu/MWh and Gen B, which is marginal in real-time, has a heat rate of 7 MMBtu/MWh. If the gas price is $5/MMBtu, the generation cost for Gen A is $50/MWh (10 MMBtu/MWh x $5/MMBtu) and the cost for Gen B is $35/MWh (7 MMBtu/MWh x $5/MMBtu). The difference in generation cost between Gen A and Gen B – and by construction, the difference between the day-ahead price and the real-time price – is $15/MWh. If the gas price were to increase to $10/MMBtu, the generation costs for Gen A and Gen B would now be $100/MWh and $70/MWh, respectively, for a day-ahead premium of $30/MWh. In this example, the increased day-ahead premium ($30/MWh from $15/MWh) is only reflective of a higher gas price ($10/MMBtu from $5/MMBtu).

[132] The growth in solar generation in New England is discussed in more detail in Section 1.3.1.

market are likely to be dampened relative to the day-ahead market (and often considerably so).[133,134]

3.2 Drivers of Energy Market Outcomes

This section presents a more detailed assessment of the important contributing market and operational factors that impact energy market outcomes. For example, as we covered in Section 1 earlier, underlying natural gas prices explain, to a large degree, movements in energy prices. Here we explore that relationship in more detail. Operational factors, such as load forecast error or notable system events, provide additional insight into pricing outcomes. The section is structured as follows:

- Generation costs (3.2.1)
- Supply-side participation (3.2.2)
- Reserve Adequacy Analysis (RAA) commitments (3.2.3)
- Load and weather conditions (3.2.4)
- Demand bidding (3.2.5)
- Load forecast error and market implications (3.2.6)
- System events (3.2.7)
- Reliability commitments and posturing (3.2.8)
- Transmission Congestion (3.2.9)
- Marginal resources (3.2.10)

Key Takeaways

Day-ahead and real-time electricity prices continue to be closely correlated with the estimated cost of operating a natural gas-fired generator. In fact, with the exception of 2020, the day-ahead and real-time gas price-adjusted LMPs have been within a narrow band over the reporting period ($29-$32/MWh), indicating that changes in gas prices are a key driver of changes in in the LMP. Natural gas was the marginal fuel for 43% of load in the day-ahead market in 2022 and 79% in the real-time market in 2022.

New England continued to be relatively unconstrained system due to its robust transmission grid; in 2022 congestion revenue represented only 0.44% of total energy costs.

While average temperatures in 2022 were similar to those in 2021, weather did play an important role in energy market outcomes at times. One of the most notable events occurred on December 24 when Winter Storm Elliot moved through New England. The cold weather led to tight system conditions, which culminated in a capacity deficiency.

Unpriced or out-of-market actions to maintain system reliability can also impact energy market outcomes. In 2022, the ISO's reliability commitments averaged only 15 MW per hour. The level of posturing also remained low.

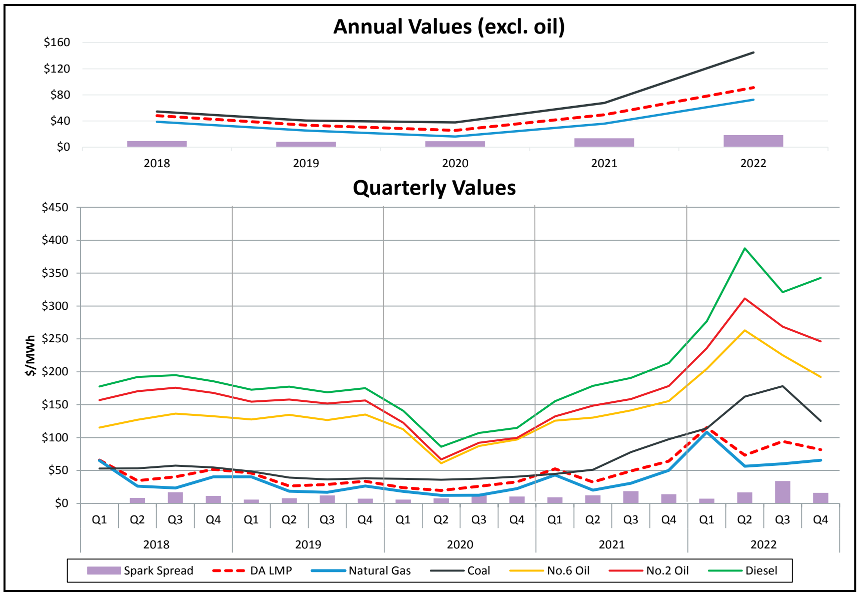
[133] In the day-ahead energy market, it is often virtual supply that takes the place of the expected additional real-time solar production. See Section 4.1 for more information about this relationship.

[134] Section 3.2.2 looks more closely at the differences in the supply mix between the day-ahead and real-time energy markets.

3.2.1 Generation Costs

Day-ahead and real-time electricity prices, as well as year-over-year changes, continue to be closely correlated with the estimated cost of operating a natural gas-fired generator. In 2022, natural gas-fired generators continued to be the dominant price setters (79% in real-time) and supply over 50% of native generation. Other fossil fuel-types have a comparatively minimal impact on overall energy prices. The relationship between electricity prices and generation fuel costs are shown in Figure 3-8 below, alongside the estimated gross margin of a natural gas-fired generator, commonly referred to as a spark spread.[135]

Figure 3-8: Estimated Generation Costs and On-Peak LMPs



Natural gas generation costs averaged $72.57/MWh (or $9.28/MWh) in 2022, double last year's gas costs and the highest since 2008.[136] See Section 1.2 of this report for more information on the global, national and regional factors impacting 2022 natural gas prices.

The relationship between gas and energy costs varies within each year, especially during the summer (Q3) when electricity demand is higher. Higher demand typically requires the operation of less efficient natural gas-fired generators and/or generators that burn more expensive fuels. During the summer months, efficient natural gas-fired generators earn higher margins (commonly referred to as spark spreads) compared to other months.[137] Despite higher Q3 demand (10% higher) compared to Q1, the highest energy *costs* (the product of demand and

[135] Variable generation costs are calculated by multiplying the average daily fuel price ($/MMBtu) by the average standard efficiency of generators of a given technology and fuel type. Our standard heat rates are measured in MMBtu/MWh as follows: Natural Gas 7.8, Coal – 10.0, No. 6 Oil – 10.7, No. 2 Oil – 11.7. The spark spread is the difference between the on-peak LMP and the fuel cost of a gas-fired generator with a heat rate of 7.8.

[136] Based on a time series of historical Algonquin City Gates pricing data from Bloomberg.

[137] During the winter months, coal- and oil-fired generators, as well as imports, can displace natural gas-fired generators in economic merit order more frequently than in other seasons, as natural gas prices increase due to gas network demand and constraints. This tends to lessen the impact of higher gas prices on LMPs as more costly gas-fired generators are pushed out of merit and leads to reduced spark spreads.

LMP) were in Q1, totaling $3.7 billion and accounting for 32% of the annual total of $11.7 billion. Energy costs in Q3 totaled $3.4 billion.

Quarter 1 2022 saw the highest natural gas prices since Q1 2014, with gas generation costs exceeding $100/MWh on average, resulting in average day-ahead LMPs of $115.23/MWh, also the highest since Q1 2014. Natural gas prices remained high for several long periods, particularly in January 2022, when prices frequently exceeded $20/MMBtu ($156/MWh equivalent). More frequent in-merit oil generation (than prior years) attenuated upward price pressure of natural gas on these higher-priced natural gas days.[138]

Industry-standard profitability metrics

Industry-standard profitability metrics for gas-fired generators – implied heat rates and spark spreads – indicate a significant increase in profitability across most generator efficiency levels due to high gas prices and their pass-through effect on electricity prices. Table 3-2 shows the annual average day-ahead on-peak LMP and natural gas price - the key inputs into the implied heat rate, or breakeven point. For context, a heat rate of 7,800 Btu/kWh represents the average standard efficiency of the New England fleet of combined cycle natural-gas fired generators, and a heat rate of 6,381 Btu/kWh reflects the standard efficiency of a new entrant combined cycle gas-fired generator.

Table 3-2: Annual Average On-Peak Implied Heat Rates and Spark Spreads

Year	Day-Ahead On-Peak LMP ($/MWh)	Gas Price ($/MMBtu)	Implied Heat Rate (Btu/kWh)	Spread ($/MWh) corresponding to Heat Rate (Btu/kWh)					
				6,381	7,000	7,800	8,000	9,000	10,000
2018	50.11	5.05	9,918	17.87	14.74	10.70	9.69	4.64	(0.41)
2019	34.89	3.32	10,518	13.73	11.67	9.02	8.35	5.04	1.72
2020	26.57	2.12	12,558	13.07	11.76	10.07	9.65	7.53	5.41
2021	51.77	4.60	11,247	22.40	19.55	15.86	14.94	10.34	5.74
2022	92.17	9.07	10,159	34.28	28.66	21.40	19.59	10.52	1.44

The spark spreads for the typical New England gas-fired generator (7,800Btu/kWh) increased significantly for the second year in a row, up 35% year-over-year ($15.86/MWh to $21.40/MWh). The higher spark spreads were driven by the increase in gas prices and the pass-through effect on energy prices.[139] The implied (breakeven) heat rate decreased by 10%

[138] More information on New England's oil generation in January 2022 can be found on EIA's website here. More information on oil-fired generator utilization can be found in Section 2.2.

[139] For example, assume the implied heat rate was 10,000 MMBtu/MWh in both 2021 and 2022. Given the natural gas prices, 2021 LMPs would average $46.00/MWh ($4.60/MMBtu x 10,000 Btu/kWh) in 2021 and $90.07/MWh ($9.07/MMBtu x 10,000 Btu/kWh) in 2022. Since we estimate a heat rate of 7,800 Btu/kWh for standard efficiency gas-fired generator, the estimated cost of natural gas-fired generation would be $35.88/MWh ($4.60/MMBtu x 7,800 Btu/kWh) in 2021 and $70.75/MWh ($9.07/MMBtu x 7,800 Btu/kWh) in 2022. This means the spark spreads (or LMP minus estimated cost of generation) would average $10.12/MWh ($46.00/MWh minus $35.88/MWh) in 2021 and $19.32/MWh ($90.07/MWh minus $70.75/MWh) in 2022. In this example, the increase in natural gas prices caused the increase in spark spreads.

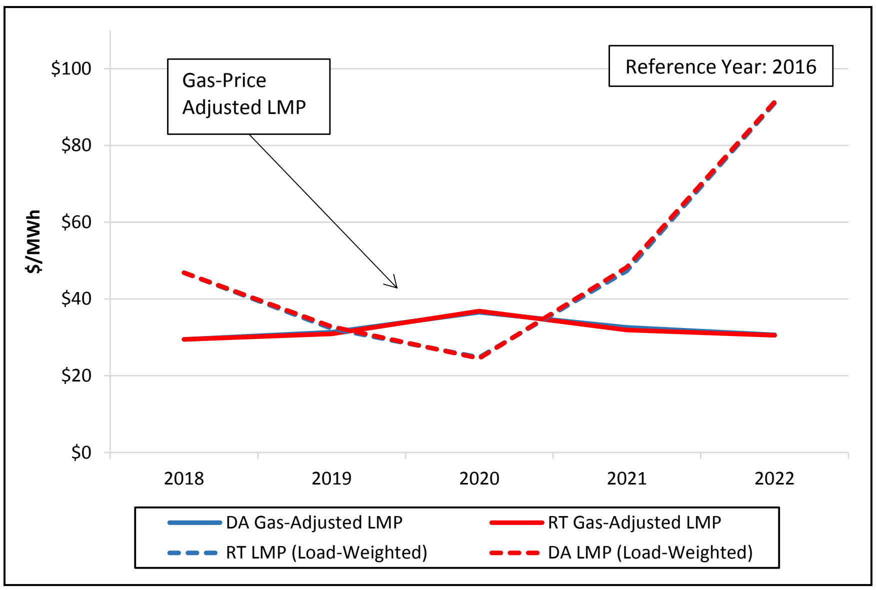
(11,247 Btu/kWh in 2021 to 10,159 Btu/kWh in 2022), indicating that slightly more efficient gas generation was marginal on average in 2022.

Natural Gas Price-Adjusted LMP

While changes in LMPs have a strong, positive correlation with changes in natural gas prices, other factors influence LMPs, including supply mix changes, system demand levels, and unanticipated events, such as forced equipment outages. The gas price-adjusted LMP is a high level metric used to estimate the impact of these of non-gas price factors on the energy price and is shown in in the Figure 3-9 below.[140]

The solid lines show the gas-price adjusted load-weighted LMPs, while the dashed lines are the actual unadjusted LMPs for the day-ahead and real-time markets (note that the red and blue lines overlap due to little average price separation between the markets on a load-weighted basis).

Figure 3-9: Annual Average Natural Gas Price-Adjusted LMPs



With the exception of 2020, the day-ahead and real-time gas price-adjusted LMPs were within a relatively narrow band ($29-$32/MWh), indicating that the change in gas prices explains nearly all of the change in the LMP.[141] In 2022, on a gas price-adjusted basis, day-ahead and real-time prices decreased slightly by 6% (from $32.60 to $30.65/MWh) and 4% (from $31.90 to $30.55/MWh), respectively.

[140] The gas price-adjusted LMP is derived by dividing the reference year natural gas price (2016) by the current year natural gas price, then multiplying by the load-weighted LMP.

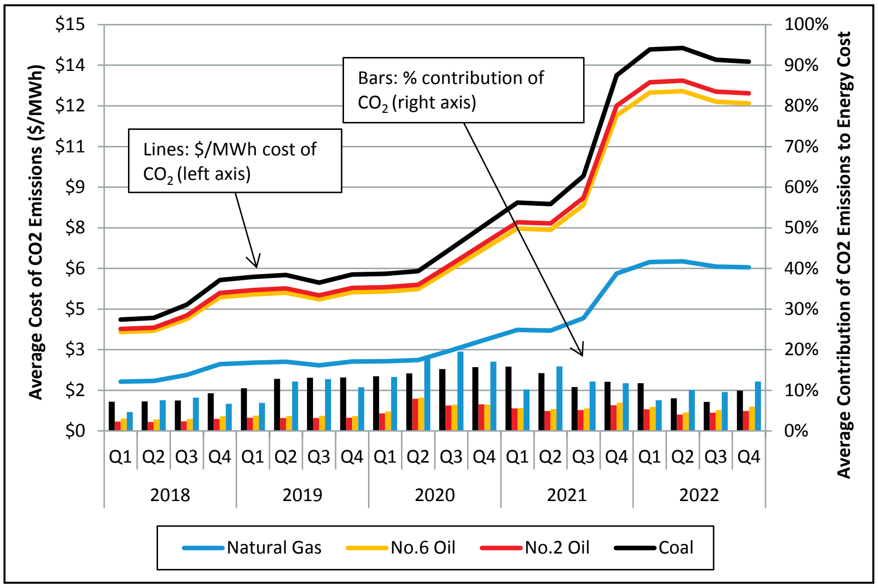
[141] The results for 2020 were somewhat of an outlier. The behavior was largely due to less fixed supply on the system as a result of increased nuclear generator outages and a nuclear generator retirement. This supply was replaced by more expensive priced supply from gas-fired generation.

Regional Greenhouse Gas Initiative (RGGI) Prices

The key driver of emissions costs for generators in New England is RGGI, a marketplace for CO_2 credits in the Northeast and Mid-Atlantic regions; it covers all six New England states. RGGI operates as a cap-and-trade system, where fossil fuel-fired generators must purchase emission allowances equal to their level of CO_2 emitted over a specific compliance period.[142]

The average estimated dollar per MWh costs of CO_2 emissions and their percent contribution to total variable production costs are shown in Figure 3-10 below.[143] The line series illustrate the average estimated cost of emissions allowances by fuel type for the past five years. The bar series show the proportion of the average energy production costs attributable to CO_2 emissions costs for each year.[144, 145]

Figure 3-10: Estimated Average Cost of RGGI CO_2 Allowances and Contribution of Emissions to Energy Production Costs



As shown in Figure 3-10 above, the estimated RGGI costs for generators of all fuel types increased over the period. RGGI allowance prices increased by 41% in 2022 (from $9.56/short ton in 2021 to $13.48/short ton in 2022). For a typical natural gas-fired generator the average estimated CO_2 cost was $6.15/MWh in 2022. This was an increase of $1.79/MWh from 2021.

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[142] For more information, see the RGGI website: https://www.rggi.org/program-overview-and-design/elements

[143] Only fuel and CO_2 emission costs are considered in calculating the variable cost of each generator. In practice, generators incur other variable operating and maintenance productions costs, but fuel comprises the vast majority of variable costs. CO_2 prices in $ per ton are converted to estimated $/MWh using average generator heat rates for each fuel type and an emissions rate for each fuel.

[144] This average CO_2 cost is an estimated cost using average heat and emission rates. This figure shows the CO_2 costs associated with the RGGI program only. Generators in Massachusetts are subject to additional CO_2 costs from the Massachusetts GWSA program, which is covered further below.

[145] RGGI accounts for nearly all of emissions costs.

The bars in Figure 3-10 show the relative contribution of emissions allowance costs to generator energy costs. This contribution remained similar for all fuel types in 2022, although the cost of CO_2 increased 41%, on average, from the previous year. The impact of these higher CO_2 prices on generator costs was diminished by a 101% increase in natural gas prices from 2021 to 2022.

Although prices increased from the previous year, the figure shows that costs flattened over 2022. This was due to RGGI allowance prices remaining around $13/short ton of CO_2.[146] There are several factors potentially influencing the price of RGGI allowances:

- The Emission Containment Reserve (ECR) continues in the program. Through the ECR, allowances would be withheld from circulation to secure additional emission reductions if prices fell below an established price.[147]
- The conclusion of the third RGGI program review in 2023, signaling potential further emission reductions similar to the second program review in 2017.[148]
- Futures trading activity and participation by investors increased.[149]
- Pennsylvania and North Carolina potentially joining the program.

A wider view of the impact of RGGI CO_2 allowances on generator production costs is presented in Figure 3-11 below. The line series in the figure illustrate the quarterly estimated production costs using the average heat rate for generators of a representative technology type in each fuel category. The height of the shaded band above each line series represents the average energy production costs attributable to emissions costs in each quarter.

[146] Allowances remained below the Cost Containment Reserve (CCR) trigger price of $13.91/short ton in 2022. The CCR is a quantity of allowances in addition to the cap which are held in reserve. These allowances are sold if prices exceed the annual level. https://www.rggi.org/sites/default/files/Uploads/Market-Monitor/Quarterly-Reports/MM_Secondary_Market_Report_2022_Q4.pdf

[147] The 2022 ECR trigger price was $6.42/allowance and will rise 7% each year through 2030. https://www.rggi.org/sites/default/files/Uploads/Market-Monitor/Quarterly-Reports/MM_Secondary_Market_Report_2022_Q4.pdf

[148] https://www.rggi.org/program-overview-and-design/program-review

[149] https://www.rggi.org/sites/default/files/Uploads/Market-Monitor/Quarterly-Reports/MM_Secondary_Market_Report_2022_Q3.pdf

Figure 3-11: Contributions of Emissions Cost to Energy Production Costs

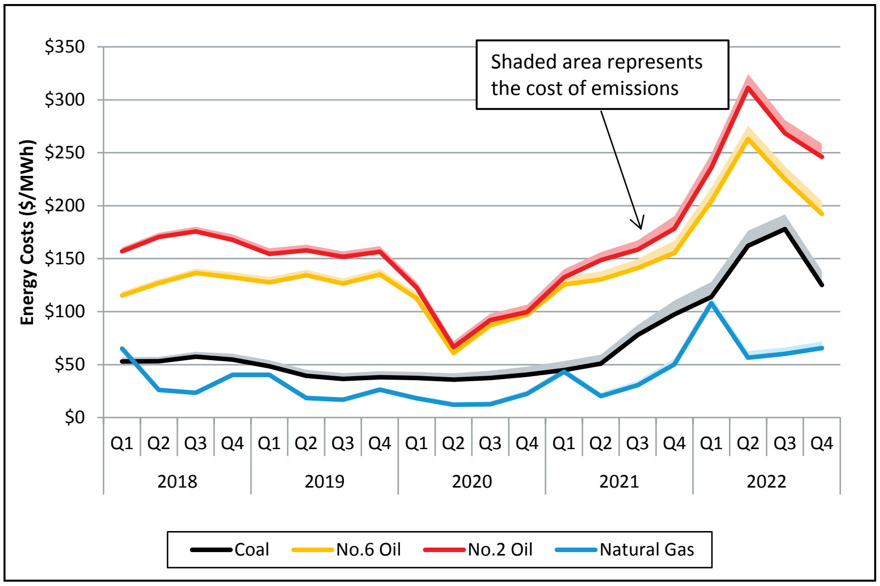


Figure 3-11 highlights that CO_2 allowance costs continue to have a relatively small impact on generator production costs, and consequently, they do not have a noticeable impact on the economic merit order of generators.

Massachusetts GWSA (310 CMR 7.74)

The Massachusetts CO_2 cap-and-trade program has been in place since 2018.[150] This program provides additional requirements to the RGGI program discussed above, thus generators located in Massachusetts must meet both requirements. Administered by the Massachusetts Department of Environmental Protection (MassDEP), the program places an annual cap on aggregate CO_2 production for the majority of fossil fuel-fired generators within the state.[151] The cap will be lowered every year until the target annual CO_2 emission rate is reached in 2050.[152]

The regulation requires fossil fuel-fired generators to hold an allowance for each metric ton of CO_2 they produce during a year. For the first two years, these allowances were primarily allocated based on historical emissions levels, but beginning in 2021, allowances were available for sale through auction only.[153] The program also allows generators to trade emissions allowances to meet their compliance obligations.

[150] 310 CMR 7.74: Reducing CO_2 Emissions from Electricity Generating Facilities https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774

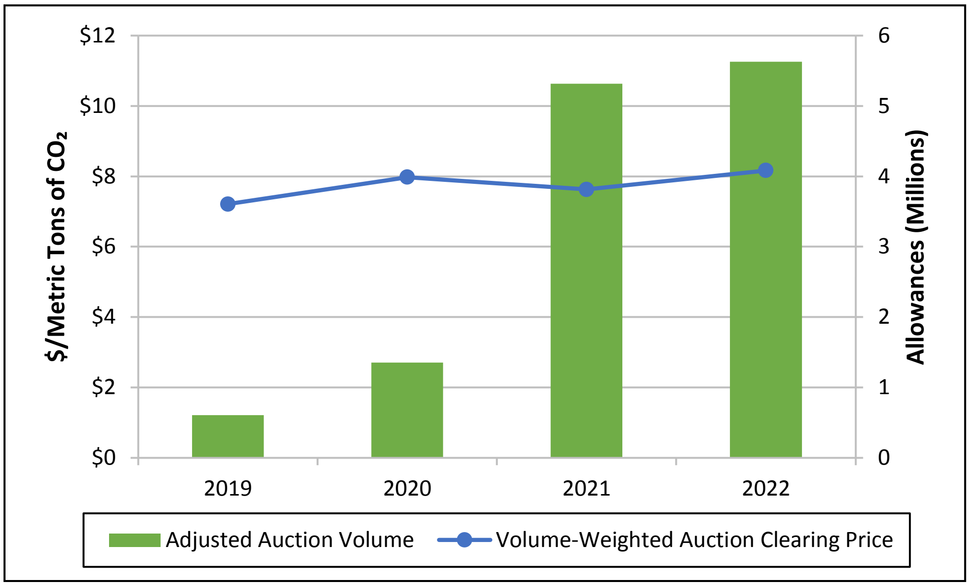
[151] Participating generators are fossil-fuel generators with a nameplate capacity of 25 MW or more. https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download

[152] The annual emissions cap for 310 CMR 7.74 will reduce by 223,876 metric tons in each subsequent year, eventually reaching 1,791,019 metric tons in 2050.

[153] For more information about allowance allocations see market monitor quarterly report: https://www.mass.gov/doc/market-monitor-quarterly-report-2021-q3/download

The annual volume of CO_2 allowances sold at auction and the respective volume-weighted auction clearing prices for the MA GWSA program are shown in Figure 3-12 below.[154, 155]

Figure 3-12: Massachusetts GWSA Auction Results



The volume-weighted annual auction clearing prices increased 7% to $8.17/metric ton of CO_2 in 2022 from the previous year. The phasing out of direct allowance allocations after 2020 meant that 2021 was the first year all allowances were offered at auction. The increase in price reflected expectations of a need for more allowances to fulfill obligations in the future. They also reflected some participants seeking to meet compliance obligations for the year as electric load, and thus emissions increased.[156] In general, generators continued to incorporate the cost of allowances into their energy market supply offers.[157] As the number of available allowances decreases, prices are expected to rise. If the volume of secondary market transactions remains low, participants may find it difficult to obtain additional allowances without paying significant premiums.[158]

[154] For the 2018, 2019, and 2020 compliance years, MassDEP directly allocated 100, 75, and 50 percent of emissions cap. Beginning in 2021, MassDEP no longer distributes allowances through direct allocation and all allowances were offered at auction.

[155] There were less allowances at auction in 2021 compared to 2022 because there were more allowances banked going into that year. Auction volumes are adjusted based on banked allowances. For example, to calculate 2022 allowances to be distributed, you subtract the 2.7 million banked allowances minus 223,875 (because the number of banked allowances is over 223,875) from original cap of 8 million to get 5.6 million total allowances.

[156] The total CO_2 emissions for all MA GWSA-affected generators was 6.7 metric tons in 2022, which was more than the previous year.

[157] To incorporate the cost of these allowances into generator reference levels, the IMM uses an adder that values the allowances based on recent trades and auction results.

[158] https://www.mass.gov/doc/market-monitor-quarterly-report-2022-q3/download

3.2.2 Supply-Side Participation

In 2022, unpriced supply made up around 70% of total supply in the energy market, a level similar to previous years. Unpriced supply consists of offers from suppliers that are willing to sell (i.e., clear) at any price, and offers that cannot set price. These suppliers may be insensitive to price for a number of reasons, including fuel and power contracts, hedging arrangements, unwillingness to cycle (on and off) a generator, or operational constraints. The remaining 30% of supply is considered priced supply (i.e., it is willing to sell at a specified offer price or higher, and it is eligible to set price).

There are three categories of *unpriced* supply: fixed imports, self-scheduled generation, and generation-up-to economic minimum.

- **Fixed imports** are scheduled to flow power into New England on the external interfaces regardless of price.
- **Self-scheduled generation** is offered into the energy market as must-run generation. Generators self-schedule at their economic minimum (EcoMin).[159]
- **Generation-up-to economic minimum** from economically-committed generators is the portion of output that is below EcoMin. For example, if a unit generating 150 MW has an EcoMin of 100 MW, then its generation-up-to EcoMin is the portion below 100 MW. Generation-up-to EcoMin is ineligible to set price, as the market software cannot dispatch it up or down.

There are two categories of *priced* supply: priced native supply and priced imports.

- **Priced native supply** is energy from generators, demand response resources (DRRs), and virtual transactions (day-ahead market only) that is dispatched economically (i.e., is scheduled based on its price).
- **Priced imports** include price-sensitive imports and up-to-congestion transactions.[160, 161]

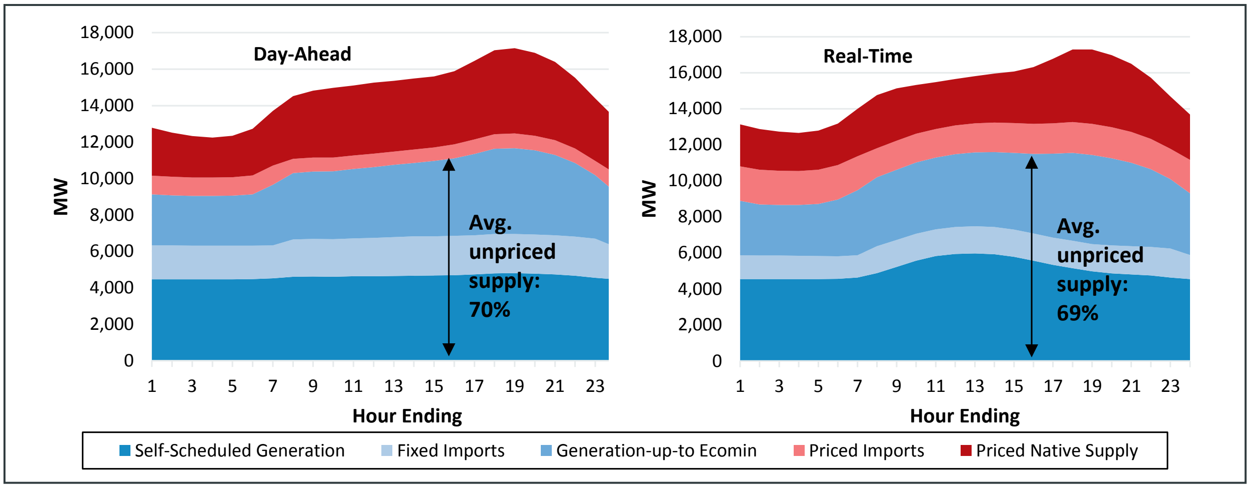
[159] The Economic Minimum (EcoMin) is the minimum MW output available from a generator for economic dispatch.

[160] Up-to-congestion (UTC) transactions are external contracts in the day-ahead energy market that do not flow if the congestion charge is above a specified level. Real-time external transactions cannot be submitted as up-to-congestion contracts. Participants with real-time external transactions are considered willing to pay congestion charges.

[161] There are some nuances to the priced imports category in terms of price-setting ability. While priced imports regularly set price in the day-ahead market, they rarely set price in real-time market. This is because the tie lines are scheduled in advance of the delivery interval in real time and are given a small dispatchable range in the real-time dispatch and pricing algorithm. This prevents the market software from dispatching the tie lines far away from the scheduled amount determined by the transaction scheduling process.

An hourly average breakdown of unpriced and priced supply by category for the day-ahead and real-time markets in 2022 is provided in Figure 3-13 below.

Figure 3-13: Day-Ahead and Real-Time Supply Breakdown by Hour Ending, 2022



On average, unpriced supply made up 70% and 69% of total supply in the day-ahead and real-time markets, a small decrease compared to 2021 shares (72% and 71%). The decrease was due to fewer fixed imports and more priced imports in 2022 compared to 2021.[162] Priced supply averaged 31% of total supply over all hours in real time in 2022, with its share peaking in hours ending (HE) 18-21 at 33-34%. In both markets, the daily ramp-ups in load are typically met by additional supply from *generation-up-to EcoMin* and *priced* supply. In the day-ahead market, the share of supply from *self-scheduled* generation (the largest component of unpriced supply) and *fixed imports* was fairly stable over the course of a day. In contrast, in the real-time market, average hourly self-scheduled generation was higher during midday due to output from settlement-only solar generators (SOGs). In 2022, hourly SOG output averaged 428 MW, or 8% of total real-time self-scheduled generation. These smaller generators do not clear in the day-ahead market because they are not modeled in the market nor centrally dispatched by the ISO control room.[163] Fewer *fixed imports* offset the impact of additional self-scheduled generation in both markets in 2022 compared to 2021. Specifically, the resulting increase in native load limited the price-suppressing effect of additional self-scheduled generation.

Price formation and unpriced supply

Large volumes of unpriced (or fixed) supply can have important implications for pricing outcomes because it increases the likelihood of low or negative prices. This will become more common when combined with significant amounts of additional capacity from renewable generation (e.g., wind, and solar) with low marginal costs. However, we generally find that energy price formation is robust under current levels of unpriced supply, with prices reflecting the marginal input costs of the highest cost resources dispatched to meet demand. Further, as more low marginal cost generation participates in the wholesale market, one would expect to

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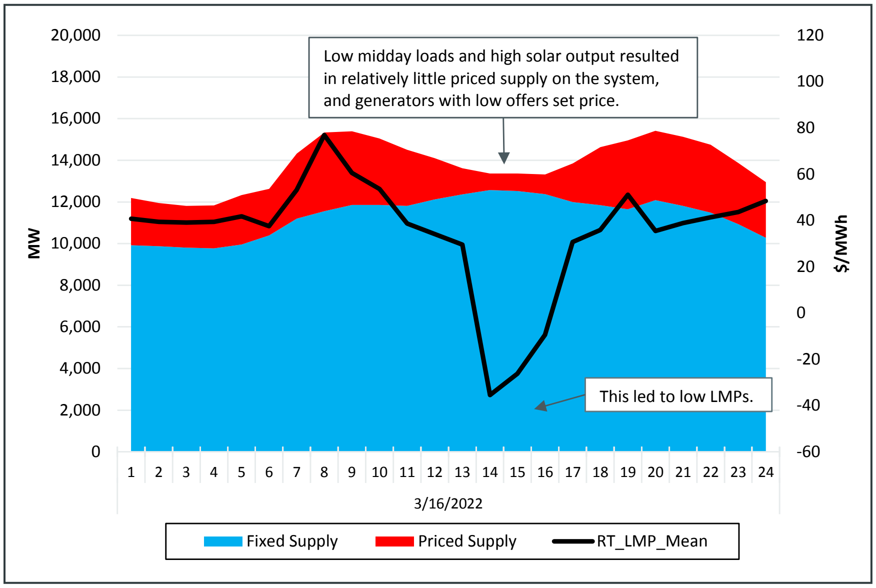
[162] The metrics in this section focus on the supply side and therefore do not account for exports, which increased in 2022, leading to further decreases in net interchange. Section 5 discusses net interchange.

[163] SOGs are passive participants in the real-time energy market only.

see a market response in terms of more price-responsive supply, as otherwise there is a higher risk of energy prices not covering short-run production costs.

The example below illustrates negative pricing at a time when there is a significant amount of fixed supply, and combined with negative energy supply offers, results in negative LMPs.[164]

Figure 3-14: Priced and Unpriced Supply vs. Real-Time LMP, March 16, 2022



In the midday hours of March 16, real-time loads were relatively low. Additionally, wholesale solar output (largely participating as SOGs) that had not cleared in the day-ahead market was high, averaging about 1,050-1,875 MW between 10 am and 4 pm. This had two effects: 1) low loads due to increased behind-the-meter solar output; and 2) more fixed supply from settlement-only solar generation. As a result, the ISO only had to dispatch a small amount of priced generation. The small amount of economically dispatched generation had offered into the market at negative values, resulting in negative prices. The five-minute Hub LMP ranged from -$129.50 to $0/MWh from 1:10 pm to 3:25 pm, and the hourly price averaged -$9.39 to -$35.42/MWh from 1 pm to 4 pm.

The combination of low loads and large amounts of unpriced generation can bring about a sudden drop in prices, to low or even negative levels. However, the overall frequency of negative real-time prices at the Hub remains relatively low. Negative prices at the Hub occurred in 0.5% of five-minute real-time pricing intervals in 2022, and in 0.3% of intervals in 2021. Even in Maine, which tends to have a higher frequency of negative nodal prices at export-constrained pockets with wind generation, the zonal price was negative in only 0.5% of five-minute real-time pricing intervals in 2022 and 0.3% of intervals in 2021.

3.2.3 Reserve Adequacy Analysis Commitments

The commitment, dispatch and pricing outcomes in the *financial* day-ahead market may not always reflect expected *physical* real-time conditions. For example, load-serving entities may

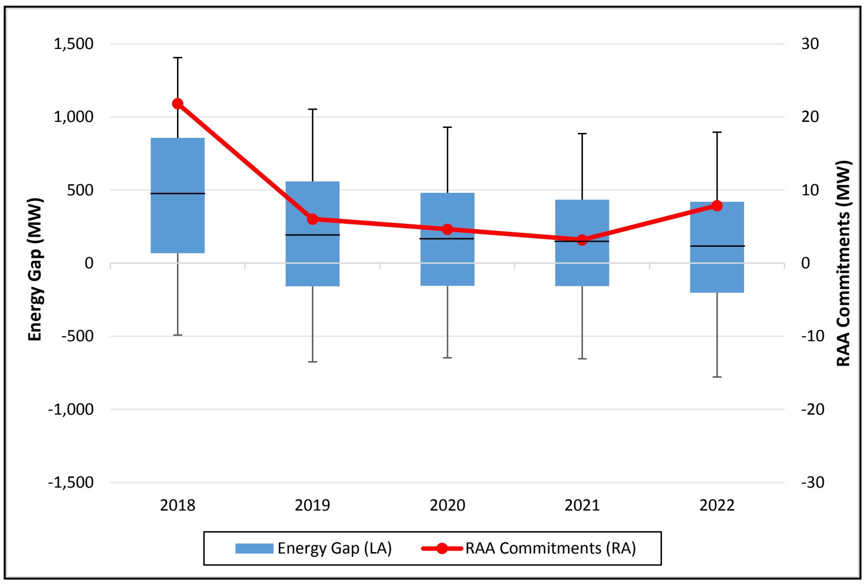
[164] Unlike the figure above, this figure includes all imports in the fixed supply category for convenient illustrative purposes.

clear less demand than the ISO's load forecast. When this happens, ISO-NE must ensure there is enough capacity and reserves to meet forecasted real-time load and reserve requirements.

To that end, after the day-ahead market, the ISO performs the Reserve Adequacy Analysis (RAA) to meet these forecasted capacity and reserve requirements. If the day-ahead market did not commit enough *physical* supply to meet the ISO's forecasted demand and reserve, additional generator commitments may be required. Conversely, if the day-ahead market satisfies the expected real-time requirement, additional generators will not need to be committed in the RAA process.

The difference between the amount of physical cleared generation (i.e., no virtual supply) in the day-ahead market and the expected real-time load and reserve requirement (the energy gap), is shown below (left axis) as a box plot in Figure 3-15.[165, 166] The figure also includes the average RAA committed capacity (right axis).

Figure 3-15: Average RAA Generator Commitments and the Day-Ahead Energy Gap



When the energy gap is high, the RAA process may need to commit additional generation to meet real-time load. However, the energy gap remained fairly low in most hours, and the RAA process committed less than 10 MW per hour on average. The day-ahead market generally cleared sufficient supply and online generation capacity to meet the ISO's load forecast and reserve requirements. On average in 2022, the load-serving entities cleared more demand in the day-ahead market than what they consumed in the real-time.[167] Therefore, additional RAA commitments were not typically necessary as over-clearing of demand in day-ahead market led to sufficient levels of physical supply.

[165] The box plot shows the 25th and 75th percentiles (interquartile range), the median (50th percentile), along with the more extreme observations at the 5th and 95th percentiles.

[166] The Day-Ahead Ancillary Services Initiative (see Section 8) proposes to procure and price this "energy gap".

[167] See Section 3.2.5 for more information on high levels of demand clearing in the day-ahead market.

3.2.4 Load and Weather Conditions

Load is a key determinant of day-ahead and real-time energy prices. Higher loads generally require costlier generation to be dispatched, resulting in higher prices. Weather, economic factors, energy efficiency measures, and, increasingly, behind-the-meter photovoltaic generation drive changes in wholesale electricity load, in terms of both the level and profile of load (load curve). The electrification of heating and transportation sectors are forecasted to continue to increase wholesale load and will play a growing role in determining pricing outcomes.[168]

Demand/Load Statistics

Net Energy for Load (NEL) averaged 13,576 MW per hour in 2022, not meaningfully different to the 2021 average (a 0.1% increase, 11 MW, compared to 2021). New England's native electricity load is shown in Table 3-3 below.[169, 170]

Table 3-3: Average, Peak and Weather-Normalized Load

Year	Load (GWh)	Average Hourly Load (MW)	Peak Load (MW)	Weather Normalized Load (GWh)	Average Hourly Weather Normalized Load (MW)
2018	123,472	14,095	26,024	120,560	13,762
2019	119,235	13,614	24,361	118,772	13,558
2020	116,874	13,309	25,121	116,322	13,242
2021	118,758	13,565	25,801	117,551	13,419
2022	118,874	13,576	24,780	118,337	13,508

During the year, load reached a peak of 24,780 MW, which occurred in HE 18 on August 4, when temperatures reached nearly 92^{0}F, the hottest weekday over the five-year period. This was 4.0% (or 1,020 MW) lower than the peak load in 2021.[171] July 24 saw higher temperatures, reaching just over 94^{0}F but it was a weekend day when loads tend to be lower.

New England has had declining weather-normalized load, which reflects the long-term trend of increased energy efficiency and behind-the-meter solar generation. However, weather-normalized load increased slightly over the past two years. While it is difficult to attribute this directly to any particular driver, this change is consistent with the ISO forecast that average load will increase each year with the continued adoptions of electricity-fueled transportation and electric heating.

[168] For more information on the growth of electrification, see the ISO New England CELT Report.

[169] In this analysis, load refers to *net energy for load* (NEL). NEL is calculated by summing the metered output of native generation, price-responsive demand and net interchange (imports – exports). It excludes pumped-storage demand.

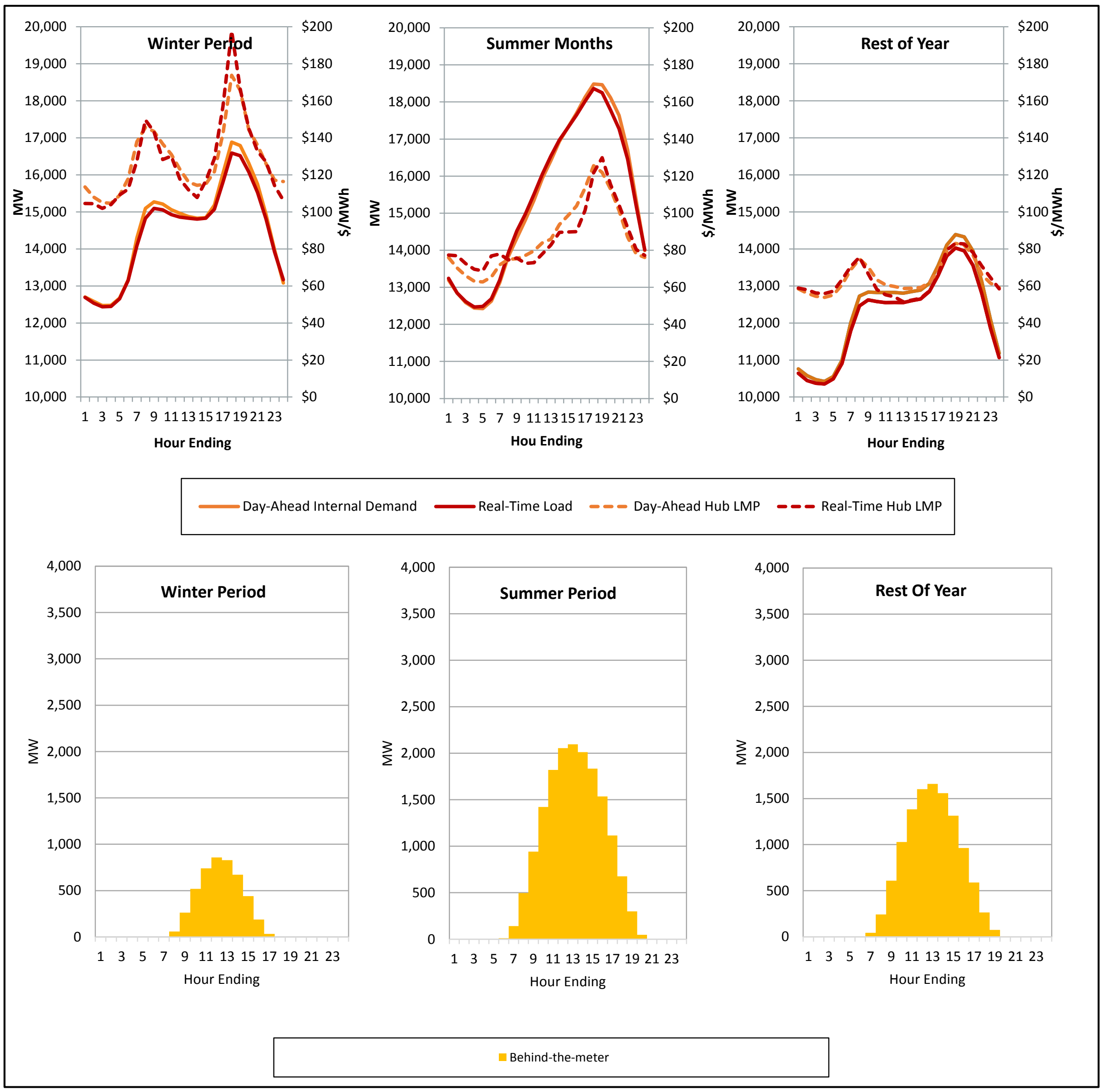
[170] Weather-normalized load estimates what load would be if monthly total heating degree days and cooling degree days were in line with historical averages. The estimate also factors in differences non-holiday weekdays and leap days.

[171] The all-time peak load was 28,130 MW and occurred on August 2, 2006 at HE 15.

Demand Curves and Energy Prices

The strong connection between energy prices and load is particularly evident over the course of the operating day. Figure 3-16 below depicts two series of figures. The first shows the average time-of-day profile for both day-ahead demand and real-time load (solid lines) compared to day-ahead and real-time LMPs (dashed lines). The second shows how wholesale, settlement-only and behind-the-meter (BTM) solar generation (yellow areas) compare to the ISO solar forecast (dashed line). BTM solar generation lowers load required to be met through the wholesale market. Since load curves and solar production have different shapes depending on season, the figure is broken into three panels: winter (December, January, and February), summer (June – August) and rest of year.

Figure 3-16: Average Demand and LMP by Hour, 2022[172]



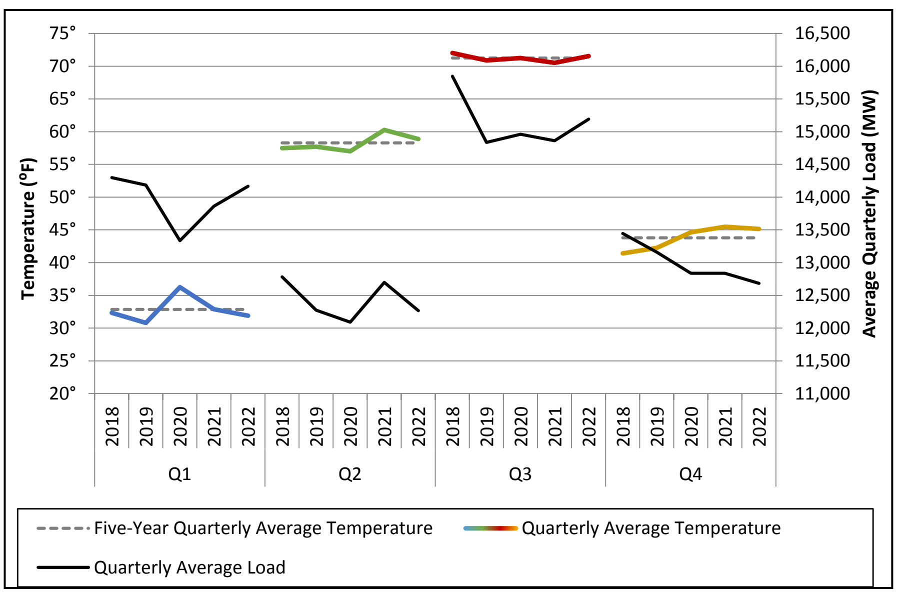
[172] Day-ahead internal demand is equal to fixed demand + price-sensitive demand + virtual demand. This includes pumped-storage demand and excludes virtual demand at external nodes. Real-time load is the total end-use wholesale electricity load within the ISO New England footprint.

In the winter, high gas prices lead to higher energy prices even with lower energy demand than the summer months. Winter, like the rest of the year, also has a distinct evening demand peak. These peaks have been made more prevalent with the increase in solar generation. Winter solar generation is notably less than the summer and rest-of-year but has still depressed midday loads. During the summer, load and prices tend to climb throughout the day as temperatures increase and air conditioning demand rises. Even with solar production reaching over 3,500 MW during air conditioning demand had not allowed for midday dips. The right panel shows the average load curve for the rest of the year, when load usually has morning and evening peaks, with a midday dip. In 2022, even with over 3,000 MW of solar generation, the rest of the year load profile does not have the usual midday dip. Figure 3-16 also shows that the day-ahead market tends to clear more internal demand than actually materializes in real time, which is discussed further in Section 3.2.5.

Impact of Weather

Weather is a significant driver of load in New England. In 2022, average quarterly temperature was consistent with the prior year, leading to consistent load year-over-year. While warmer weather in the winter typically contributes to lower loads, warmer weather in the summer leads to higher electricity usage due to increased air-conditioning demand.[173] Quarterly average and five-year average temperatures for 2018 through 2022 are illustrated in Figure 3-17 below.[174]

Figure 3-17: Seasonal vs. Five-Year Average Temperatures



Load levels tend to be more sensitive to temperature changes during Q3 and Q1, due to cooling and heating demand, respectively. Higher Q3 temperatures and lower Q1 temperatures (compared to 2021) both had the impact of increasing load. In Q1 2022, temperatures averaged

[173] While the system currently peaks in the summer, the system is forecasted to become a winter peaking system as soon as Winter 2029. For more information see the Pathways Study.

[174] Actual New England temperatures are based on weighted hourly temperatures measured in eight New England cities: Windsor CT, Boston MA, Bridgeport CT, Worcester MA, Providence RI, Concord NH, Burlington VT, and Portland ME.

32^0F, down 1.0^0F from Q1 2021 (33^0F) and just below the five-year average (33^0F). The slightly colder temperatures led to a small increase in Heating Degree Days (HDD) (2,985 vs. 2,894), with a 2% (305 MW per hour) increase in demand. Notable, average temperatures in January 2022 were 4^0F cooler than January 2021 and average loads were 854 MW higher.

For the remainder of the year, the average temperature was warmer than the five-year average. The Q2 and Q3 average temperatures were within one degree of the five-year average. Compared to 2021, Q3 2022 loads increased due to warmer weather. Heat waves in July and August 2022 increased loads as air-conditioning demand increased.

In the lowest demand period, Q2 and Q4, weather tends not to be a significant driver. In fact, BTM solar generation has a comparatively larger impact on wholesale load levels during these quarters. Q2 average load decreased the most from the prior year, down by 3.5% (434 MW). Q4 2022 was 1.3^0F warmer than the five-year average resulting in lower loads. This was the largest temperature difference from the five-year-average of any quarter in 2022, and resulted in the lowest Q4 load over the five-year period.

3.2.5 Demand Bidding

The quantity and pricing of bid-in demand in the day-ahead market has important pricing and operational implications. For example, generator commitments for the operating day are determined by the clearing process that matches supply and demand at last cost, which in turn impact ISO's reserve adequacy analysis (RAA). [175]

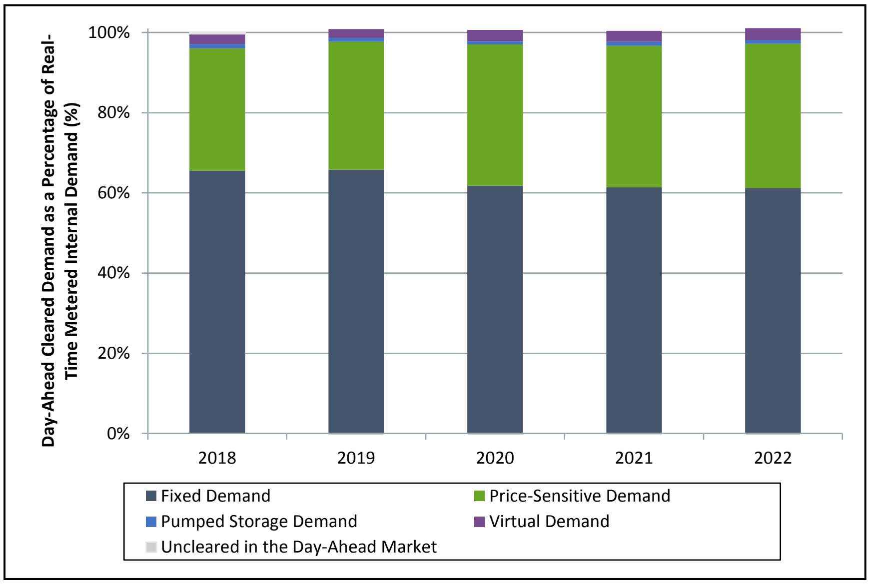
In this section, we examine native day-ahead cleared demand (i.e., delivery within the New England jurisdiction, which excludes exports).[176] Native demand consists of cleared fixed, price-sensitive, virtual, and pumped-storage demand bids. Day-ahead cleared demand by bid type as a percentage of real-time load is shown below in Figure 3-18.[177]

[175] The reserve adequacy analysis (RAA) is conducted after the day-ahead market is finalized and is designed to ensure sufficient capacity is available at least cost to meet ISO-NE real-time demand, reserve requirements, and regulation requirements. For more information see Section 3.2.3.

[176] Exports are not included as this section focuses on demand participation within New England. Exports are discussed in Section 1.4 and Section 5.

[177] Real-time load is the total end-use wholesale electricity load within the ISO New England footprint. Real-time load is equal to Net Energy for Load – Losses.

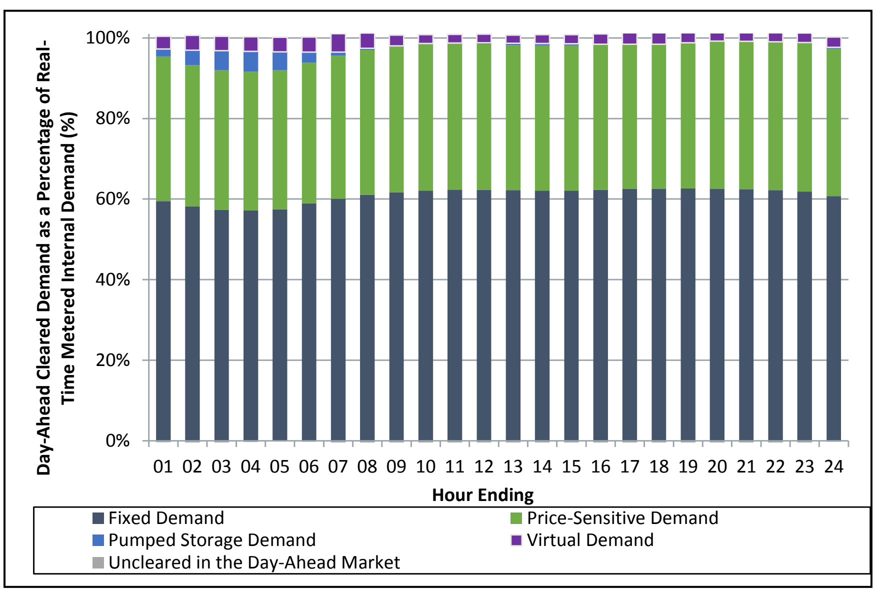
Figure 3-18: Day-Ahead Cleared Demand as a Percentage of Real-Time Load by Bid Type



In 2022, participants continued to clear more demand in the day-ahead market than they actually consumed in real time, with a modest average increase compared to 2021 (100.6% vs. 101.1%). However, it should be noted that this does not account for time-of-day.

In Figure 3-19 below day-ahead cleared demand as a percentage of real-time load by bid type is averaged by hour. Similar to above this figure shows that, on average, during every hour of the day participants cleared more than 100% of real-time load in the day-ahead market.

Figure 3-19: Day-Ahead Cleared Demand as Percentage of Real-Time Load by Bid Type by hour, 2022

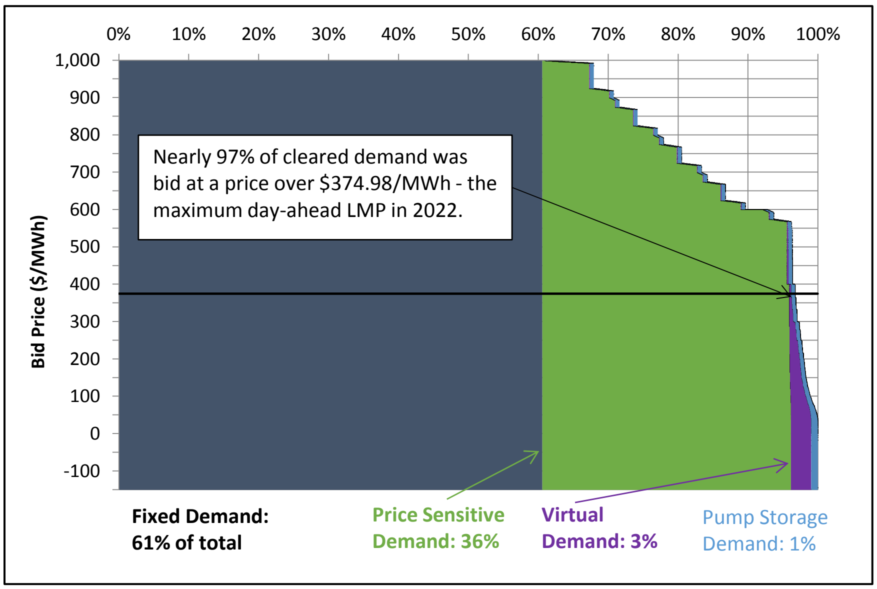


Both "price-sensitive" and virtual demand's share of cleared demand increased in 2022 to the highest percentage over the five-year period. Price-sensitive transactions accounted for 36% of real-time load, a 0.6% increase from 2021 (35.3%); virtual demand transactions increased slightly from 2.7% in 2021 to 2.9% in 2022. In addition, fixed day-ahead cleared demand was the lowest average over the period, averaging 61.2% of real-time load in 2022, a 0.2% decrease from 2021 (61.4%).

However, even though price-sensitive demand bids are submitted with a MW quantity and corresponding price, the majority of bids are priced significantly above the LMP, and are, in practical terms, fixed demand bids. Lastly, pumped-storage demand accounted for 1.0% of real-time load, consistent with 2021.

Cleared internal demand bids by price are shown in Figure 3-20 below. The bid prices are shown on the vertical axis of both graphs. In the first graph the percentage of cleared bids that were willing to pay at each bid price are shown on the horizontal axis. For example, nearly 97% of cleared day-ahead demand was willing to pay more than $374.98/MWh, the maximum day-ahead hub LMP in 2022.

Figure 3-20: Components of Day-Ahead Cleared Demand as a Percentage of Total Day-Ahead Cleared Demand



Demand in New England continued to be primarily price insensitive. Nearly two-thirds (61%) of total day-ahead cleared demand was bid as fixed demand, so it clears in the market at any price. While price-sensitive demand bids have an attached price, the price usually exceeds the day-ahead LMP. Therefore, price-sensitive demand bids typically clear, accounting for over 36% of all day-ahead cleared demand. Virtual demand and price-sensitive pumped-storage demand bids often have lower prices attached to the bid, so they do not clear as often. However, virtual and pumped-storage demand only account for approximately 4% of cleared demand bids.

3.2.6 Load Forecast and Market Implications

This section focuses on the *day-ahead load forecast*: the daily forecast made around 9:30 am that predicts hourly load for the next operating day and is published on the ISO website.[178] This

[178] Twice a day, the ISO produces a three-day system load forecast that projects load for the current day and the following two days. The first forecast is typically released around 4:30 am and the second, and typically final forecast, is published near 9:30 am.

forecast is the ISO's last load projection prior to the close of the day-ahead market offer window. Although the ISO's forecast is not a direct input into the day-ahead market, it serves as an informational tool for participants bidding in the day-ahead market, and generally aligns well with total day-ahead cleared demand.[179] Additionally, and as mentioned in Section 3.2.3, the load forecast is used in the RAA process to finalize the ISO's next day operating plan.

When the market's (participants collectively) load forecast is higher than actual load, LSE's will tend to clear more price-insensitive demand in the day-ahead market, resulting in the clearing of higher-priced supply than is needed in real-time. Consequently, day-ahead prices will tend to be higher than real-time prices as the most expensive physical supply is backed down. Conversely, lower forecasted load tends to have the opposite effect. We see this dynamic play out frequently in our empirical assessments, and there is a meaningful statistical relationship between forecast error and pricing as we present below.

Load Forecast Accuracy

Just as the day-ahead market cannot perfectly predict real-time conditions, the ISO load forecast will inevitably differ from real-time load. Since weather is both a key driver of load and difficult to predict, real-time load is challenging to forecast. Additionally, increasing amounts of behind-the-meter solar generation (discussed in more detail below) add to the challenge of accurately estimating load even over short time horizons.[180]

The mean absolute percent error (MAPE) of the ISO's day-ahead load forecast by time of year is shown in Figure 3-21 below. Months are partitioned into four groups based on the ISO's monthly load forecast goal (shown as dashed lines).[181]

[179] Load Serving Entities (LSEs) may also rely on their own in-house or third-party forecasting tools to inform their day-ahead bidding strategy.

[180] The ISO has revised the load forecasting goals to account for growing behind-the-meter solar generation which increases the volatility of the load forecast.

[181] The ISO's target MAPE goals during the year are 1.8% in January–April and October–December; 2.0% in May and September, and 2.6% in June–August.

Figure 3-21: ISO Day-Ahead Load Forecast Error by Time of Year

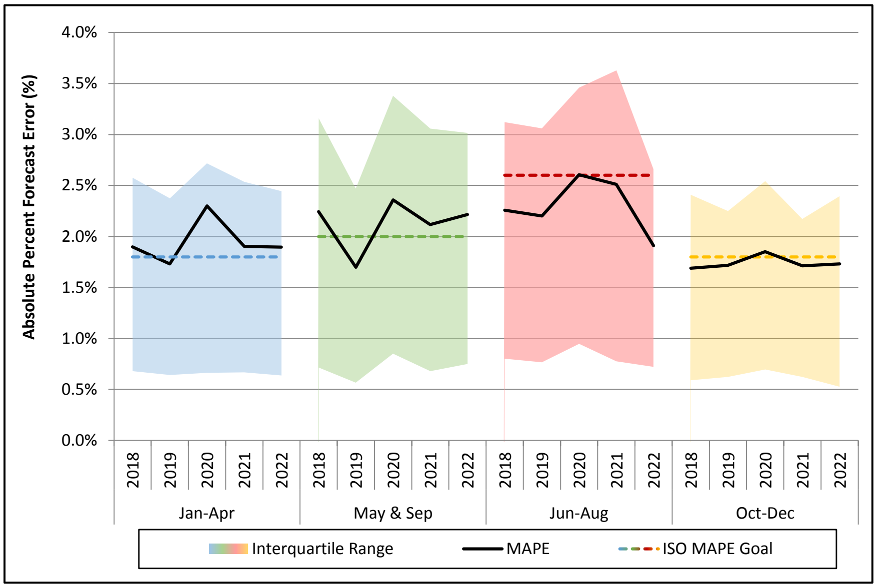


Figure 3-21 shows that 2022 forecast error and volatility decreased compared to 2021. In 2022, the MAPE for May & Sep. increased by 0.1%, from 2.1% to 2.2%, remaining above the ISO's goal. The MAPE decreased for Jun – Aug. by 0.6%, from 2.5% in 2021 to 1.9% in 2022, falling well below the ISO's goal. The other two groups remained constant with 2021 errors. At a monthly level, the ISO's forecast missed the monthly goal in five months in 2022, consistent with five months in 2021.

Impact of Behind-The-Meter Solar

The growth in behind-the-meter[182] (BTM) solar generation in recent years add to the challenge of forecasting load.[183] For one, it is difficult to estimate the location and installed capacity of thousands of small-scale solar installations around New England. Second, forecasting solar generation at a granular level is notoriously difficult with cloud cover or snowfall having significant impacts.[184] BTM generation reduces wholesale load, and therefore when less solar generation occurs than anticipated, the ISO may need to commit more expensive generators to meet higher real-time wholesale load.

The relationship between the daily average BTM solar forecast and the system level load forecast is shown below in Figure 3-22.

[182] With respect to forecasting, the ISO includes settlement-only solar generation or SOGs in the forecasted impact of BTM.

[183] In recent years the ISO has made significant investments to better forecast BTM solar generation.[183] For more information on ISO New England's investment in forecasting behind-the-meter solar generation, see https://www.esig.energy/building-data-intelligence-for-short-term-load-forecasting-with-behind-the-meter-pv/

[184] See, for example, https://www.bnl.gov/isd/documents/94838.pdf.

Figure 3-22: Impact of BTM Solar on Load Forecast Error

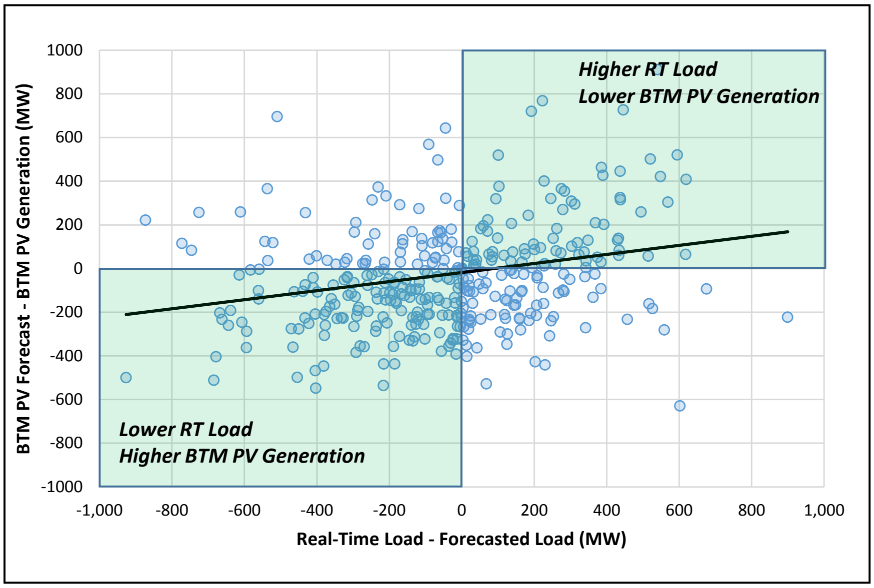


Figure 3-22 shows that BTM solar forecast error generally causes a greater load forecast error. In other words, when there is less BTM solar generation than forecasted, system load is typically higher than the ISO's load forecast (top right quadrant) and vice versa (bottom left quadrant). In 2022, this relationship was stronger than in prior years, suggesting that load forecast error was more correlated with BTM photovoltaic (PV) forecast error in 2022 than in prior years. However, this relationship does not always hold as other factors, like temperature, impact load forecasting.

The Interaction between Forecast Error and Pricing Outcomes in 2022

The ISO's load forecast error tends to be consistent with the market's forecast error. This has important market clearing and pricing implications as discussed previously. The statistical relationship between average daily load forecast error and price divergence is shown in Figure 3-23 below.

Figure 3-23: Price Difference and Forecast Error Relationship

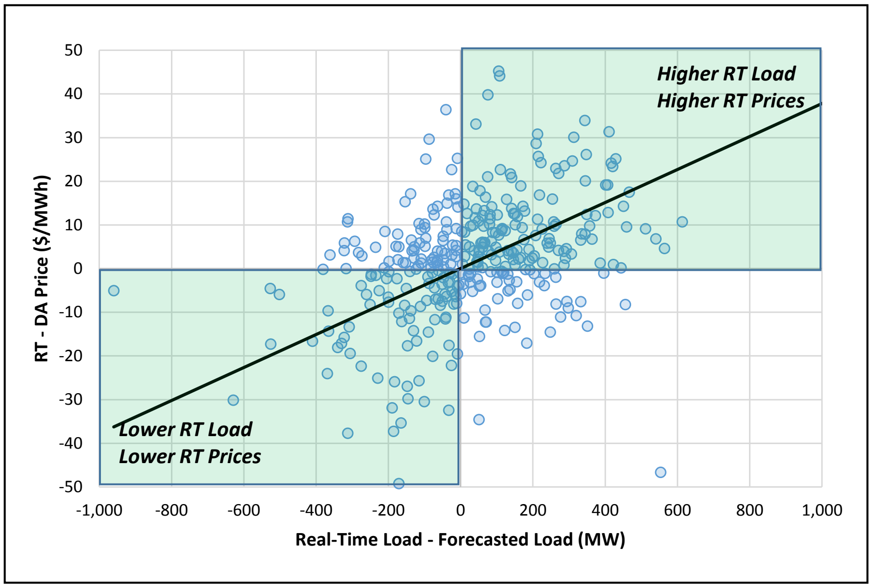


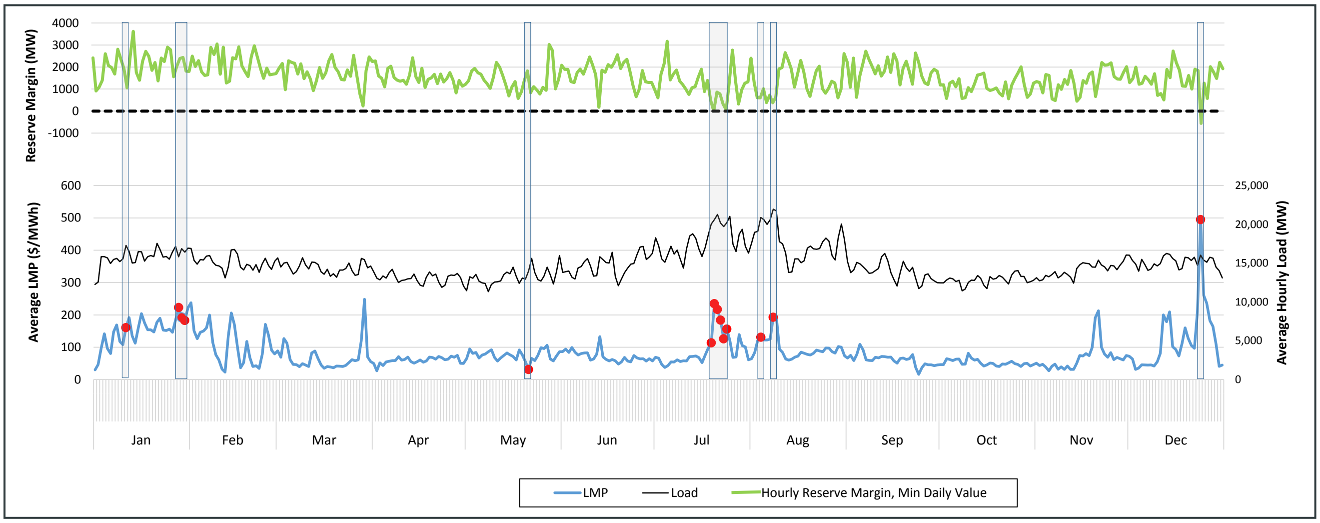
Figure 3-23 illustrates that in 2022 there was a positive correlation between the forecast error and the price difference between the day-ahead and real-time markets. In other words, when real-time loads were higher than day-ahead forecasted demand, real-time prices tended to be higher than day-ahead prices (top right quadrant), and vice versa (bottom left quadrant). Similarly to above, this relationship was stronger in 2022 than in prior years, suggesting that load forecast error was more correlated with price differences in 2022 than in previous years.

3.2.7 System Events During 2022

System events, such as unusual conditions resulting from generator outages or load forecast error, can have a significant impact on energy market outcomes. Two events occurred in 2022 that bear specific mention: the May 21 minimum generation emergency and the December 24 capacity deficiency (shortage event). This section details the frequency of system events and abnormal conditions over the past five years, and then provides a summary of the May 21 and December 24 events.

To provide context for the events covered in this section, the graph below overlays their timing on a time series of daily real-time LMPs and load levels. Also shown is the minimum total reserve margin (for an hour) for each day.

Figure 3-24: Pricing, Demand and the Reserve Margin during System Events in 2022



The following metrics illustrate the frequency of abnormal system conditions and extreme market outcomes over the past five years:

- Number of OP-4 and M/LCC 2 Events
- Reserve Deficiency Events
- Frequency of Extreme Hub LMPs

Each of these is examined in more detail below.

OP-4 and M/LCC 2 Events

The ISO uses the following established procedures to alert participants and address issues during times of tight or abnormal system conditions:

- **Master Local Control Center Procedure No. 2** (M/LCC 2, Abnormal Conditions Alert)[185] notifies market participants and power system operations personnel when an abnormal condition is affecting the reliability of the power system, or when such conditions are anticipated. The ISO expects these entities to take certain precautions during M/LCC 2 events, such as rescheduling routine generator maintenance to a time when it would be less likely to jeopardize system reliability.
- **Operating Procedure No. 4** (OP-4, Action during a Capacity Deficiency)[186] establishes criteria and guidelines for actions during capacity deficiencies. There are eleven actions described in the procedure that the ISO can invoke as system conditions worsen.

The number of instances for each type of event during the reporting period is shown in Table 3-4 below.

[185] For more information on M/LCC 2, see https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/mast_satllte/mlcc2.pdf

[186] See ISO New England Operating Procedure No. 4 – Action During A Capacity Deficiency, available at https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf

Table 3-4: OP-4 and M/LCC 2 Event Frequency

	2018	2019	2020	2021	2022
# of OP-4 Events	1	0	0	0	1
# of M/LCC 2 Events	7	0	3	6	6

The ISO implemented six M/LCC 2 events in 2022, the same amount as in 2021. In our assessment of the system events, detailed in the quarterly reports, we generally found that the market performed well during these periods. The following bullet points summarize the high-level causes and outcomes of each M/LCC 2 event in 2022.

- January 11: The ISO declared M/LCC 2 due to an imminent capacity deficiency caused by the partial loss of the Phase II interconnection with Hydro Quebec and several generators tripping offline due to mechanical issues. Five-minute real-time Hub LMPs peaked during the evening ramp at $276.92/MWh. This was higher than the peak hourly day-ahead price of $234.86/MWh, which also occurred during the evening ramp.
- January 28-30: The ISO declared M/LCC 2 due to severe weather when Winter Storm Kenan brought heavy snowfall to the region. Customer outages peaked at approximately 125,000 customers on January 29, which had little effect on total system load. Five-minute real-time Hub LMPs peaked at $373.97 during the late morning on January 28, while the hourly day-ahead price peaked at $260.42 during the evening ramp on January 29.[187]
- July 19-24, August 4, and August 8 (three events total): M/LCC 2 events were declared on these heat wave days due to imminent capacity deficiencies on days with hot temperatures and high loads. Five-minute real-time Hub LMPs peaked at $1,036.92/MWh during the evening ramp on July 20 as a result of high reserve prices. Hourly day-ahead Hub LMPs peaked at $362.74/MWh during the evening ramp on July 22.[188]
- December 24: The ISO declared M/LCC 2 due to an imminent capacity deficiency driven by cold weather, unplanned generator outages, and reductions in net imports. This resulted in the highest prices of the year, with five-minute real-time LMPs peaking at $2,816/MWh in the afternoon. This was notably higher that the peak hourly day-ahead Hub LMP of $315.27.

The only OP-4 event of 2022 occurred on December 24, which also coincided with an M/LCC 2 event. The last OP-4 event before that occurred on September 3, 2018. The latter part of this section describes this day in detail.

Reserve Deficiency Events

Reserve deficiency events (i.e., periods when there are negative reserve margins) are indicative of stressed system conditions. In these instances, the system does not have enough available supply to meet the requirement for an off-line reserve product, and the product is priced at the Reserve Constraint Penalty Factor (RCPF prices of $1,000-$1,500/MWh) and added to the

[187] The Winter 2022 QMR covers the January 11 and January 28-30 M/LCC 2 events in detail, and is available at: https://www.iso-ne.com/static-assets/documents/2022/05/2022-winter-quarterly-markets-report.pdf

[188] The Summer 2022 QMR covers the July and August M/LCC 2 events in detail, and is available at: https://www.iso-ne.com/static-assets/documents/2022/11/2022-summer-quarterly-markets-report.pdf

energy price. Below, Table 3-5 shows the number of hours during which each reserve margin was negative.

Table 3-5: Frequency of Negative Reserve Margins (System Level) [189]

Year	Hours of Negative Total30 Margins	Hours of Negative Total10 Margins	Hours of Negative Spinning Reserve Margins
2018	2.4	0.9	68.1
2019	0.0	0.0	25.9
2020	0.0	0.0	14.5
2021	0.0	0.0	26.8
2022	1.4	0.1	48.1

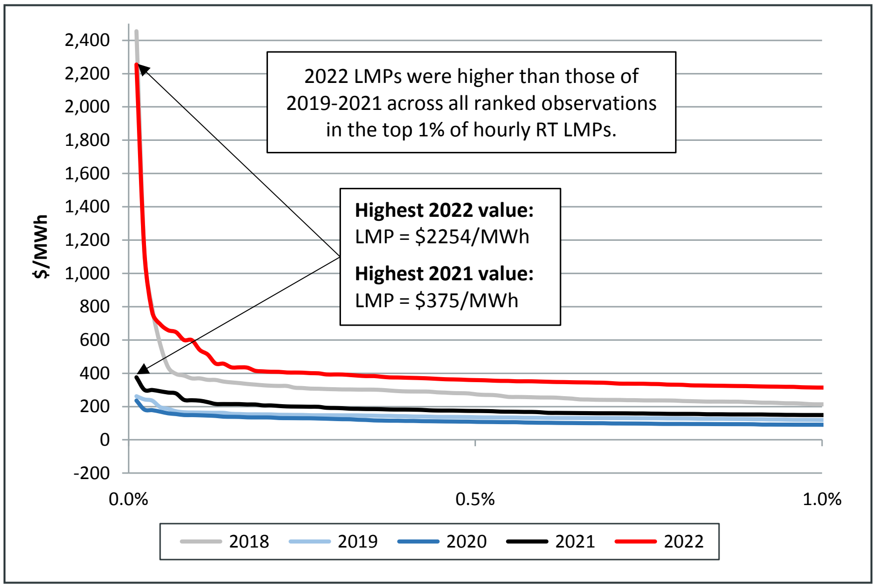
Overall, these outcomes reflect a system that has had a healthy reserve margin on average with few periods of system stress in the past few years. The Total30 and Total10 margins (which are associated with the TMOR and TMNSR products, respectively) fell below zero in 2018 and 2022, when tight system conditions led to capacity scarcity events. No comparable events occurred during 2019-2021. Shortages of ten-minute spinning reserves (with an associated RCPF of $50/MWh) were also more frequent in 2022 compared to 2019-2021, but occurred less frequently than in 2018. The spinning reserve shortages occurred across 83 days throughout the year in 2022 due to a variety of factors, such as tight system conditions caused by higher real-time loads or unplanned outages.

Frequency of Extreme Hub LMPs

High real-time LMPs can also indicate stressed system conditions, as higher-cost generation is required to meet load and reserve requirements. The duration curves in Figure 3-25 below show the top 1% of hourly average real-time LMPs ranked from high to low over the past five years.

[189] The calculations in this table come from the LMP calculation processes in the real-time market software. The "Hours of Negative Total30 Margins" column does not include instances where only the replacement reserve margin is negative, because those instances are not associated with the high $1,000/MWh and $1,500/MWh RCPFs.

Figure 3-25: LMP Duration Curves for Top 1% of Real-Time Pricing Hours



This figure shows that 2022 saw the highest real-time Hub LMPs since 2018, reflecting higher natural gas prices and tight conditions during system events. Of the top 1% of hourly average real-time Hub LMPs for 2022, 18% occurred on December 24, including the highest hourly price of the year ($2,254/MWh). There was also a shortage event in 2018 that resulted in high non-spinning reserve pricing and high LMPs. No comparable events occurred in 2019-2021.

Overview of Notable Events

May 21, 2022: Minimum Generation Emergency

On May 21, the ISO declared a minimum generation emergency event between 12:00 and 14:00. This abnormal system occurs when the ISO expects that generation and external transactions will exceed system demand, which could result in high system frequencies and unscheduled flows of power into neighboring control areas.[190] With limited downward flexibility, the ISO takes action to reduce supply to emergency minimum levels and prices are administratively set to *negative* $150/MWh. This sends strong signals to supply to reduce output, or conversely to demand to increase consumption (e.g., battery charging, pumped-storage hydro demand).

Actual loads were significantly less than the forecasted load heading into the operating day due to lower temperatures than expected and sunnier conditions, resulting in more solar production. The day-ahead market cleared an excess amount of physical generation compared to what was required in real-time. Hourly forecasted and actual loads are shown in Figure 3-26 below.

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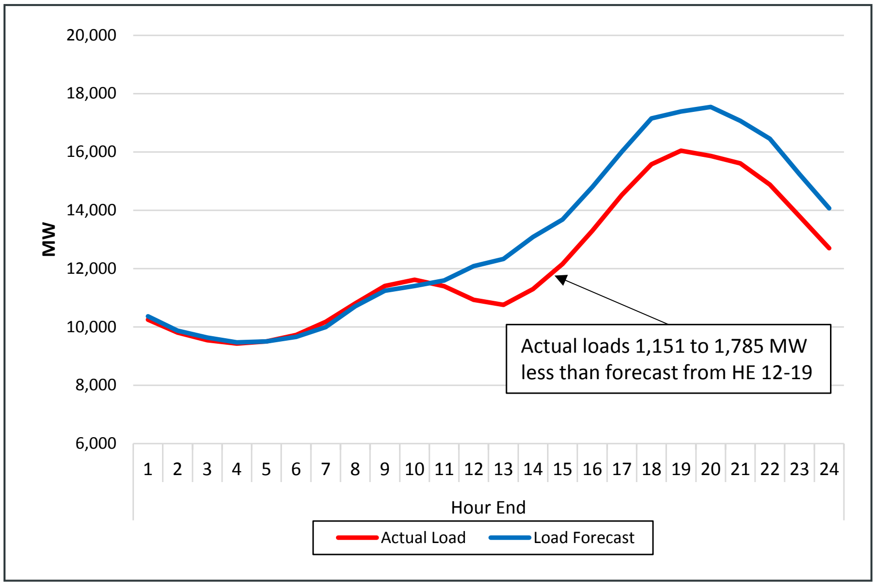
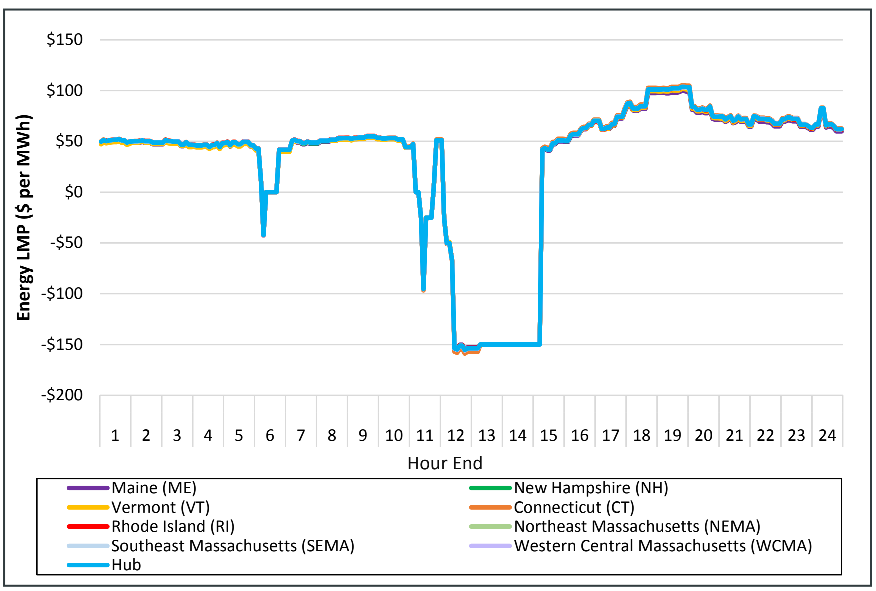
[190] For additional information on minimum generation emergencies, see: https://www.iso-ne.com/participate/support/faq/minimum-generation-emergency

Figure 3-26: Actual vs. Forecasted Load on May 21



During the minimum generation emergency, gas-fired generators were dispatched down and produced 2,300 to 2,500 MW less in real time compared to the total day-ahead cleared amount. The control room reduced transactions across Phase II and Highgate, which led to 500 to 1,200 MW fewer net imports during the event. Prices across the system were administratively set at -$150/MWh. This occurred for two hours between 12:15 and 14:15. Five-minute real-time Hub and zonal prices are shown in Figure 3-27 below.

Figure 3-27: Real-Time Prices on May 21, 2022

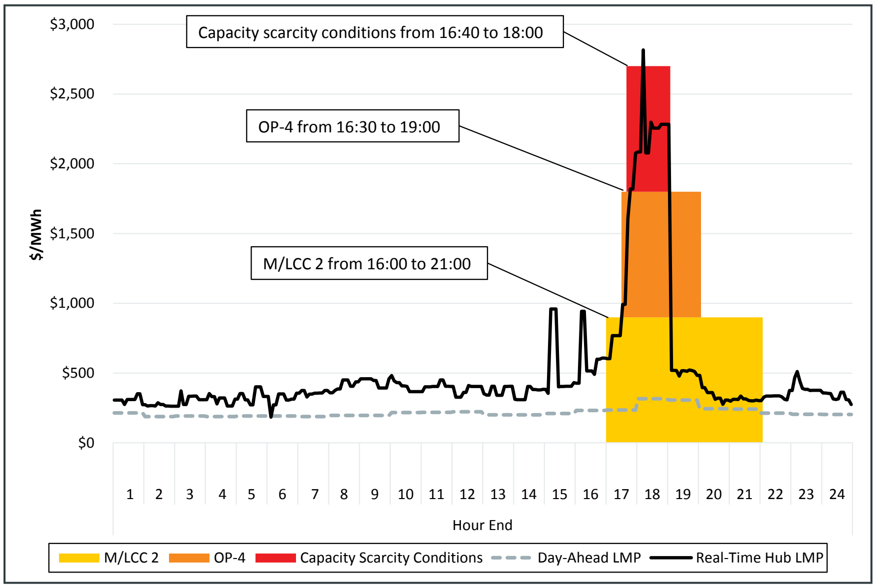


December 24, 2022: Shortage event

On Saturday, December 24, 2022, the ISO experienced its first capacity scarcity conditions (CSC) in over four years. The ISO initiated emergency procedures in response to tight system conditions that resulted from multiple factors, including cold weather, unplanned generator outages, and reductions in net imports. The conditions led to operating reserve deficits and high energy prices.

A timeline of the ISO's emergency procedure actions, along with energy prices, is shown in Figure 3-28 below.

Figure 3-28: December 24 Event Timeline

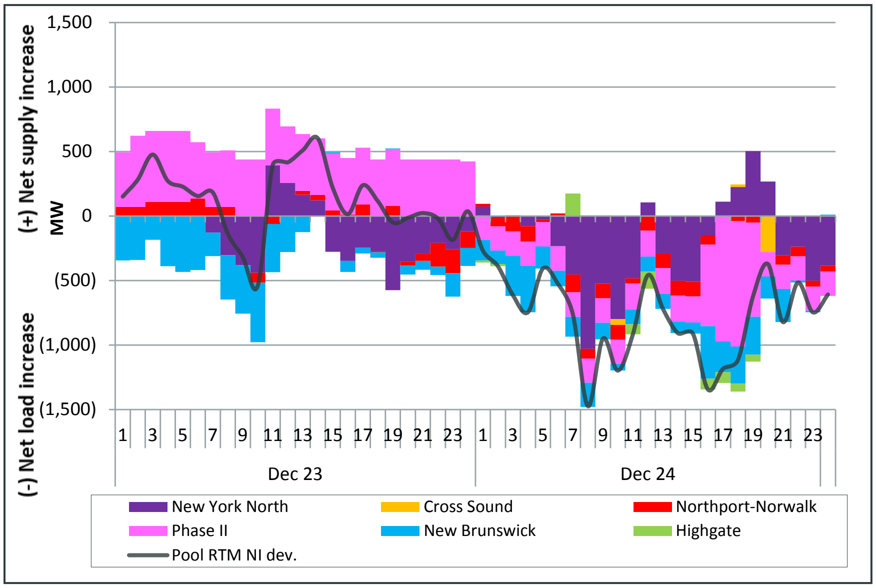


The following paragraphs detail the factors that contributed to the event and how event outcomes were reflected in market settlements.

Weather and Load: On the day before the shortage event, Winter Storm Elliott affected the region and resulted in around 200,000 customer outages. Temperatures declined rapidly between December 23 and 24, resulting in a steep increase in demand for natural gas for heating. Despite the load forecast error, real-time load was close to or under day-ahead cleared demand for most of the day.

Net Imports: During the capacity scarcity condition, real-time imports from neighboring control areas decreased relative to day-ahead cleared imports. Deviations between day-ahead cleared and real-time scheduled MWs by interface are illustrated in Figure 3-29 below.

Figure 3-29: Day-Ahead vs. Real-Time Net Import Deviations by Interface

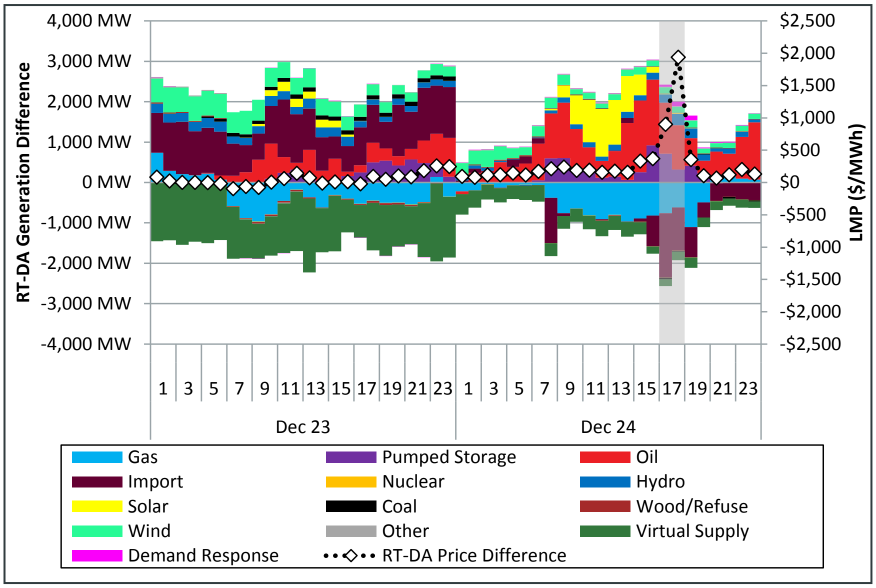


On December 24, there was a substantial decline in real-time net imports compared to the day-ahead schedule. The deviations were most severe from 7:00 to 11:00 and 13:00 to 18:00, when there were 910-1,675 MW fewer net imports in real-time. Around the time of the capacity scarcity conditions in the afternoon, the most substantial reductions in net imports occurred over the Canadian interfaces due to high demand and transmission system issues there.

Unplanned Generator Outages: The system lost a large volume of generation capacity shortly before and during the operating day on December 24 due to unplanned generator outages. The outages were caused by mechanical problems rather than by fuel availability issues. While out-of-service capacity varied throughout the day based on the start and end times of the outages, the sum of out-of-service generation that tripped on December 23 and December 24 was about 2,180 MW. Most of the resources that tripped were older generators that are typically only committed during tight system conditions.

Supply Mix Changes: Supply Mix Changes: The unplanned outages and net import deviations resulted in changes to the real-time supply mix compared to the day-ahead mix. The breakdown in differences between day ahead and real-time generation obligations is shown in Figure 3-30 below.

Figure 3-30: Differences between Hourly Real-time and Day-Ahead Generation Obligations



During several hours on December 24, there was significantly less real-time gas generation compared to the day-ahead schedule, primarily due to generator trips and a large dual-fuel generator switching to oil in real-time. Additionally, large decreases in imports occurred leading up to and during the capacity scarcity conditions.[191] During the shortage event, there was increased fast-start generation from pumped-storage and oil-fired generators.

Most of the additional generation commitments were made by the market software rather than by the operators. From HE 17 to HE 18, the real-time market software committed 2,560-2,680 MW of fast-start generation. The system operators manually committed 175-200 MW of generation during the same period.

LMPs and real-time reserve pricing: Five-minute real-time energy prices reached a peak of $2,816/MWh at the Hub over the five-minute period beginning at 17:10. High energy prices were a result of high reserve prices, which were incorporated into the LMP. During the scarcity event, there were deficits in both the thirty-minute operating reserve (TMOR) requirement and the ten-minute non-spinning reserve (TMNSR) requirement. These deficits triggered reserve constraint penalty factors. The TMOR penalty factor ($1,000/MWh) was in effect from 17:40 to 18:00. The TMNSR ($1,500/MWh) penalty factor was also activated for five minutes during this interval, resulting in a combined reserve price of $2,500/MWh for that duration.

Market settlements-energy market: Day-ahead and real-time energy costs were significant on December 24, totaling $81.7 million and $5.2 million, respectively. Uplift payments totaled $1.5 million, and were driven by fast-start pricing opportunity cost payments and payments to resources dispatched above their economic dispatch point between 13:00 and 17:00.

Market settlements-pay for performance rules: Under pay for performance rules, participants with a capacity supply obligation (CSO) were expected to provide an average of 67% of their

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[191] Figure 3-30 illustrates supply side deviations, and therefore shows imports rather than net interchange (which accounts for exports).

contracted capacity in form of energy or reserves during this event. Deviations from obligated performance were settled at the performance payment rate of $3,500/MWh during each five-minute interval of the capacity scarcity condition. Credits and charges totaled $35.9 million each. Performance varied widely by fuel type. Import transactions and nuclear resources saw the largest payments, while gas and dual-fuel generators incurred charges.

3.2.8 Reliability Commitments and Posturing

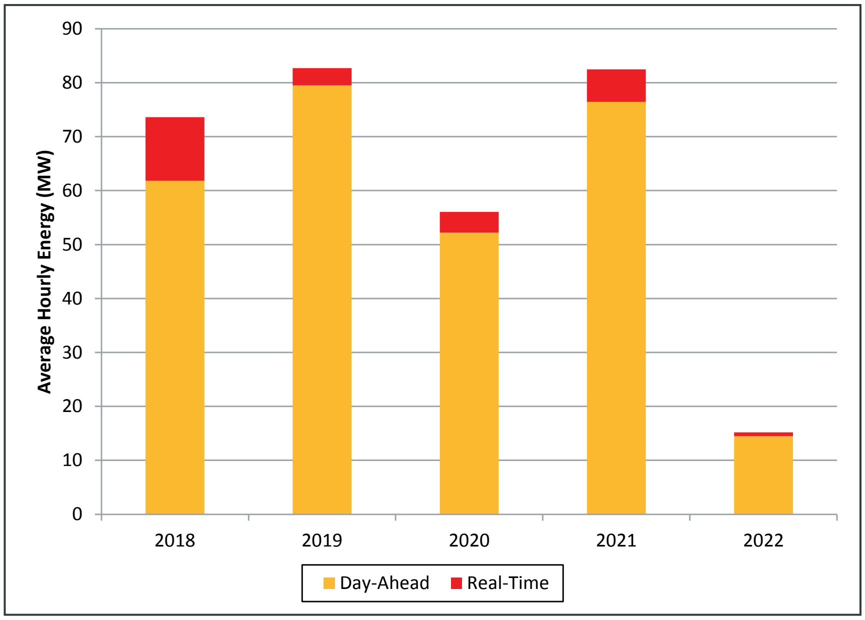
The ISO is required to operate New England's wholesale power system to the reliability standards developed by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and in accordance with its own reliability criteria.[192] To meet reliability standard these requirements, the ISO may commit additional resources for several reasons, including to ensure that adequate capacity is available in constrained areas, for voltage protection, and to support local distribution networks. The ISO also may take manual actions to constrain (posture) resources from operating at the economic dispatch point determined by the market software, in order to improve system reliability. This typically occurs in order to maintain adequate reserves from fast-start pumped-storage generators and to reserve limited fuel oil inventory.

Reliability Commitments

The real-time average hourly energy output (MW) from reliability commitments during the peak load hours (hours ending 8-23) for 2018 through 2022 is shown in Figure 3-31 below. The figure also shows whether the commitment decision was made in the day-ahead or real-time market.

[192] These requirements are codified in the NERC standards, NPCC criteria, and the ISO's operating procedures. For more information on the NERC standards, see http://www.nerc.com/pa/stand/Pages/default.aspx. For more information on the NPCC standards, see https://www.npcc.org/program-areas/standards-and-criteria. For more information on the ISO's operating procedures, see http://www.iso-ne.com/rules_proceds/operating/isone/index.html.

Figure 3-31: Average Hourly Energy Output from Reliability Commitments, Peak Load Hours



Reliability commitments remain a relatively small component of total system generation, at less than 0.1%, or just 15 MW, on average. While the decrease in reliability commitments may be partially explained by reduced transmission work, the primary explanation for the very large decline is unclear. Reliability commitments were low over the past five years, averaging just 62 MW per hour. Commitments continue to be more common in the day-ahead market as a percentage of total reliability commitments.[193]

The vast majority (96%) of these commitments occurred for local reserve support – known as Local Second Contingency Reliability Protection (LSCPR).[194] Other support services - Special-Constraint Resources (SCR) and voltage - accounted for 3% and 1% of reliability commitment resources, respectively.[195] Most reliability commitments (83%) occurred in Maine and SEMA-RI; the remainder were in NEMA (5%) and New Hampshire (10%). These reliability commitments primarily reflected a need for additional on-line generation in areas with transmission upgrades and outages, to ensure local reliability.

A monthly breakdown of reliability commitments made during 2022 is shown in Figure 3-32 below. The figure shows the out-of-rate energy for reliability commitments during the peak

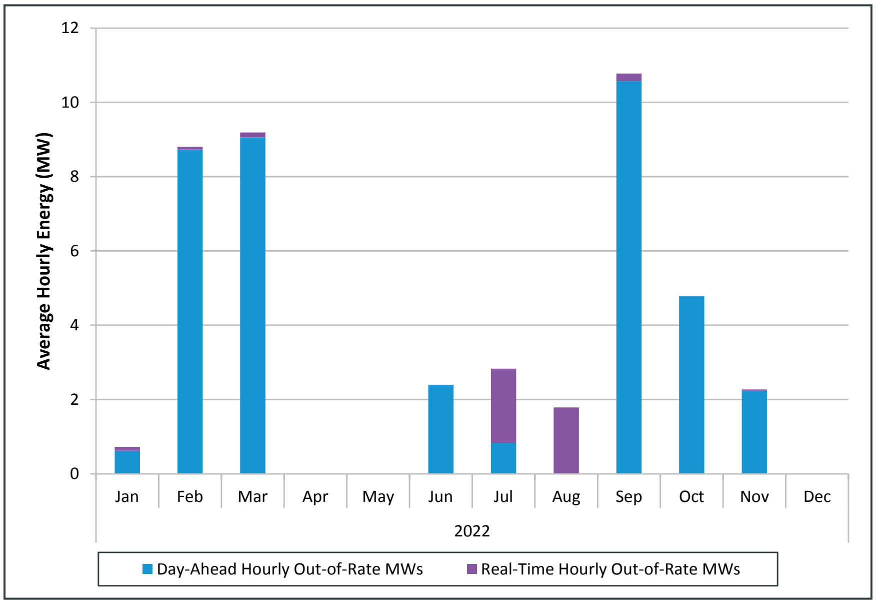
[193] Committing generators in the day-ahead market is more desirable than commitments later in the Reserve Adequacy Analysis (RAA) process or in real time as day-ahead commitments tend to reduce the risk of suppressed real-time prices and higher NCPC payments. If reliability commitments are known in the day-ahead market, the commitment schedules of other generators can be adjusted to accommodate the reliability commitment. This provides more flexibility than if the commitment is made later, reducing the risk of having excess inflexible supply online. Excessive generator commitments can distort prices by removing other generators from the supply stack and adding fixed energy to the supply stack. The excess fixed supply could potentially suppress real-time prices and increase NCPC.

[194] Local second contingency protection reliability (LSCPR) commitments are made for import-constrained sub-areas, if necessary, to ensure that the ISO can re-dispatch the system to withstand a second contingency loss within 30 minutes after the first contingency loss without exceeding transmission element operating limits.

[195] An explanation for the reliability commitment types may be found here: https://www.iso-ne.com/participate/support/glossary-acronyms/

load hours in 2022, by market and month. Out-of-rate energy includes reliability commitment output that is offered at a higher price than the LMP, and, therefore, would not likely have been committed or dispatched in economics.

Figure 3-32: Day-Ahead and Real-Time Average Out-of-Rate Energy from Reliability Commitments, Peak Load Hours, 2022



Of the roughly 15 MW of average hourly output from generators committed for reliability, only 4 MW (on average) was out-of-rate. Figure 3-32 shows that the greatest amount of out-of-rate energy from reliability commitments occurred in February, March, and September; these commitments supported planned transmission outages in Maine and SEMA-RI. Out-of-rate commitments require uplift payments, to ensure that operating costs are recovered. NCPC payments to generators providing LSCPR in 2022 totaled just $1.1 million; while this represented 2% of total uplift payments for the year, it represented just 0.01% of total energy payments.

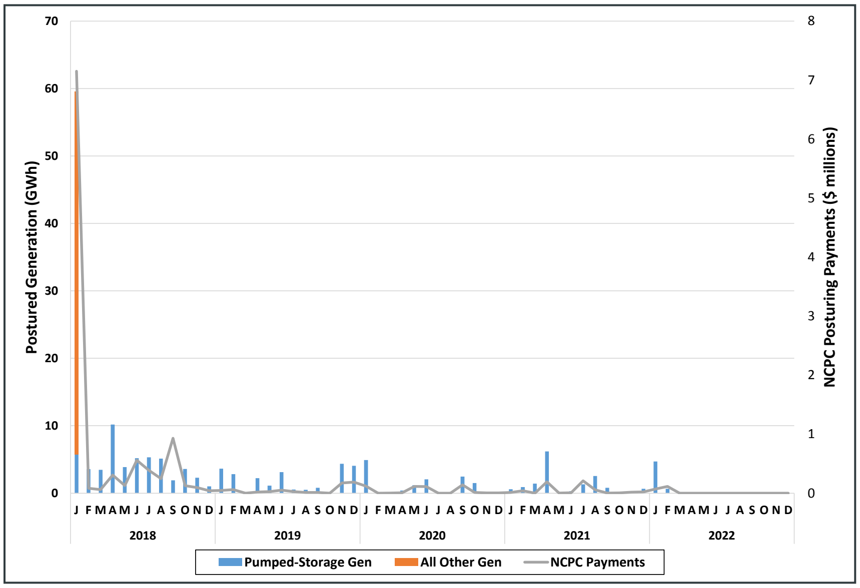
Posturing Actions

The ISO may limit the output of potentially in-merit generators to ensure either system-wide or local reliability, an action known as "posturing". Posturing generators results in the preservation of fuel for "limited energy" generators, allowing fuel to be used later in the event of system contingencies. A generator may provide operating reserves while postured, but is only available for manual dispatch above the posturing level in the event of a system contingency. Postured generators are eligible to receive NCPC for any foregone profits that occurred during the posturing period.[196]

[196] See Market Rule 1, Appendix F, Sections 2.3.8 and 2.3.9.

Postured energy (GWh) and NCPC payments by month are shown in Figure 3-33 below.[197] The bars indicate the postured energy obtained (the amount of energy constrained down) from pumped-storage generators and all other types of generators.[198]

Figure 3-33 Monthly Postured Energy and NCPC Payments



Pumped-storage generators were frequently postured throughout the year, prior to 2022. In 2022, posturing was less frequent, resulting in just 5 GWh of posturing. In earlier years, the ISO tended to posture pumped-storage generating units, during certain periods, to preserve pondage and maintain operating reserves. This activity declined significantly in 2022.

Posturing actions in January 2018 stand out. Except for this month, only pumped- storage generators have been postured. The posturing in January 2018 involved a number of oil-fired generators, with limited fuel, during a prolonged cold snap period due to Operator concerns about the day-to-day availability of natural gas for electric generation. The postured oil-fired generators were effectively providing back-up electricity supply, in the event of a natural gas shortage during the cold snap.

As indicated in the figure, NCPC payments to postured generators were quite low in 2022, with approximately $0.2 million in total payments (accounting for 0.4% of all NCPC payments in 2022). NCPC payments were highest during January 2018, when the cold snap period resulted in significant posturing of oil-fired generators. While the magnitude of NCPC payments is generally consistent with the quantity of energy being postured, posturing during very high energy price periods also can result in high NCPC payments, even when the postured energy quantity is not extremely large. This occurs because the postured generators forgo the high

[197] Postured energy is the amount of energy that is unavailable for economic dispatch, given the posturing action; this value is used in the settlement compensation for the posturing action.

[198] Very infrequently, pumped-storage demand (or asset-related demand) is postured. These resources are postured on-line (in consumption mode) to increase operating reserves. The energy associated with these posturing activities is not depicted in the figure.

LMPs and must be compensated for lost profits. This is noticeable in September 2018, during a capacity deficiency period with operating reserve deficiencies and high energy prices.

3.2.9 Transmission Congestion

Levels of transmission congestion are relatively low in New England compared to other ISO markets due to the significant amount of transmission investment over the past decade or so. In contrast, transmission costs in New England are relatively high.[199] However, there are some specific areas on the New England System that regularly experience congestion, which limits power flowing from relatively cheaper supply.

This section examines transmission congestion in New England over the last five years. Subsequently, this section explores the most congested areas within New England in 2022. It concludes by listing the most frequently binding transmission constraints in New England in 2022.

Congestion Revenue

A feature of New England's locational energy market is that load pays for energy at the price where it is *consumed* and generation is paid for energy at the price where it is *produced*. This means that, when there is a binding transmission constraint, load will often pay more for the energy that it consumes than generation receives for the energy that it produces. Congestion revenue represents the difference between what load pays for energy and what generation receives for energy that happens as a result of transmission congestion.[200]

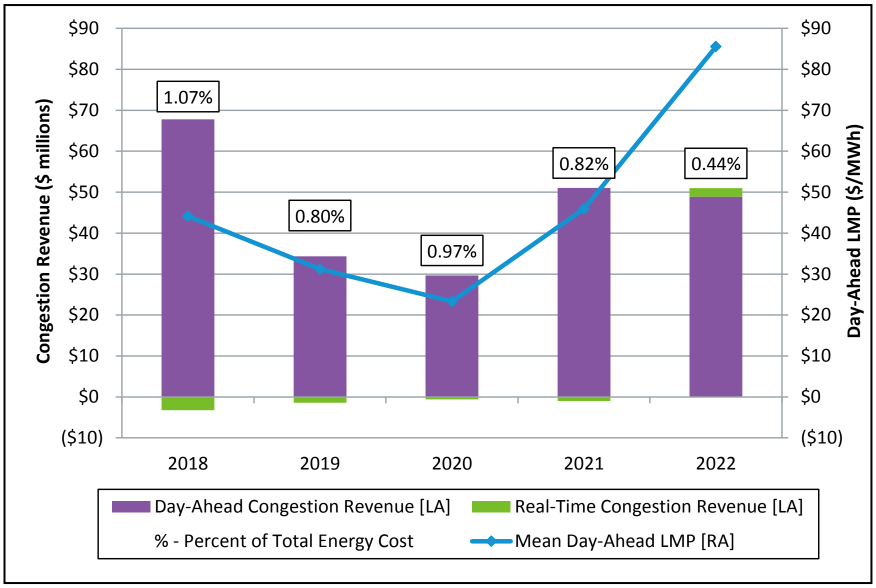
Over the last five years, congestion revenue has been small relative to total energy market payments and it has generally moved in line with the price of energy. This can be seen in Figure 3-34 below. The purple bars represent the day-ahead congestion revenue and the green bars represent the real-time congestion revenue. The percentages in the figure are the total congestion revenue each year (i.e., the day-ahead congestion revenue plus the real-time congestion revenue) expressed as a percent of total energy market costs. This figure also depicts the annual average day-ahead Hub LMP (blue line).[201]

[199] In its *2021 Assessment of the ISO New England Electricity Markets*, Potomac Economics, the External Market Monitor for ISO-NE, showed that ISO-NE had the lowest congestion rate in 2021 ($0.38/MWh) of ERCOT, MISO, PJM, and NYISO, but had the highest transmission rate (nearly $22/MWh) of these other RTOs. See Figure 2 in its *2021 Assessment*: https://www.potomaceconomics.com/wp-content/uploads/2022/06/ISO-NE-2021-SOM-Report_Full-Report_Final-Clean.pdf

[200] See Section III.3.2.1 (i) of ISO-NE Market Rule 1 for an exact definition of day-ahead and real-time congestion revenue.

[201] The day-ahead and real-time congestion revenue totals are measured on the left axis ("LA"), while the average annual day-ahead Hub LMP is measured on the right axis ("RA").

Figure 3-34: Average Day-Ahead Hub LMP, Congestion Revenue Totals and as Percent of Total Energy Cost



Total day-ahead and real-time congestion revenue was $51 million in 2022, which represented only 0.44% of total energy costs, and was much lower than the prior four years in relative terms. The majority of the congestion revenue is in day-ahead market (as opposed to the real-time market) where the vast majority of load and generation clear. The day-ahead congestion revenue totals tend to be strongly correlated with the average day-ahead LMP, although this relationship weakened in 2022. This was largely driven by a less constrained transmission system in 2022.

Congested Areas in New England

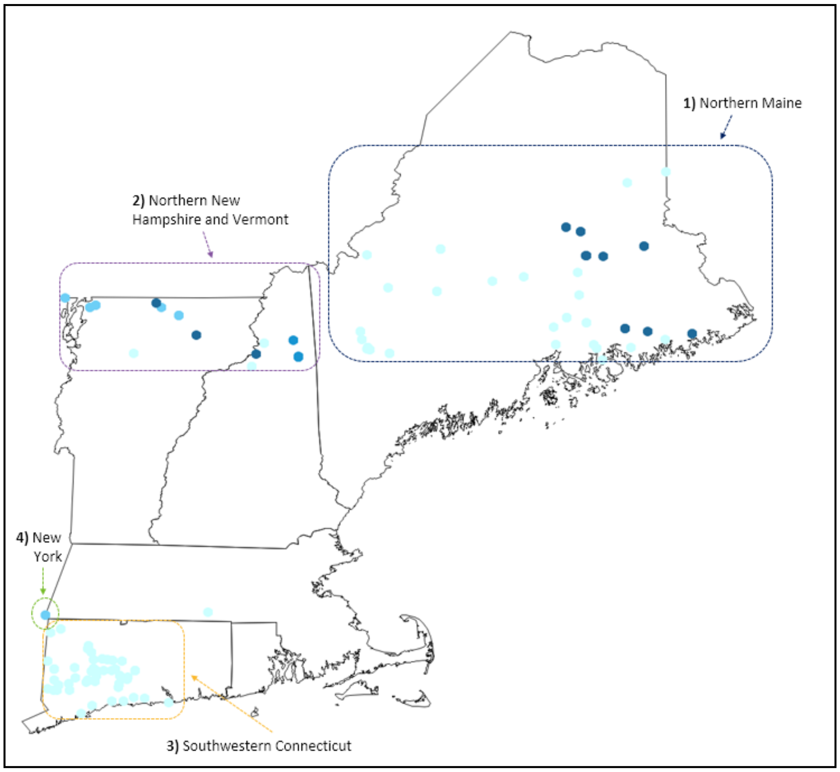
The New England nodes most affected by transmission congestion in the day-ahead market in 2022 are shown in Figure 3-35 below.[202] The colors of the nodes indicate the average day-ahead congestion component in 2022. Blue dots represent locations with negative average day-ahead congestion components – the darker the blue, the lower the congestion component (i.e., more negative). Locations that are "upstream" of a binding transmission constraint have a negative congestion component.[203] Meanwhile, red dots represent locations that had a positive average day-ahead congestion component.[204] Locations that are "downstream" of a binding constraint have a positive congestion component.

[202] This figure only includes nodes that had an average day-ahead congestion component of greater than or equal to $0.15/MWh or less than or equal to -$0.15/MWh in 2022 in order to better highlight the constrained areas.

[203] More specifically, a negative congestion component occurs when a location has a positive shift factor to a binding constraint. Conversely, a positive congestion component occurs when a location has a negative shift factor to a binding constraint. In simple terms, a shift factor measures how an injection of energy at a location impacts the flow of energy over a transmission constraint.

[204] In 2022, there were no locations with average day-ahead congestion components greater than or equal to 0.15/MWh and, therefore, there are no red dots in this figure.

Figure 3-35: New England Pricing Nodes Most Affected by Congestion, 2022



Many of the congested areas in New England in 2022 were relatively small geographic areas where transmission capacity limited the ability to export power to the rest of the system. Several areas in Figure 3-35 have been highlighted and each of them is discussed in detail below:

1) **Northern Maine**: This area has a relatively high concentration of intermittent (predominantly wind) generators and is also where the New England system interconnects to the New Brunswick control area (i.e., imports from New Brunswick flow into this area).

2) **Northern New Hampshire and Vermont**: Similar to northern Maine, northern New Hampshire and Vermont are areas with relatively high concentrations of wind generation. Additionally, northern Vermont receives the power imported from the Hydro-Québec control area over the Highgate tie line.

3) **Southwestern Connecticut**: This region also experienced negative congestion pricing at times in 2022. Multiple high capacity and efficient natural gas-fired generators have been added in this region in recent years resulting in increased in-merit supply (CPV Towantic, Bridgeport Harbor). At times, the 115-kV system can limit the export of low-cost power out of this region to the rest of the system, especially when nearby transmission lines are taken out of service for repair or upgrade work.

4) **New York**: The lines connecting New York and New England frequently reach their limit during periods when there are large spreads between power prices in New England and New York (e.g., some winter months when New England's gas

infrastructure can become constrained resulting in higher New England prices) or when there are reductions in the interface limit.

The Most Frequently Binding Interface Constraints

The 10 interface constraints that bound most frequently in the day-ahead market in 2022 are listed in Table 3-6 below.[205] Also included in the table is the average marginal value ($/MWh) of each constraint when it bound in the day-ahead market in 2022.[206] Lastly, this table includes a location column, which places the constraints in the areas defined in Figure 3-35.

Table 3-6: Most Frequently Binding Interface Constraints in the Day-Ahead Market, 2022

Constraint Name	Constraint Short Name	% of Hours Binding	Average Marginal Value of Constraint ($/MWh)	Location
Keene Road Export	KR-EXP	15.5%	-$33.12	1
Sheffield + Highgate Export	SHFHGE	14.3%	-$12.23	2
New York - New England	NYNE	5.9%	-$24.22	4
Whitefield South + GRPW	WTS+GR	4.9%	-$18.59	2
Orrington - South	ORR-SO	4.7%	-$14.88	1
Inner Rumford Export	IRMF-E	2.1%	-$32.16	1
New England West-East	NE_WE	1.3%	-$11.95	-
Sheffield Wind Generation	SHEF	1.0%	-$66.93	1
Tiverton Generation	TIVRTN	1.0%	-$14.29	-
Kingdom Wind Generation	KCW	0.9%	-$132.57	2

The most frequently binding interface constraint in 2022 was the Keene Road Export (KR-EXP) interface, which bound in 15.5% of hours in the day-ahead market. The only other constraint that bound in more than 10% of hours in the day-ahead market was the Sheffield + Highgate Export (SHFHGE) interface, which bound in 14.3% of hours. Several of the interface constraints listed bound in just one percent of hours or less, indicating that the day-ahead energy market in New England was relatively unconstrained in 2022.

3.2.10 Marginal Resources

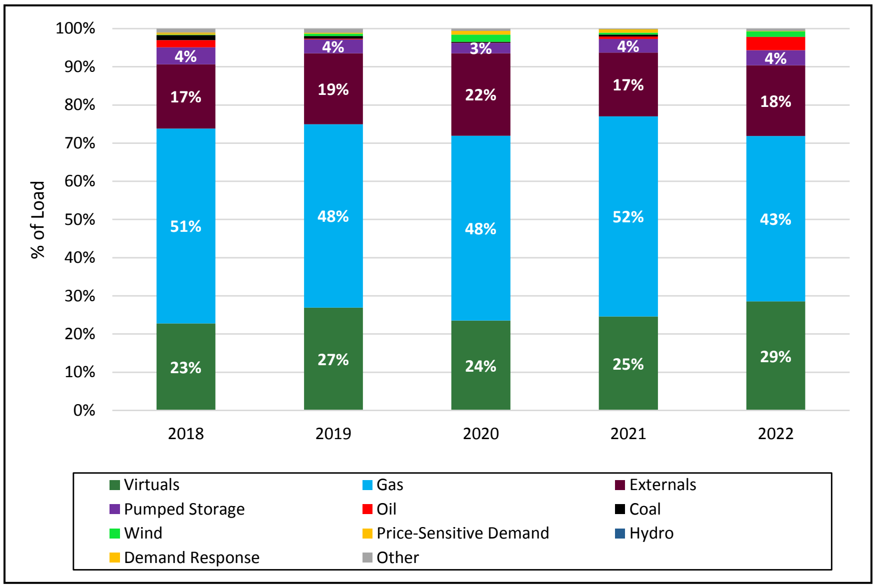
Offers and bids that are *physical or financial* in nature can set clearing prices in the day-ahead market, including virtual transactions, price-sensitive demand bids, price-responsive demand,

[205] Interface constraints are typically sets of transmission elements whose power flows are jointly monitored for voltage, stability, or thermal reasons. They can often have a larger impact on congestion revenue when they bind than individual transmission elements because they likely affect more load and generation.

[206] The marginal value of a binding transmission constraint indicates the change in the system production costs if the limit of the transmission constraint were increased by one MW for one hour. For example, a marginal value of -$10/MWh indicates that system production costs could be reduced by $10 if the limit of the transmission constraint were increased by one MW for one hour. The more negative the marginal value of the binding transmission constraint, the more the system production costs could be reduced if the constraint were relaxed.

asset-related demand, generator supply offers, and external transactions. Figure 3-36 illustrates the percentage of load for which each transaction type was marginal over the past five years.

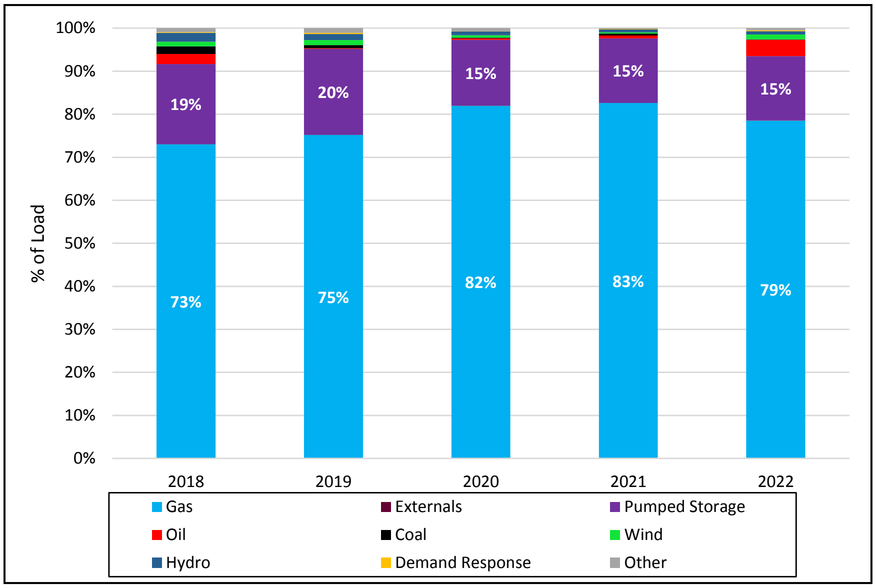
Figure 3-36: Day-Ahead Marginal Resource by Transaction Type



In the 2022 day-ahead market, natural gas (43%), virtual transactions (29%), and external transactions (18%) continued to set price for a majority of load (90%), which is comparable across the five years. Of note in 2022, was the increase in oil and virtual transactions setting price, and the corresponding reduction in marginal gas generation. Oil generation was in merit more frequently during the winter when natural gas prices were high, leading oil generators to set price for 3% of load. The increase in marginal virtual transactions was due to the increase in virtual *supply* transactions on days with high solar output. Since the majority of wholesale solar clears in the real-time market only, it can be profitable for virtual supply to take solar's place in the day-ahead market. These offers often set price, as they are typically priced near the margin to maximize their opportunity to arbitrage lower real-time prices.

In the real-time market, only *physical* assets can set price: generators, pumped-storage demand, demand response resources, and external transactions. Real-time marginal resources are typically generators (predominantly natural gas-fired generators) and pumped-storage demand. The real-time marginal fuel mix over the past five years is shown in Figure 3-37 below.

Figure 3-37: Real-Time Marginal Resource by Transaction Type



Other than generators offering on oil during the winter, the mix of resources that set price in 2022 was very similar to 2021. *Natural gas* continued to set price for the majority of load (79%), while *pumped-storage* units (both generators and demand) remained the second largest marginal resource (15%).[207] Because pumped-storage generators are often online during peak load conditions and priced close to the margin, they can set price frequently. *Oil* generators set price for 4% of load in the real-time market, the highest over the five-year period. The price-setting intervals are concentrated in January 2022, when very high natural gas price during cold periods resulted in more oil generation capacity being in economic merit and setting price.

The remaining transaction types were marginal for less than 3% of load in 2022. Although wind generators are frequently marginal for a small geographic area, they are usually marginal for only a small share of total system load (1% in 2022).[208]

3.3 Net Commitment Period Compensation (Uplift)

This section provides an assessment of Net Commitment Period Compensation (NCPC) payments. In the marginal cost-based energy market, prices will not always cover the full production cost as offered by cleared supply resources, and therefore a make whole payment is required in the form of NCPC.

[207] Pumped-storage generation and demand have different operational and financial incentives. Pumped-storage generators (supply) tend to operate and set price in on-peak hours when electricity prices are generally higher. Pumped-storage demand have lower offers and typically consume energy and set price in off-peak hours, when it is generally cheaper to pump water. In 2022, pumped-storage generation set price about 10% of the time and pumped-storage demand set price about 5% of the time.

[208] Wind generators are often located in export-constrained areas and can only deliver the next increment of load in a small number of low-load locations. Wind generators often cannot set price outside of the constrained area they are operating in because the transmission network that moves electricity out of their constrained area is at maximum capacity.

In this section, we review NCPC in the context of total energy payments and provide a breakdown of payments across market category, which can provide some insight into specific drivers.

Key Takeaways

NCPC totaled $52.9 million in 2022, a $17.0 million increase (47%) from $35.9 million in 2021. However, NCPC payments represented only 0.5% of energy payments in 2022, which was the lowest level over the five-year reporting period. NCPC per MWh of load served totaled $0.44/MWh compared to energy payment of $98/MWh.

The vast majority of NCPC payments in 2022 (95%) were paid to cover the operating costs of resources committed and dispatched in economic merit order ("economic" NCPC category). Payments to resources committed for local reserve support decreased from $6.8 million in 2021 to $1.1 million in 2022 (local second-contingency protection resource, or LSCPR, NCPC category). This was due to significantly fewer local reliability commitments due to fewer impactful transmission outages.

NCPC payments in the context of the energy market payments

The level of NCPC payments relative to energy payments can be a useful high-level gauge of the energy market's ability to cover the as-offered production costs of ISO- or market-scheduled resources; high levels of NCPC could be symptomatic of price formation issues or gaps in market products or design.

In 2022, NCPC payments remained relatively low compared to energy payments. Total NCPC payments (dollars) tend to be positively correlated with energy market prices, as was the case in 2022, but in relative terms (percentage of energy payments) NCPC declined. Energy and NCPC payments are summarized in Table 3-7 below.

Table 3-7: Energy and Uplift Payments

	2018	2019	2020	2021	2022
Energy Payments ($ millions)	$6,041	$4,105	$2,996	$6,099	$11,698
NCPC Payments ($ million)	$70.30	$30.60	$25.95	$35.94	$53.06
NCPC in $/MWh	$0.57	$0.25	$0.22	$0.30	$0.44

NCPC as % Energy Payments					
Day-Ahead NCPC	0.4%	0.3%	0.3%	0.3%	0.1%
Real-Time NCPC	0.7%	0.4%	0.5%	0.3%	0.3%
Total NCPC as % Energy Costs	**1.2%**	**0.7%**	**0.9%**	**0.6%**	**0.5%**

In 2022, energy payments totaled $11.7 billion, the highest in the five-year reporting period, and nearly double the 2021 total. As covered in earlier sections, higher natural gas prices were the key driver of energy payments, which also doubled year over year.

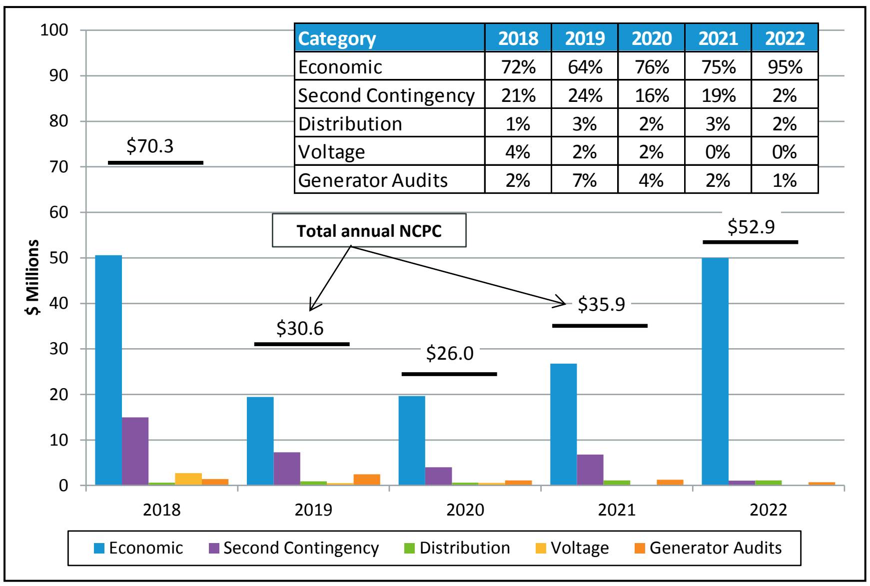
NCPC payments totaled $52.9 million, about 50% higher ($17.0 million) than 2021 NCPC of $35.9 million in 2021. This was due to an almost 90% increase ($23.2 million) in uplift payments to resources cleared in economic merit order to meet system-wide or first-contingency protection ("economic" NCPC payments). This is in line with higher production costs associated with higher gas prices. As discussed further below, the increase in economic NCPC was offset by lower payments for local reliability.

The table also shows the downward trend in NCPC payments as a percentage of energy costs; in 2022 this was the lowest level over the five-year period at just 0.5%. Most of this share comprised NCPC in the real-time market, which at $53 million was over 70% of total NCPC.

NCPC Payments by Category

Uplift payments mostly cover the production costs of generators committed and dispatched in economic merit order (economic or first contingency), as can be seen in Figure 3-38 below. The inset table shows the percent share of total uplift for each category by year.

Figure 3-38: Total Uplift Payments by Year and Category



Economic payments made up the bulk (95% or $ 50.0 million) of NCPC, and increased by $23.2 million (87%). This was consistent with the increase in energy costs and explains the overall annual increase in NCPC. All other categories of NCPC payments either dropped or remained the same compared to 2021.

Local second-contingency protection payments decreased by $5.7 million (85%), from $6.8 million in 2021 to $1.1 million in 2022. This decrease was driven by the lowest level of reliability commitments required to support local system contingency needs over the past few years.[209]

Distribution reliability payments and voltage payments were consistent with 2021 payments. Distribution payments totaled $1.1 million in both 2021 and 2022. All of these payments were

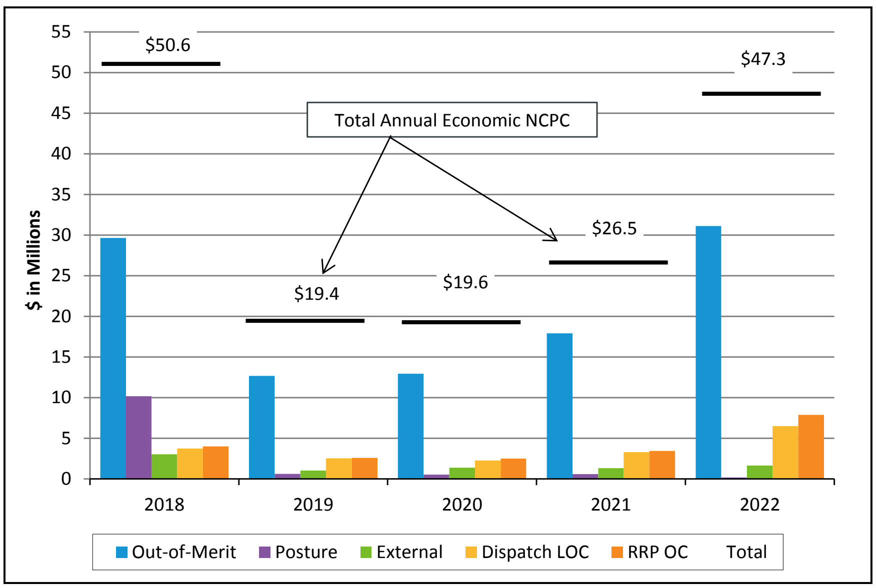
[209] See Section 3.2.8 for further details on reliability commitments and posturing actions.

made in real time to two oil-fired generators on Cape Cod that were committed to support distribution reliability in the SEMA load zone in January and July through September 2022. In 2022, there were no voltage reliability commitments that necessitated uplift. Uplift paid to generators conducting ISO-initiated audits totaled $0.6 million in 2022, down slightly (by $0.2 million) on 2021 costs in this category.

A closer look at "economic" NCPC

There are several subcategories within "economic" NCPC that cover a range of make-whole payments to cover production costs as well as economic costs (or lost opportunity costs) not recovered through energy prices. A breakdown of economic uplift by year and by sub-category is shown in Figure 3-39 below.

Figure 3-39: Economic Uplift by Sub-Category



"Out-of-merit" payments primarily cover the commitment costs of economic scheduled resources. These payments continued to make up the majority of total economic payment at $31.1 million, increasing by $13.2 million (74%) from the prior year.

Dispatch lost opportunity cost (DLOC) and rapid response pricing opportunity cost (RRP OC) both increased significantly in 2022. Even though each sub-category made up less than 20% of economic uplift, they increased by 98% and 130%, respectively. This was due to more periods of tight system conditions, when resources were compensated for following dispatch instructions when faced with higher prices. Posturing payments were the only economic sub-category that decreased in 2022. This was primarily driven by a significant reduction in ISO-issued posturing instructions to pumped-storage generators (as discussed in Section 3.2.8).

3.4 Demand Response Resources

This section summarizes outcomes and provides insights related to the Price-Responsive Demand (PRD) program, which integrates demand response resources into the day-ahead and real-time energy markets.[210] The first subsection (3.4.1) analyzes how demand response resources participate in the day-ahead and real-time energy markets. The second subsection (3.4.2) quantifies the level of energy and NCPC payments to demand response resources since the implementation of PRD.

Key Takeaways

In 2022, participation in the PRD program followed trends observed since the initial implementation in 2018. Most PRD resources primarily served as capacity and operating reserve resources available for dispatch at very high offer prices: 81% of PRD capacity was offered at the energy market offer cap of $1,000/MWh in 2022; on average, 96% of offers have been priced above $200/MWh since the program's implementation. Given offer prices, dispatch of these resources averaged just 7.2 MW per hour in the day-ahead energy market and 9.3 MW per hour in the real-time energy market in 2022.

PRD resources also provided operating reserves in 2022, averaging 0.3 MW per hour of ten-minute reserves and 272 MW per hour of thirty-minute reserves. With low dispatch levels and infrequent thirty-minute reserve pricing in 2022, energy revenues totaled just $4.3 million in the day-ahead energy market, while energy and reserve revenues totaled $3.7 in the real-time energy market and NCPC payments totaled $0.3 million for both markets.

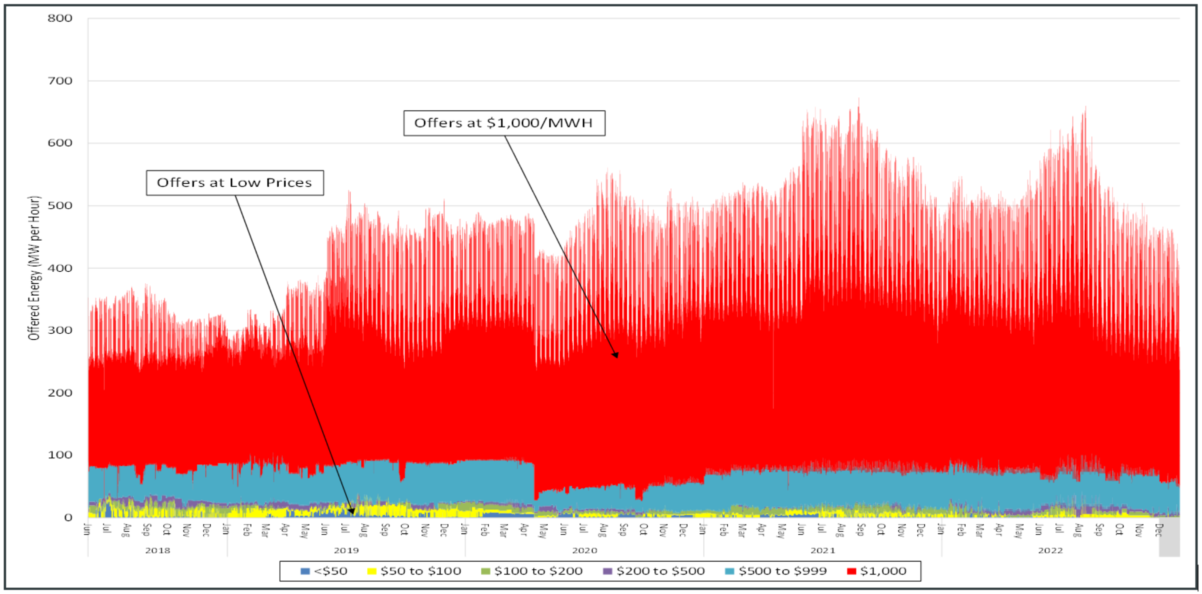
3.4.1 Energy Market Offers and Dispatch under PRD

Under the Price-Responsive Demand (PRD) program, over 600 MWs of demand response resources participate in the day-ahead and real-time energy markets. By virtue of their high offer prices, most demand resources essentially function as capacity deficiency resources, providing of energy and 30-minute operating reserves in the real-time energy market only when prices are extremely high (~$1,000/MWh).[211] Figure 3-40 below indicates hourly demand reduction offers in the real-time energy market, by offer price category for segment energy offers since the implementation of PRD in 2018.

[210] This was done in order to comply with FERC Order 745 (Demand-Response Compensation in Organized Wholesale Energy Markets). Prior to June 1, 2018, demand response resources participated in the ISO's energy markets (1) as emergency resources activated during OP-4 system conditions (i.e., a capacity deficiency) in the real-time market and (2) through the Transitional Price-Responsive Demand (TPRD) Program in the day-ahead market.

[211] Because these resources primarily function as a source of operating reserves and are dispatched at slightly higher levels (on average) in the real-time energy market, this section uses real-time offer and dispatch data to illustrate these resources' participation in the ISO's energy markets.

Figure 3-40: Demand Response Resource Offers in the Real-Time Energy Market

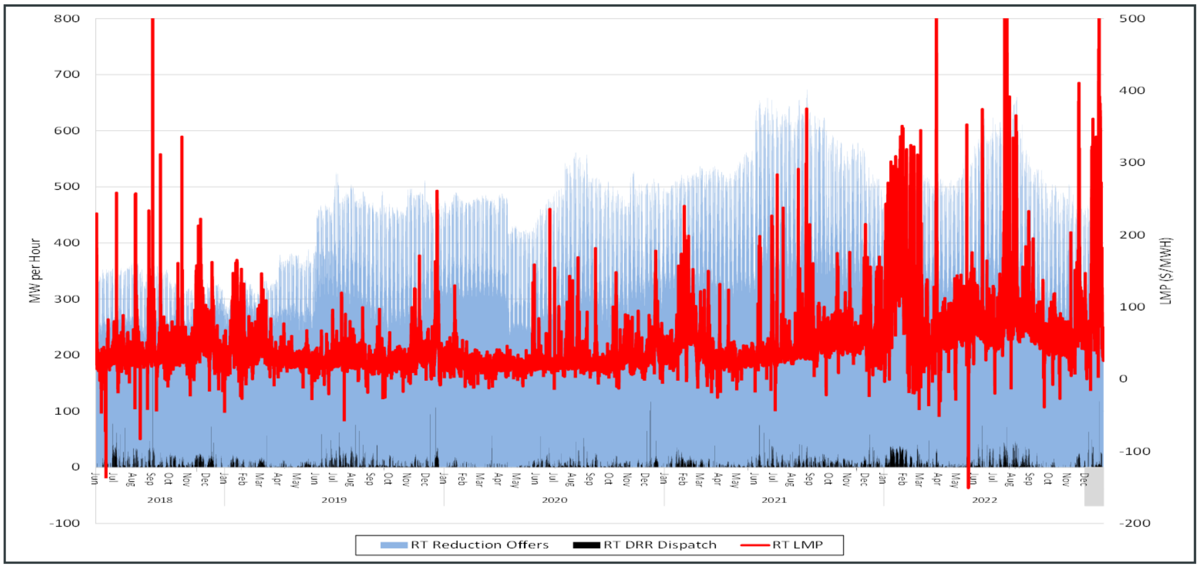


As indicated in the figure, most offers continue to be priced at the energy market offer cap of $1,000/MWh; 81% of offered capacity, on average, in 2021 and 2022. In most hours, only the lower tiers of offered capacity ($200/MWh or less) have a reasonable likelihood of being dispatched in the real-time energy market; these offers did not exceed 10% of offered demand reduction capacity in any hour of 2021 or 2022, and averaged just 3% of offered capacity.[212]

Given the pattern of offer prices for PRD, the ISO dispatches relatively small quantities in the energy markets. Figure 3-41 below illustrates the hourly dispatch of Demand Response Resources (DRRs) in the real-time energy market, relative to resources' offered reductions and hourly energy prices since the implementation of PRD in 2018.

[212] Energy prices in the real-time market exceeded $200/MWh in just 5.4% of pricing intervals in 2022 and 1.3% over the review period.

Figure 3-41: Demand Response Resource Dispatch in the Real-Time Energy Market[213]



The maximum hourly quantity of demand response capacity dispatched in the real-time energy market was 117.8 MW in 2022 (during the December 24 shortage event) and 75.7 MW in 2021. While demand resources were dispatched frequently in the real-time market – in 50% of hours in 2022 and 52% of hours in 2021 – the dispatch level was very small, averaging just 9.3 MW per hour in 2022 and 6.4 MW per hour in 2021.

As noted earlier, DRRs also provide a source of operating reserves in the real-time energy market. DRRs are considered fast-start capable, if those capabilities have previously been demonstrated[214] In 2022, DRRs provided only 0.3 MW per hour, on average, of ten-minute operating reserves[215], but provided substantially more in thirty-minute operating reserves (TMOR), averaging 272 MW per hour. In 2021, ten-minute reserve designations were not substantially different, equaling 0.4 MW on average; thirty-minute operating reserves (TMOR) for 2021 averaged 299 MW per hour – 9% more than in 2022.

3.4.2 Energy Market Compensation under PRD

Demand Response Resources (DRRs) have received relatively modest energy market compensation during the review period. This results from low dispatch rates in the energy market and infrequent TMOR pricing in the real-time energy market. When dispatched, DRRs are eligible to receive uplift payments. NCPC provides additional compensation to resources when energy market revenues are insufficient to cover as-offered operating costs in the day-

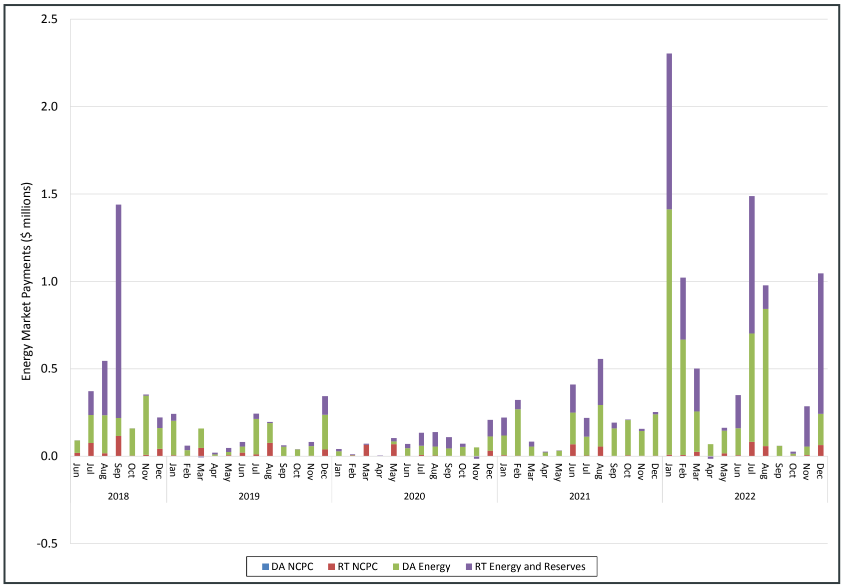
[213] The right vertical axis (LMPs) has been truncated to improve the figure's legibility. During tight system conditions, real-time LMPs have exceeded $500/MWh on several occasions. The truncation obscures the magnitude of those prices, which have reached as high as $2,677/MWh.

[214] To be designated during the operating day as providing thirty-minute fast-start reserves, a DRR must offer certain operating constraints consistent with fast-start operation. These operating constraints are: total start-up time (including notification time) of less than or equal to 30 minutes, minimum time between reductions and a minimum reduction time of less than or equal to 1 hour, and a "claim 30" (30-minute reserve capability) greater than 0.

[215] While DRRs can provide ten-minute reserves, that service requires interval metering with granularity of one minute or less, to be able to provide either non-synchronized (TMNSR) or synchronized reserves (TMSR).

ahead and real-time energy markets. Figure 3-42 indicates energy and NCPC payments by month since the implementation of PRD in 2018.

Figure 3-42: Energy Market Payments to Demand Response Resources



As indicated in the figure, both NCPC payments and energy market payments have been relatively small, since the implementation of PRD in June 2018.[216] In 2022, total energy payments were $8.3 million; energy payments to DRRs in 2021 were $2.7 million.[217] The increase in total energy market payments to DRRs in 2022 (compared to 2021) is consistent with the small increase in average dispatch and the more significant increases in day-ahead and real-time LMPs that occurred in 2022.[218] The high winter and summer month payments in 2022 reflect months with elevated LMPs, resulting from high fuel prices (winter months) and seasonally high loads (summer). The December 2022 real-time energy payments also reflect payments to DRRs during the system event on December 24, 2022. Energy market LMPs on that day reached $1,000 to $2,000 per MWh on an hourly basis.

[216] Energy market payments include payments for MWh provided to satisfy the energy market's energy and reserve needs (labelled "DA Energy" and "RT Energy and Reserves" in the figure) and uplift payments when energy and reserve revenues are insufficient to cover all of the costs of providing energy and reserves (labelled "DA NCPC" and "RT NCPC" in the graph).

[217] This is in contrast to capacity market compensation in 2022, which totaled about $27 million. The capacity market is discussed in more detail in Section 6.

[218] Energy market payments to DRRs represent a very small component of overall energy market payments, which were $11.7 billion for all resources in 2022.

Section 4
Virtual Transactions and Financial Transmission Rights

This section discusses trends in two important financial instruments that are available to participants in New England's wholesale electricity markets: virtual transactions and financial transmission rights (FTRs). While both instruments can be used by participants to manage certain risks associated with the actual production or consumption of energy, they can also be used for completely speculative purposes. Virtual transactions are covered in Section 4.1 and FTRs are discussed in Section 4.2.

Although the average volume of virtual transactions has remained fairly constant over the past five years, the use of virtual transactions by time of day is evolving to match changing grid conditions. Most notably, this is occurring with virtual supply, which is clearing in larger volumes during the daytime hours. On the other hand, FTR use by participants is generally declining. This may be due to lower perceived basis risk by market participants, as the system has experienced relatively low levels of congestion in recent years, partly as a result of significant amount of transmission investment.

The use of these financial instruments will be motivated by expected profits, particularly for participants taking a speculative position (i.e., one without a corresponding physical position). Market participants are likely to deploy their capital toward other uses if they believe that they cannot earn a reasonable risk-adjusted return. In 2022, virtual supply transactions realized their highest net profit per MWh of any of the past five years, while virtual demand was unprofitable as it has been in four of the last five years.[219] Meanwhile, FTR holders realized a modest profit in 2022, a year after making over $25 million in net profits.

Virtual transactions also perform an important market function by helping converge day-ahead and real-time market prices. However, virtual transactions are not costless – they are subject to highly variable uplift charges – and this cost can limit the ability of virtual transactions to perform this important market function. This report finds that the NCPC charge rate increased in 2022 to its highest level since 2018, in large part due to the overall increase in energy costs and prices in 2022.

4.1 Virtual Transactions

This section presents our assessment of virtual transaction activity and performance. Specifically, the first subsection (4.1.1) covers trading volumes, the second subsection (4.1.2) covers profitability, including the impact of uplift charges, and the final subsection (4.1.3) looks at the relationship between virtual transactions and price convergence.

[219] Virtual demand is often used as a hedging tool for generators that are at risk of tripping in real time, while virtual supply tends to be more of a speculative instrument.

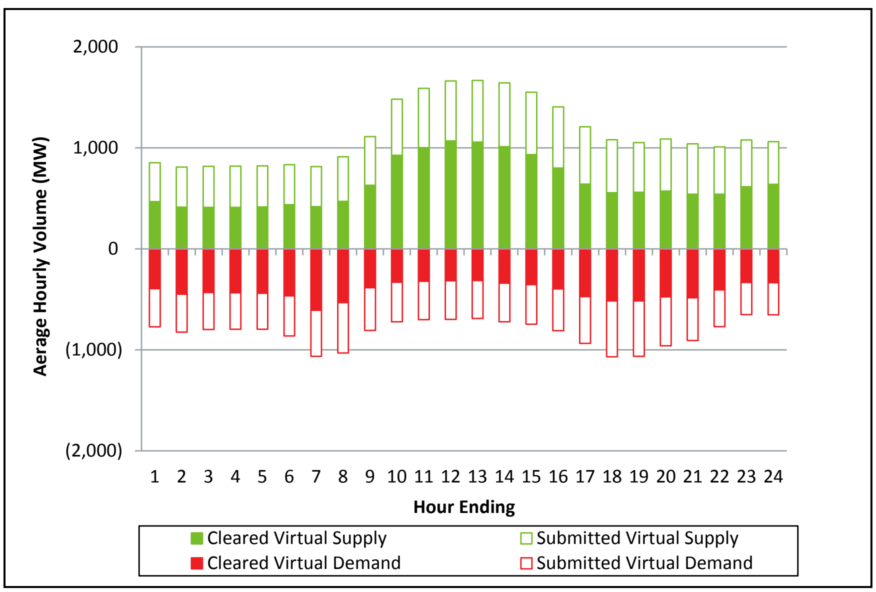
Key Takeaways

In general, the volume of cleared virtual transactions increased slightly in 2022. Average hourly cleared virtual supply increased by 4% (from 594 MW to 649 MW per hour) and average cleared virtual demand increased by 12% (from 372 MW to 418 MW per hour) year-over-year. The average volumes of cleared virtual supply in 2022 were notably higher during the daytime hours than other times of the day, reaching as high as 1,069 MW per hour. NCPC charges for virtual transactions increased in 2022. From 2018 through 2021, this rate averaged about $0.56/MWh, but increased to $0.88/MWh in 2022. This was the highest NCPC charge rate since 2018 ($0.89/MWh). Despite this increased NCPC charge rate, virtual supply transactions made an average of $1.99/MWh, the highest net profit for either transaction type in the past five years. However, virtual demand lost an average of $1.51/MWh, the third highest losses observed over the reporting period for any bid type. Some virtual participant profit came from external NCPC credits that result from relieving congestion at the external interfaces.

4.1.1 Virtual Transaction Volume

In 2022, higher levels of virtual supply tended to be submitted and cleared during the middle part of the day, while higher levels of demand tended to be submitted and cleared during the morning and evening ramp periods. This can be seen in Figure 4-1, which shows the average hourly volume of submitted and cleared virtual transactions by time of day in 2022. Virtual supply is depicted as positive values, while virtual demand is depicted as negative values.

Figure 4-1: Average Hourly Submitted and Cleared Virtual Transaction Volumes by Time of Day, 2022



The average volumes of cleared virtual supply in 2022 were notably higher during the daytime hours than other times of the day. Between hours ending 9 through 17, virtual supply averaged about 900 MW per hour compared to 500 MW during the rest of the day. We have observed a clear relationship between virtual supply and photovoltaic generation, particularly on high solar output days. Most photovoltaic generation registers as settlement-only generation

(SOG).[220] Since SOGs cannot clear in the day-ahead market, virtual participants anticipate the additional real-time generation and clear virtual supply in the day-ahead market in their place.[221] These virtual supply offers effectively replace the price-taking SOGs that show up in the real time.

Meanwhile, the average volume of cleared virtual demand tends to be slightly higher during the morning and evening ramping periods, when loads are higher and prices tend to be higher in the real-time.

4.1.2 Virtual Transaction Profitability

Virtual transactions profit from differences between day-ahead and real-time prices. However, transaction costs in the form of NCPC charges can turn otherwise profitable virtual transactions into unprofitable transactions on a net basis.[222] This limits the ability of virtual transactions to converge prices between day-ahead and real-time prices, which is one of their intended market functions.[223]

This price-converging function is becoming increasingly important as low-marginal cost intermittent generation enters the market and tends to produce more energy in the real-time market rather than it clears in the day-ahead market. The IMM continues to recommend that the ISO review the allocation of NCPC charges to virtual transactions to ensure the charges are consistent with principles of cost causation.[224]

Figure 4-2 illustrates the profitability of virtual transactions along with the impact of NCPC charges on profitability. This figure displays the average annual gross and net profit of virtual transactions since 2018 (left axis). The bars are categorized by year and bid type with virtual demand shown in red and virtual supply shown in blue. The top of each bar represents gross profit, the bottom represents net profit, and the length of the bar represents the per-MWh NCPC charge. Additionally, the dashed black line shows the percentage of hours each year in which virtual transactions were profitable on a gross basis (right axis).[225]

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[220] By the end of 2022, settlement-only photovoltaic generation had an installed capacity of about 1,950 MWs.

[221] The differences in the supply mix between the day-ahead and real-time energy markets are looked at in Section 3.2.2.

[222] The ISO allocates the following NCPC charges to cleared virtual transactions: (1) **Real-time Economic NCPC**: all cleared virtual transactions (supply and demand) incur a charge to contribute towards the payment of real-time economic NCPC because they are considered real-time deviations; and (2) **Day-ahead Economic NCPC**: virtual demand bids are also charged day-ahead economic NCPC based on their share of day-ahead load obligation. This charge is typically much smaller because the total day-ahead economic NCPC is divided among a much larger quantity of energy.

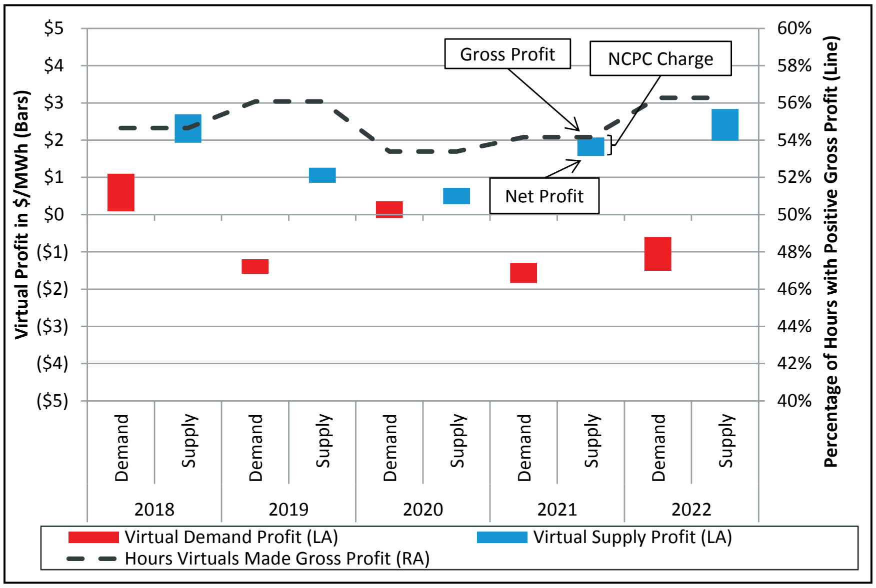
Virtual transactions can also incur NCPC charges associated with congestion at the non-CTS (coordinated transaction scheduling) external interfaces. Because these NCPC charges do not have a broad market impact or apply to virtual transactions at most locations, they are not considered in much detail in this report.

[223] The role of virtual transactions in price convergence is discussed in more detail in Section 4.1.3.

[224] For more information on recommended market design changes, see Section 8

[225] The line is flat for observations in the same year because the value is computed as the number of hours that all virtual transactions together were profitable on a gross basis, as a percentage of total hours in the year.

Figure 4-2: Average Annual Gross and Net Profits for Virtual Transactions



In 2022, virtual supply made an annual average gross profit ($2.84/MWh) while virtual demand a gross loss (-$0.60/MWh).

Virtual supply profitability was the highest over the last five years (on a gross basis), $0.77/MWh higher than 2021 ($2.07/MWh). Virtual supply tended to be profitable during the middle of the operating day, when day-ahead prices were typically higher than real-time prices. Between hours ending 9 and 17, participants made a total gross profit of $15.6 million in 2022, which accounted for 97% of the virtual supply's gross profit ($16.1 million) during the year. The relationship between virtual supply and photovoltaic generation helped drive these higher profits. Additionally, load-serving entities (LSEs) frequently cleared excess demand in the day-ahead market on days with higher behind-the-meter photovoltaic generation during Spring 2022. This contributed to higher day-ahead prices and higher profits for virtual supply.[226, 227]

Virtual demand, conversely, incurred a gross loss of -$0.60/MWh on average in 2022. However, this was a smaller loss than 2021 (-$1.29/MWh). In total, virtual demand, on a gross basis, lost $2.2 million during 2022. Lower real-time prices led to participants losing a total of $5.2 million during hours ending 9 to 17 on virtual demand, which drove overall losses. Virtual demand made a profit of $3.0 million during the rest of the operating day.

Average NCPC charges for virtual transactions increased compared to 2021 (from $0.52/MWh to $0.88/MWh). NCPC charges increased as total NCPC charges increased for the system.[228] In 2022, virtual supply stayed profitable after the netting of NCPC charges, making a net profit of $1.99/MWh, on average. Virtual demand lost $1.51/MWh, on average, after accounting for NCPC charges.

[226] See the Internal Market Monitor's Section 2.2 of the Spring 2022 Quarterly Markets Report for more information on over-clearing in the day-ahead market.

[227] The price premium in the day-ahead energy market is discussed in more detail in Section 3.1.3.

[228] For more information on why NCPC increased in 2022, see Section 3.3.

Most Profitable Locations for Virtual Supply

Details of the top 10 most profitable locations for virtual supply in 2022, after accounting for transaction costs and NCPC charges/credits (ranked by total net profit), are shown in Table 4-1 below.

Table 4-1: Top 10 Most Profitable Locations for Virtual Supply

Location	Location Type	Submitted MWh	Cleared MWh	Gross Profit ($k)	Net Profit ($k)	Gross Profit per MWh	Net Profit per MWh	# of Participants
.I.SHOREHAM138 99	Ext Node	452,621	19,273	$(1)	**$1,953**	$(0.06)	$101.31	2
UN.BULL_HL 34.5BLHW	Gen Node	322,409	193,569	$1,890	**$1,706**	$9.76	$8.81	16
.H.INTERNAL_HUB	Hub	1,865,879	1,174,050	$2,412	**$1,454**	$2.05	$1.24	28
.Z.MAINE	Load Zone	602,049	452,628	$1,352	**$956**	$2.99	$2.11	19
.Z.SEMASS	Load Zone	856,181	657,390	$1,389	**$836**	$2.11	$1.27	14
.Z.NEMASSBOST	Load Zone	499,703	453,640	$1,194	**$834**	$2.63	$1.84	12
.Z.NEWHAMPSHIRE	Load Zone	396,047	311,580	$1,038	**$767**	$3.33	$2.46	11
UN.BULL_HL 34.5HANW	Gen Node	152,635	95,640	$818	**$721**	$8.55	$7.54	12
.Z.VERMONT	Load Zone	306,198	252,857	$813	**$592**	$3.21	$2.34	12
.Z.RHODEISLAND	Load Zone	258,489	218,771	$653	**$463**	$2.98	$2.12	13

The most profitable location for virtual supply was an external node, .I.SHOREHAM138 99, where two participants received external credits for relieving congestion in the export direction. This node is the external node for the Cross Sound Cable interface, one of the two interfaces connecting New England to Long Island. Participants made nearly $2 million in external credits at this interface, which led the largest net profit of any location, despite losing money on a gross basis.

Seven of the top ten locations consisted of the Hub and six of the eight load zones.[229] High total net profits at these locations were in line with the lower real-time prices at these locations, especially during the middle of the operating day.

The other two locations are associated with wind power generation. Certain wind generators are part of the set of resources known as do-not-exceed (DNE) dispatchable generators, or DDGs. Wind generators often clear lower volumes in the day-ahead market, but produce more real-time output at low or even negative real-time prices. Virtual supply participants fill this gap by clearing virtual supply at prices more in line with real-time expectations, particularly on windy days.[230]

[229] The other two load zones (.Z.WCMASS and .Z.CONNECTICUT) ranked 14th and 15th in total net profit, respectively.

[230] These locations tend to be riskier as well, given the difficulty of forecasting wind generation. For example, if a participant expects high wind output in the real-time market, they might clear virtual supply in the day-ahead market at a low price, and expect to profit off negative real-time prices. However, if the wind generation does not meet day-ahead expectations, these locations will likely be unconstrained, and the participant would have to pay its day-ahead obligation back at a higher real-time price.

Most Profitable Locations for Virtual Demand

Details for the 10 most profitable locations for virtual demand in 2022, after accounting for transaction charges and all relevant NCPC charges/credits (ranked by total net profit), are shown in Table 4-2 below.[231]

Table 4-2: Top 10 Most Profitable Locations for Virtual Demand

Location	Location Type	Submitted MWh	Cleared MWh	Gross Profit ($k)	Net Profit ($k)	Gross Profit per MWh	Net Profit per MWh	# of Participants
.I.HQHIGATE120 2	Ext Node	275,246	46,789	$462	**$484**	$9.88	$10.33	6
.I.HQ_P1_P2345 5	Ext Node	332,710	81,360	$130	**$364**	$1.60	$4.47	4
UN.MONTVLLE69 MO10	Gen Node	7,448	7,438	$64	**$58**	$8.65	$7.76	2
AR.MADISON 34.5MADBD	ARD Node	1,298	1,236	$52	**$49**	$41.72	$39.64	3
LD.KINGSTON23	Load Node	2,397	1,238	$44	**$42**	$35.37	$33.86	1
LD.RUMFD_IP34.5	Load Node	2,540	2,485	$40	**$37**	$16.28	$14.79	3
UN.BINGHAM 34.5BNGW	Gen Node	8,553	3,157	$38	**$34**	$12.05	$10.76	3
LD.SALISBRY69	Load Node	10,605	8,204	$33	**$28**	$4.01	$3.36	3
UN.PARIS 34.5GRPW	Gen Node	48,145	9,566	$27	**$20**	$2.82	$2.12	8
LD.FREIGHT 13.8	Load Node	3,248	2,753	$23	**$20**	$8.38	$7.36	2

The most profitable locations consisted mostly of nodes with relatively lower total profits and low trading activity during 2022 (compared to virtual supply). Like virtual supply, the most profitable locations were at external nodes (.I.HQHIGATE120 2 and .I.HQ_P1_P2_2345 5), associated with the Highgate and Phase II interfaces. Typically, transaction costs associated with virtual transactions reduce net profits. However, participants made a larger net profit at these external nodes as they received external NCPC credits for relieving congestion with uneconomic bids at the external interface in the day-ahead market.[232]

Virtual demand at the Highgate interface was particularly profitable on December 24, 2022 when generator trips and import reductions led to capacity shortage conditions and very high

[231] For more information about the additional charges for virtual transactions, see Schedule 2 of the ISO Funding Mechanism.

[232] Virtual participants receive external NCPC credits for relieving congestion at the external interfaces. For example, if two participants are willing to import 150 MWs (300 MWs total) over the Highgate interface, they may each submit fixed import transactions, which will clear at any LMP. However, the interface has a total transfer capability (TTC) of 225 MWs, so the interface cannot support all 300 MWs. Without virtual transactions, the two fixed import transactions would be pro-rated to prevent the bids violating the TTC. However, if a participant cleared a low priced 75 MW virtual demand bid, this would provide counter-flow across the interface and lower the net imports from 300 MW to 225 MW, the maximum allowed over the interface. In this scenario, if the cleared virtual demand bid is priced below the system LMP, their transaction is uneconomic, and require a make-whole payments. The two participants importing power in the day-ahead market would pay the uplift to the participant relieving congestion with the virtual demand bid.

real-time prices.[233]. Participants cleared an average of 174 MW of virtual demand, with a net profit over $1 million on this day, and were unprofitable the rest of the year.

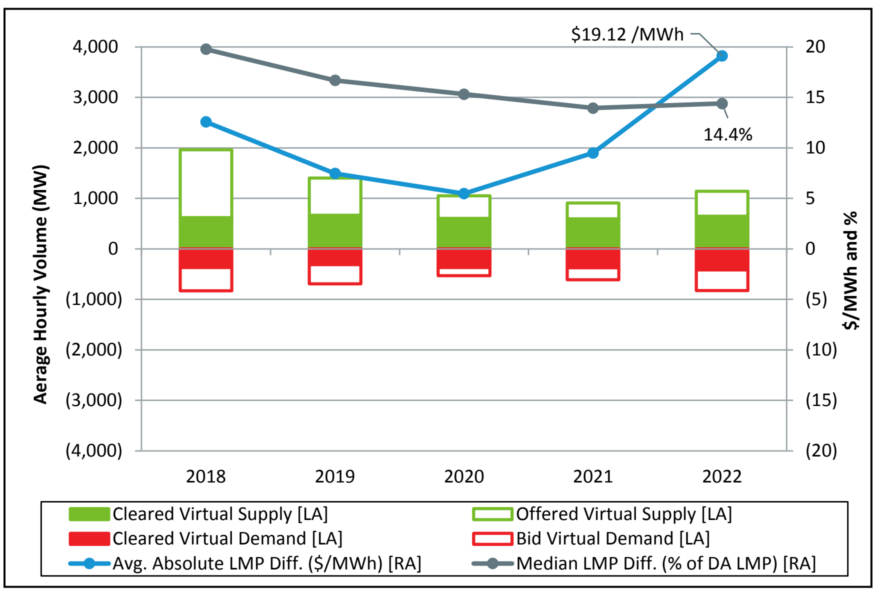
The other eight most profitable locations averaged less than 1.1 MWs per hour of cleared virtual demand.

4.1.3 Virtual Transactions and Price Convergence

One of the primary benefits that virtual transactions can provide is to improve market efficiency, by helping achieve the necessary real-time generation commitments at the lowest cost. Market participants can, by pursuing profitable opportunities, use virtual transactions to converge day-ahead commitments closer to real-time commitments. Improved price convergence is reflective of improved commitment convergence.[234] Consequently, one might expect to see higher levels of price convergence associated with higher levels of cleared virtual transactions. The relationship between the volume of virtual transactions (measured on the left y-axis [LA]) and the level of price convergence (measured on the right y-axis [RA]) is shown in Figure 4-3 below. This figure presents two measures of price convergence:[235]

1) The mean absolute difference (in $/MWh) between the day-ahead and real-time Hub prices (blue line series).
2) The median absolute difference between day-ahead and real-time Hub prices as a percentage of the day-ahead Hub LMP (gray line series).

Figure 4-3: Virtual Transaction Volumes and Price Convergence



[233] See Section 3.2.7 for more information about the events on December 24, 2022.

[234] Section 3.1.3 discusses price convergence in more depth.

[235] For both of these metrics, the price difference is the absolute value of the day-ahead and real-time price difference. The absolute value is used because we are interested in virtual transactions' potential impact on price convergence, including both positive and negative price differences. For the second metric, the price difference is divided by the day-ahead LMP to help normalize for systematic differences between prices in different years. The median is used to reduce the influence of outliers.

The measures of price convergence provide a mixed picture about the level of convergence between day-ahead and real-time prices in 2022 compared to prior years. The average absolute price difference between the day-ahead and real-time Hub prices (blue line) was $19.12/MWh, the highest difference over the reporting period. However, this increase aligns with higher LMPs during 2022. When assessed as a percent of the day-ahead price (gray line), price was comparable to 2021 (14.4% vs. 13.9%) and has generally improved compared to levels prior to 2021.

The figure also shows that, in general, the quantity of *submitted* virtual transactions increased in 2022, after decreasing over the prior four years. In 2022, participants submitted an average of 1,969 MWs of virtual transactions per hour, up 30% on 2021, with more activity across the Hub and eight load zones. Submitted virtual transactions remained almost 30% lower than submitted volumes in 2018.[236] *Cleared* transactions averaged 1,066 MW per hour in 2022, up 10% on 2021. Both cleared virtual supply and cleared virtual demand increased; virtual supply by 9% and virtual demand by 12%.

4.2 Financial Transmission Rights

This section presents our assessment of financial transmission rights (FTRs) activity and performance. The first subsection (4.2.1) covers FTR auction volumes, the second subsection (4.2.2) covers FTR funding, and the final subsection (4.2.3) covers profitability at a market and locational level. Given their outsized impact on FTR market outcomes, special attention is given to FTR paths that source from .I.ROSETON 345 1 ("Roseton"), which is ISO-NE's external node for trading across the New York - New England ("NYNE") interface.[237]

Key Takeaways

FTRs volumes decreased by 8%, from 32,443 MW per hour in 2021 to 29,847 MW per hour in 2022, consistent with the general trend over the past few years. FTRs were fully funded in 2022, meaning there was sufficient revenue collected through the energy markets' congestion revenue fund to pay FTR holders. After a very profitable year in 2021 ($25.9 million), FTR holders made a collective profit of just $0.6 million in 2022. FTR activity associated with the NYNE interface was one reason for this decreased profitability. Profit for FTRs sourcing from this interface decreased by $16.7 million between 2021 ($9.8 million) and 2022 (-$6.8 million), partly from lower levels of congestion between the two regions as a result of changing system dynamics.

4.2.1 FTR Volume

The volume of FTRs that participants hold depends on a number of factors, including participants' expectations of congestion in the day-ahead market. If participants expect more congestion in the day-ahead market than in prior years, they may purchase more MWs of FTRs to hedge against this congestion. Conversely, if participants expect less congestion in the day-

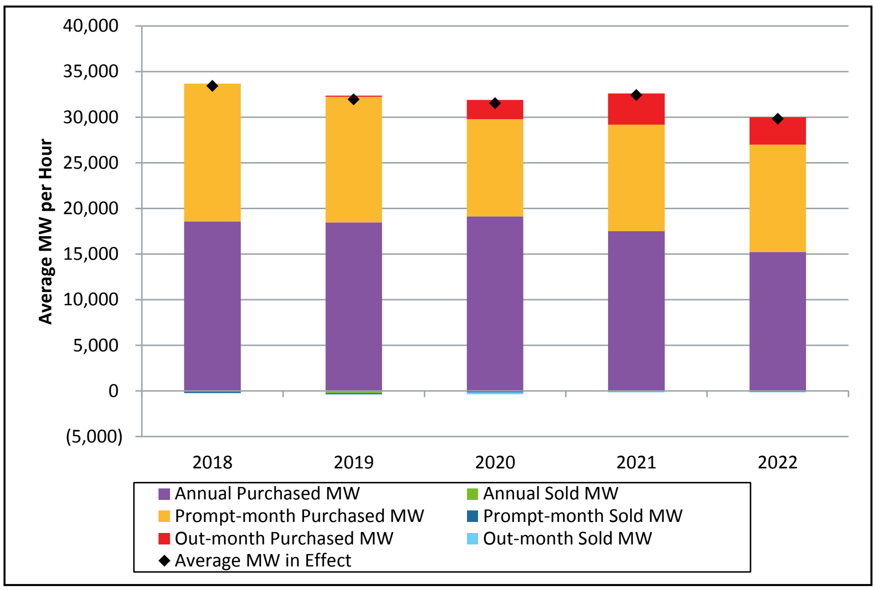
[236] One participant contributed significantly to the decrease in submitted virtual transactions between 2018 and 2022. In 2018, this participant submitted an average of 941 MWs per hour, but submitted only 11 MW per hour in 2022.

[237] The New York - New England (NYNE) interface is sometimes referred to as the New York North interface, the New York Northern AC interface, or the Roseton interface.

ahead market, they may purchase fewer MWs of FTRs. Another important factor is the set of transmission limits that the ISO uses in the auctions it conducts to award FTRs. The ISO performs a market feasibility test in each FTR auction that ensures that the awarded set of FTRs respects the transmission system's physical and operational limits.[238] Essentially, these limits restrict the MW volume of FTRs that can be purchased in FTR auctions.

Participants held fewer FTRs (by MWs) per hour, on average, in 2022 than in any other year over the past ten years. The trend in declining FTR volumes can be seen in Figure 4-4, which shows the average MW volume of FTRs that were in effect each hour by year (black diamonds) for the past five years.[239] This figure also shows the average hourly MW volume of FTRs purchased and sold by auction type (i.e., annual, prompt-month, or out-month) during each year.[240] FTR purchases are depicted as positive values, while FTR sales are depicted as negative values.

Figure 4-4: Average FTR MWs in Effect per Hour by Year



Market participants held an average of 29,847 MWs of FTRs per hour in 2022, representing an 8% decrease from the average amount of FTRs in effect in 2021 (32,443 MWs per hour). This decrease was largely the result of reduced purchases in the annual auctions; these purchases in 2022 (15,241 MWs per hour) were down by 13% compared to 2021 (17,519 MWs per hour).

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[238] This test is performed in order to increase the likelihood of revenue adequacy, which means that there is sufficient congestion revenue collected in the energy market and from FTR holders with negative target allocations to fully compensate all FTR holders with positive target allocations. This is further discussed in Section 4.2.2.

[239] The averages are hourly-weighted MW volumes. This weighting accounts for the fact that there are more off-peak hours than on-peak hours in a year. The volume of FTRs in effect each year represents the hourly-weighted average MW volume of FTRs purchased less the hourly-weighted average MW volume of FTRs sold.

[240] An *annual* auction refers to an auction where participants purchase (or sell) FTRs whose term is one calendar year, while both *prompt-month* and *out-month* auctions refer to auctions where participants purchase (or sell) FTRs whose term is one month. P*rompt-month* refers to the monthly auctions for FTRs that are in effect for the month immediately after when the auction takes place, while *out-month* refers the monthly auctions for FTRs that are in effect for any other month remaining in the calendar year (excluding the prompt month). *Out-month* auctions did not exist until the Balance of Planning Period ("BoPP) project was implemented in September 2019.

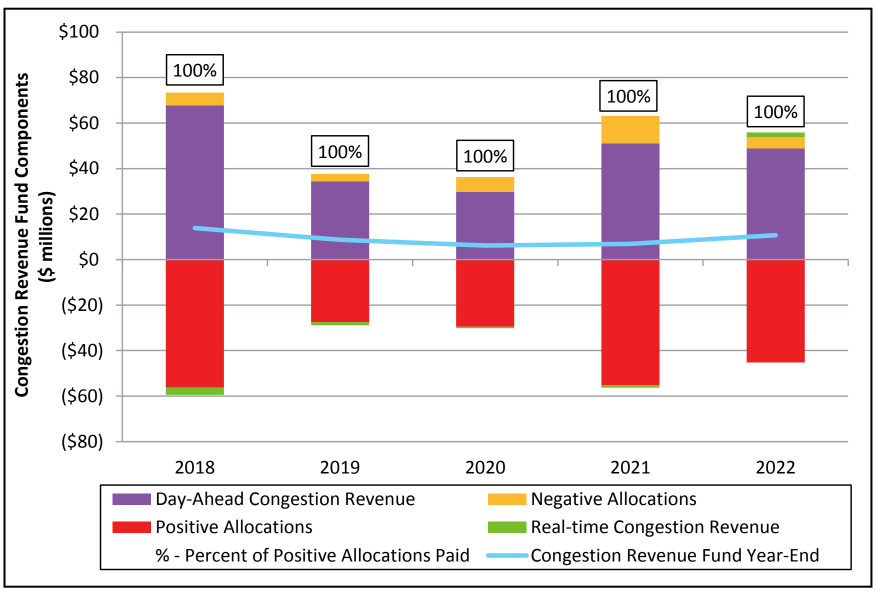
Average prompt-month FTR purchases rose by 1% in 2022 (11,773 MWs per hour) compared to 2021 (11,668 MWs per hour), while average out-month FTR purchases decreased by 12% in 2022 (2,987 MWs per hour) compared to 2021 (3,412 MWs per hour). In general, FTR holders sell very few FTRs each year (just 153 MWs in 2022), as can be seen below the horizontal axis in Figure 4-4.

4.2.2 FTR Funding

FTR funding refers to the ability to pay FTR holders the full value of their positive target allocations. Positive target allocations arise when the congestion component at the sink location (point of delivery) of an FTR path is larger the congestion component at the source location (point of injection). When there is sufficient revenue to pay all the positive target allocations, FTRs are said to be *fully funded*. Fully funding FTRs is an important aspect of a well-functioning FTR market, because it gives market participants confidence that they will receive the full value of their FTRs.

FTRs were fully funded in 2022 and have been in each of the last five years, as can be seen in Figure 4-5 below. The graph captures the inflows (positive values) into the Congestion Revenue Fund ("CRF") – mainly day-ahead congestion revenue – and the outflows from the fund – mainly positive target allocations.[241] The balance in the CRF at the end of each year is shown by the blue line.[242]

Figure 4-5: FTR Funding and Congestion Revenue Fund Components by Year



[241] The CRF is used to pay FTR holders with positive target allocations. This fund collects money from three sources: (1) day-ahead congestion revenue, (2) real-time congestion revenue, and (3) the holders of FTRs with negative target allocations. See Section III.5 of ISO-NE Market Rule 1 for more information about transmission congestion revenue and FTR funding.

[242] The CRF balance is defined here as the ∑[day-ahead congestion revenue + real-time congestion revenue + abs(negative target allocations) – positive target allocations].

Positive target allocations in 2022 ($45.2 million) declined by $10.0 million from their 2021 value ($55.2 million). This was consistent with the combination of lower FTR volumes and lower levels of transmission congestion. Day-ahead congestion revenue also decreased in 2022 ($48.9 million) from its 2021 value ($51.1 million), although the decline was more modest. Real-time congestion revenue added an additional $2.1 million to the CRF in 2022, marking the first time in the reporting period that this value was positive. Negative target allocations in 2022 ($4.9 million) dropped from their 2021 value ($12.1 million). The CRF year-end balance at the end of 2022 was $10.7 million; this surplus was distributed proportionately to entities that paid congestion costs during the year.[243]

4.2.3 FTR Profitability

Profit in the FTR market is measured as the sum of the positive target allocations and the revenue from FTR sales, minus the negative target allocations and the cost of FTR purchases. In a competitive FTR market, one would not expect to see excessive (risk-adjusted) profits or losses sustained over numerous years. Prolonged periods of high profitability would likely spur the entry of new participants (or at least an increase in FTR bid prices among existing participants), raising the cost to purchase FTRs and reducing FTR profitability.[244] Analysis of FTR profitability takes on additional importance in the context of participation costs (in economic terms, a "barrier to entry") that exist in this marketplace in the form of financial assurance requirements.[245]

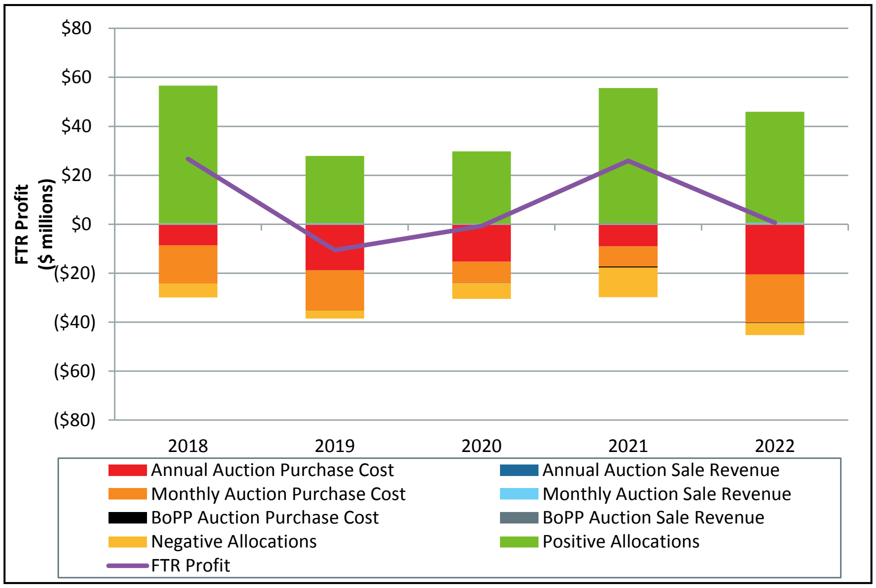
As a group, FTR holders were profitable in 2022. Figure 4-6 below shows total profit (purple line) as well as each of the different profit components. In this figure, FTR sales revenue and positive target allocations are shown as positive values (as they increase FTR profitability), while FTR purchase costs and negative target allocations are shown as negative values (as they reduce FTR profitability). Further, this figure classifies purchase costs and sales revenues by auction type (i.e., annual, prompt-month, or out-month).

[243] In 2022, the participants that received this money included generator owners, participants that engaged in virtual and external transactions, and load-serving entities, among others. See Section III.5.2.6 of Market Rule 1 for more information about the distribution of excess congestion revenue.

[244] Conversely, prolonged periods of large losses might motivate existing participants to exit the market (or at least decrease their FTR bid prices), lowering the cost to purchase FTRs and increasing FTR profitability.

[245] See Section VI of the ISO-NE Financial Assurance Policy for the financial assurance requirement provisions placed on FTR transactions. https://www.iso-ne.com/static-assets/documents/2017/09/sect_i_ex_ia.pdf

Figure 4-6: FTR Costs, Revenues, and Profits



In 2022, the total profit from FTRs was $0.6 million. This represents a substantial decrease from 2021 when total FTR profit was $25.9 million, but a modest increase from 2020 when total FTR profit was -$0.8 million. An increase in FTR purchase costs was one of the primary drivers of reduced profits. Participants spent $22.7 million more (or 128%) to procure FTRs in 2022 ($40.4 million) than they did in 2021 ($17.7 million); spending increased by over $11 million in both annual and monthly auctions. Another contributing factor was the reduction in positive target allocations, which was generally reflective of lower levels of congestion on the system.

Most Profitable FTR Paths

Analyzing FTR outcomes at the path level provides insight into paths that were more congested in the day-ahead energy market than reflected in auction clearing prices. Table 4-3 below provides details of the 10 most profitable FTR paths in 2022. The purchase amount indicates the total dollars spent in FTR auctions, while the sale amount shows the amount participants earned from sales in the FTR auctions.

Table 4-3: Top 10 Most Profitable FTR Paths in 2022

Source Location	Sink Location	Purchase Amount ($k)	Sale Amount ($k)	Positive Target Allocations ($k)	Negative Target Allocations ($k)	Profit ($k)
UN.BULL_HL 34.5WEVW	LD.HARRINGT34.5	$(227)	$0	$654	$0	$428
.I.SALBRYNB345 1	.H.INTERNAL_HUB	$(151)	$0	$637	$(59)	$427
UN.POWERSVL115 GNRT	.H.INTERNAL_HUB	$(3,182)	$0	$3,630	$(51)	$397
LD.IRASBURG46	LD.STJHNSBY34.5	$(201)	$0	$546	$(1)	$345
LD.S_NAUGTK13.8	LD.BEACN_FL13.8	$0	$0	$349	$(6)	$343
UN.HIGHGATE46 SHEL	LD.LYNDONVL34.5	$(76)	$2	$353	$(1)	$278
LD.DEBLOIS 34.5	LD.TUNK 34.5	$(58)	$7	$327	$0	$276

Source Location	Sink Location	Purchase Amount ($k)	Sale Amount ($k)	Positive Target Allocations ($k)	Negative Target Allocations ($k)	Profit ($k)
UN.PONTOOK 34.5PONT	LD.LOSTNATN34.5	$(189)	$0	$440	$0	$251
UN.BULL_HL 34.5HANW	LD.HARRINGT34.5	$(106)	$0	$352	$0	$246
LD.DEBLOIS 34.5	LD.BOGGY_BK44	$(57)	$9	$282	$0	$234

All 10 of the most profitable FTR paths included locations that experienced negative congestion pricing. Participants can hedge this type of congestion by procuring FTRs that source from within the area experiencing negative congestion pricing and that sink in a location outside that constrained area (the Hub is often used by participants) as paths of this type would produce positive target allocations. Additionally, with the exception of one path, every path was a prevailing flow FTR path.[246] This means they were paths defined in the direction that congestion was expected to occur based on FTR auction clearing prices (i.e., participants had to pay to acquire these paths, which can be seen by the negative value for each FTR path in the purchase amount column).

Congestion on the New York – New England Interface

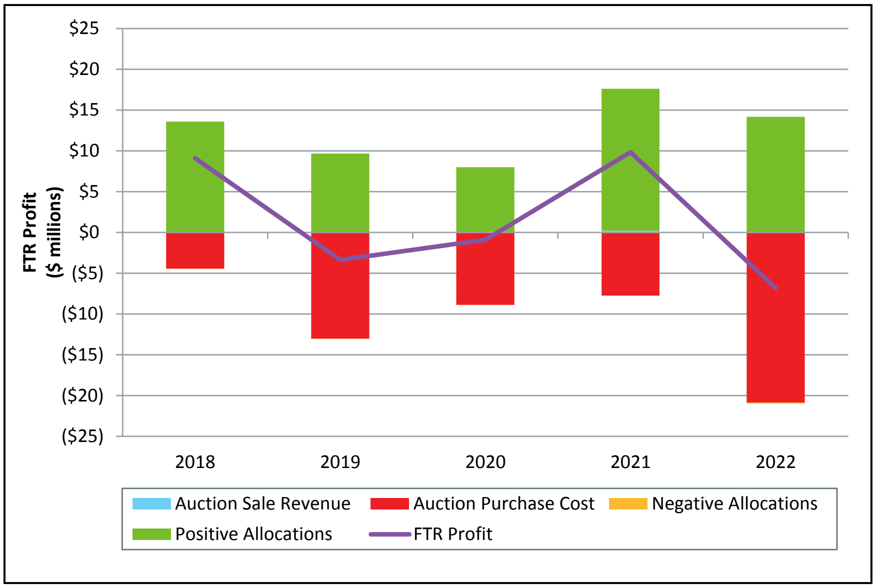
Changes in profitability of FTRs that source from Roseton, ISO-NE's external node for trading across the NYNE interface, can contribute significantly to overall FTR market outcomes. This is because the NYNE interface tends to be one of the most frequently binding transmission constraints in the day-ahead market.[247] Typically, participants purchase FTRs that source from Roseton and sink somewhere within the ISO-NE system, as Roseton tends to experience negative congestion pricing in the day-ahead market. To provide some perspective, the purchase costs for FTRs sourcing from Roseton represented 52% of all the FTR auction purchase costs in 2022, while the positive target allocations for FTRs sourcing from Roseton represented 31% of all positive target allocations.

FTRs sourcing from Roseton were unprofitable in 2022, meaning that the value of congestion in the day-ahead market was less than the cost anticipated in FTR auction clearing prices. Total annual profits (purple line) are shown in Figure 4-7, which also shows the purchase costs, sale revenues, and positive and negative target allocations for FTRs that sourced from Roseton.

[246] The exception is the path from LD.S_NAUGTK13.8 to LD.BEACN_FL13.8.

[247] See Section 3.2.9 for more information about the most frequently binding constraints in 2022.

Figure 4-7: FTR Profits and Costs for FTRs Sourcing from Roseton



Profitability decreased by $16.7 million between 2021 ($9.8 million) and 2022 (-$6.8 million). This decrease in profitability was largely the result of a sizeable jump in purchase costs associated with this group of FTRs; participants paid $13.1 million more to acquire FTRs sourcing from Roseton in 2022 ($20.9 million) than they did in 2021 ($7.7 million). At the same time, the holders of these FTRs received $3.2 million less in positive target allocations in 2022 ($14.2 million) than they did in 2021 ($17.4 million). One reason for this decrease was that the NYNE interface was significantly less constrained in the day-ahead market in 2021 (when it bound in 15.5% of hours) compared to 2022 (when it bound in 5.9% of hours) as average flows of power from New York into New England decreased year over year.[248]

[248] See Section 5 for more information about the why net interchange decreased over the NYNE interface.

Section 5
External Transactions

This section examines trends in external transactions in the day-ahead and real-time energy markets. The first section (5.1) provides an overview of external transactions across all external interfaces, while the second section (0) looks specifically at the performance of Coordinated Transaction Scheduling (CTS) with New York.

External transactions are energy market transactions that allow market participants to transfer power between New England and its neighboring control areas, and represent an important part of the overall supply and demand picture.[249] Transferring power between different control areas can help reduce total production costs across control areas by allowing power to flow from lower priced to higher priced control areas, and provide reliability benefits to the interconnected systems.

In 2022, net interchange (imports minus exports) was at its lowest level over the five-year period. Net interchange averaged 1,914 MW per hour, down from 2,144 MW per hour 2021. Over 90% of total net interchange came from Canadian interfaces. At New York North, net interchange decreased by 189 MW per hour compared to 2021 due to increased congestion in New York. This contributed to higher prices at this interface in New York compared to New England. At New Brunswick, a nuclear generator outage lasted from April to July, resulting in less net interchange over that period. Outside of New York North and New Brunswick, volumes of net interchange remained in line with prior years. In 2022, external transactions received more uplift than in each of the prior four years. In the day-ahead market, external transactions received $3.1 million in uplift, most of which ($2.7 million) was paid to virtual transactions for relieving congestion at external interfaces. In the real-time market, external transactions received $1.2 million in uplift as make-whole payments for external transactions scheduled out-of-merit.

The higher prices in New York compared to New England led to New England being a net importer of power over the Roseton interface just 51% of the time, a decrease from 69% of the time in 2021. Coordinated transaction scheduling (CTS) at the interface moved power from the lower-priced region to the higher-priced in just 57% of hours, which was in line with prior years. The average absolute price difference between New England and New York was about $25/MWh, 96% higher than in 2021, but consistent with the overall increase in energy prices in New York and New England. The average absolute price spread forecast error also increased with higher energy prices, more than doubling from 2021 up to almost $24/MWh. ISO forecast error continues to dampen the positive impacts of CTS by producing loss-making schedules and risk for participants at the Roseton interface. Possibly in response to forecast-error-driven inefficiencies, many CTS participants take on day-ahead positions and offer price-insensitive real-time bids and offers. In 2022, the quantity of both imports and exports offering at prices less than -$50/MWh increased from 2021.

[249] A control area, or balancing authority area, is an area comprising a collection of generation, transmission and load within metered boundaries for which a responsible entity (defined by NERC to be a balancing authority) integrates resource plans for that area, maintains the area's load-resource balance, and supports the area's interconnection frequency in real time.

5.1 External Transactions

This section reviews outcomes, trends and drivers of import and export (external) transactions. Specifically, we assess overall flows between New England and its neighboring control areas and provide a breakdown across the six interfaces (subsection 5.1.1). We also assess the pattern of fixed bidding versus price-sensitive bidding (5.1.2), and the drivers of uplift (NCPC) payments to external transactions (5.1.3).

Key Takeaways

In 2022, net interchange (or net imports) averaged 1,914 MWs per hour, an 11% (or 231 MWs) decrease compared to 2021 and the lowest average net interchange over the five year period. Average net interchange fell due to decreased net interchange across the New York North and New Brunswick interfaces.

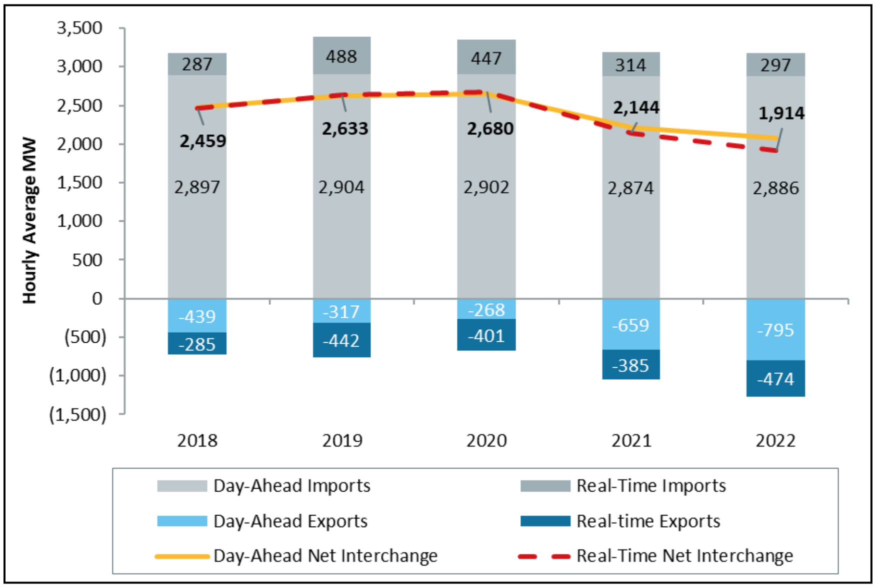
At New York North, average net interchange decreased by 189 MWs per hour compared to 2021 (401 MWs vs. 590 MWs). Increased congestion in New York led to higher New York prices and increased exports over the interface. At New Brunswick, average net interchange decreased by 68 MWs (228 MWs vs. 296 MWs) compared to 2021 due to the extended outage of a nuclear generator in New Brunswick.

External transactions received more uplift payments than in 2021 despite higher energy prices in 2021. In the day-ahead market, virtual transactions received a majority of the uplift payments for relieving congestion at external interfaces. In the real-time market, uplift payments increased due to increased forecast error at non-CTS interfaces leading to increased clearing of out-of-merit external transactions.

5.1.1 External Transaction Volumes

The average hourly system-wide net interchange from the day-ahead and real-time markets are shown in the line series of Figure 5-1 below. The bar series chart the hourly average imported volume (positive values) and exported volume (negative values). The real-time import and export volumes are shown as the incremental additions to the amounts cleared in the day-ahead market.

Figure 5-1: Hourly Average Day-Ahead and Real-Time Pool Net Interchange



Real-time net imports averaged 1,914 MW each hour, the lowest level of net interchange over the five-year period, and down by 11% (or 231 MW) on 2021. The continued decline in net interchange from 2020 was due to an increase in export transactions. Total exports were up by 22% (or 225 MW) compared to 2021, with the greatest changes at the New York North interface.

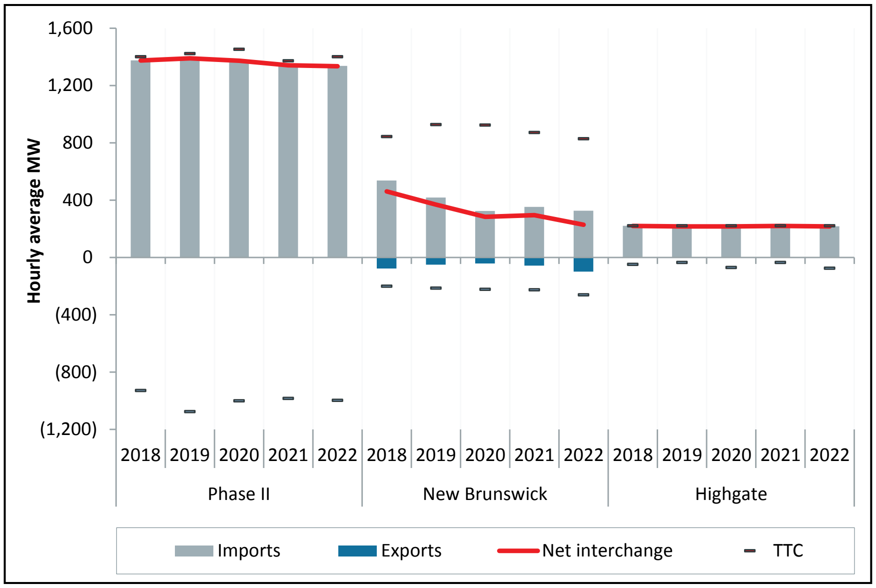
The close proximity of the day-ahead net interchange (orange) and real-time net interchange (red) line series highlights that day-ahead market outcomes across the external nodes do, on average, align well with real-time scheduled flows (historically within 2%).[250] However, average real-time net interchange was less than day-ahead net interchange by 8% (or 177 MW) in 2022 (i.e., less power was imported in real-time than planned for in the day-ahead market) due to the increase in real-time export bids at New York North.

A breakdown of flows across the Canadian Interfaces

Figure 5-2 below shows the annual hourly average real-time net interchange volumes (red line) as well as the gross import (positive values) and export (negative values) volumes at each of the three Canadian interconnections. The average hourly real-time total transfer capability (TTC) ratings for each interface in the import and export directions are plotted using the black dashed lines.

[250] Virtual transactions cleared at external interfaces in the day-ahead market are included in the day-ahead net interchange value. In the day-ahead energy market, virtual supply and demand are treated similarly to imports or exports.

Figure 5-2: Real-Time Net Interchange at Canadian Interfaces



New England continues to import significant volumes of power from Canada, averaging 1,781 MW per hour in 2022, or 93% of total net imports. To put this in perspective, net imports from Canada represented 13% of real-time load in 2022. Net imports declined by 4% (or 79 MW) from 2021.

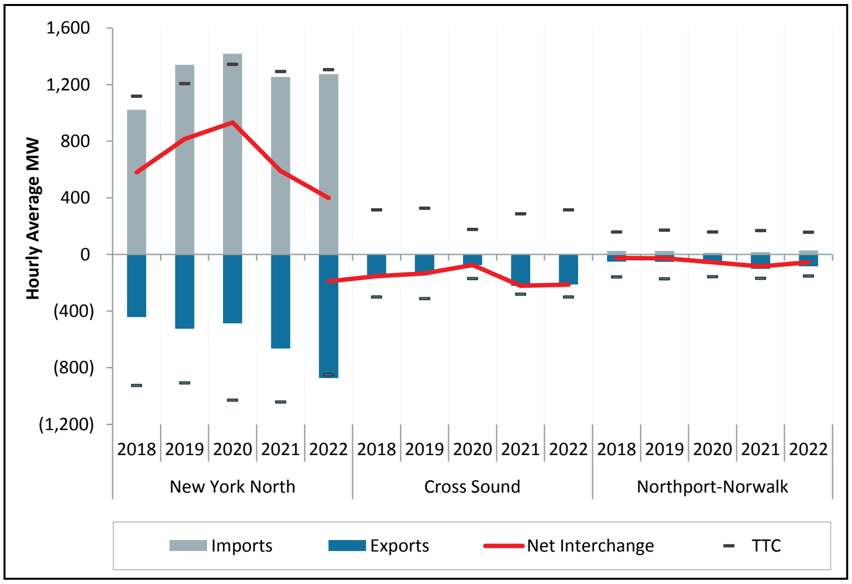
Average flows across *Phase II* and *Highgate* have been relatively steady over the past five years; combined flows in 2022 were just 11 MW per hour less than 2021. Reduced flows at the New *Brunswick* interface explain the majority of the decrease (68 MW). In 2022, a 660-MW New Brunswick nuclear generator experienced an extended outage, which resulted in decreased imports and increased exports over the interface.

A breakdown of flows across the New York Interfaces

Figure 5-3 below shows the annual hourly average real-time net interchange volumes (red line) as well as the gross import and export volumes at each of the three New York interconnections. The average hourly real-time total transfer capability (TTC) ratings for each interface in the import and export directions are plotted using black dashed lines.[251]

[251] The total transfer capability (TTC) rating is the MW amount of power that can be reliably transferred from one system to the other over the transmission interface.

Figure 5-3: Real-Time Net Interchange at New York Interfaces



On a net basis, New England imports power over the New York North interface and exports power over both the Cross Sound and Northport-Norwalk interfaces. Combining flows at all three interfaces, ISO-NE averaged just 133 MW per hour, the lowest volume of the five-year period.

At *New York North,* net interchange (red line) decreased for the second consecutive year, down 32% (or 189 MW per hour) compared to 2021 and down 57% (or 533 MW) compared to the five-year high value (2020). While cleared import transactions were comparable to 2021, real-time exports increased by 31% (or 209 MW). The increase in exports was due to increased congestion and higher prices in Eastern New York. The retirement of a nuclear power plant (870-MW Indian Point 3 unit), and increased planned transmission outages during 2022 were major drivers of higher New York prices compared to prices in New England.[252, 253]

At *Cross-Sound Cable,* net interchange continued in the export direction in 2022 (212 MW) and was comparable to 2021.[254] Exports remained well above levels from 2018 – 2020 (121 MW). New York's prices ($95.39/MWh) were higher than New England ($83.89/MWh) at the interface, on average, which led to the continued high volumes of export transactions compared to 2018 – 2020.

[252] Quarterly Report on the New York ISO Electricity Markets Third Quarter of 2021. See https://www.potomaceconomics.com/wp-content/uploads/2021/12/NYISO-Quarterly-Report_2021Q3__11-29-2021.pdf

[253] For more on congestion in New York, see Potomac Economics Quarterly Report on New York ISO Electricity Markets Third Quarter of 2022: https://www.potomaceconomics.com/wp-content/uploads/2022/12/NYISO-Quarterly-Report_2022Q3__11-21-2022.pdf

[254] Imports at the Cross Sound Cable averaged less than 0.1 MW since 2019 and have averaged less than 0.9 MWs every year over the reporting period.

At *Northport-Norwalk* net exports were down slightly on 2021 (55 MW per hour in 2022 versus 84 MW in 2022) due to a decrease in fixed exports submitted by participants (77 MW vs 95 MW per hour).[255]

5.1.2 External Transaction Offer Composition

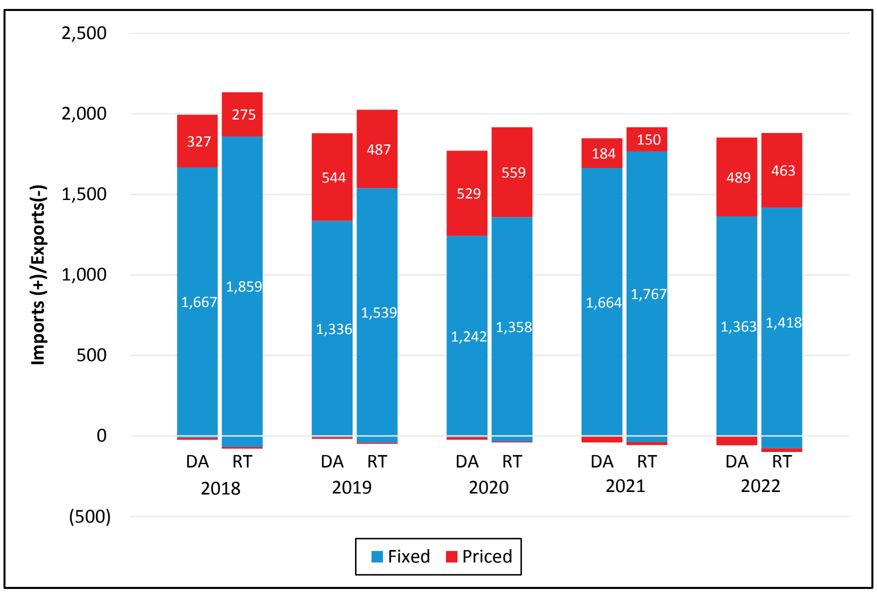
In Section 3 (see 3.2.2 and 3.2.5) we assessed overall market supply and demand-side participation in terms of the extent to which supply offers or demand bids are price-taking (fixed) versus price-making (priced). This can have important implications for price formation in the energy markets. In this section, we present a similar analysis focusing on external transactions, which participate on both the supply and demand sides of the market (i.e., supply offers for imports and demand bids for exports).

At the *Canadian* interfaces, the majority of transactions continue to be fixed, but levels of fixed transactions decreased compared to 2021. By contrast, at the *New York* interfaces transactions are mostly priced, and the split between priced and fixed remained steady compared to 2021.

Canadian Interfaces

The composition of transactions that cleared at the Canadian interfaces in the day-ahead and real-time markets by fixed and priced is shown in Figure 5-4 below. Volumes are average MW per hour.

Figure 5-4: Transaction Types by Market and Direction at Canadian Interfaces (Average MW per hour)



Imports at the Canadian interfaces continue to be predominantly fixed, but levels of fixed transactions decreased compared to levels in 2021 in both the day-ahead and real-time markets. In 2022, priced transactions accounted for 29% of volumes in the day-ahead and 25% of volumes in real-time market. On average, flows are higher in the real-time market due to additional real-time fixed transactions. In particular, participants submitted more priced transactions (and conversely fewer fixed transactions) over the *Phase II* interface, leading to the

[255] An 11 MW increase in *imports* over Northport-Norwalk also contributed to the decrease in net *exports*.

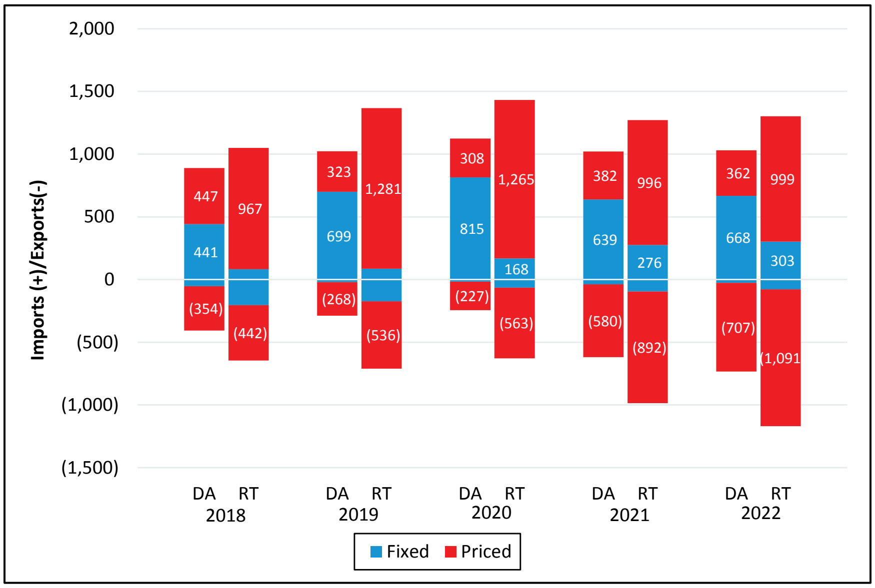
difference in system-level transactions. At Phase II, participants cleared an average 407 MW of priced transactions in 2022 compared to 58 MW on average in 2021.

On the exports side, volumes increased, but remained low at an average of just 100 MW. Both the decrease in imports and increase in exports occurred at the New Brunswick interface from April to July when a nuclear generator was on an extended outage.

New York Interfaces

The composition of transactions that cleared at the New York interfaces in the day-ahead and real-time markets by fixed and priced is shown in Figure 5-5.[256]

Figure 5-5: Transaction Types by Market and Direction at New York Interfaces (Average MW per hour)



Most day-ahead cleared import transactions at the New York interfaces are fixed (65% in 2022) while most exports are priced (96%). However, the share of total priced day-ahead external transactions (both imports and exports) increased slightly in 2022, to about 60%, due to more priced exports. In fact, export transactions have increased significantly in the past two years. A driver of higher exports was higher prices at the NYN interface, particularly due to constraints associated with the retirement of Indian Point 3 and increased transmission work that caused congestion at Central-East interface.[257]

A higher percentage of real-time imports (77%) are priced due to the bidding mechanics of Coordinated Transaction Scheduling (CTS) at the New York North interface. The majority of total cleared import transaction volumes come from New York North. Under CTS, all real-time transactions are evaluated based on price, although participants may offer prices as low as -

[256] Volumes not listed in the figure all averaged less than 100 MW.

[257] For more on congestion in New York, see Potomac Economics Quarterly Report on New York ISO Electricity Markets Third Quarter of 2022: https://www.potomaceconomics.com/wp-content/uploads/2022/12/NYISO-Quarterly-Report_2022Q3__11-21-2022.pdf

$1,000/MWh, which effectively schedules the transaction as fixed. For example, about 637 MW of imports and 390 MW of export transactions were willing to clear in each hour at a greater than $50/MWh loss.[258] A majority of the fixed import transactions also occurred at New York North. The higher volume of fixed import transactions over the past two years mostly reflects the growth in wheeled transactions through New York into New England.[259]

5.1.3 External Transaction Uplift (NCPC) Payments

External transactions are eligible to receive uplift (or NCPC) payments when revenues are not sufficient to recover their costs. These payments often occur when external transactions clear on an ISO price forecast but are unable to recover as-offered costs through energy market transactions. External transactions (or virtual transactions placed at external nodes) can also receive uplift for relieving congestion at non-CTS external interfaces since congestion is not captured in the LMP. These payments occur when a transaction that is out-of-the-money at the system price clears in the direction counter to the constraint (e.g., an export or virtual demand bid when the interface is import-constrained) allowing a counter-party to clear in excess of the interface limit.[260] These otherwise uneconomic transactions require uplift in absence of congestion pricing.

The annual uplift credit totals at all external nodes in both the day-ahead and real-time markets are presented in Table 5-1 below.

Table 5-1: NCPC Credits at External Nodes

Year	Day-ahead credits ($million)	Real-time credits ($million)
2018	$0.30	$2.73
2019	$0.02	$1.02
2020	$0.00	$1.39
2021	$1.04	$0.53
2022	$3.13	$1.17

Typically, total uplift paid at external nodes is very small compared with other types of uplift (see Section 3.3). In the day-ahead market, these payments typically occur when there is a surplus of fixed external transactions in excess of the TTC and a virtual or priced external

258 Participant CTS bidding behavior is discussed below in Section 5.2.3.

259 A wheeled transaction is when power is flowed from one system to another over a third party's transmission lines. For example, a participant might use these transactions to flow power from PJM through New York and into New England.

260 For example, consider an interface with an import TTC of 100MW and an LMP of $100. If there are 200MW of imports offered at $0, only 100MW can clear (due to the TTC), unless there is a transaction to offset the remaining 100MW of excess imports. If a 100MW export is offered at $50, it can provide counterflow. The $50 exports are willing to purchase the $0 imports. However, because congestion is not captured in the LMP, the energy settlement for the export will result in a loss; the exports are only willing to pay $50, and the LMP is $100. Therefore, these 100MW of exports must be paid $50/MWh to make them whole, for a total NCPC payment of $5,000. The NCPC charges are only levied to the participants importing over the interface.

transaction provides "counter-flow."[261] In 2022, most of the day-ahead uplift was due to virtual transactions relieving congestion by providing counter-flow for surplus fixed transactions at external interfaces.

In 2022, *day-ahead* uplift credits totaled $3.1 million, significantly higher than prior years. Virtual transactions received nearly $2.7 million in uplift credits and external transactions received about $0.5 million. Most of the uplift credits ($2 million) accrued at the Cross Sounds Cable interface for congestion relief in the export direction, with the remainder mainly at New Brunswick and Highgate for relieving congestion in the import direction.

Total *real-time* uplift credits during 2022 were higher than in 2021. This was because (1) more external transactions were bid as priced in 2022, making more transactions eligible to receive NCPC compared to 2021, and (2) more transactions (at non-CTS interfaces[262]) were in-rate based on forecast prices, but were out-of-rate based actual prices used in settlement . Accurate price forecasting of LMPs helps reduce NCPC paid to external transactions. In 2022, forecast error at the non-CTS interfaces increased, with actual LMPs much higher than forecasted LMPs. Real-time LMPs at all interfaces averaged nearly $7.00/MWh higher than the forecasted LMPs, which was up from $4.46/MWh in 2021.

[261] Since congestion is not priced at the interface, the participant relieving congestion with virtual supply receives uplift if the bid was cleared out of economic merit order. Often, this occurs when there is a large decrease in an interface TTC and participants have not adjusted their fixed bidding behavior.

[262] At the CTS interface, out-of-rate transactions are not entitled to NCPC, but also do not incur NCPC charges.

5.2 Coordinated Transaction Scheduling

In this section, we provide an updated assessment of how coordinated transaction scheduling (CTS) is functioning. Specifically, we review CTS performance metrics against its high-level primary goals (subsection 5.2.1), including the level of inefficient scheduling (5.2.2), and CTS impacts on efficient bidding opportunities (5.2.3).

Key Takeaways

In 2022, New York energy prices exceeded New England prices for the first time in the last five years. As a result, New England was a net importer of power over the Roseton interface 51% of the time, a decrease from 69% of the time in 2021.

The Roseton interface did not move power from the lower-to-higher priced region significantly more often (about 57% of the time) than previous years. The average absolute price difference between New England and New York was about $25/MWh, 96% higher than in 2021, but consistent with the overall increase in energy prices in New York and New England. The average absolute price spread forecast error also increased with higher energy prices, more than doubling from 2021 up to almost $24/MWh. Rather than submitting price-sensitive spread bids, participants continued a trend of clearing in the day-ahead market and offering price-insensitive transactions in real time. In 2022, the quantity of both imports and exports offering at prices less than -$50/MWh increased from 2021.

ISO forecast error continues to dampen the positive impacts of CTS by producing loss-making schedules and risk for participants at the Roseton interface. Possibly in response to forecast-error-driven inefficiencies, many CTS participants take on day-ahead positions and offer price-insensitive real-time bids and offers.

Since price forecast error is unlikely to be completely eliminated, minimizing the impact of price forecast error through changes to CTS mechanics or settlement may better incentivize participants to offer at cost. We will continue to evaluate these issues and encourage ISO-NE to review its price forecasting tools and explore opportunities to improve forecast accuracy.

5.2.1 CTS Performance

In this section, we analyze CTS performance against two measures of efficiency: the flow of power from the lower-to higher-cost region and price convergence between regions.

A summary of CTS power flows between the two control areas is shown in Table 5-2 below. The percentage of time power flowed into each control area is shown in the *Net Flow* columns.[263] The percentage of time the flow was directionally correct (i.e., power flowed from lower- to

[263] Fixed wheeling transactions at the NYN interface are ignored in all of the analyses contained in this section. These transactions are not cleared in the CTS process. On average, in 2022 there were 292 MW of fixed-wheeling transactions net importing over the NYN interface in each interval.

high-cost region, based on the forecasted or actual prices) is shown in the *Correct Flow* columns.[264]

Table 5-2: Summary of CTS Flow Outcomes

	Net Flow (% of intervals), to:		Correct Flow (% of intervals), based on:	
Year	ISO-NE	NYISO	Forecast Price Spread	Actual Price Spread
2018	77%	23%	61%	63%
2019	91%	9%	49%	58%
2020	95%	5%	40%	55%
2021	69%	31%	52%	56%
2022	51%	49%	59%	57%

In 2022, power flowed into New England from New York 51% of the time, the lowest frequency in the five-year period. In 2022, the decrease in importing-intervals was driven by an increase in price-insensitive export bids. Although ISO-NE exported over the NYN interface more often in 2022, the impact on *correct* flows was modest. In 2022, power flowed in the correct (economic) direction, based on the actual price spread between New York and New England 57% of the time – a similar percentage to the prior three years.

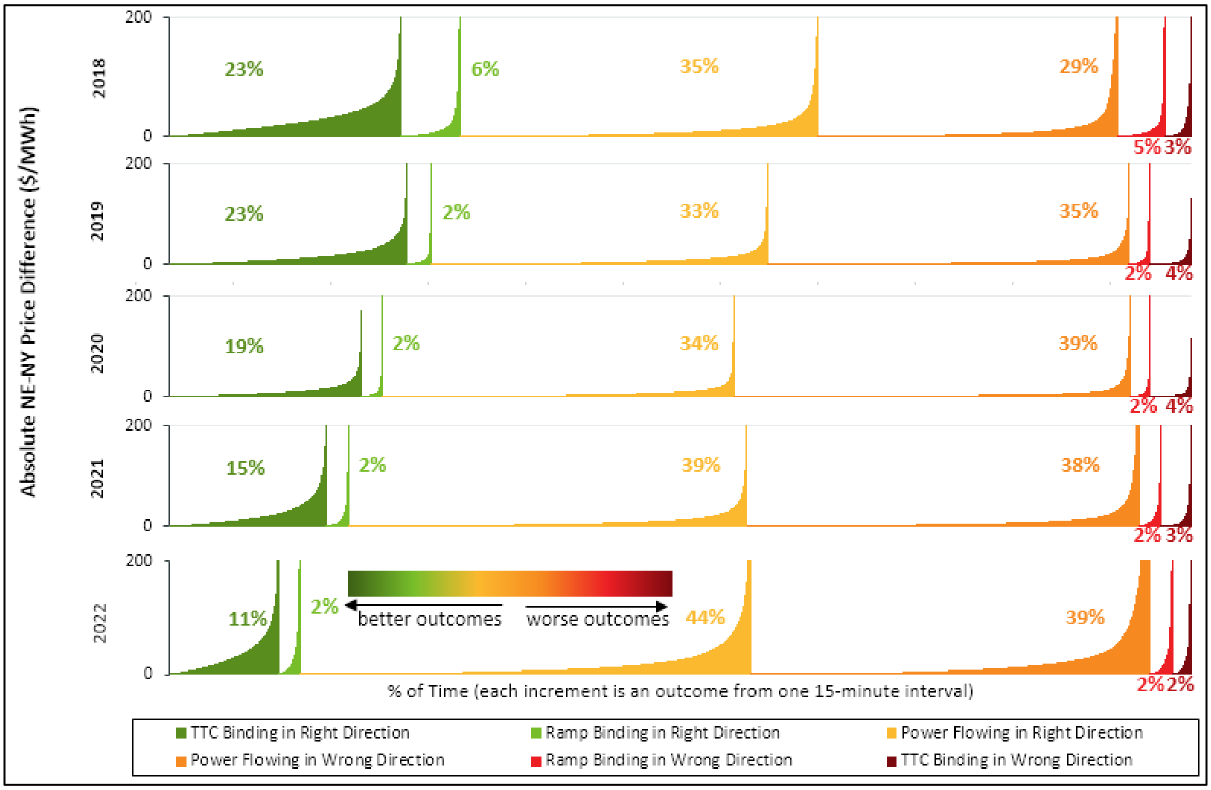
Economic flow direction metric

Ideally, power would flow from the control area with lower energy prices to the control area with higher prices until prices converge or a physical limit is hit (the TTC or the ramp limit). A breakdown of the intervals in which each of these constraints were binding and the absolute price difference between the control areas in each interval over the last five years is illustrated in Figure 5-6 below. The overall price difference between control areas is shown by the height of the area, in descending order of price difference. The following is a description of how to read the graph.

- The green areas on the chart represent the best possible outcomes; when power flowed in the correct (economic) direction and the TTC or ramp constraint were binding.
- The yellow area shows intervals where power flowed in the correct (economic) direction without binding constraints.
- The orange area shows intervals where power flowed in the wrong (uneconomic) direction without binding constraints.
- The red areas on the right show the less desirable outcomes: when power flowed in the wrong (uneconomic) direction and the TTC or ramp constraint were binding. In other words, when CTS was diverging prices as much as the constraints allowed.

[264] The prices used in this subsection are proxy prices that represent the marginal cost of energy on each side of the NYN interface. The NYISO pricing node is "N.E._GEN_SANDY PD" (Sandy Pond) and the ISO-NE node is ".I.ROSETON 345 1" (Roseton). Congestion pricing is removed from external prices to ensure we are better-capturing the marginal cost of energy in each control area at the border. When the ramp or flow limit binds, the prices at the interface reflect the bids and offers that set price based on the forecast, and not necessarily the marginal cost of energy in each control area.

Figure 5-6: CTS Outcome Summary



Overall, there was a similar percentage of intervals when power flowed in the correct direction (dark green and yellow areas) or the interface was ramp-constrained but adjusting in the correct direction (light green areas) in 2021 (56%) and 2022 (57%). However, in 2022, CTS performance continued to decline (since 2018) by flowing in the correct direction up to the TTC or ramp limit (the green areas) only 13% of the time, 4% less often than in 2021, and continuing a downward trend from 2018.[265] The reduction in this performance metric is driven by an increase in price-insensitive export transactions. Due to the volume of price-insensitive imports and exports offered over the NYN interface, CTS has limited ability to adjust to price differences between New England and New York. In past years, CTS has produced schedules with the most efficient outcomes (ramp constrained in the correct direction or flowing at the flow limit in the correct direction) almost exclusively in the import direction. In 2020 and 2021, New England was importing over 95% of the time when a physical constraint (TTC or ramp) was binding. In 2022, CTS was more balanced in the direction of these outcomes; New England was importing only 58% of the time when a constraint was binding. Even though CTS schedules were correctly binding in the *export* direction more often, the total percentage of the time CTS constraints were binding in the *correct* direction decreased.

[265] In some cases, CTS could be converging prices as efficiently as possible without a ramp constraint or flow constraint binding, if prices are equal on either side of the interface. Although there were only 2.5 cumulative hours in which the price difference was $0/MWh, 7% of the total time in 2022 there was no constraint binding and the price difference was under $2/MWh. This also represents a decrease from 2021, when no constraint was binding and the price difference was under $2/MWh for 21% of the time.

Price convergence metric

As a primary consideration for the implementation of CTS, it is important to evaluate its impact on price convergence between the markets. The height of each bar in Figure 5-6 above represents the absolute price difference in each interval. Less area under each curve represents better price convergence. In 2022, the average absolute price difference (the average of the lines in each year) between NE and NY was $25.06, 96% higher than in 2021. This is visually apparent because there are much larger areas under each curve, shown in the graph above, in 2022. However, overall NE LMPs were 93% higher in 2022 (not shown). Therefore, as a percentage of average LMPs, the absolute price difference in 2021 and 2022 were similar; average absolute price differences were about 30% of average NE LMPs in each year.

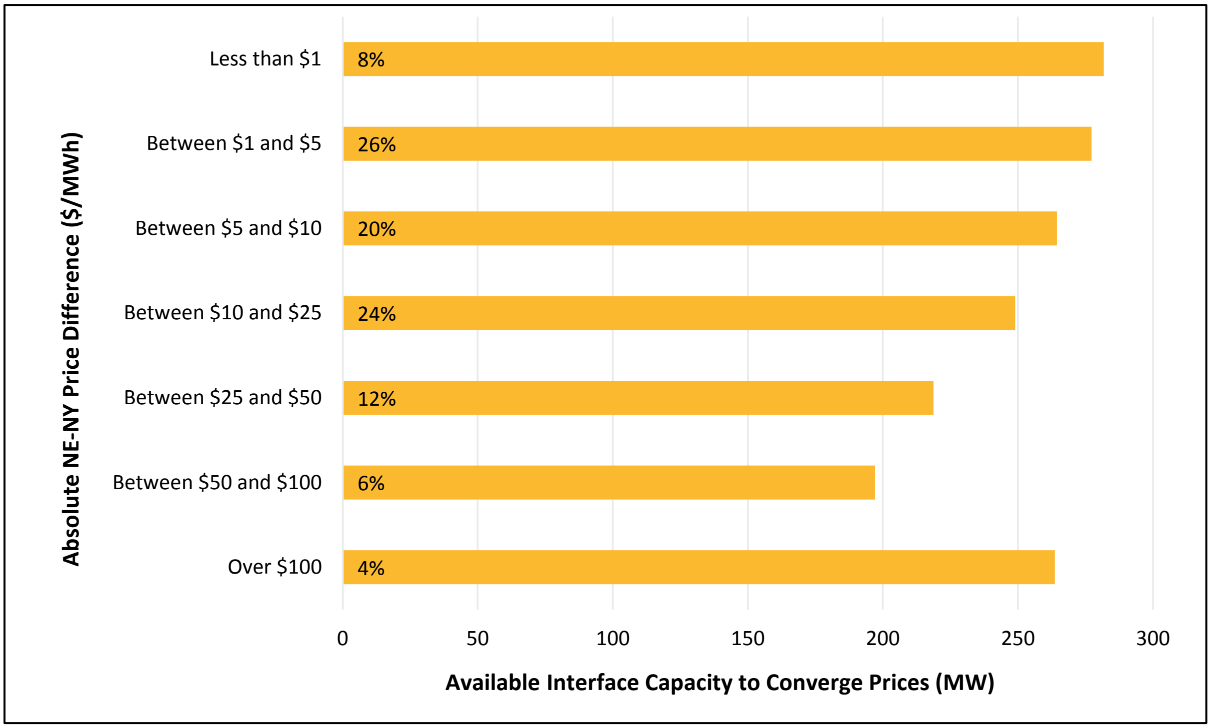
Tie line capacity utilization metric

When prices differ between control areas and neither the TTC or ramp constraint is binding, CTS is not converging prices optimally, and there is underutilized capacity on the transmission ties. Figure 5-7 below shows the available, but unused, capacity up to the physical constraint (TTC or ramp) in the low- to high-price direction.[266] This surplus capacity could be used to help converge prices further. This analysis is bucketed by price difference because at lower price difference levels, we would not expect CTS to utilize as much of the capacity.[267] The percentages on the left side of the bar show the percentage of time each price bin occurred during the year.

[266] This figure does not account for schedule cuts. In some circumstances, after schedules are generated for an interval, schedules are cut and actual flows do not match pricing outcomes. The ramp limit in this chart is calculated from the previous interval's *scheduled* net interchange, rather than actual net interchange after cuts. In cases where there are schedule cuts, the available capacity in this chart may not represent the available capacity used in CTS clearing.

[267] For instance, if the price difference is less than $1/MWh, the interface may have already reached the optimal flow to converge prices, and clearing one more MW could result in a larger price difference. However, this scenario is less likely as the price difference gets larger.

Figure 5-7: CTS Unused Capacity, 2022



Even when the price difference between regions is high, on average, CTS did not fully utilize the available capacity to help converge prices. In scenarios where price differences were greater than $50/MWh, there was about 200 MW of average unused interface capacity. Since implementation, CTS has consistently left NYN interface capacity underutilized. Figure 5-7 indicates that CTS is not effectively utilizing the available capacity to improve price convergence.

5.2.2 CTS and ISO Scheduling Efficiency

CTS participants are not compensated when energy-price incentives are misaligned with CTS transaction schedules. In other words, transactions are scheduled based on forecast prices, but settled based on actual prices. Therefore, participants bear the risk resulting from scheduling inefficiencies due to price forecast error.

A summary of forecast versus actual prices, as well as the average and absolute forecasting errors, is provided in Table 5-3 below. Similar to above analyses, unless otherwise noted (i.e., in the *Spread, with Cong.* column), NYN proxy prices net of congestion are shown to better capture the marginal cost of energy on each side of the interface.[268]

[268] Proxy prices do not include external congestion. The average forecast error and average absolute forecast error will not change if congestion is added to both the forecast and actual LMPs.

Table 5-3: Forecast Error in CTS Solution

	Actual LMP ($/MWh)				Forecast LMP ($/MWh)			Average Forecast Error ($/MWh)			Average Absolute Forecast Error ($/MWh)		
	ISO-NE	NYISO	Spread	Spread, with Cong.	ISO-NE	NYISO	Spread	ISO-NE	NYISO	Spread	ISO-NE	NYISO	Spread
2018	$42.53	$37.52	$5.01	($1.51)	$41.45	$35.71	$5.74	($1.07)	($1.81)	$0.73	$8.09	$8.42	$13.46
2019	$29.66	$26.47	$3.19	($0.72)	$28.64	$26.83	$1.81	($1.02)	$0.36	($1.38)	$4.69	$5.07	$7.96
2020	$22.45	$20.46	$1.99	($0.67)	$21.72	$21.33	$0.39	($0.73)	$0.87	($1.60)	$3.76	$4.04	$6.34
2021	$43.03	$41.07	$1.96	($1.65)	$41.32	$41.66	($0.34)	($1.71)	$0.60	($2.31)	$5.50	$7.93	$10.78
2022	$82.94	$86.39	($3.45)	($4.63)	$79.80	$84.57	($4.77)	($3.14)	($1.82)	($1.32)	$11.23	$18.51	$23.87

Price forecasting continues to be a challenge for the ISOs. The *Average Absolute Forecast Error* columns show the amount that the forecast differed from the actual prices (ignoring directionality). In 2022, average absolute forecast error increased to $23.87/MWh, more than double the 2021 error ($10.78/MWh), indicating that the CTS forecasts became less accurate.

The *Average Forecast Error* columns take direction into account. Since 2018, actual ISO-NE prices have been higher than the forecast. In 2022, NYISO actual prices were also, on average, higher than the forecast. Since the 2022 errors were in the same direction, they helped to diminish the impact of each individual ISO's forecast error; the forecast error in the spread (-$1.32/MWh) was smaller than each ISO's individual forecast error (-$3.14 and -$1.82/MWh).

The *Actual LMP* column shows that in 2022, NYISO energy prices were higher than ISO-NE for the first time over the past five years.[269] Due to the NY premium, 2022 was the first year in the study period in which the price spread with congestion, shown in the *Actual LMP, Spread with Cong.* column, was directionally similar to the price spread without congestion. In 2018-2021, interface constraints, coupled with bid and offer behavior from CTS participants, drove a sub-optimal outcome where, on average, bids and offers converging prices (i.e., moving energy from the lower- to higher-cost region) were loss generating. This occurs when participants make bids and offers that are less than zero (i.e., willing to clear at a loss).[270]

For instance, consider a scenario in which there are 2,000 MW of imports offered at a -$10/MWh spread price, the CTS flow limit is 1,400 MW, and the New England price is forecasted to be $20/MWh higher than New York. CTS will schedule 1,400 W of the 2,000 MW of imports (up to the flow limit) because the offered spread bids are priced lower than the forecasted spread price. A -$10/MWh spread bid will set the congestion price at the interface, because the interface is constrained—in other words, based on the $20/MWh price spread more of the -$10/MWh imports would like to clear, but cannot due to the flow limit. The CTS congestion price will be -$30/MWh, because if one more MW could clear over the interface because the flow limit was relaxed 1 MW, the system would benefit $30/MWh (the $20/MWh

[269] The day-ahead NY price premium at the NYN interface was $4.63/MWh, identical to the real-time NY price premium with congestion.

[270] Bid prices can be positive, negative, or zero. A positive bid price indicates the participant is willing to move power when the price in the destination market exceeds the price in the source market by at least the bid price (i.e., buy low and sell high). A negative bid price indicates a willingness to trade power when the energy price is higher at the source than at the destination, by as much as the negative bid price (i.e., to buy high and sell low).

less expensive power from New York could flow into New England plus the $10/MWh the participant is willing to *pay* to flow the import). If the actual price spread is $20/MWh, the same as the forecast, the CTS spread price with congestion will be -$10/MWh ($20/MWh actual price spread minus $30/MWh congestion price). This outcome highlights a scenario in which CTS is flowing from the lower- to higher-cost region (New England prices are $20/MWh higher without congestion pricing), but the import offers are loss making (the settled CTS price spread is -$10/MWh with congestion pricing).

The risk of uneconomic scheduling due to forecast error could be one driver of negative real-time CTS bid and offer prices. One strategy for mitigating risk is to lock in (hedge) the day-ahead position by submitting low-priced real-time transactions to minimize day-ahead/real-time deviations.

Table 5-4 shows the average bid prices of 2022 bids and offers cleared in each price bin, by direction, along with forecasted and settled LMPs.[271] When forecasted LMP differences are greater than average bid prices, bids were scheduled and are shown in green. All forecasted LMP differences are greater than average bid prices in this table because if forecasted LMP differences are less than the bid price, the bids are not scheduled. When settled LMP differences are greater than average bid prices, bids were profitable and are shown in green. Due to forecast error, some settled LMP differences are less than bid prices and are shown in red. This indicates that, if participants were offering at cost, these bids were loss making due to forecast error in 2022.

Table 5-4: Profit Scenarios, 2022

Direction	Bid Price Bin	Average Bid Price	Forecasted LMP Difference	Settled LMP Difference	Hourly Scheduled MW
Export	Less than -$25	(585.85)	5.09	4.48	413.9
	-$25 and -$5	(16.61)	5.14	3.60	102.3
	-$5 and $0	(1.17)	6.63	3.50	101.9
	$0 and $5	2.52	9.38	4.47	200.7
	$5 and $25	9.31	15.97	7.26	39.0
	Greater than $25	68.60	151.44	85.89	0.7
Import	Less than -$25	(755.52)	(7.02)	(6.54)	727.2
	-$25 and -$5	(17.76)	(5.19)	(6.30)	242.0
	-$5 and $0	(2.53)	1.23	(0.76)	7.6
	$0 and $5	2.76	10.66	(9.26)	9.9
	$5 and $25	9.76	24.38	(2.70)	2.1
	Greater than $25	48.56	68.42	(11.50)	0.2

Table 5-4 above shows how forecast error has impacted CTS participants in each bid and offer price bin. Settled LMP differences were negative for all import bins in 2022, indicating that,

[271] To better compare LMPs with bid prices, forecasted and settled LMPs in this table are weighted by scheduled MWs, reflect external congestion, and show price differences in the direction of bids. Imports clear when NE – NY > bid price and exports clear when NY – NE > bid price; the NE-NY LMP difference is included for imports and the NY-NE LMP difference is included for exports.

although the offers were economic based on the offer price, they were moving power counter-intuitively, from the higher- to lower-cost region. Due to price forecast error, import offers priced above $0/MWh, as well as export transactions priced between $5 and $25/MWh, were, on average, loss generating due to forecast error (i.e., scheduled transactions with positive costs were uneconomic once prices materialized). Faced with these risks, participants may prefer offering in the day-ahead market (where there is no forecast error) and minimizing real-time deviations with price-insensitive bids in real time. The *Hourly Scheduled MW* column highlights these dynamics, with about half of export transactions and about three-quarters of import transactions offered at prices less than -$25/MWh. Consequently, the NYN interface has limited price-sensitive bids and offers needed to adjust to regional price differences.

5.2.3 CTS and Participant Bidding Opportunities

Forecast error drives inefficient scheduling that reduces efficient bidding opportunities. In other words, if the price forecast error was zero, then participants should be willing to offer at *de minimus* price (say $0.01/MWh) in the import and export direction and flow to the higher-price market. However, from the table in the prior section, we see that in many cases a $0.01/MWh import would be scheduled to flow from the lower- to high-price market but, due to forecast error, would end up flowing at a loss because the actual spread can materialize in the opposite direction from the forecasted spread. A rational bidder would create a bidding strategy to account for forecast error inefficiencies. In this subsection, we take a closer look at actual participant bidding behavior.

Average CTS transaction curves, by year, are shown in Figure 5-8 below. Import offers for 2022 are shown in the first graph (gold curves) followed by 2022 export bids (red curves). Lastly, imports and exports are aggregated to produce a net supply curve (orange curves). The import and export curves show the average volume of energy willing to clear at each New England - New York price spread. The aggregate supply curve shows the net flow that would be produced if all of the economic import and export transactions were to clear.

For example, in 2022, at a price spread of $0/MWh (i.e., NE price is equal to the NY price), about 1,075 MW of imports would have cleared, 725 MW of exports would have cleared, and the net flow of CTS transactions would have been 350 MW, on average. The typical import TTCs, less the average number of wheeling transactions, are shown in dotted lines.[272] The net imports cannot clear above these lines, and when the price difference is forecasted to be greater than the intersection (about $500/MWh New England – New York when the TTC is 1,200MW) a CTS bid will set the congestion prices at NYN.[273]

[272] The export TTC (plus wheeling transactions) is not shown because the average net imports curve does not cross the limit.

[273] Only one of these TTCs will be active at a time. Both are shown to visualize the difference in flows and prices when either is binding.

Figure 5-8: Price Sensitivity of Offered CTS Transactions

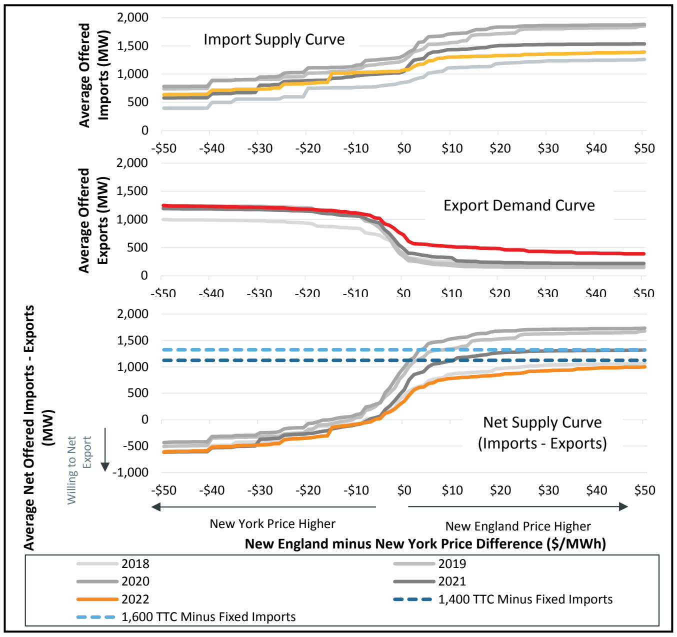


Figure 5-8 highlights a few key takeaways about participant bidding behavior at a high level. On average:

1) There were many price-insensitive imports willing to clear in each interval.
   - About 637 MW of imports were willing to clear in each hour at a greater than $50/MWh loss, an increase from 576 MW in 2021.
2) There were also many more exports willing to clear at a loss.
   - About 390 MW per hour were willing to clear at a greater than $50/MWh loss, compared to only 218 MW in 2021.
3) CTS participants, as a whole, were net importers even when New England prices were lower.
   - Participants would import when prices were up to $7/MWh lower in New England, and would import about 352 MW at a price difference of $0/MWh.
4) The TCC in the import direction bound at a much higher average price premium.
   - In 2021, a relatively small New England price premium – about $11/MWh – was enough to bind the TTC when the TTC was 1,400 MW. In 2022, the additional exports willing to provide counter-flow increased the price premium at which the TTC bound to $1,000/MWh.

The large quantity of price-insensitive bids reflect participants with day-ahead positions. 50% of exports and 71% of imports scheduled in real-time were hedged with a day-ahead position. While this is a reasonable business strategy to mitigate forecast error risk (or based on contractual positions), this bidding behavior inhibits CTS from adjusting to changes in price between New York and New England.[274]

[274] This section highlights CTS mechanics that degrade participant incentives. In reality, market participants may offer in ways that appear uneconomic for many reasons, including capturing environmental credits or long-term contracts.

Since price forecast error is unlikely to be completely eliminated, minimizing the impact of price forecast error through changes to CTS mechanics or settlement may better incentivize participants to offer at cost. We will continue to evaluate these issues and encourage ISO-NE to review its price forecasting tools and explore opportunities to improve forecast accuracy.

Section 6
Forward Capacity Market

This section reviews key trends and performance of New England's forward capacity market (FCM). The seventeenth forward capacity auction (FCA) is covered in Section 6.1. The auction cleared with a surplus of capacity at a payment rate well below the estimated cost of new entry. The outcomes of FCA 17 were closely aligned with the prevailing trend of surplus capacity and low clearing rates.

Section 6.2 reviews FCM trends over the past seven years. The surplus conditions can be attributed to low amounts of retirements and steady additions of new generation, notably from renewable or policy-sponsored projects (wind, solar, and battery storage). New additions in New England have transitioned away from gas-fired generation and demand response and toward mostly renewable projects that will come online over the next three years.

A capacity scarcity condition under the Pay for Performance (PfP) rules was triggered in December 2022 for the first time since 2018. Import and nuclear resources performed above expectations, as measured by their financial obligation, while gas-fired and dual-fuel (gas/oil) resources performed below expectations.

6.1 Review of Seventeenth Forward Capacity Auction (FCA)

This section provides a closer review of FCA 17, the most recent primary auction held in March 2023.[275]

Key Takeaways

Qualified capacity participating in FCA 17 exceeded the Net Installed Capacity Requirement by over 7 GW (37,386 MW qualified compared to 30,305 MW). About 6 GW left during the auction, comprised of 2,236 MW of existing resources, 3,106 MW of import resources, and 674 MW of new resources. Cleared capacity totaled 31,370 MW, leaving a surplus of about 1 GW (1,065 MW) at the auction clearing price of $2.59/kW-month.

Over 770 MW of new resources cleared, with battery storage projects (400 MW) and solar projects (124 MW) representing the largest entrant types. The vast majority of capacity that left FCA 17 de-listed for one year under the Dynamic De-list Bid Threshold of $2.59/kW-month. The largest groups of generators that dynamically de-listed were gas-fired (800 MW), oil-fired (778 MW), and coal-fired (438 MW) generators.

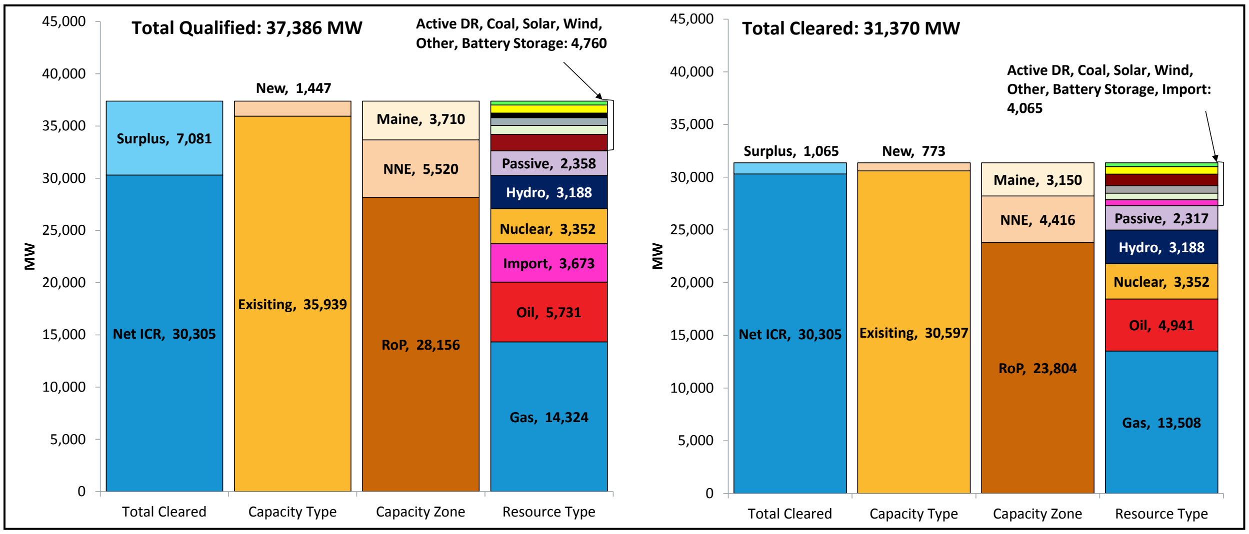
FCA 17 was structurally competitive with limited ability and incentive to exercise market power. We did not observe bidding behavior that was consistent with the exercise of market power. Based on the pre-auction mitigations, excess capacity during the auction, and liquidity of dynamic de-list bids, it is our opinion that a competitive process drove the results of the auction.

[275] Further detail on the auction is contained in the IMM's Winter 2023 quarterly markets report. See https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

6.1.1 Qualified and Cleared Capacity

The qualified and cleared capacity in FCA 17 compared to Net ICR (blue bars) is illustrated in Figure 6-1 below. Total qualified and cleared capacity are broken down across three dimensions: capacity type, capacity zone and resource type.

Figure 6-1: Qualified and Cleared Capacity in FCA 17



In FCA 17, qualified capacity exceeded Net ICR by 7,081 MW, or 23%. New qualified capacity totaled 1,447 MW, down by just over 200 MW from the FCA 16 value (1,696 MW). New battery storage projects held the largest portion of new qualified capacity, totaling over 876 MW. The ISO reintroduced the renewable technology resource (RTR) exemption in FCA 17.[276] Total new qualified capacity under the RTR exemption reached the maximum auction allowance of 300 MW.

As excess supply declined during the auction rounds, the surplus (above Net ICR) fell from 7,081 MW to 1,065 MW at the end of the auction. The capacity that dropped out of the auction (6,016 MW) comprised of existing resources that de-listed and new supply resources that exited the market at prices at or greater than the associated zonal clearing price. The first orange "Total Cleared" bar (capacity type) illustrates that existing capacity accounted for 98% of cleared capacity, with just 2% (773 MW) of capacity obligations held by new resources.

Two capacity zones were modelled in addition to Rest-of-Pool: the export-constrained zone of Northern New England (NNE), and the nested export-constrained zone of Maine. The qualified and cleared values are illustrated in the second orange bars (by Capacity Zone). There was no price separation between capacity zones in FCA 17.

[276] More information on the RTR exemption for FCA 17 can be found in the FERC filing accepting tariff revisions centered on the removal of the minimum offer price rule (MOPR).

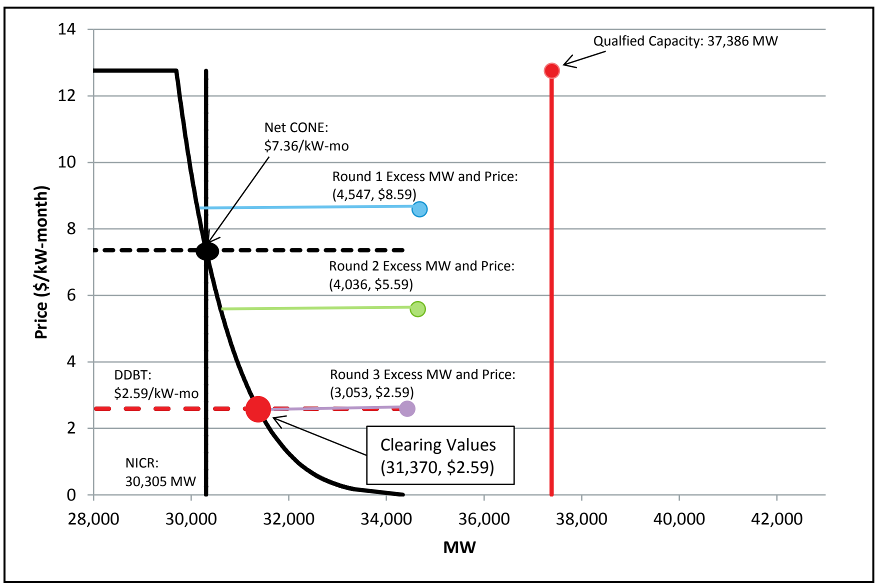
6.1.2 Results and Competitiveness

In addition to the amount of qualified capacity eligible to participate in the auction, several other factors contribute to auction outcomes. These factors, including the ISO-provided auction parameters as well as participant behavior, are summarized in Figure 6-2 below.

On the *demand* side, the demand curve, Net CONE, and Net ICR are shown in black. FCA 17 was the fourth auction with a demand curve that relied solely on the Marginal Reliability Impact (MRI) methodology.[277]

On the *supply* side, the qualified and cleared capacities are shown (solid and dashed red lines, respectively). The clearing price of $2.59/kW-month is shown at the intersection of the cleared MW and the demand curve, just below the dynamic de-list bid threshold (DDBT) price of $2.59/kW-month. Lastly, the blue, green, purple, and orange markers represent the end-of-round prices, and the corresponding dots depict excess end-of-round supply.[278]

Figure 6-2: System-wide FCA 17 Demand Curve, Prices, and Quantities



The auction closed in the fourth round for all capacity zones and interfaces except for slight price separation at the New Brunswick interface. The fourth round opened with 3,053 MW of excess capacity above demand at the system level (purple dot) and a starting price equal to the DDBT price, allowing existing resources to exit the market through dynamic de-list bids.[279]

[277] The MRI methodology estimates how an incremental change in capacity impacts system reliability at various capacity levels. Prior to FCA 14, a transitional approach was taken, with the demand curve reflecting a hybrid of the previous linear demand curve and the new convex-shaped MRI curve. The transition period began with FCA 11 and could last for up to three FCAs, unless certain conditions relating to Net ICR growth are met, pursuant to Section III.13.2.2.1 of the Tariff.

[278] The colored dots and lines move from cooler colors at higher prices and capacity, to warmer colors at lower prices and less capacity.

[279] Excess system capacity only includes import capacity up to the capacity transfer limit.

All 3,053 MW excess supply exited the auction in the final round at the round starting price of $2.59/kW-month. A fully-rationable dynamic de-list bid set the final clearing price of $2.59/kW-month for all capacity zones and interfaces (except New Brunswick). The market clearing engine could not clear all new supply offers and de-list bids attempting to leave the auction at $2.589/kW-month without falling below system-wide demand.[280]

FCA 17 Competitiveness

The IMM conducts a pivotal supplier test prior to the auction based on portfolios with existing capacity relative to the system and local requirements (see Section 2.4.1).[281] However, capacity conditions change as the auction proceeds (new resources leave, existing capacity de-lists, the demanded quantity changes) and a supplier that was not pivotal at the start of the auction (when the IMM made the pivotal status determination) may become pivotal during the auction as the surplus falls.[282]

There were no pivotal suppliers at the start of the auction. As the auction entered its fourth round, with excess capacity of 3 GW, there was one pivotal supplier with a portfolio slightly above the system-wide excess capacity. This indicates that the possibility of exercising seller-side market power was theoretically possible, yet the pivotal supplier's de-list bids comprised of less than 14% of all submitted de-list bids in the final auction rounds. Given the surplus capacity conditions associated with prices below the dynamic de-list bid threshold and the significant amount of de-list bids submitted by non-pivotal suppliers, it is unlikely that the pivotal participant could exercise seller-side market power.

In summary, since the auction was structurally competitive there was limited ability and incentive to exercise market power. Further, we did not observe bidding behavior that was consistent with the exercise of market power. Based on the pre-auction mitigations, excess capacity during the auction, and liquidity of dynamic de-list bids, it is our opinion that a competitive process drove the results of the auction.

6.1.3 Results of the Substitution Auction (CASPR)

In FCA 17, the substitution auction did not proceed, as there were no active demand bids. The two retiring resources that qualified for the substitution auction did not receive CSOs in the primary auction, a prerequisite for submitting a demand bid in the substitution auction.

280 Due to minimum rationing limits, the necessary CSO to meet system-wide demand could not be allocated evenly among all resources attempting to exit the auction. Instead, the market clearing engine rationed one resource's de-list bid to retain the necessary amount of CSO for system-wide supply to meet system-wide demand.

281 The initial pivotal supplier calculation is limited to pre-auction calculations and applies only the mitigation of static de-list bids.

282 In fact, suppliers that have been deemed pivotal prior to the auction may not be pivotal at the start of the auction (if the quantity demanded along the sloped demand curve is greater than Net ICR or Local Sourcing Requirement in import-constrained capacity zones).

6.2 Forward Capacity Market Outcomes

This section reviews the overall trends in prices and volumes in the FCM; specifically we cover the FCM credits and charges, trends in the resource mix, and finally, activity in secondary markets for trading capacity.

Key Takeaways

Capacity market outcomes remained relatively constant year-over-year, driven by an unchanged FCA 16 and 17 Rest-of-Pool clearing price of $2.59/kW-month. Since FCA 10, capacity prices have decreased 63% ($4.44/kW-month) and Net ICR has decreased 11% (3,846 MW), resulting in a record low $0.9 billion in projected capacity payments for capacity commitment period (CCP) 2026-2027 (FCA 17).

New entrants to New England have varied over the past seven auctions, with gas and energy efficiency resources making up a majority of new capacity additions from FCA 10-13. Since FCA 14, renewable technologies, typically sponsored-policy resources, have made up 56% of all new generator additions. Major retirements have comprised of nuclear, oil, and gas resources, and an additional 1,100 MW of new gas resources have been terminated since FCA 10, as they failed to meet critical development milestones.

December 2022 saw the first Pay-for-Performance event since 2018. The December 2022 event lasted 17 five-minute intervals (1 hour 25 minutes) and resulted in the transfer of $35.9 million from under-performing resources to over-performing resources. Import and nuclear resources received the most over-performance payments, while gas resources were charged the most for under-performance. A significant amount of gas generation was out of economic merit order in the day-ahead market due to very high natural gas costs, and in real time could not respond to high prices during the emerging event due to start time constraints.

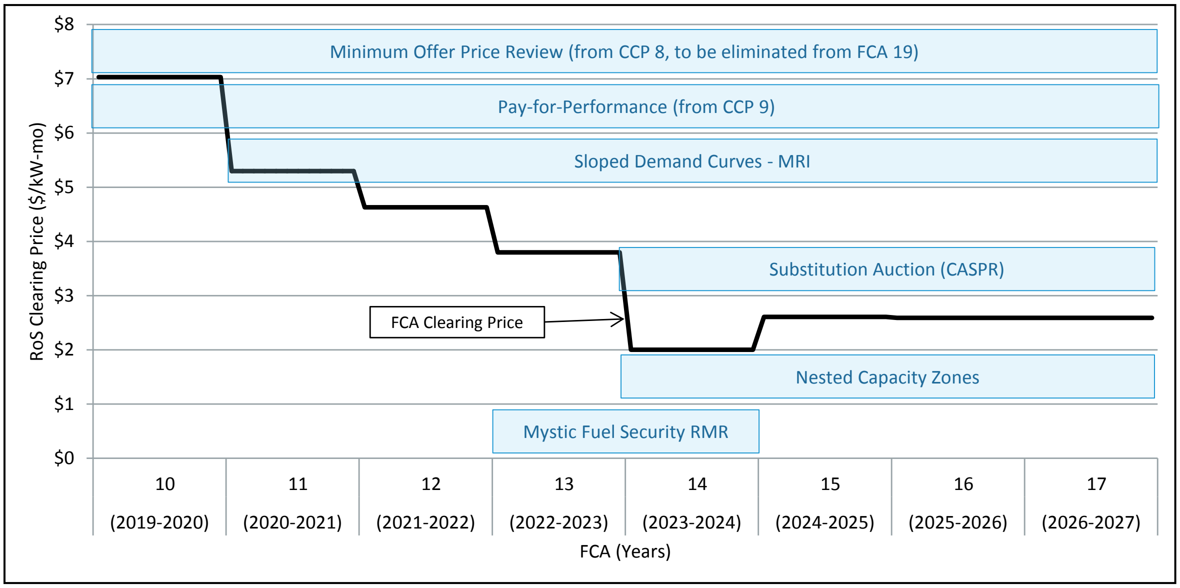
Market Rule Changes, Clearing Prices, and Payments

FCM prices are determined by the interaction of capacity supply and demand. When capacity is in relatively short supply, we expect higher prices. When supply is more abundant, we expect the opposite. In addition to evolving supply and demand conditions, the capacity market design has also undergone a number of significant market rule changes in recent years.

A brief history of the FCM: Market design changes

The trend in Rest-of-Pool FCA clearing prices against the backdrop of some of the major design changes over the reporting period is shown in Figure 6-3 over an eight year period, including 3½ years of actual delivery and 4½ years of future delivery periods. The impact of market rule changes on auction outcomes is varied, in terms of both level and direction, and the graph is intended to provide useful context rather than infer a particular relationship between individual changes and clearing prices.

Figure 6-3: FCA Clearing Prices in the Context of Market Rule Changes



The *minimum offer price rule (MOPR)* was implemented in FCA 8, intended to mitigate the impact of below-cost offers (in practice mostly subsidized offers) on clearing prices. From FCA 9, the *Pay-for-Performance* (PFP) market rules were implemented and placed a financial obligation on capacity resources to perform during capacity scarcity events. Combined, the MOPR and PFP rules encouraged a greater degree of priced participation in the auctions, with more new and existing resources submitting offers (as opposed to price-taking).

The *sloped demand curve* was introduced in FCA 9 with the objective of improving price formation and reducing price volatility, by reflecting the willingness of load to procure a given amount of capacity (reliability) at various price levels.[283] When the auction clears at a surplus (over NICR), a sloped demand curve results in a clearing price below Net CONE, which occurred in all auctions shown above (FCA 10-17). Following a three-year transition period, as the system demand curve shifted to a non-linear form in FCA 11, the value of excess capacity decreased, and clearing prices continued to drop.

In FCA 13, two rule changes were implemented with implications for price formation. First, the ISO retained Mystic 8 and 9 (~1,400 MW) for their fuel security attributes under a *cost-of-service agreement*, rather than those resources retiring (which will happen in May 2024). The Mystic resources were treated as price takers in the FCA, with a resulting downward impact on prices.

Second, *CASPR* was introduced as a *secondary* means to allow sponsored policy resources, which may not clear due to MOPR, to obtain a CSO from retiring resources. The design objective

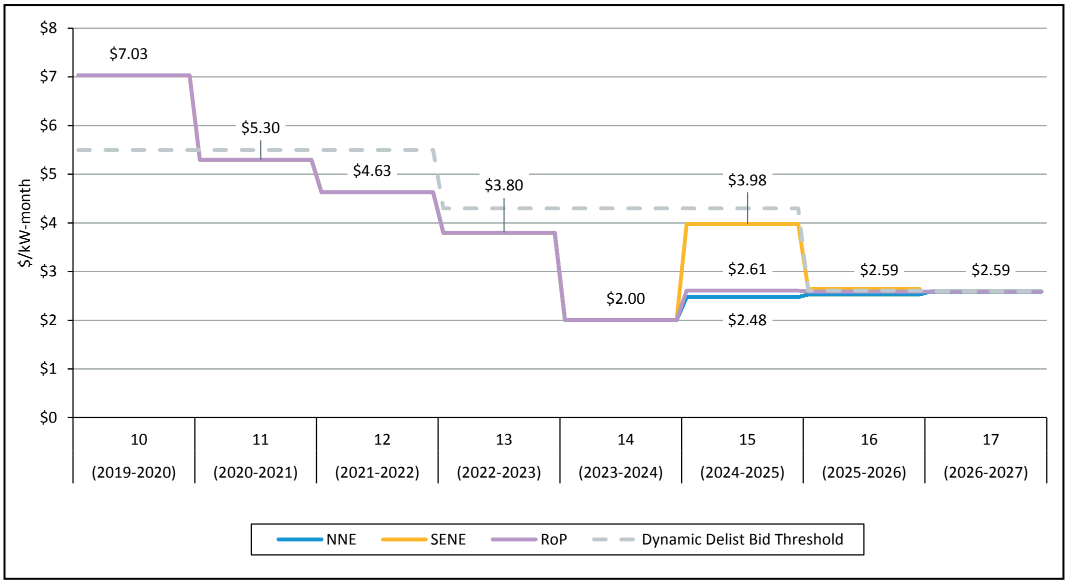
[283] A linear sloped system demand curve was implemented for FCA 9, but the zonal demand curves remained vertical. In FCA 10 linear sloped demand curves were used at both the system and zonal levels. More recently, for FCA 11 both sloped and non-linear demand curves (except for a portion of the system curve) were implemented based on the MRI methodology.

was to facilitate the orderly exit and entry of existing and new resources through a secondary (substitution) auction, while mitigating the price-suppressing impact on the primary auction.

Rest-of-Pool and Zonal FCA Clearing Prices

The changes in new and existing capacity clearing prices for each FCA are illustrated in Figure 6-4 below. The different colored lines represent the price paid to resources in each modeled capacity zone.

Figure 6-4: Forward Capacity Auction Clearing Prices



Prior to *FCA 10*, higher capacity prices sent a signal to market participants that load was willing to pay for more capacity that would improve system reliability.[284] Once new generation responded to price signals and entered the FCM in greater volumes, clearing prices fell steadily, beginning at $7.03/kW-month in *FCA 10* and continuing to drop in *FCA 11*.

In *FCAs 12 through 14*, a downward trend in New England capacity requirements reduced clearing prices below the dynamic de-list bid threshold (DDBT) – where de-list bids are not subject to an IMM cost review. In each auction, the closing round started at the DDBT price. Dynamic de-list bids from existing resources set the system-wide clearing price in FCAs 12-13.

In *FCA 15*, the Rest-of-Pool (RoP) clearing price increased for the first time in six auctions, as did price separation among the capacity zones. Significant decreases in capacity in the South Eastern New England (SENE) capacity zone, led by the retirement of Mystic 8 and 9, meant that the zone cleared one round earlier and at a higher price than the RoP price. The RoP and Northern New England capacity zones cleared in the fifth round of the auction, two rounds past the DDBT threshold of $4.30/kW-month. Due to large amounts of cleared capacity in the export-constrained Northern New England capacity zone, the zonal clearing rate cleared slightly below the RoP benchmark.

[284] Clearing prices for FCA 8 and 9 were $15.00/kW-month and $9.551/kW-month, respectively.

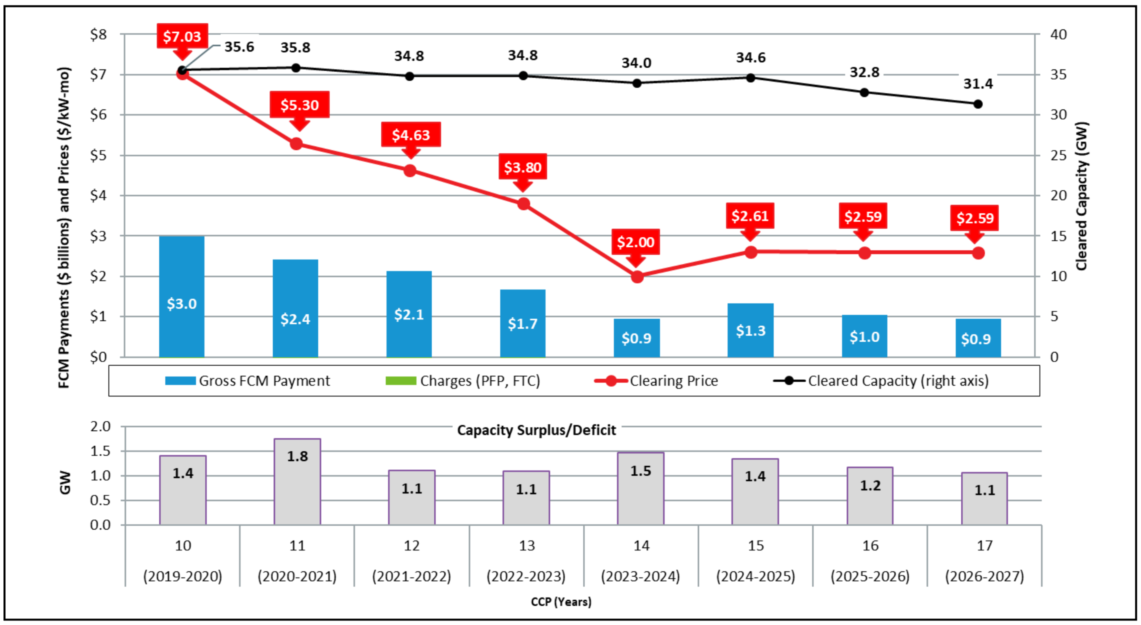
In *FCA 16*, the RoP clearing price was comparable to *FCA 15*. Price separation also occurred in FCA 16, but to a much lesser degree (SENE cleared $0.04/kW-mo higher). All zones cleared immediately after the dynamic de-list bid threshold was reached in the fourth round.

In *FCA 17*, the clearing price remained constant year-over-year. Price separation only occurred at the New Brunswick interface, which cleared 177 MW of import capacity at a price of $2.55/kW-month (not shown). Despite over 3,000 MW of excess supply entering the fourth round of the FCA, the auction cleared at that round's starting price (equal to the DDBT).

Payments by Commitment Period

FCM payments are primarily a function of clearing prices and capacity (volume) in each FCA. Total payments for capacity commitment periods (CCPs) 10-17 are shown in Figure 6-5 below, along with the key determinants: Rest-of-Pool clearing prices and cleared capacity.[285] The gray boxes in the bottom graph represent the amount of surplus capacity above the Net ICR that cleared in each FCA.

Figure 6-5: FCM Payments and FCA Volumes by Commitment Period



Capacity prices have generally trended downwards over the eights auctions, consistent with a surplus of cleared system capacity, and a decrease in the capacity required (NICR) to meet the 1 day-in-10 year loss of load reliability standard.

Payments peaked with high clearing prices for *FCA 10* and fell significantly over the remaining four auctions as both cleared capacity and prices declined; total payments are projected to

[285] The blue bars represent gross FCM payments by commitment period. Payments for CCPs 13-17 are projected payments based on FCA outcomes, as those periods have not yet been settled. Payments for incomplete periods, CCP 13 through CCP 17, have been estimated as: *FCA Clearing Price* × 1,000 × *Cleared MW* × 12 for each resource.

decrease by 68% from CCP 10 to 14. Lower clearing prices were consistent with lower demand (NICR) and system capacity surplus exceeding 1 GW.

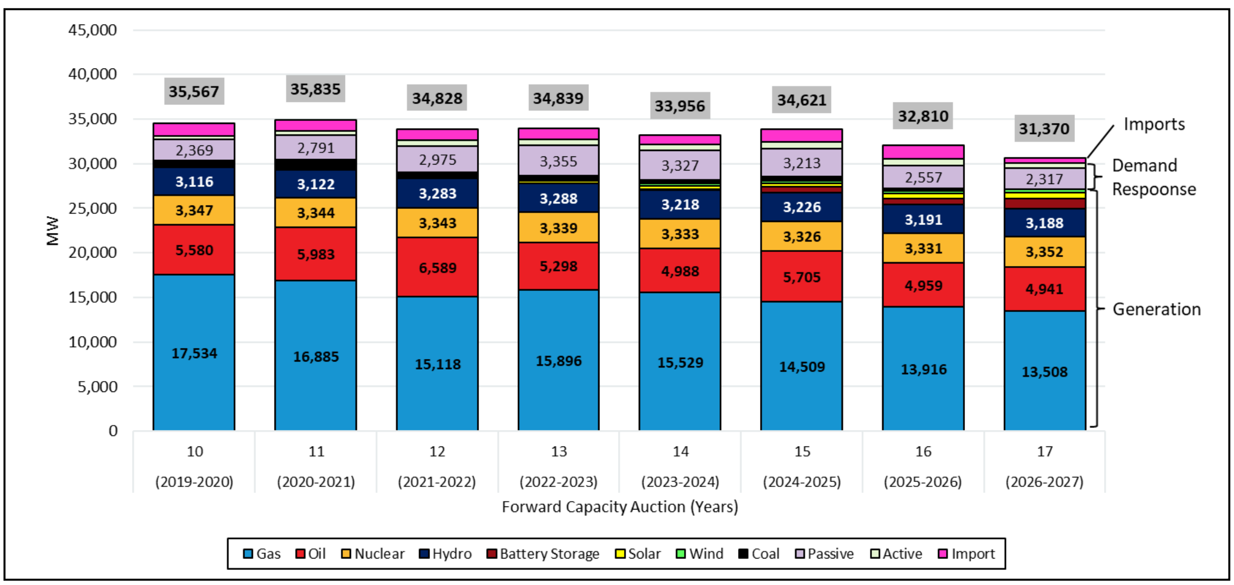
In *FCA 15*, capacity prices and payments rebounded slightly due to an increase in Net ICR and the retirements of major supply resources (Mystic 8 and 9). Higher zonal and RoP clearing prices in FCA 15 increased projected payments to $1.3 billion. In *FCAs 16 and 17*, projected payments declined with lower clearing prices and capacity; total payments for CCP 16 and 17 are projected to be $1.0 billion and $0.9 billion, respectively – among the lowest in the FCM's history.

Charges – or reductions in base FCM payments – are grouped together and have been negligible in the context of annual payments (green bar is not visible). Failure-to-Cover charges have affected a small portion of FCM payments since implementation in 2019, with resources only charged a maximum of about $1.0 million to date. Pay-for Performance (PFP) are essentially a transfer from under-performing capacity resources (charges) to over-performing resources (credits) and are expected to net to zero. PFP outcomes are covered in Section 6.2.2.

6.2.1 Capacity Resource Mix

This section discusses trends and major changes in cleared capacity since FCA 10, including a review of major retirements and new entry driving changes to capacity supply. There are three categories of capacity resources that can participate in the FCM: generation, demand response and import resources. The share of these categories in the context of total capacity (gray box), with generation broken down by fuel type ,and demand response by passive (primarily energy efficiency) and active (price-responsive) resources is illustrated in Figure 6-6.

Figure 6-6: Capacity Mix by Fuel Type



Since FCA 10, total cleared capacity has trended down and has followed the downward trend in Net ICR. Despite the decrease in cleared capacity, the auctions have maintained surplus cleared capacity of at least 1 GW (~4% on average) above NICR in each of the past eight auctions.

Gas-fired generation capacity has also trended downwards, driven by large generator retirements and terminations.[286] Material reductions include the termination of Burrillville Energy Center (485 MW in FCA 12)[287], retirement of Mystic 8 and 9 (1,413 MW in FCA 15), and termination of Killingly Energy Center (632 MW in FCA 16)[288], together accounting for over 2.5 GW.

Other notable changes were to passive demand resources, solar generation, and battery storage projects. Between FCAs 9 and 13, capacity from *passive demand* sharply increased, reaching a peak of 3,355 MW, in line with significant utility investment supported by state policy goals to increase energy efficiency. Since FCA 13, however, passive demand capacity has decreased down to 2,317 MW as existing capacity has amortized over time.[289]

Solar capacity has jumped from 20 MW in FCA 9 to 710 MW in FCA 17. More efficient solar technology has reduced project costs and the renewable technology resource exemption helped solar projects enter the capacity market.[290] *Battery storage* projects are a significant new entrant to New England's capacity market. FCA 17 added 400 MW of new battery storage capacity to the existing 700 MW. Since being introduced to the market in FCA 13, battery storage projects have increased their share of capacity from 5 MW to 1,100 MW. The total share of cleared capacity for solar and battery storage resources reached 6% in FCA 17. *Wind* capacity comprises just 1% of the FCM (~360 MW), but has increased by 227 MW since FCA 10.

Retirement of Capacity Resources

Resources can submit retirement bids in the FCA to fully exit both the capacity and the energy markets. Major retired generating resources, defined here as capacity exceeding 50 MW, from FCA 10 through FCA 17 are shown in Table 6-1 below.

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[286] Terminated resources clear capacity in previous FCAs but have their capacity revoked from FCAs following termination.

[287] In September 2018, ISO-NE filed to terminate the 485 MW CSO of the Burrillville Energy Center, which was accepted by the Commission. Per the filing, the project sponsor had not made sufficient progress to achieve Clear River Unit 1's critical path schedule milestones. With the insufficient progress, the commercial operation date for Clear River Unit 1 was more than two years beyond June 1, 2019, which is the start of the Capacity Commitment Period in which the resource first obtained a CSO.

[288] In November 2021, ISO-NE filed to terminate the 632 MW CSO of Killingly Energy Center, which was accepted and upheld by the Commission. Per the filing, the project sponsor had not made sufficient progress to achieve Killingly Energy Center's critical path schedule milestones. With the insufficient progress, the commercial operation date for Killingly Energy Center was more than two years beyond June 1, 2022, which is the start of the Capacity Commitment Period in which the resource first obtained a CSO.

[289] Energy efficiency assets are modelled with a Measure Life, or expected length of performance. The qualified capacity of a passive demand resource, most commonly an aggregation of energy efficiency assets, will decrease over time as individual assets reach their Measure Life.

[290] The renewable technology resource (RTR) exemption allowed a set MW of state-sponsored renewable resources into the FCM without being subjected to buyer-side mitigation rules. In almost all cases, buyer-side mitigation rules denied state-sponsored resources entry into the primary FCA.

Table 6-1: Generating Resource Retirements over 50 MW

FCA # (Commitment Period)	Resource Name	Fuel Type	Capacity Zone	FCA MW
FCA 10 (2019/20)	**Pilgrim Nuclear**	**Nuclear**	**SEMA**	**677**
FCA 12 (2021/22)	**Bridgeport Harbor 3**	**Oil**	**Connecticut**	**383**
FCA 13 (2022/23)	**Mystic 7**	**Oil**	**NEMA/Boston**	**575**
FCA 14 (2023/24)	Yarmouth 1	Oil	Maine	50
FCA 14 (2023/24)	Yarmouth 2	Oil	Maine	51
FCA 14 Total (resources > 50 MW)				**101 MW**
FCA 15 (2024/25)	Mystic 9	Gas	NEMA/Boston	710
FCA 15 (2024/25)	Mystic 8	Gas	NEMA/Boston	703
FCA 15 (2024/25)	West Springfield 3	Gas	WCMA	95
FCA 15 (2024/25)	CDECCA	Gas	Connecticut	52
FCA 15 Total (resources > 50 MW)				**1,560 MW**
FCA 16 (2025/26)	**Potter 2 CC**	**Gas**	**SEMA**	**72**
Total Major Retirements since FCA 10				**3,368 MW**

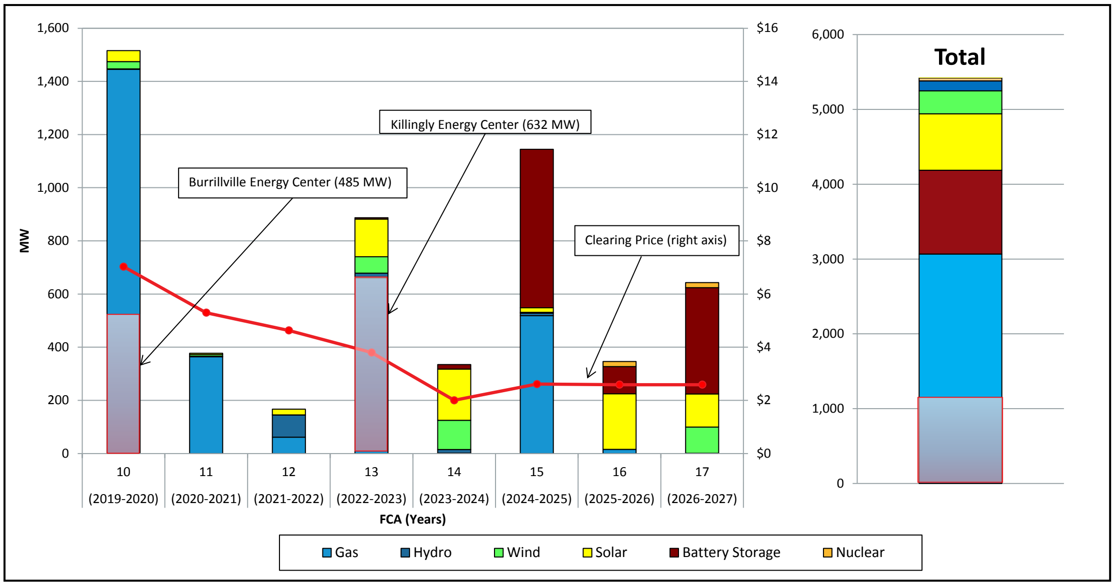
Energy policy and market dynamics have been cited as reasons leading to increased retirement pressure on nuclear, coal- and oil-fired generators. Increasing emissions prices and environmental regulations have led to increased production and capital costs. Many of the retiring resources are older resources that may require environmental upgrades or major overhauls.

FCAs 15 and 16 saw the first large retirements of older natural gas-fired generators as the market shifted toward more efficient gas technology and brought in large volumes of renewable projects. There were no retirements over 50 MW in FCA 17 despite continued low capacity prices.

New Entry of Generation Capacity Resources

There has been a significant amount of new entry generation capacity over the past eight auctions, totaling about 5.4 GW (averaging over 680 MW per auction). New generation capacity by fuel type since FCA 10 is shown in Figure 6-7. The shaded red bars indicate gas capacity that was ultimately terminated due to not realizing commercial operation.

Figure 6-7: New Generation Capacity by Fuel Type



Natural gas-fired resources comprised the majority of new additions between *FCA 10 and FCA 13*, totaling ~2,530 MW. However, over 1,100 MW of the new additions were ultimately terminated as the Burrillville Energy Center and Killingly Energy Center failed to meet key development milestones. *FCA 10* saw the largest amount of new delivered generation entry, with an additional 960 MW of new natural gas-fired capacity including Bridgeport Harbor 5 (484 MW) and Canal 3 (333 MW). In *FCA 14*, no new, large gas-fired resources cleared in the auction. Instead, an increase in state-sponsored solar resources and new wind resources were the primary sources of new cleared generation.

In *FCA 15*, new gas-fired capacity entered the market again, driven by a 334 MW repowering of the existing Ocean State Power facility. Battery storage projects also cleared a significant amount (596 MW) of new capacity for the first time in an FCA.

In the past two auctions, new entry has largely comprised state sponsored policy resources. *In FCA 16*, battery storage projects continued to enter (but only 100 MW), while the largest increase came from new solar projects (208 MW).

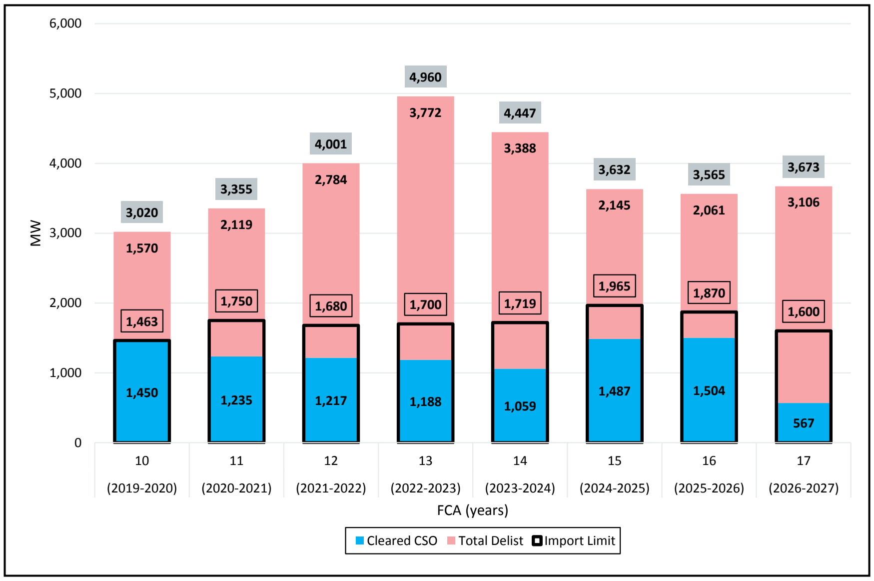
In *FCA 17*, battery storage projects made up the largest share of new capacity (400 MW). Solar and wind cleared 120 MW and 100 MW of new capacity, respectively. A decreased minimum offer price for battery storage projects and the reintroduction of the renewable technology resource exemption facilitated the entry of new renewable capacity.

Exit of Import Capacity Resources

From FCA 10-16, the volume of cleared import capacity has fluctuated from between 1,000 MW to 1,500 MW across the four external ties in the FCM, with most capacity at the New York AC lines (50%) and Phase II (30%). However, cleared import capacity was down significantly in the most recent auction, FCA 17, at just 567 MW comprising 390 MW at New York and 177 MW at New Brunswick. This section reviews changes in cleared import capacity.

Import resources using existing tie line capacity are deemed "new capacity" in the market rules. However, for the purpose of this review, and indeed for a market power mitigation perspective, import resources are similar to existing capacity resources. We therefore view these resources as essentially de-listing capacity when they exit the market. Cleared CSO MW and de-list MW totals from import capacity resources from FCA 10–17 are shown in Figure 6-8 below. The import limit represents the maximum amount of import capacity that can clear over New England's external interfaces in each FCA.

Figure 6-8: FCA Import De-list MW



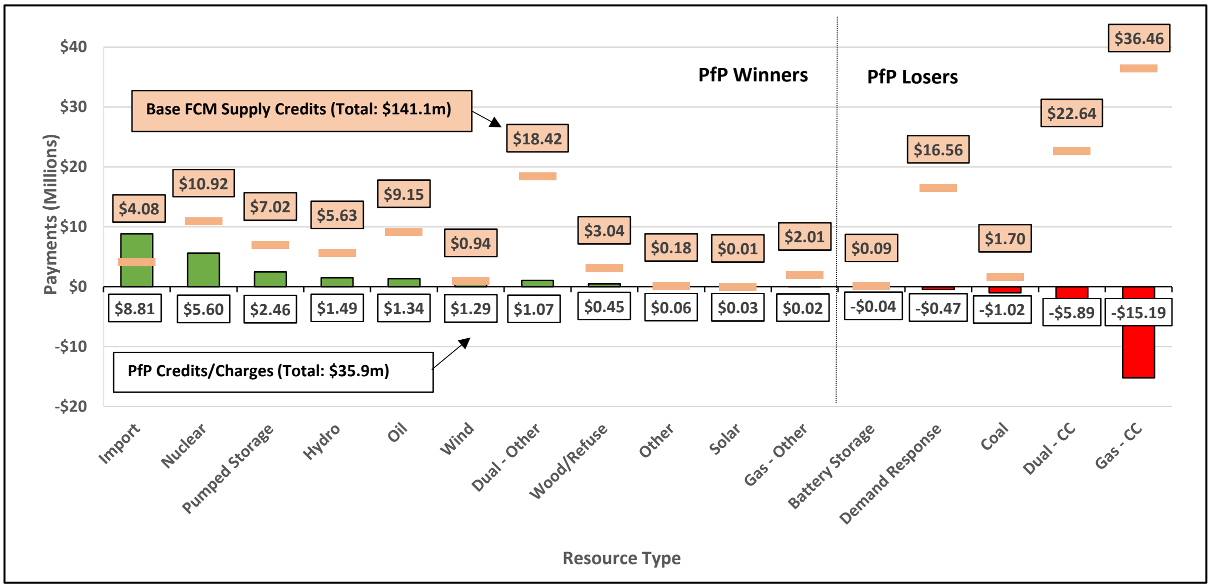
From FCA 10 – 16, import resources de-listed an average of 2,549 MW, or 65% of their qualified capacity. A key factor driving import resource behavior is the expected price they can receive in their neighboring control areas ("the next best alternative"). For example, if there is a higher likelihood that New York capacity prices will be higher, one would expect less capacity to clear across New York North. In FCA 17, we observed the largest percentage of import capacity de-listing (85%). Despite an import limit of 1,600 MW, import resources cleared the lowest amount of CSO over the reporting period at just 567 MW.

6.2.2 Pay-for-Performance Outcomes

One Pay-for-Performance (PfP) event occurred in 2022, the first since September 2018 and only the second event since the rules were introduced in June 2018. On December 24, from 4:40 PM to 6:00 PM (17 five-minute intervals), system-wide energy supply failed to meet customer load plus the 30-minute reserve requirement, triggering a capacity scarcity condition. That day, Winter Storm Elliot brought in lower-than-expected temperatures and influenced sudden, unexpected generator outages. The supply-side disruptions pushed New England's grid into its first PfP event since 2018.

During the scarcity condition, only 19,995 MW of the contracted 30,114 CSO MW provided energy and reserves to New England. The average load and reserve requirement for the scarcity condition was 20,283 MW, resulting in a balancing ratio of 67% - meaning that capacity resources were financially obligated to provide two-thirds of their CSO position in the form of energy or reserves. Under-performance resulted in $35.9 million in charges, which were transferred to over-performing resources. Resource performance by PfP charges and credit are aggregated by fuel type, and ranked, in Figure 6-9.[291]

Figure 6-9: Total PfP Payments by Resource Type (December 2022)



Import resources were the best-performing resource type, with over $6.5 million (74%) of their total $8.81 million in payments going to import transactions without an associated CSO. Following import resources, *nuclear resources* received the second highest net payment; these generators operate as baseload resources at their full CSO MW during all hours and typically over-perform relative to their CSO. Both import resources and nuclear resources were two of the three best performing resource groups during the 2018 PfP event as well.

Gas- and gas/oil-fired resources were the worst performers. While cold weather led to forced outages for some of the gas fleet, the leading cause of gas resource under-performance was high gas prices. Spot natural gas prices climbed to over $30/MMBtu, resulting in gas generation pushed out of economic merit order and, instead, relatively cheaper oil generation was scheduled in the day-ahead energy market.[292] Once system conditions tightened in real time and system-wide LMPs increased significantly, operating limitations prevented many gas-fired resources from coming online in time to contribute to meeting the load and reserve requirement.

6.2.3 Secondary Forward Capacity Market Results

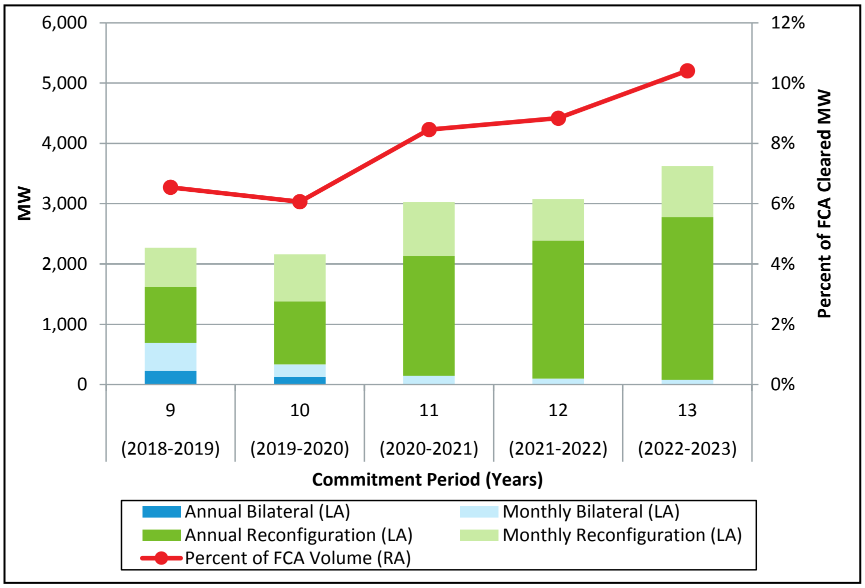
After each FCA and up to just before the commitment period, resources can adjust their CSOs through a variety of reconfiguration auctions in the secondary market. The average annual volume by secondary market products (stacked bars corresponding to the left axis) and volume

[291] In this figure, "Dual" refers to dual-fuel (gas/oil) assets and "CC" refers to combined-cycle assets.

[292] More information on fuel prices in Q4 2022 can be found in Section 1.2.2.

as a percentage of cleared volume in the corresponding FCA (red line corresponding to the right axis) are shown in Figure 6-10 below.[293]

Figure 6-10: Traded Volumes in Reconfiguration Auctions



Historically, traded volumes in the secondary markets have been much lower than in the primary auctions. Since CCP 9, the trade volumes as a percentage of FCA volumes have increased steadily, ranging from 6% in CCP 10 to over 10% in CCP 13. The majority of secondary trading occurs during annual reconfiguration auctions and monthly reconfiguration auctions. CCP 13, beginning in June 2022, saw the largest portion of secondary trading in annual reconfiguration auctions (dark green), reaching almost 2,700 MW.

293 Volumes are shown as average annual weighted values. A monthly product gets a weight of 1/12th; an annual product a weight of 1, etc.

Section 7
Ancillary Services

This section reviews the performance of ancillary services in ISO New England's forward and real-time markets. While there are six main types of ancillary services (listed below), this section focuses on real-time operating reserves, forward reserves, and regulation services.

The six main types of ancillary services are:

- *Real-time operating reserves* represent additional generating capacity that is available to respond to unexpected contingencies (such as the unexpected loss of a generator or transmission line) during operation of the real-time energy market (Section 7.1).
- *Forward reserves* represent the procurement of offline operating reserves in advance of the delivery period; that is, the ability to start and ramp quickly in the event of system contingencies (Section 7.2).
- *Regulation service* is provided by resources that alter their energy output over very short time intervals (minute-to-minute) to balance supply and demand and maintain system frequency levels in the real-time energy market (Section 7.3).
- *The Winter Reliability Program* was implemented by the ISO from 2013 to 2018 to remedy fuel supply issues that threatened reliability. The program paid market participants to purchase sufficient fuel inventories (oil or LNG) or provide additional demand response during the winter months. The program ended after winter 2018.[294]
- *Voltage support* helps the ISO maintain an acceptable range of voltage on the transmission system, and is necessary for the reliable flow of electricity. The ISO regulates voltage through reactive power dispatch, and the generators that provide this service receive voltage support payments.[295]
- *Blackstart service* is provided by generators that are able to start quickly without outside electrical supply. The ISO selects and compensates strategically located generators for providing blackstart service. This service is necessary to facilitate power system restoration in the event of a partial or complete system shutdown.

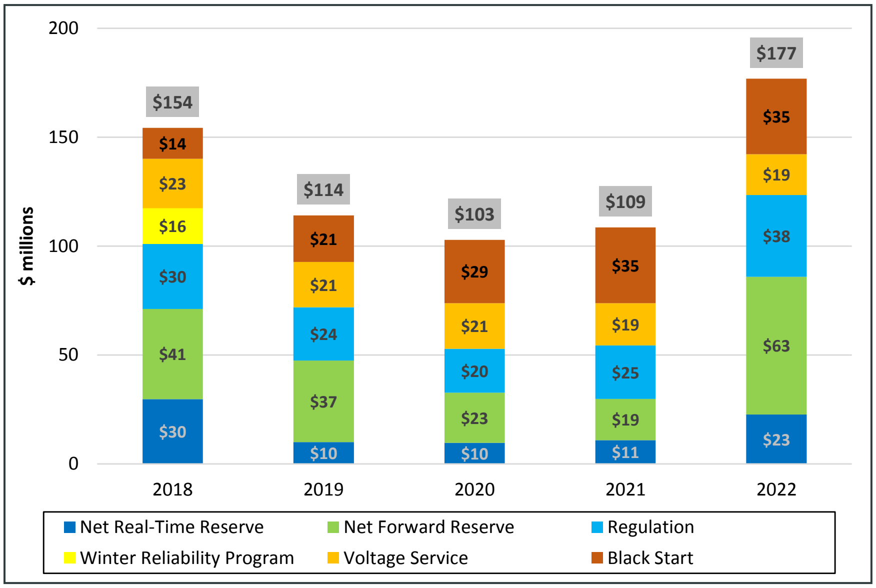
Ancillary service costs by submarket are shown in Figure 7-1 below.[296] The gray boxes above each bar show the total ancillary service cost for each year.

[294] A similar out of market program known as known as Interim Compensation Treatment (ICT) is scheduled to be implemented for Winters 2023/24 and 2024/25.

[295] Transmission customers who use regional network service or through-or-out service incur voltage support charges. If the ISO commits a resource for voltage support in the energy market and it does not recover its effective offer, the resource is eligible for NCPC. The ISO Tariff contains detailed rules regarding compensation for voltage support. See Schedule 2 of Section II: Open Access Transmission Tariff (the OATT), available at: https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf

[296] The Voltage Service category includes payments for capacity costs, lost opportunity costs, costs of energy consumed, and costs of energy produced.

Figure 7-1: Ancillary Service Costs by Product



Overall, ancillary costs in 2022 were the highest over the last five years, totaling $177 million, an increase of over 60%, or $68 million, on 2021 ($109 million). The largest increase was in forward reserve costs, which rose by $44.2 million due to increased supply offer pricing by participants with resources capable of providing ten-minute non-spinning reserves. Regulation and net real-time reserve costs rose by $13.0 and $11.8 million, respectively, primarily due to higher energy prices. Blackstart and voltage service costs were similar to 2021 costs. The only year with Winter Reliability Program payments was 2018, since the program expired in March 2018.

7.1 Real-Time Operating Reserves

The following section reviews real-time operating reserve products and outcomes. The first subsection (7.1.1) summarizes the level of real-time reserve payments and explores the impact that fast-start pricing (FSP).[297] The second subsection (7.1.2) explores the frequency and magnitude of real-time reserve prices, including the frequency of reserve constraint penalty pricing.

[297] Fast-start pricing (FSP) was implemented in March 2017 to improve price formation and performance incentives in the real-time energy market. See Section 5.5 of our Summer 2017 Quarterly Markets report for detail on fast-start pricing: https://www.iso-ne.com/static-assets/documents/2017/12/2017-summer-quarterly-markets-report.pdf

Key Takeaways

During 2022, extreme weather events in summer and winter led to higher total reserve payments and prices, particularly for ten and thirty-minute non-spinning reserves (TMNSR and TMOR). Offline reserve payments totaled $8.4 million, compared to $3.7 million in 2021. Nearly 70% of the non-spinning reserve payments occurred during the extreme weather events in summer and winter.

While the frequency of spinning reserves (TMSR) declined in 2022 due to lower requirements, payments increased due to higher energy prices; non-zero TMSR prices increased by 88%.

For the first time since 2018, the reserve constraint penalty factors (RCPFs) for non-spinning reserve products bound and there was a deficit of reserves. This occurred due to supply issues on December 24, and led to capacity scarcity conditions during 17 five-minute intervals (almost 1.5 hours).

7.1.1 Real-Time Operating Reserve Payments

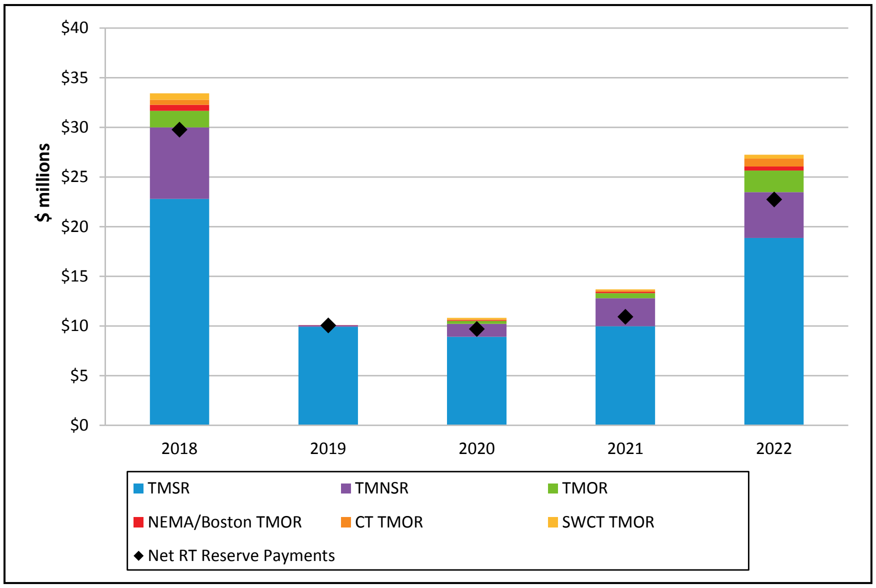
The ISO maintains system-wide and local real-time operating reserves to respond to unexpected losses. There are three products for the system: ten-minute spinning reserves (TMSR), ten-minute non-spinning reserves (TMNSR), and thirty-minute operating reserves (TMOR). Local reserve zones only have TMOR.

Real-time operating reserve payment totals may change significantly on a percentage basis from year to year because of changes in operating reserve requirements, fuel costs, and system conditions. However, total payments are relatively small compared to overall energy market and capacity market payments.

The payments presented in Figure 7-2 below are a measure of the value of real-time reserves. The height of each bar represents the payments by system and local reserve products, with each reflecting the product of total real-time reserve designations and market clearing prices. The black diamond shows total net real-time reserve payments.[298]

[298] The diamond will be lower than the height of the bars when real-time payments are removed to ensure resources paid in the forward reserve market are not paid again in the real-time reserve market.

Figure 7-2: Real-Time Reserve Payments



Total gross real-time reserve payments in 2022 totaled $27.3 million, approximately 0.2% of total wholesale market costs. Reserve payments doubled (up by $13.6 million) compared to 2021 ($13.7 million). Real-time payments were reduced by $4.5 million, for resources holding a forward reserve market obligation resulting in net reserve payments of $22.7 million (or 108% higher than in 2021).[299]

An increase in extreme weather events in summer and winter led to more non-zero non-spinning reserve frequency and higher re-dispatch costs in the co-optimization process, resulting in higher reserve clearing prices. Specifically, during twelve days in summer and one day in winter, gross reserve payments were $15.0 million, or 55% of total payments.[300]

Due to increased reserve prices, *spinning* reserve (TMSR) payments increased by almost 90% (by $8.9 million) compared to 2021 ($10.0 million). Payments increased despite a lower frequency (down by 12%) of non-zero TMSR pricing intervals.[301] Payments for *non-spinning* reserves increased due to the tight system conditions during the system events in summer and winter. TMNSR ($4.6 million) and TMOR ($3.8 million) payments increased by 62% and 329% year-over-year, respectively; 70% of the payments were accrued during the system event days in July, August, and December.

Impact of Fast-Start Pricing on Operating Reserve Payments

An objective of the fast-start pricing (FSP) rules is to better reflect the short-term operating cost of fast-start generators in real-time market pricing.[302] On average, FSP has increased the price of energy. Consequently, the opportunity costs to provide reserves has increased as well, resulting

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299 Section 2.6.1 discusses FRM payments. For reference, net FRM payments in 2022 were roughly $63.2 million.

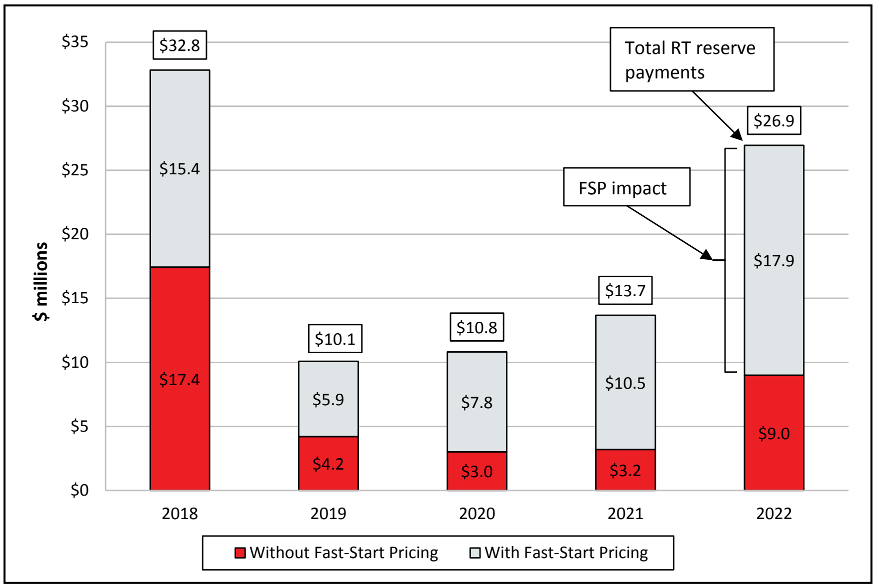
300 See Section 3.2.7 for more information on these system events.

301 Section 7.1 explains the decline in TMSR pricing frequency.

302 The impact of fast-starting pricing on real-time energy prices is discussed in Section 3.1.2.

in higher reserve prices. Figure 7-3 below shows the impact of fast-start pricing on real-time reserve payments over the past five years.[303]

Figure 7-3: Impact of Fast-Start on Reserve Payments



Without fast-start pricing, real-time reserve payments would have been approximately $9.0 million in 2022, compared to the actual amount of $26.9 million.[304] Fast-start pricing has had a significant impact on real-time reserve payments, increasing payments by over 60% ($57 million) between 2018 and 2022. A detailed assessment of the impact of fast-start pricing in provided in Section 3.1.2 of this report.

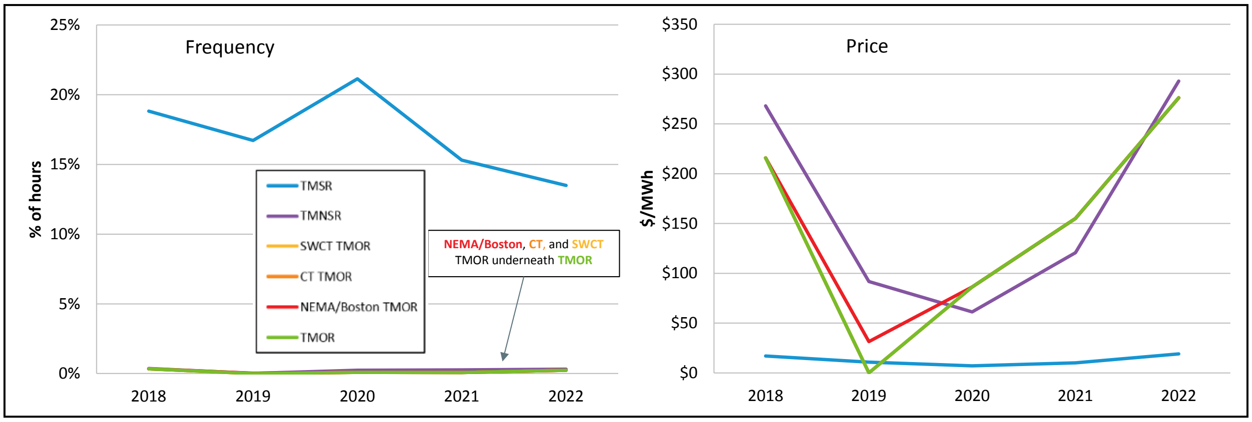
7.1.2 Real-Time Operating Reserve Prices and Frequency

Average reserve prices are a function of two factors: frequency and magnitude. *Frequency* represents the number of intervals with non-zero reserve pricing. *Magnitude* is the average real-time reserve price for all non-zero five-minute pricing intervals. Figure 7-4 below shows both the frequency (left panel) and magnitude (right panel) of non-zero reserve prices by reserve product.

[303] We approximate the impact of fast-start pricing by comparing prices from the dispatch and pricing software solutions. The dispatch solution acts as a proxy for pricing outcomes prior to fast-start pricing rules.

[304] The total payments ($26.9 million) are an approximation using the dispatch and pricing software solutions. These values differ from the settlement payments ($27.3 million) discussed above due processes in-between the pricing run and settlement outcome.

Figure 7-4: Frequency and Average of Non-Zero Reserve Prices

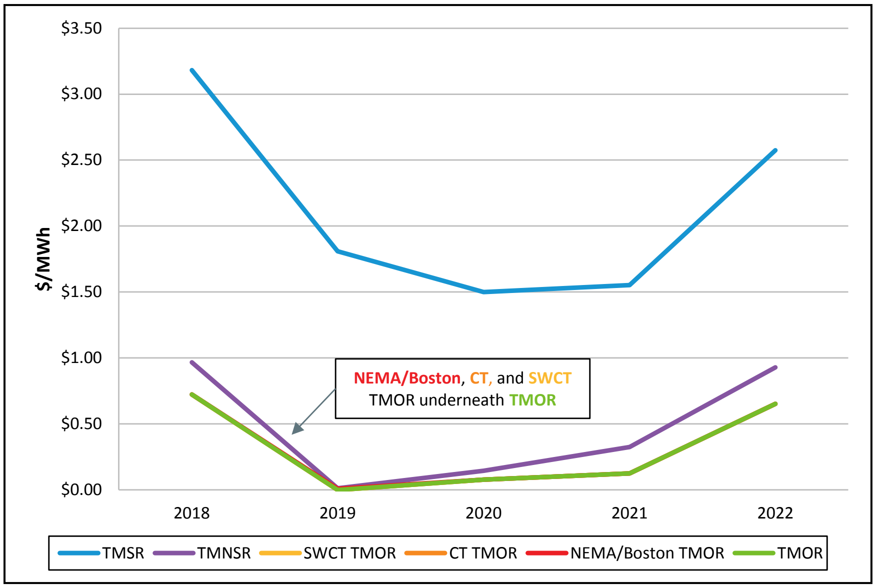


In 2022, TMSR pricing was non-zero for 13% of all intervals, down from 15% in 2021 (left-panel). Therefore, in 87% of intervals no resource had an opportunity cost to provide reserves (i.e., prices were $0/MWh). From 2021 to 2022, the average TMSR margin increased due to lower TMSR requirements during the second half of 2022, which was discussed in Section 1.2.1. TMSR prices averaged $19.09/MWh in non-zero pricing intervals, an increase from $10.15/MWh in 2021 (right panel). The higher non-zero TMSR price was driven by higher fuel prices, energy prices, and tight system conditions.

The frequency of the non-spinning products (TMNSR and TMOR) pricing was below 0.6% in all intervals for 2021 and 2022. There were only 28 hours of TMNSR and 21 hours of TMOR in 2022, compared to 24 and 7 hours, respectively in 2021. The system events in 2022 had a positive impact on reserve prices, and a muted impact on reserve frequency. Similar to average TMSR prices, average TMNSR and TMOR prices increased year-over-year. Additionally, in 2022 there were more instances when reserve costs were capped at their Reserve Constraint Penalty Factors (RCPFs). In 2022, there was no *local* TMOR pricing.

We can evaluate the impact of reserve *frequency* and *magnitude* by looking at real-time reserve prices for all pricing intervals in Figure 7-5 below.

Figure 7-5: Average Real-Time Reserve Prices for all Pricing Intervals

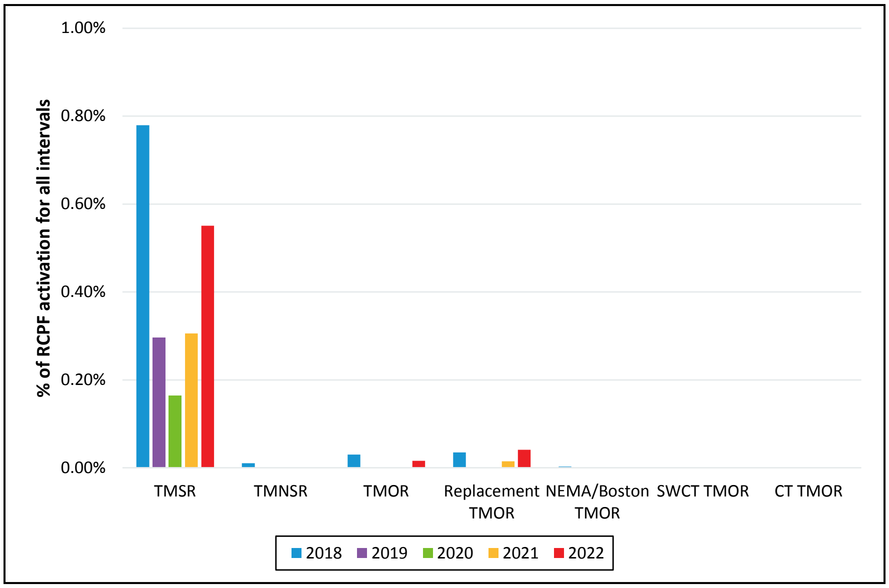


The increase in average prices across all hours for all reserve products drove the 108% year-over-year increase in reserve payments. Average TMSR prices during all pricing intervals (i.e., zero- and non-zero pricing intervals) increased by 66%, from $1.55/MWh in 2021 to $2.57/MWh in 2022. The increase in the magnitude of non-zero prices (88%) was partially offset by the decrease in the frequency (12%). In addition, as non-spinning reserve prices are included in the price of TMSR, the increase in TMSR prices reflects increases in both TMOR and TMNSR prices.

Reserve Constraint Penalty Factors (RCPFs)

RCPFs for reserve products are triggered due to either a shortage of available capacity to meet the reserve requirements or re-dispatch costs that exceed RCPF values. The percentage of five-minute intervals during which the RCPFs were triggered for each reserve constraint are shown in Figure 7-6 below.

Figure 7-6: Reserve Constraint Penalty Factor Activation Frequency



Overall, the low level of reserve scarcity is consistent with high reserve margins in recent years. In 2022, the RCPF for TMSR bound 0.6% of total intervals, or roughly two days of the year. The TMSR RCPF bound most frequently due to its relatively low RCPF value ($50/MWh). The replacement TMOR RCPF, which has a lower penalty factor than TMOR ($250/MWh vs $1,000/MWh) bound in 43 five-minute intervals (0.02% of total intervals or ~ 3.5 hours).

During the December 24 system event, which was caused by unexpected outages and reduced imports that led to tight system conditions, there were 17 intervals (85 minutes) where the minimum TMOR RCPF ($1,000/MWh) bound and one interval where the TMNSR RCPF ($1,500/MWh) bound. There were 17 capacity scarcity condition intervals under the capacity markets pay-for-performance rules, which is discussed further in Section 6.2.

7.2 Forward Reserves

This section assesses outcomes in the forward reserve market (FRM), which procures non-spinning reserve products in advance of summer and winter seasons. Specifically, in this section we review the trends in auction demand quantities over the past five years (7.2.1), auction results (0), and the resulting levels of forward reserve payments, noting the impact that penalties have had on these payments (7.2.3).

Key Takeaways

Over the last few years, the quantities of reserve capacity required in the FRM have been reasonably stable at the system level. Additionally, in the eight most recent auctions (Summer 2019 through Winter 2022-23), there has been no need for a local requirement in any local reserve zone due to transmission improvements.

FRM auction prices for TMOR have generally been below $2,000/MW-month, and in some auctions have been below $1,000/MW-month over the review period. While TMNSR auction prices frequently have been below $2,000/MW-month, the most recent auctions (Summer 2022 and Winter 2022-23) have seen increasing price levels. The Summer 2022 auction, in particular, had TMNSR prices of $7,386/MW-month, reflecting a significant increase in participant offer prices. The IMM reviewed participant offers in the Summer 2022 auction and did not find evidence of the exercise of market power.

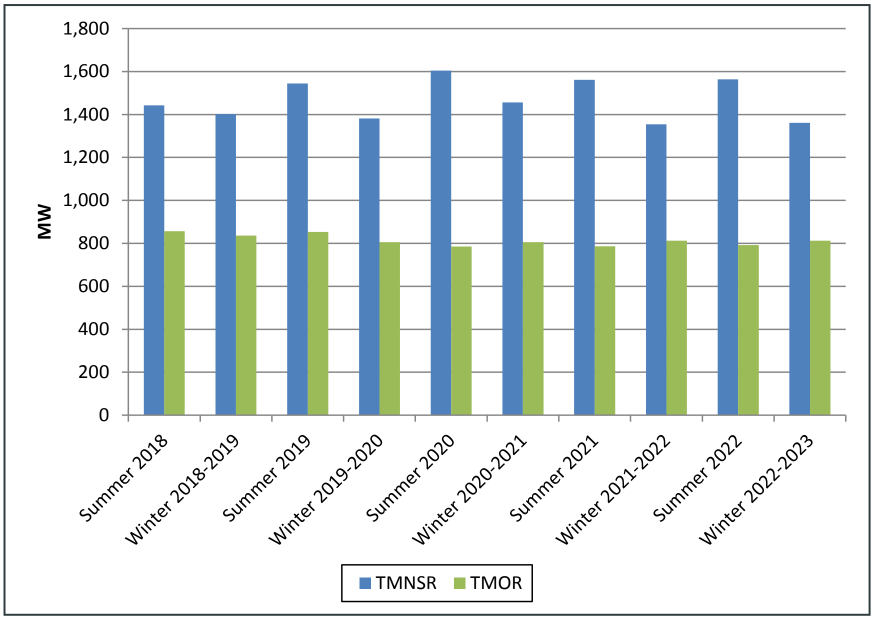
FRM payments significantly exceed real-time operating reserve payments ($63 million vs. $27 million in 2022), reflecting significantly different structures between these forward and spot markets. While FRM payments have declined significantly from 2018 to 2021, increased auction clearing prices for TMNSR in 2022 resulted in a large increase (233%) in FRM payments.

7.2.1 Market Requirements

The FRM auction is intended to ensure that there are adequate reserves to meet ten-minute non-spinning reserve (TMNSR) and thirty-minute operating reserve (TMOR) requirements.[305] The FRM requirements for the New England control area are based on the forecast of the first (TMNSR) and second (TMOR) largest contingency supply losses for each procurement period. The system-wide requirements from Summer 2018 through Winter 2022-23 are shown in Figure 7-7 below.

[305] Reserve requirements represent the minimum quantity of unloaded capacity needed to meet the system's first and second contingencies.

Figure 7-7: Forward Reserve Market System-wide Requirements

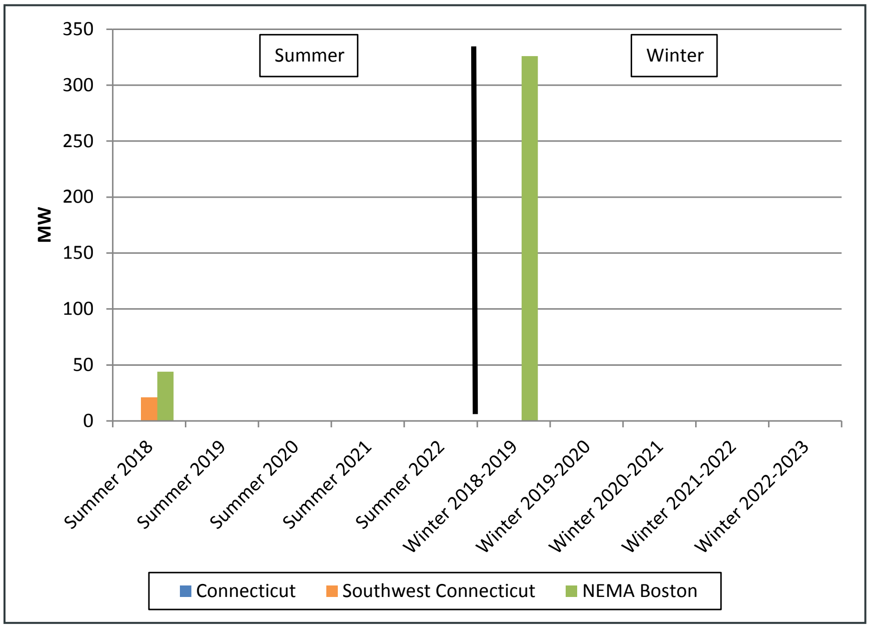


Over the past ten auctions, the TMNSR purchase amount has represented the expected single contingency of the HQ Phase II Interconnection. The TMOR purchase amount has represented the expected single second contingency of either Mystic 8/9 or Seabrook.[306] Therefore, the requirements have been relatively consistent around 1,300-1,600 MW for TMNSR and around 800 MW for TMOR. The reasonably small fluctuations in seasonal requirements reflect seasonal variation in expected capabilities for Phase II and Mystic 8/9 (or Seabrook), and relatively stable expectations for non-spinning reserve needs (affecting TMNSR), generator performance when called upon for system contingencies (affecting TMNSR), and replacement reserve needs (affecting TMOR).

Some zones are constrained in terms of how much power they can import from other zones and so, instead of having a single reserve requirement for each reserve product the entire system, the ISO identifies requirements at a zonal level and at the system level. The aggregate reserve requirements for the past ten auctions for the import-constrained reserve zones of Connecticut, NEMA/Boston, and Southwest Connecticut are shown in Figure 7-8 below. The local 30-minute operating reserve requirement can be met through 10- or 30-minute reserve supply offers in each local reserve zone.

[306] As noted in the ISO's assumptions memoranda for the individual FRM auctions, the FRM system requirements also may be biased up or down and, in the case of TMOR, include a replacement reserve adjustment. See: https://www.iso-ne.com/markets-operations/markets/reserves/?document-type=Forward Reserve Market Assumptions

Figure 7-8: Aggregate Local Forward Reserve (TMOR) Requirements



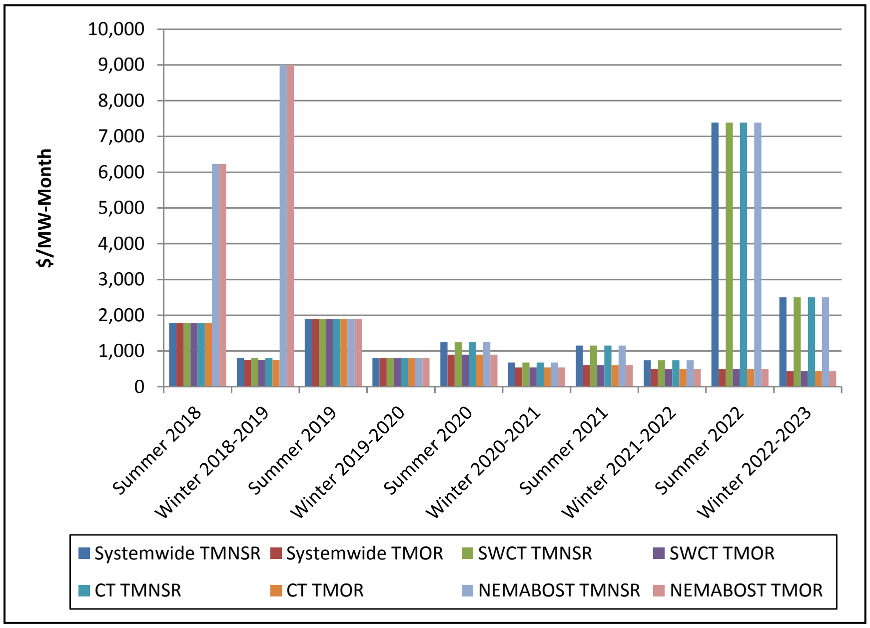
The summer and winter procurement periods have experienced a significant reduction in local FRM requirements. Only NEMA/Boston and Southwest Connecticut needed a local reserve requirement in the 2018 auctions. Since then, external reserve support (ERS) has been sufficient to alleviate the need for local reserve requirements. This results from a considerable increase in ERS for Connecticut and Southwest Connecticut due mainly to transmission upgrades. Similarly, transmission upgrades in NEMA/Boston have increased ERS for that area, resulting in no need for a local requirement in the last four summer and winter periods. The ERS in NEMA/Boston has typically exceeded the local second contingency by more than 1,000 MW in these auctions.[307]

[307] External reserve support (ERS) refers to the ability of a local reserve zone to obtain operating reserves from other reserve zones. The ERS reflects the amount of available transfer capability on the transmission interface for the local reserve zone. See Manual M-36, Forward Reserve and Real-Time Reserve, Section 2.2.

7.2.2 Auction Results

This section covers FRM auction pricing outcomes from the Summer 2018 auction through the Winter 2022-23 auction. The TMNSR and TMOR clearing prices by reserve zone for each auction are shown in Figure 7-9 below.[308]

Figure 7-9: Forward Reserve Prices by FRM Procurement Period



System-wide TMOR pricing was either stable or declining in the Summer and Winter auctions, respectively, throughout the review period. This decline is consistent with lower auction offer prices by participants.[309] TMNSR prices, however, increased in 2022 for both the Summer and Winter auctions; the Summer 2022 auction prices increased dramatically, rising from $1,150/MW-month in Summer 2021 to $7,386/MW-month in Summer 2022. TMNSR prices also increased in the Winter 2022-23 auction relative to the Winter 2021-22 auction prices, rising from $740/MW-month to $2,500/MW-month. The TMNSR prices in 2022 reflect significantly higher offer prices. When reviewing participants' auction offers, the IMM has not found evidence of the exercise of market power.

In NEMA/Boston, limited forward reserve supply resulted in high auction clearing prices for the Summer 2018 and Winter 2018/19 auctions. In fact, there was a shortfall of supply in this zone in the Winter 2018-19 auction, which resulted in the clearing prices for this zone being set at the offer cap. However, a local reserve requirement for NEMA/Boston has not been needed for

[308] Forward reserve auction clearing prices are calculated for each reserve product in each reserve zone. The requirements for the Connecticut reserve zone can be fulfilled by reserve offers for the Southwest Connecticut reserve zone. When supply offers for forward reserve are not adequate to meet a requirement, the clearing price for that product is set to the offer price cap. When enough supply is offered under the price cap to meet the requirement in a particular zone, the auction clearing price for that product is set equal to the price of the marginal supply offer.

[309] In general, a number of factors can affect TMNSR and TMOR clearing prices, including: (1) offer prices for TMNSR and TMOR, (2) the ability to substitute lower-priced TMNSR supply for TMOR supply when there is low-priced TMNSR supply in excess of the TMNSR requirement, and (3) cleared high-priced TMOR supply needed for local requirements that reduces the amount of TMOR supply needed to meet the rest-of-system requirement, among other factors.

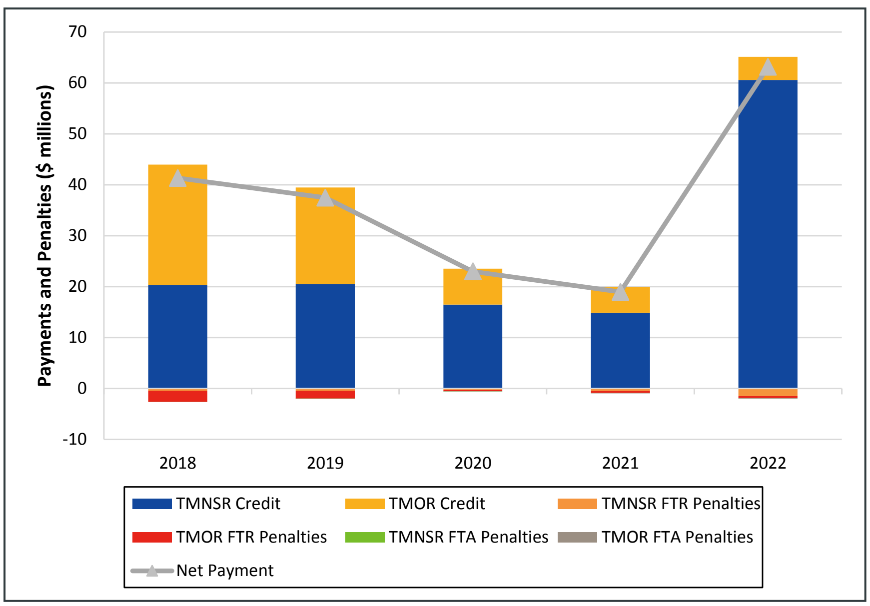
the eight most recent auctions (occurring in 2019 to 2022), as external reserve support has supplanted that need.

7.2.3 FRM Payments

FRM payments are based on auction obligations, auction clearing prices, and the actual delivery of the obligation in the real-time energy market.[310] Participants obtain FRM obligations by participating in forward reserve auctions or by obtaining an obligation from another participant that has an auction-based obligation.[311,312] Participants must convert their obligations into the physical delivery of operating reserve capacity by assigning obligations to resources for the real-time energy market. When a participant's assignments to resources are less than the participant's FRM obligation, it results in failure-to-reserve penalties. Additionally, participants can incur failure-to-activate penalties when a resource that has been assigned an FRM obligation fails to provide energy (when called upon by the ISO).

Annual FRM payment and penalty data over the past five years are provided in Figure 7-10 below. The chart indicates the annual auction-based payments as positive stacked bar values and penalties as negative stacked bar values; the line graph indicates annual payments net of total penalties.[313]

Figure 7-10: FRM Payments and Penalties by Year



[310] See Manual M-36, Forward Reserve and Real-Time Reserve, Section 6.

[311] Hourly FRM obligations may be transferred by participants on a daily basis up to two days after the delivery period. These transfers take place through "internal bilateral transactions" that allow the ISO to determine whether the holder of the obligation delivered the physical capacity needed to back the obligation in the real-time energy market. See ISO Manual M-36, Forward Reserve and Real-Time Reserve, Section 3.1.2.

[312] FRM auction obligations are specific to participants and are not specific to resources.

[313] "FTR" refers to failure-to-reserve and "FTA" refers to failure-to-activate.

Net forward reserve payments increased significantly in 2022 due to the much higher TMNSR auction clearing prices discussed previously. Prior to 2022, net forward reserve payments declined from 2018 through 2021. The decline primarily reflects a reduction in TMOR clearing prices in 2020 and 2021.[314]

Penalties have been low relative to gross payments and have been stable in the 2% to 8% range of total payments over the period. These penalties have been predominately for failing to reserve (97%). Since failure-to-reserve penalties result in forfeiture of auction-based payments for unassigned obligations, the payments are directly influenced by FRM clearing prices. Total penalties declined prior to 2022 (in part because FRM clearing prices declined), but increased by 118% to $1.9 million in 2022 (when FRM clearing prices significantly increased). Total penalties in 2022 represented just 3% of gross FRM payments.

[314] Summer TMOR auction prices fell by 53% (or $999/MW-month) in 2020 (relative to summer 2019), and fell by additional 33% in the Summer 2021 auction. A 32% decline in TMOR auction prices for Winter 2020-21 (compared to Winter 2019-20) added to the reduced payments in 2020 and 2021.

7.3 Regulation

This section examines the participation, outcomes, and competitiveness of the regulation market in 2022. Specifically, we review regulation clearing prices (7.3.1), payments (7.3.2) and the amount of regulation capability needed by the ISO (7.3.3).

Key Takeaways

The regulation market produces two clearing prices, for capacity and service. Clearing prices for capacity, which makes up about 90% of the overall market value, increased from $19.23/MWh in 2021 to $30.96/MWh in 2022 (a 61% change), reflecting a rise in energy market opportunity costs. Regulation service prices increased modestly from $0.21/mile in 2021 to $0.27/mile in 2022.

Regulation payments increased by 52% in 2022, primarily reflecting the increase in capacity prices; 2021 payments were $25.3 million compared to $38.4 million in 2022.

Regulation requirements in 2022 were relatively steady compared to 2021, needing just over 90 MW of regulation capacity per hour, on average. The resource mix of committed regulation capacity has changed significantly over the review period. In 2018, alternative regulation resources (such as batteries) accounted for 10% of committed capacity; by 2020, such resources accounted for 25%, and by 2022, these resources accounted for 50%.

7.3.1 Regulation Prices

Regulation Clearing Prices (RCP) are calculated in real-time and are based on the regulation offer of the highest-priced generator providing the service. There are two types of regulation clearing prices: "service" and "capacity."[315] Clearing prices for the past five years are shown in Table 7-1 below.[316]

[315] The service price represents the direct cost of providing the regulation service (also known as regulation "mileage"). Mileage represents the up and down movement of generators providing regulation and is measured as the absolute MW variation in output per hour. These direct costs may include increased operating and maintenance costs, as well as incremental fuel costs resulting from the generator operating less efficiently when providing regulation service. The capacity price may represent several types of costs, including: (1) the expected value of lost energy market opportunities when providing regulation service,[315] (2) the value of intertemporal opportunities that would be lost from providing regulation, (3) elements of fixed costs such as incremental maintenance to ensure a generator's continued performance when providing regulation, and (4) fuel market or other risks associated with providing regulation.

[316] The prices in the table are simple average prices for each year.

Table 7-1: Regulation Prices

Year	Regulation Service Clearing Price ($/Mile)			Regulation Capacity Clearing Price ($/MW per Hour)		
	Min	Avg	Max	Min	Avg	Max
2018	0.00	0.25	10.00	0.00	28.30	2,331.55
2019	0.00	0.28	10.00	0.75	21.96	258.67
2020	0.00	0.21	10.00	0.40	16.12	396.08
2021	0.00	0.21	10.00	0.00	19.23	699.11
2022	0.00	0.27	10.00	0.00	30.96	1,068.09

Regulation capacity prices increased by 61% in 2022, reflecting an increase in the "opportunity cost" and "incremental cost saving" components of regulation capacity pricing. The opportunity cost component of the regulation price indicates the expected value of foregone energy market opportunities, when providing regulation. The increase in opportunity costs is consistent with a significant increase in real-time energy market LMPs, which rose by 89% in 2022 compared to 2021. The increase in incremental cost savings is affected by other regulation offer components, and reflects the cost difference between the marginal offer and the next most expensive offer.

Regulation service prices also increased compared to 2021. In 2022, the average service price was $0.27/mile, up $0.06/mile compared to the prior year. Mileage payments represent a small share of overall regulation payments (13% or $5.1 million in 2022).

Between 2018 and 2021, regulation capacity prices declined and then increased (decreasing by 19% in 2019, decreasing by 22% in 2020 and increasing by 19% in 2021). In each instance, the variation in capacity prices was strongly influenced by variation in the "opportunity cost" component of regulation capacity pricing; regulation opportunity costs reflected declining real-time energy market LMPs between 2018 and 2020 and increasing energy market LMPs in 2021.

7.3.2 Regulation Payments

Compensation to generators providing regulation includes a regulation capacity payment, a service payment, a make-whole payment, and an operating reserve adjustment.[317] Annual regulation payments over the past five years are shown in Figure 7-11 below.[318]

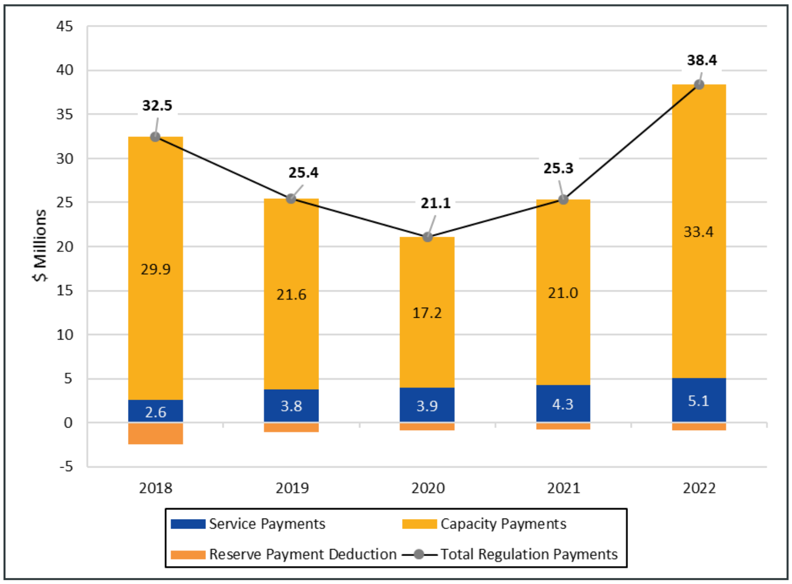
The reserve payment deduction is shown as a negative value in the exhibit; the positive values represent total payments (prior to reserve payment deductions) for the regulation capacity and service (mileage) provided by regulation resources during the period. The make-whole

[317] The operating reserve adjustment represents a deduction to regulation payments. Under certain circumstances, part of a regulation resource's regulating range may overlap with the resource's operating reserve range. Since generators do not actually provide operating reserves within the regulating range, reserve compensation needs to be deducted from the resource's market compensation. The reserve payment deduction represents the MW quantity overlap of the regulating range and operating reserve range, multiplied by the operating reserve price.

[318] In the figure, capacity payments include regulation uplift payments. Regulation uplift is provided when opportunity cost estimates included in regulation capacity prices are insufficient to cover actual energy market opportunity costs incurred by regulation resources.

payment is included in capacity payment totals, since it represents an uplift payment when the capacity payments do not fully compensate resources for energy market opportunity costs.

Figure 7-11: Regulation Payments



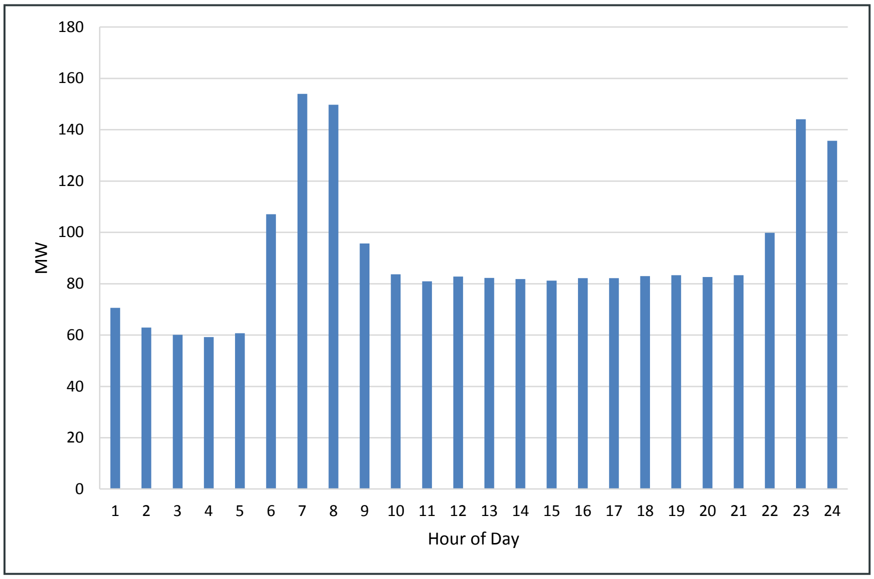
Payments to regulation resources totaled $38.4 million in 2022, 52% more than the $25.3 million in 2021 (these totals exclude the reserve payment adjustment). The increase in 2022 payments resulted primarily from a 59% increase in capacity payments; this increase in capacity payments is consistent with the above-noted increase in capacity prices (61%). A modest increase in regulation service prices and payments ($0.8 million increase in service payments) in 2022 also contributed to the overall increase in regulation payments.

In the earlier years (2018-2021), capacity payments constituted 81% to 92% of overall regulation payments. Year-to-year variation in regulation payments, consequently, resulted primarily from variation in capacity prices and associated payments. As noted in the preceding section, capacity prices are significantly influenced by energy market opportunity costs and tend to follow increases and decreases in real-time energy market LMPs.

7.3.3 Regulation Requirements, Resource Mix, and Performance

The regulation *requirement* in New England varies throughout the day and is typically highest in the morning and the late evening. The higher regulation requirement during these hours is the result of greater load variability (load ramping up in the morning and down in the evening). The average hourly regulation requirement by hour of day for 2022 is shown in Figure 7-12 below.

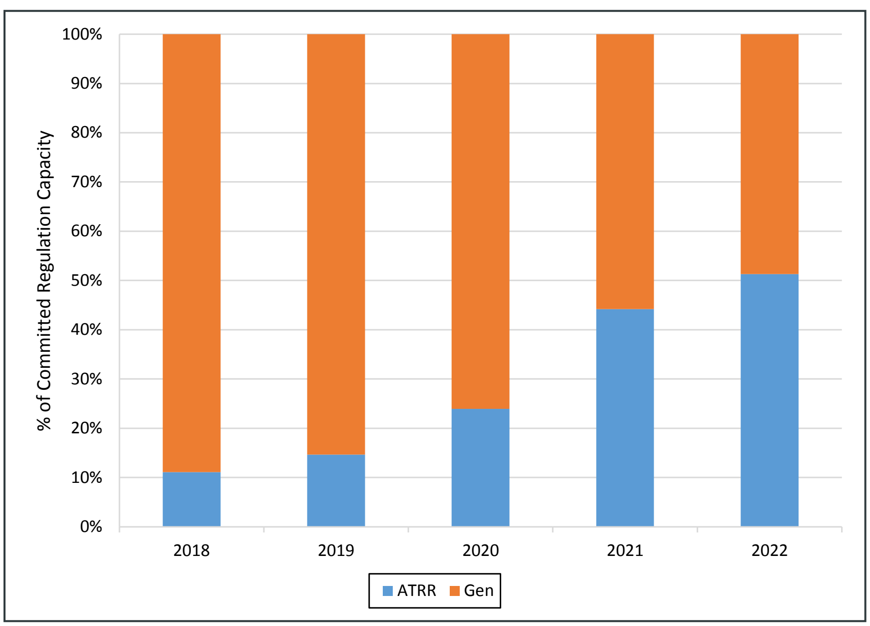
Figure 7-12: Average Hourly Regulation Requirement, 2022



The average hourly regulation requirement of 91.2 MW in 2022, a negligible change (0.5 MW) from the 2021 requirement (90.7 MW). In each hour, the ISO commits resources to meet the requirement. Two different types of resources can provide regulation in the ISO's regulation market: traditional generators and alternative regulation resources (ATRRs). Almost all of the ATRRs are battery resources that may function solely as regulation resources or may operate as a combination of energy market services: consumption (battery charging), generation (battery discharging), and regulation.

The regulation market resource mix for 2018 to 2022 is shown in Figure 7-13.

Figure 7-13: Regulation Resource Mix



The *resource mix* of committed regulation capacity has changed significantly. In 2018, ATRRs (blue shading) provided approximately 10% of committed regulation capacity; by 2022, ATRRs provided 50%. This change follows continuing increases in the installed capacity of battery resources in the ISO's energy markets. Regulation capacity available from ATRRs has increased from 19 MW to 127 MW over the period. The change in resource mix also suggests that battery resources are lower-cost regulation resources (i.e., have lower-cost regulation market offers), as these ATRRs have increasingly displaced traditional generators in the merit order for regulation market commitment.

Finally, regulation *performance* is measured relative to a NERC standard. With the ISO's implementation of NERC BAL-001-2 standards in 2016, the ISO uses violations of Balancing Authority ACE Limits (BAAL) to measure performance. Violations result from exceeding ACE limits for more than 30 consecutive minutes; in 2022, there were no BAAL violations.

Section 8
Market Design or Rule Changes

This section provides an overview of the major market design and rule changes that were recently implemented or are being assessed or planned for future years. Table 8-1 below lists the design changes summarized in this section.[319]

Table 8-1: Market Design or Rule Changes

Major Design or Rule Changes Recently Implemented	Major Design or Rule Changes in Development or Implementation for Future Years
Transmission Cost Allocation to Network Customers with Behind-the-Meter Generation	Incorporate Solar into Do-Not-Exceed Dispatch
Competitive Transmission Solicitation Enhancements	Inventoried Energy Program
Extended-Term Transmission Planning Tariff Changes	FERC Order 2222, Distributed Energy Resources
	Competitive Capacity Markets without a Minimum Offer Price Rule (MOPR)
	Resource Capacity Accreditation (RCA) in the Forward Capacity Market
	Day-Ahead Ancillary Services Initiative

8.1 Major Design Changes Recently Implemented

The following subsections provide an overview of changes recently implemented.

8.1.1 Transmission Cost Allocation to Network Customers with Behind-the-Meter Generation

FERC accepted Participating Transmission Owners (PTO) proposal in 2022

In our Spring 2020 Quarterly Markets Report (QMR), we conducted an analysis of transmission cost allocation issues with respect to the treatment of behind-the-meter (BTM) generation during monthly peak demand hours.[320] We expressed our concern about potential widespread non-compliance with the tariff requirement to reconstitute peak load by adding back BTM generation. Further, the IMM recognized that the transmission cost allocation rules were established over 20 years ago and should be re-evaluated.

In 2020 and 2021, the IMM engaged with stakeholders in the review of a Participating Transmission Owners (PTO) proposal developed in response to our analysis.[321] In July 2021, the

[319] An overview of key ISO projects is also available on the ISO website at https://www.iso-ne.com/committees/key-projects

[320] IMM, *Spring 2020 Quarterly Markets Report* (August 17, 2020 – Revision 1), https://www.iso-ne.com/static-assets/documents/2020/07/2020-spring-quarterly-markets-report.pdf

[321] IMM, *IMM Feedback on the Participating Transmission Owners' (PTOs) Transmission Cost Allocation Proposal* (January 20, 2021), https://www.iso-ne.com/static-assets/documents/2021/01/a03_tc_2021_06_imm_feedback_ptoac.docx

Participating Transmission Owners Administrative Committee (PTO AC), joined by the ISO,[322] filed a proposal to modify the monthly Regional Network Load (RNL) calculation to exclude BTM generation. In filed comments, the IMM described why the PTO proposal was deficient and should be rejected.[323] In 2022, FERC issued an order accepting the PTO's proposal effective September 1, 2021.[324]

8.1.2 Competitive Transmission Solicitation Enhancements

FERC accepted ISO's lessons learned tariff changes in 2022

FERC Order No. 1000 required the ISO, along with other ISOs/RTOs across the US, to change aspects of their regional and interregional transmission planning and cost-allocation processes. As part of its compliance with this order, the ISO created a Request for Proposal (RFP) process to solicit competitive proposals for certain transmission upgrades, such as non-time sensitive (more than three year's out) transmission needs in the region.

From December 2019 to July 2020, the ISO conducted its first RFP under Order 1000 to address necessary transmission upgrades to maintain reliability in the Boston area due to the retirement of the Mystic generating station.[325] Following the RFP, the ISO and stakeholders held "lessons learned" discussions, and in December 2021, the ISO and NEPOOL jointly proposed tariff changes to improve the competitive transmission planning process.[326] In 2022, FERC issued an order accepting the ISO's filing.[327]

8.1.3 Extended-Term Transmission Planning Tariff Changes

FERC accepted first phase tariff revisions in 2022

In December 2021, the ISO and NEPOOL jointly filed proposed tariff changes to allow the ISO to perform extended-term (beyond 10 years) system planning analyses requested by the New England states on a recurring basis. The proposal was in response to a request by the states to "implement a state-led, proactive scenario-based planning process for long-term analysis of

[322] The ISO joined the filing in its capacity as the administrator of the ISO-NE Tariff and to facilitate the proposed revisions in eTariff but took no position on the PTO Proposal. Filing Letter, p. 1, footnote 4 ("the ISO does not take a position on the proposed revisions").

[323] IMM, Comments of the Internal Market Monitor on the Proposal to Exclude Behind-the-Meter Generation from Transmission Cost Allocation, Docket No. ER21-2337-000 (July 22, 2021), https://www.iso-ne.com/static-assets/documents/2021/07/imm_comments_on_pto_proposal.pdf

[324] FERC, *Letter Order Accepting Tariff Revisions*, Docket No. ER21-2337-002 (February 22, 2022), https://www.iso-ne.com/static-assets/documents/2022/02/er21-2337-002_order_accept_monthly_regional_load_calculation.pdf

[325] ISO New England ISO Newswire, "ISO-NE makes selection in first Order 1000 transmission RFP," (July 24, 2020), https://isonewswire.com/2020/07/24/iso-ne-makes-selection-in-first-order-1000-transmission-rfp/

[326] ISO New England Inc. and New England Power Pool, *Transmission Planning Improvements,* Docket No. ER-22-733-000 (December 28, 2021), https://www.iso-ne.com/static-assets/documents/2021/12/transmission_planning_improvements.pdf

[327] FERC, *Order Accepting Tariff Revisions*, Docket No. ER22-733-000 (February 25, 2022), https://www.iso-ne.com/static-assets/documents/2022/02/er22-733-000_2_25_22_order_accepting_transmission_planning_improvements.pdf

state mandates and policies as a routine planning practice."[328] In February 2022, FERC accepted the proposed tariff changes.[329]

8.2 Major Design or Rule Changes in Development or Implementation for Future Years

The following market design or rule changes are either (i) currently being assessed or are in the design phase or (ii) have been completed and the planned implementation date is in the future.

8.2.1 Incorporate Solar into Do-Not-Exceed Dispatch

Planned implementation for December 2023

In November 2022, the ISO submitted to FERC proposed tariff changes to incorporate front-of-meter solar resources into the Do-Not-Exceed (DNE) dispatch rules. Existing DNE dispatch rules allow for inclusion of certain intermittent resources—wind and run-of-river hydro generators—into the ISO's real-time economic dispatch and avoids the need for manual dispatch of these resources. With DNE dispatch, the ISO sends to each DNE resource, a DNE dispatch point, which is the maximum output level that the generator must not exceed.

In January 2023, FERC issued a letter order accepting the ISO's proposal to incorporate solar into DNE dispatch with an effective date of December 5, 2023.[330] As of this effective date, the existing DNE rules for wind and run-of-river hydro will extend to front-of-meter solar resources.

8.2.2 Inventoried Energy Program

Planned implementation for Winters 2023/24 and 2024/25

The Inventoried Energy Program (IEP) provides an interim solution to compensate and incent inventoried energy during winter seasons of 2023/24 and 2024/25. The IEP allows resources to sell inventoried energy that will be held for certain trigger conditions.[331] Participating resources can sell this inventoried energy at either a forward settlement rate for the winter season or a spot rate. If a resource sells inventoried energy forward, it must either (i) maintain this amount of inventoried energy during each trigger condition or (ii) buy out of any shortfall at the spot rate, for each trigger condition.

In 2022, following a FERC order that was in response to a decision from the U.S. Court of Appeals for the D.C. Circuit, the ISO made a compliance filing to make nuclear, coal, biomass,

[328] NESCOE, *Report to the Governors* (June 2021), https://nescoe.com/wp-content/uploads/2021/06/Advancing_Vision_Report_6-29-21.pdf

[329] FERC, Letter Order Accepting ISO New England Inc's et al 12/27/2021 Filing of Proposed Tariff Revisions to Attachment K of its Open Access Transmission Tariff etc., Docket No. ER22-727-000 (February 25, 2022), https://www.iso-ne.com/static-assets/documents/2022/02/er22-727-000_2_25_22_ltr_order_accepting_longer-term_planning.pdf

[330] FERC, Letter order accepting ISO New England Inc.'s November 30, 2022 filing of revisions to section III.1.11.3(e) of Market Rule 1 of its Transmission, Markets and Services Tariff etc. under ER23-517., Docket No. ER23-517-000 (January 19, 2023), https://www.iso-ne.com/static-assets/documents/2023/01/er23-517-000_1-19-23_ltr_order_accept_incorporate_solar_sources_dne.pdf

[331] A trigger condition occurs when the average of the daily high and low temperature measured at Bradley International Airport in Windsor Locks, CT is 17°F or lower.

and hydroelectric generators ineligible for the program.[332] In 2023, the ISO has filed further proposed changes to the IEP program that include an update the settlement rate calculation to better reflect evolving global LNG market conditions.

8.2.3 FERC Order 2222, Distributed Energy Resources

FERC issued order in 2023 on the ISO's compliance filing

On September 17, 2020, FERC issued Order 2222, which found that existing ISO/RTO market rules were unjust and unreasonable, because they contained barriers to the participation of distributed energy resources aggregations (DERAs).[333] The purpose of Order 2222 is to remove these barriers and allow DERAs to provide all services that they are technically capable of providing. Specifically, the order outlined 11 directives for ISOs/RTOs to follow, including allowing participation of DERAs, allowing DER aggregators to register DERAs under one or more participation models[334], and establishing a minimum size requirement for DERAs of no more than 100 kW.

During 2020 and 2021, the ISO worked with stakeholders to develop the tariff revisions necessary to come into compliance with Order 2222. The ISO's proposed tariff changes were brought through the complete stakeholder process. At its January 2022 meeting, the NEPOOL Participant's Committee voted to support the proposal (71.10% in favor).

On February 2, 2022, the ISO, joined by NEPOOL and the PTO AC, filed a compliance proposal for Order 2222.[335] The proposal creates two new participation models for the energy and ancillary services market (called Demand Response DERA and Settlement Only DERA) and modifies existing models to accommodate the physical and operational characteristics of DERAs. The proposal includes many other changes to comply with the order, including introducing a new participation model for the FCM (called a Distributed Energy Capacity Resource), setting a minimum size of 100 kW for DERAs, specifying locational requirements, and changing existing metering and telemetry rules.

The ISO requested two effective dates: 1) November 1, 2022 for FCM-related revisions, which would be in time for the FCA 18 qualification process, and 2) November 1, 2026 for changes related to the energy and ancillary services market.

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[332] In December 2022, the ISO and NEPOOL also jointly filed tariff changes related to incorporating financial assurance and billing policy changes related to the IEP, which were accepted by FERC in early 2023. See FERC, letter order accepting ISO New England Inc.'s 12/22/2022 filing of revisions to its Transmission, Markets, and Services Tariff to revise the Financial Assurance Policy etc. under ER23-705, Docket No. ER23-705-000 (February 14, 2023), https://www.iso-ne.com/static-assets/documents/2023/02/er23-705-000.pdf

[333] DERAs are aggregations of small-scale power generation or storage technologies, such as electric storage, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their charging equipment. FERC, "FERC Order No. 2222: Fact Sheet," webpage (last updated September 28, 2020), https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet

[334] A "participation model" refers to rules created for a specific type of resource that has unique physical and operational characteristics (see Order 2222, footnote 7 on p. 5). For example, a generator is a type of participation model in ISO-NE.

[335] ISO New England Inc., Revisions to ISO New England Inc. Transmission, Markets and Services Tariff to Allow for the Participation of Distributed Energy Resource Aggregations in New England Markets, FERC filing, Docket No. ER22-983-000 (February 2, 2022), https://www.iso-ne.com/static-assets/documents/2022/02/order_no_2222_filing.pdf

In March 2023, FERC issued an order accepting in part and rejecting in part the ISO's compliance filing, subject to further compliance filings. In its order, the FERC found that the ISO's compliance filing satisfied six of the eleven aforementioned directives in Order 2222 but only partially satisfied the remaining five directives, which include issues related to storage participation models, information and data requirements, metering and telemetry requirements, and other issues.[336]

8.2.4 Competitive Capacity Markets without a Minimum Offer Price Rule (MOPR)

FERC accepted MOPR elimination filing in 2022

In May 2022, FERC accepted the ISO's and NEPOOL's joint proposed tariff revisions to remove the MOPR.[337] These approved changes eliminate the core components of the MOPR (i.e., offer review trigger prices) as well as the substitution auction effective for Forward Capacity Auction (FCA) 19 (capacity commitment period June 2028–May 2029). There is a two-year transition period (FCAs 17 and 18) where the MOPR remains in effect; during the transition period, the Renewable Technology Resource (RTR) exemption has been reinstated, which will allow a greater number of sponsored policy resources to enter the market.[338]

Beginning in FCA 19, the MOPR will be replaced with a revised buyer-side market power framework. Under this new approach, resources that fall into certain categories are not subject to buyer-side market power review; these include resources with capacity of 5 MW or less, passive demand-response resources, those with no load-side interest (i.e., "competitive entrants"), and certain federally or state-sponsored resources. Resources that do not fall into any of these categories will be subject to a buyer-side market power review by the IMM.[339]

8.2.5 Resource Capacity Accreditation (RCA) in the Forward Capacity Market (FCM)

ISO currently reviewing the projected filing date to FERC

In 2022, the ISO began the stakeholder process for the resource capacity accreditation (RCA) project. This initiative aims to assess and implement methodologies of accrediting resources in the FCM that will better reflect their contributions to resource adequacy. Under the proposed RCA reforms, the ISO would accredit resources based on their Marginal Reliability Impact (MRI), which reflects each resource's incremental contribution to resource adequacy. As part of this effort, the ISO is also pursuing changes to improve accreditation during winter by modeling gas limitations and accounting for fuel storage capability and contracting arrangements when accrediting gas-fired resources.

[336] For a summary of the FERC's order on compliance filing, see https://www.iso-ne.com/static-assets/documents/2023/03/a05_2023_03_07-09_order_2222_nepool_counsel_memo.pdf.

[337] FERC, *Order Accepting Tariff Revisions*, Docket No. ER22-1528-000 (May 27, 2022), https://www.iso-ne.com/static-assets/documents/2022/05/er22-1528-000_5-27-2022_order_accept_mopr_removal.pdf

[338] The RTR exemption would be 300 MW in FCA 17 and 400 MWs in FCA 18 (less substitution auction MWs in FCA 17). During the transition period, the substitution auction test price would also be eliminated.

[339] This review consists of a conduct test, wherein a resource fails the conduct test if its requested offer is below the resource's offer floor price. Those that fail the conduct test have the opportunity to avoid mitigation if they can sufficiently demonstrate that they would be unlikely to realize a material, net financial benefit from lowering FCA prices.

8.2.6 Day-Ahead Ancillary Services Initiative

ISO plans to file with FERC by end of 2023

The Day-Ahead Ancillary Services Initiative (DASI) sets out to procure and transparently price specific ancillary services needed for system reliability. Currently, there is no day-ahead reserves market in ISO-NE. The ISO is proposing to create four new reserve products that would be co-optimized with energy and priced in the day-ahead market.[340] These day-ahead reserve products are not forward sales of reserves that settle against real-time reserve prices; instead, they have a unique call-option settlement structure, where the settlement is based on a pre-determined strike price and the actual real-time Hub LMP.

The ISO plans to submit proposed tariff revisions for DASI to FERC by the end of 2023.

8.3 Additional Notable Studies

The following subsection provides an overview of additional notable studies that are not part of any planned market design or implementation work.

8.3.1 New England's Future Grid Initiative

Reports published in 2022

In 2022, the ISO published two major reports for the Future Grid Initiative, which is a stakeholder-led effort that seeks to help the region prepare for and support New England's transition to a future grid.[341] The initiative has two parallel tracks: the Future Grid Reliability Study and Pathways to the Future Grid.

Future Grid Reliability Study (FGRS)

The purpose of the FGRS is "to assess and discuss the future state of the regional power system in light of current state energy and environmental laws."[342] In particular, the two phases of the FGRS together will assess if existing markets will be sufficient to attract and retain resources needed for reliability and identify potential operational and reliability challenges that will need to be addressed.

In July 2022, the ISO published a report for Phase 1 of the FGRS that evaluated grid reliability issues under several decarbonization scenarios. In the upcoming Phase 2 of the FGRS, the ISO plans to determine which types of clean energy resources can be "revenue sufficient" and meet resource adequacy needs and identify any potential reliability gaps.

Pathways to the Future Grid

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340 Three of these products mirror the three real-time reserve products: TMSR, TMNSR, and TMOR; the fourth product is called Energy Imbalance Reserve, which is procured to essentially help fill any potential "energy gap" between forecasted load and cleared day-ahead physical supply.

341 See p. 12 of the *NEPOOL 2021 Annual Report* https://nepool.com/wp-content/uploads/2021/12/Annual_Report_2021.pdf

342 See pp. 1-2 of *NEPOOL Future Grid Reliability Study, Study Framework for Phase 1 Economic Study Request* (March 12, 2021) https://nepool.com/wp-content/uploads/2021/03/FG_20200331_a04_framework_document_redlined.docx

The Pathways to the Future Grid seeks to explore and evaluate market frameworks to support the region's clean energy transition. In assisting with this project, the ISO and the consulting firm Analysis Group worked with stakeholders to evaluate four different frameworks for decarbonizing the New England power sector:

- Status quo: continued use of long-term contracts as the primary tool to meet decarbonization objectives.
- Forward Clean Energy Market (FCEM): introduction of clean energy credits, which represent the clean energy attributes of generation and are procured in a forward market.
- Net carbon pricing: implementation of a price on carbon, where suppliers are charged based on their carbon emissions and these charges are rebated to load.
- Hybrid: a combination of the FCEM and net carbon pricing frameworks. Only new resources are eligible for the FCEM and the carbon price level is set to provide revenue adequacy for existing clean resources.

The Analysis Group modeled each of these frameworks to help compare and assess these different approaches to decarbonizing. The modeling assumes that New England states meet a regional target for the power sector of 80% CO_2 emissions reduction by 2040 (relative to 1990 levels) and quantifies how market and economic outcomes (e.g., LMPs, social costs) differ under each framework.

In April 2022, the final Pathways Study report was published. Following this report, the ISO is working with states and stakeholders to gather feedback on the report.

Acronyms and Abbreviations

Acronyms and Abbreviations	Description
°F	degrees Fahrenheit
AC	alternating current
ACE	area control error
ADCR	Active Demand Capacity Resources
AMR	Annual Markets Report
ARA	annual reconfiguration auction
ARD	asset-related demand
ART	Annual Reconfiguration Transaction
AS	ancillary service
BAA	balancing authority area
BAAL	Balancing Area ACE Limits
BAL-001-2	NERC's *Real Power Balancing Control Performance Standard*
BAL-003	NERC's *Frequency Response and Frequency Bias Setting Standard*
bbl	barrel (unit of oil)
Bcf	billion cubic feet
BTM	behind-the-meter
Btu	British thermal unit
C4	market concentration of the four largest competitors
CASPR	Competitive Auctions with Sponsored Policy Resources
CC	combined cycle (generator)
CCP	capacity commitment period
CDD	cooling degree day
CMR	Code of Massachusetts Regulations
CO_2	carbon dioxide
CONE	cost of new entry
CPS 2	NERC *Control Performance Standard 2*
CSC	Cross Sound Cable
CSO	capacity supply obligation
CT	State of Connecticut, Connecticut load zone, Connecticut reserve zone
CT	combustion turbine
CTL	capacity transfer limit
CTS	Coordinated Transaction Scheduling
DAGO	day-ahead generation obligation
DALO	day-ahead load obligation
DARD	dispatchable asset related demand
DDBT	dynamic de-list bid threshold

Acronyms and Abbreviations	Description
DDG	do-not-exceed dispatchable generators
DDT	dynamic de-list threshold
Dec	decrement (virtual demand)
DFC	dual fuel commissioning
DG	distributed generation
DLOC	dispatch lost opportunity costs NCPC
DNE	do not exceed
DOE	US Department of Energy
DR	demand response
EGEL	Electricity Generator Emissions Limits (program)
EIA	US Energy Information Administration (of DOE)
EMM	External Market Monitor
EMOC	Energy Market Opportunity Cost
EMOF	Energy Market Offer Flexibility
EPA	Environmental Protection Agency
ERS	external reserve support
ETU	Elective Transmission Upgrade
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
FRM	Forward Reserve Market
FSP	Fast-Start Pricing
FTR	Financial Transmission Right
GT	gas turbine
GHG	greenhouse gas
GW	gigawatt
GW-month	gigawatt-month
GWh	gigawatt-hour
GWSA	Global Warming Solutions Act
HDD	heating degree day
HE	hour ending
HQ	Hydro-Québec
HQICCS	Hydro-Québec Installed Capacity Credit
IBT	internal bilateral transaction
ICE	Intercontinental Exchange, Inc.
ICR	Installed Capacity Requirement
ICT	Interim Compensation Treatment
IMAPP	Integrating Markets and Public Policy
IMM	Internal Market Monitor

Acronyms and Abbreviations	Description
Inc	increment (virtual supply)
ISO	Independent System Operator, ISO New England
ISO tariff	*ISO New England Transmission, Markets, and Services Tariff*
kW	kilowatt
kWh	kilowatt-hour
kW-month	kilowatt-month
kW/yr	kilowatt per year
L	symbol for the competitiveness level of the LMP
LA	left axis
LCC	Local Control Center
LEG	limited-energy generator
LMP	locational marginal price
LNG	liquefied natural gas
LOC	lost opportunity cost
LOLE	loss- of-load expectation
LS/ERI	Lower SEMA/Eastern RI Import interface
LSE	load-serving entity
LSCPR	local second-contingency-protection resource
LSR	local sourcing requirement
M-36	*ISO New England Manual for Forward Reserve*
MA	State of Massachusetts
MAPE	mean absolute percent error
MassDEP	Massachusetts Department of Environmental Protection
MCL	maximum capacity limit
MDE	manual dispatch energy
ME	State of Maine and Maine load zone
M/LCC 2	Master/Local Control Center Procedure No. 2, *Abnormal Conditions Alert*
MMBtu	million British thermal units
MOPR	Minimum Offer Price Rule
MRA	monthly reconfiguration auction
MRI	marginal reliability impact
MW	megawatt
MWh	megawatt-hour
N-1	first contingency
N-1-1	second contingency
NCPC	Net Commitment-Period Compensation
NEL	net energy for load
NEMA	Northeast Massachusetts, Boston load zone

Acronyms and Abbreviations	Description
NEMA/Boston	Northeast Massachusetts/Boston local reserve zone
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Corporation
NH	State of New Hampshire, New Hampshire load zone
NHME	New Hampshire-Maine Import interface
NICR	net Installed Capacity Requirement
NNE	northern New England
No.	Number
NPCC	Northeast Power Coordinating Council
NY	State of New York
NYNE	New York-New England interface
NYISO	New York Independent System Operator
OATT	*Open Access Transmission Tariff*
OP 4	ISO Operating Procedure No. 4
OP 7	ISO Operating Procedure No. 7
OP 8	ISO Operating Procedure No. 8
ORTP	offer-review trigger price
PER	peak energy rent
PFP	pay-for-performance
PJM	PJM Interconnection, L.L.C.
pnode	pricing node
PPR	pay-for-performance penalty rate
PRD	price-responsive demand
PROBE	Portfolio Ownership and Bid Evaluation
PST	pivotal supplier test
PTO	Participating Transmission Owners
PURA	Public Utilities Regulatory Authority
PV	photovoltaic
Q	quarter
RA	reconfiguration auction
RA	right axis
RAA	reserve adequacy assessment
RCA	Reliability Coordinator Area
RCP	regulation clearing price
RCPF	Reserve Constraint Penalty Factor
RFP	Requests for Proposals
RGGI	Regional Greenhouse Gas Initiative

Acronyms and Abbreviations	Description
RI	State of Rhode Island, Rhode Island load zone
RMCP	reserve market clearing price
RNL	regional network load
RNS	regional network service
RoP	rest of pool
RoS	rest of system
RRP OC	rapid-response pricing opportunity costs NCPC
RSI	Residual Supply Index
RTDR	real-time demand response
RTLO	real-time load obligation
RTO	Regional Transmission Organization
RTR	renewable technology resource
SCR	special-constraint resource
SEMA	Southeast Massachusetts load zone
SENE	southeastern New England
SMD	Standard Market Design
SWCT	Southwest Connecticut
THI	Temperature-Humidity Index
TMNSR	10-minute non-spinning reserve
TMOR	30-minute operating reserve
TMSR	10-minute spinning reserve
TPRD	transitional price-responsive demand
TTC	total transfer capability
UDS	unit dispatch system
US	United States
UTC	up-to-congestion
VT	State of Vermont and Vermont load zone
WCMA	Western/Central Massachusetts
WRP	Winter Reliability Program
WTI	West Texas Intermediate