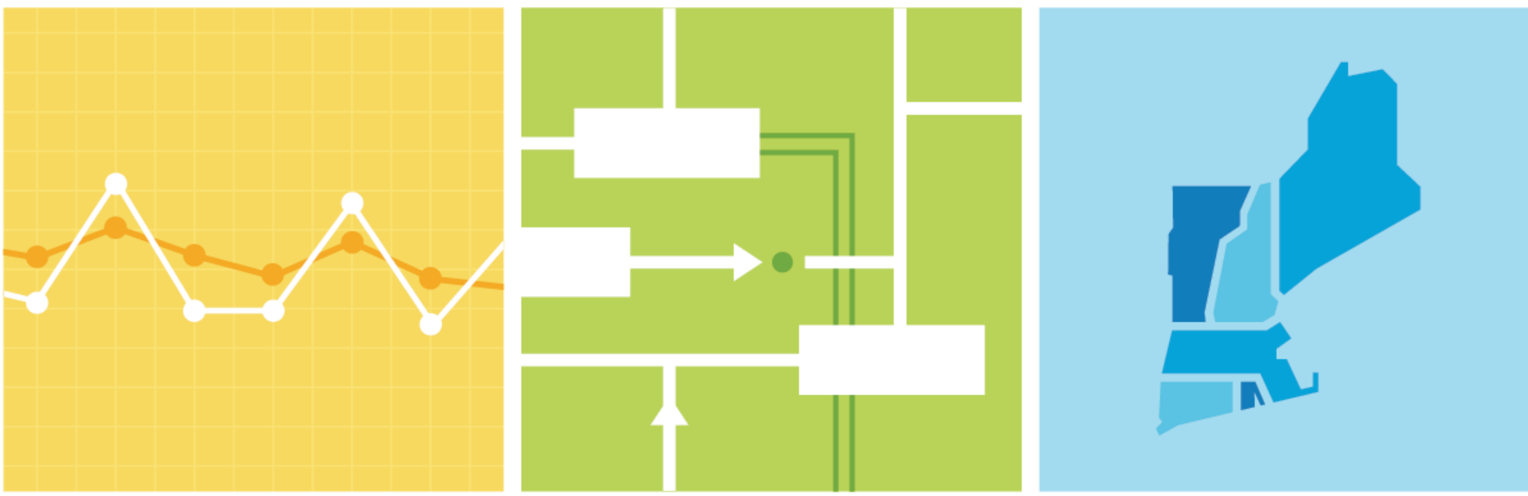
2021 Annual Markets Report

Internal Market Monitor

MAY 26, 2022



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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 *2021 Annual Markets Report* covers the ISO's most recent operating year, January 1 to December 31, 2021. 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 2021. Section 1 summarizes 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 2 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):

ICE Global markets in clear view

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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Section 1
Executive Summary

The *2021 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 administered by the ISO. 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.

In this section, we provide an overview and assessment of key market trends, performance, and issues. We then provide a summary of each section of the report in subsections 1.2 through 1.5, and conclude with an overview and consolidated list of recommended enhancements to the market design and rules from prior IMM reports.

The ISO New England capacity, energy, and ancillary service markets performed well and exhibited competitive outcomes in 2021. The day-ahead and real-time energy prices reflected changes in underlying primary fuel prices, electricity demand and the region's supply mix. No major reliability issues occurred in 2021, and there were no periods in the energy market when a shortage of energy and reserves resulted in very high energy prices or reserve scarcity pricing.

Natural gas prices drive high wholesale energy prices in New England

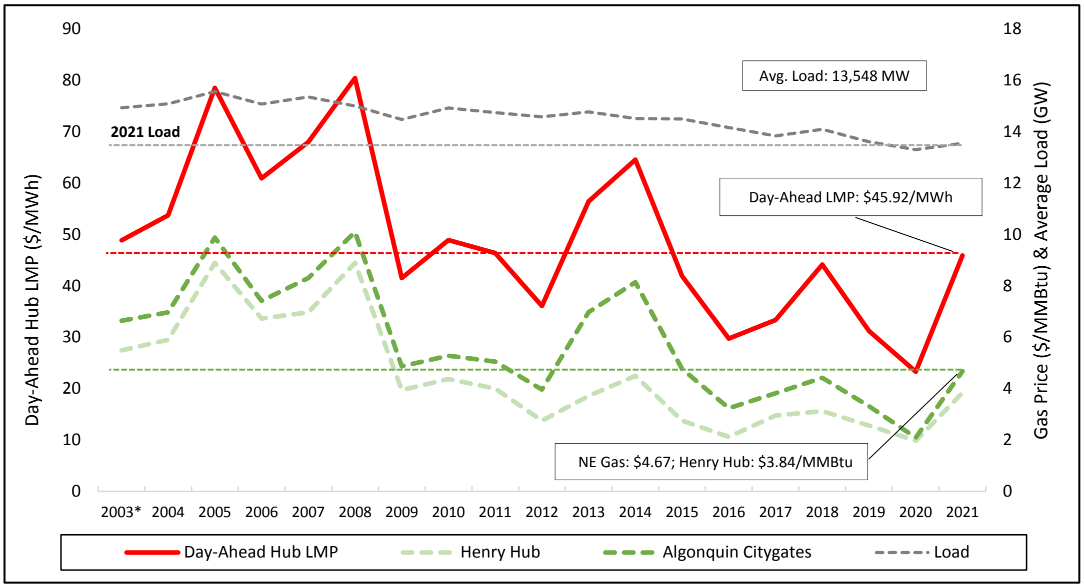
In 2021, the New England average wholesale energy price rebounded from a record low in 2020 to its highest level in seven years.[4] Gas market dynamics at both a national and regional level led to price increases. Natural gas continues to be our largest fuel source for electricity production and was the major driver of higher energy prices. A small increase in wholesale electricity demand also contributed to higher energy prices.

To put 2021 market outcomes into historical context, Figure 1-1 below illustrates the long-term trends in the annual average day-ahead LMP (left axis), gas prices at Henry Hub and in New England (right axis), and average hourly wholesale demand in New England (right axis).[5]

[4] Energy prices were the highest since 2014, but 2021 energy prices were also comparable to 2018 levels.

[5] Unless otherwise stated, the New England 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, Maritimes & Northeast, Portland and Tennessee gas pipeline Z6-200L. 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 to hour ending 11 on D+2.

Figure 1-1: Historical Electricity Prices, Wholesale Load and Natural Gas Prices[6]



Over the past ten years, an era of relatively cheap shale gas put significant downward pressure on average gas prices. This is evident in the trend in both Henry Hub, the major US pricing benchmark, and in New England's gas prices. The average annual price at Henry Hub was $3.82/MMBtu in 2021, a 91% jump from the record low price the prior year.[7] The average gas price in New England was $4.62/MMBtu, an increase of 120%, or $2.52/MMBtu, compared with 2020.[8] Driven by gas prices, day-ahead energy prices in New England averaged $45.92/MWh, which was $22.60/MWh (or 97%) higher than the prior year.

In 2021, gas and energy prices rebounded from the record low levels seen in 2020 due to the economic and societal impacts of the COVID-19 pandemic. Beginning in March 2020, natural gas demand and prices dropped quickly across the country when business closures were implemented to mitigate the spread of COVID-19. While gas production dropped, demand remained low and storage levels remained high going into December 2020.[9] These factors led to record low prices at the national level, including a record low average price in New England of just $2.10/MMBtu in 2020.[10]

[6] Standard Market Design was implemented in March 2003, and therefore the average 2003 LMP does not represent a full calendar year's data. Henry Hub and Algonquin Citygates pricing data is sourced from Bloomberg.

[7] While New England and Henry Hub gas prices have historically been closely correlated, New England prices are more closely linked to prices at the Marcellus trading hub (not shown), which jumped from a record low price of $1.32/MMBtu in 2020 to $2.90 in 2021. The Marcellus price is not included in the graph given the limited trading history, but is included in Figure 2-9 of the report.

[8] 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 and Tennessee gas pipeline Z6-200L. 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 to hour ending 11 on D+2.

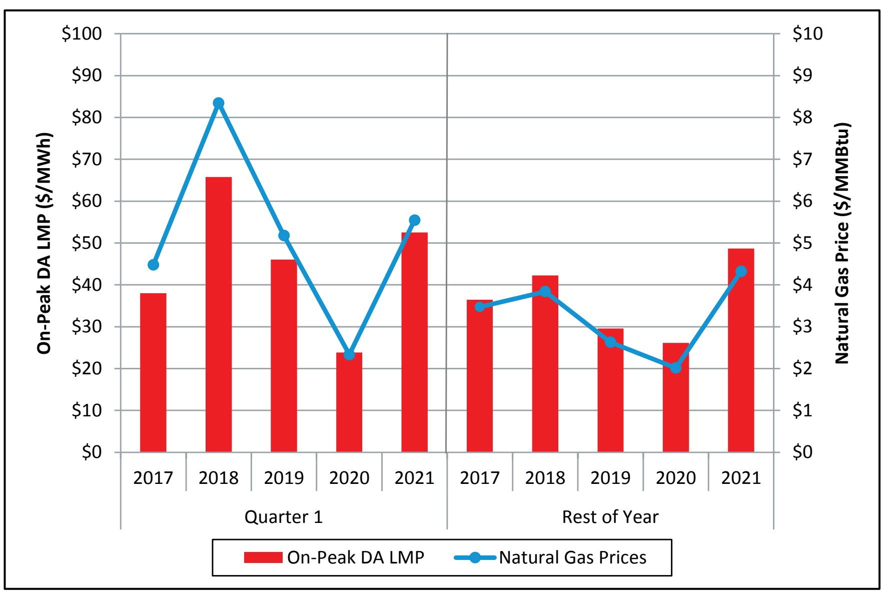
[9] Natural gas storage levels were the third highest of all time heading into the winter.

[10] Natural gas price data only goes back to 1999.

During Winter 2020/21, gas prices at the national level initially remained low as warmer than normal weather from October through January tempered demand.[11] However, during the first half of February, the Texas/Midwest cold snap sparked an increase in gas demand, which pushed storage levels significantly lower, and increased prices nationally and particularly at trading hubs within those affected markets (ERCOT, SPP, MISO). Consequently, national storage levels during the winter went from a five-year high to almost a five-year low.[12] During 2021, as gas demand increased due to U.S. consumption and LNG exports, production did not keep pace despite higher prices, with "capital discipline"[13] of producers cited as a factor. Natural gas storage inventories were well below the five-year average before the withdrawal season, and by the end of the injection season, storage levels remained at the lowest pre-winter level over the previous three years.[14,15] Gas prices continued to increase nationally heading into Winter 2021/22.

The New England market is also particularly exposed to high natural gas prices during the winter months when gas heating demand increases and the interstate gas pipeline system becomes constrained. New England winter gas prices trade at a significant premium to major US benchmark prices (like Henry Hub) and drive energy prices to often exceed price levels during the remainder of the year, even during the summer when electricity demand is at its highest. During sustained periods of very cold weather, the availability of oil-fired generation and injections from Liquefied Natural Gas (LNG) facilities play a vital role in meeting the region's energy needs. The region has not experienced such a period of sustained cold weather since winter 2018, however the impact of high winter natural gas prices on energy prices is nonetheless clear in four of the past five years as shown Figure 1-2 below, which compares day-ahead LMPs and natural gas prices in Quarter 1 to the rest of the year.

Figure 1-2: Average Electricity and Gas Prices for Q1 Compared with Rest of Year



11 https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2021/02_11/

12 https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2021/02_25/

13 https://www.bloomberg.com/news/articles/2021-11-30/shale-oil-s-newfound-production-discipline-begins-to-pay-off

14 https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2021/08_12

15 https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2021/11_18

In New England, from the end of January and into the first two weeks of February 2021, a sustained cold spell with temperatures averaging 23.5°F led to high demand and a constrained pipeline system, with average prices of $10.76/MMBtu during that period. Q1 2021 prices averaged $5.55/MMBtu, up by almost 140% on the prior year. By the end of the year, gas prices were already high early in the winter season, averaging $8.63/MMBtu in December 2021.

Electricity demand also increased year-over-year due to colder weather and increased economic activity as the region continued to recover from the impacts of the COVID-19 pandemic. Weather-normalized demand has been trending downwards in recent years due to state-sponsored energy efficiency programs and the growth in behind-the-meter photovoltaic generation. However, the ISO forecasts that weather-normalized demand will begin to increase from 2022 because of the diminishing impacts of energy efficiency and solar generation and the growth in electrification of transportation and heating.[16]

Energy costs comprise a larger share of wholesale costs due to higher natural gas prices

The total wholesale cost of electricity in 2021 was $11.2 billion, the equivalent of $94 per MWh of load served.[17] Wholesale costs were at their highest level since 2018 and considerably higher than the 2020 total of $8.1 billion, a 38% increase (or $3.1 billion). Higher energy costs drove the overall increase in wholesale costs. With the exception of capacity costs (down by $0.5 billion), each component of the wholesale cost of electricity increased in 2021.

Energy costs continued to comprise the largest share of wholesale costs, at 55%, increasing significantly from a 37% share in 2020. Energy costs totaled $6.1 billion, up 104% (or $3.1 billion) on 2020 costs. The large annual increase in natural gas prices of 120% drove higher day-ahead LMPs, averaging $45.92/MWh, up 97% (or by $22.60/MWh) on 2020. While there were increases in energy costs in each quarter, Quarter 1 (Q1) accounted for about 30% of the total annual change. In Q1, natural gas prices increased by 138% ($2.33 to $5.55/MMBtu) and demand by 1.9% year-over-year due to colder weather conditions and economic recovery from COVID-19 restrictions.

Net Commitment Period Compensation (NCPC), or uplift, costs remained relatively low at just $35 million, or 0.6% of total energy payments. Most (75%) uplift was paid to resources committed and dispatched in economic merit order, with the remaining 25% (just $9 million) required to meet the costs of out-of-merit reliability commitments. The level of NCPC is consistent with improved price formation in the real-time energy market since the implementation of the fast-start pricing rules in 2017, and with the generally low levels of operator out-of-market or unpriced actions in 2021.[18]

Capacity costs comprised one fifth of total wholesale costs, totaling $2.2 billion, down by 16% (or $0.4 billion) on 2020. The costs were a function of lower combined clearing prices and surplus cleared capacity in the eleventh and twelfth Forward Capacity Auctions (FCAs 11 and 12), which were conducted in 2017 and 2018, respectively.[19] Clearing prices in FCA 11 and 12 were $5.30 and $4.63/kW-mo, respectively, averaging $4.90/kW-mo for the 2021 calendar year.

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[16] See ISO New England's 2020 CELT report at https://www.iso-ne.com/system-planning/system-plans-studies/celt/

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

[18] High levels of uplift and can signal gaps in the market design and/or market clearing processes. For example, the posturing of oil-fired generators in January 2018 to conserve fuel supplies resulted in a significant amount of uplift to those constrained-down generators.

[19] FCA 11 corresponds to the delivery period June 1, 2020 to May 31, 2021, and FCA 12 to June 1, 2021 to May 31, 2022.

Low levels of structural market power and mitigations in the energy market

The overall price-cost markups in the day-ahead energy market were within a reasonable range for a competitive market, and were comparable to the prior four years.[20] The structural competitiveness of the real-time energy market also remained strong in 2021. There continued to be few hours with pivotal suppliers due to a high supply margin and relatively unconcentrated portfolio ownership.[21] Further, the number of energy market supply offers mitigated for market power remained very low. Of the 44,272 asset-hours that were evaluated for market power, only 957 asset-hours violated the mitigation thresholds and were mitigated, representing 2% of the 44,272 asset-hours.[22]

The mitigation process for the energy markets has functioned reasonably well and along with a structurally competitive market have helped ensure competitive outcomes. However, as we have emphasized in prior reports, the mitigation measures for both system-level and local market power provide suppliers a considerable degree of deviation from competitive marginal-cost offers before the mitigation rules trigger and mitigate a supply offer. Our analysis indicates that lower thresholds would not have had a significant impact on offer mitigation over the past few years, but the impact may not be so muted in future years as the supply margin potentially contracts as resources retire. We continue to think that the mitigation thresholds should be reviewed and potentially lowered to strike a better balance between protecting consumers and market intervention on the supply side through offer mitigation.

Low capacity costs to continue for the next four years

Capacity prices have already been established for the next four years (to end May 2026) and will result in lower capacity costs, down to an expected low of $1.2 billion in 2024, about 50% of 2021 costs.

For the eighth consecutive year, the FCA procured surplus capacity in the sixteenth auction (FCA 16). The capacity surplus heading into the 2025/26 delivery year is comparable to the prior auction, at 1,165 MW (4% above the net installed capacity requirement, or NICR). The NICR decreased by 1,625 MW from the prior year, largely driven by a change in the reconstitution of passive demand resources in the ISO load forecast.[23] The potential for a greater capacity surplus from this decrease in NICR was offset by the exit of 1,864 MW of existing resources, mostly for a one-year period, in response to the continued low prices. FCA 16 cleared at $2.59/kW-mo for the rest-of-system zone, just two cents lower than the clearing price of $2.61/kW-mo in FCA 15.

In our review of the FCA 16 auction processes, including pre-auction mitigations, excess capacity, and liquidity of dynamic de-list bids, we found no evidence of uncompetitive behavior during FCA 16.

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[20] Price-cost markup is an estimate of the premium in consumer prices as a result of supply resources bidding above their short-run marginal costs in the energy market.

[21] In other words, the capacity of the largest supplier was needed to meet demand less frequently.

[22] For additional context, 44,272 asset hours is approximately 3% of all asset-hours in the market.

[23] https://www.iso-ne.com/static-assets/documents/2021/08/a02_pspc_2021_08_25_proposed_icr_related_values_for_fca16.pptx

FCM mitigation processes working, but well-known challenges to efficient pricing and procurement remain

The seller- and buyer-side mitigation rules have helped to ensure that bids and offers from existing and new capacity resources are consistent with market-based costs and revenues. This, in turn, is important for efficient price formation in the Forward Capacity Market (FCM) and its objective to deliver entry and exit signals to meet its resource adequacy objective.

The buyer-side rules, known as the Minimum Offer Price Rules (MOPR) have been in effect since FCA 8. However, in recent years, the primary driver of below-cost offers has been out-of-market (OOM) revenues to Sponsored Policy Resources (SPRs) rather than an observable attempt to profitably exercise buyer-side market power. Therefore, while MOPR protects price formation from low offer prices due to OOM revenues, it can inhibit the clearing of SPRs in the auction and therefore fail to recognize their contribution to resource adequacy. This can lead to an "overbuild" inefficiency and excess costs to ratepayers, which will only grow as the level of policy resources increases to meet the States' decarbonization targets.

Competitive Auctions for Sponsored Policy Resources (CASPR) is the current long-term construct designed to accommodate subsidized new entry through a substitution auction, with the intent of ensuring competitive FCA pricing in the initial year of entry. However, entry via CASPR has been limited to just 54 MW in the four substitution auctions to date.

Therefore, the ISO has proposed to eliminate MOPR from FCA 19, following a two-year transition period.[24] We see this proposal as a step forward in allowing SPRs the opportunity to participate in the FCM and contribute towards meeting the region's resource adequacy requirement, while providing a limited check on the exercise of market power. However, there are market performance risks associated with the elimination of MOPR in terms of the ability of the FCM to provide efficient entry and exit price signals.[25]

Two key market design projects are underway this year, namely resource capacity accreditation and day-ahead ancillary services, and both will be important in compensating for the aforementioned price formation risks. Accurate capacity accreditation will help ensure that resources qualify and are paid to provide capacity consistent with their contribution to resource adequacy, while day-ahead ancillary services will recognize and compensate resources for meeting the next operating day's expected load and reserve requirements. We think these are important initiatives that should enhance price formation in the energy and capacity markets.

Finally, with respect to the seller-side rules, stakeholders have recently discussed a number of possible changes, or reforms, to the retirement rules for existing resources. A notable change would allow for the mothballing, or re-entry, of retired resources after a given period out of the market. We think there is economic merit to this proposal at a conceptual level and look forward to seeing more detail.

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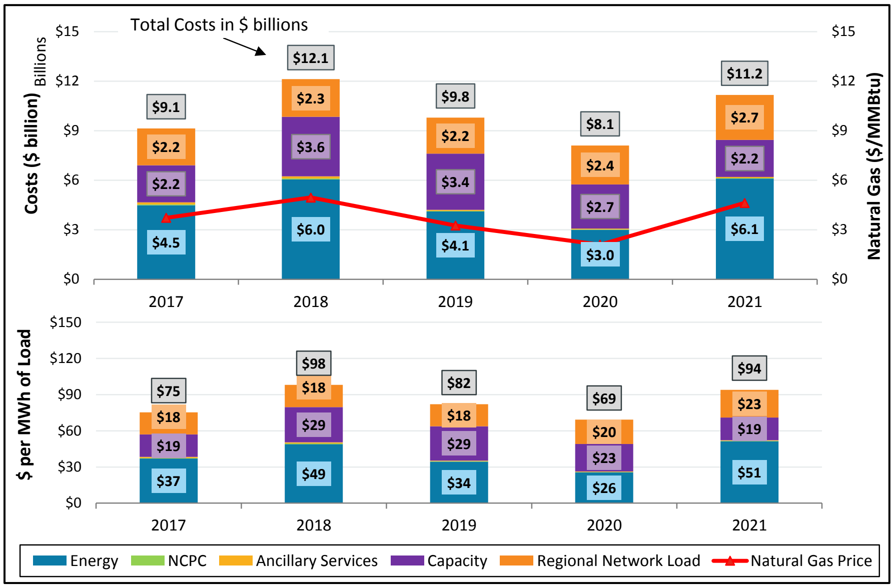
[24] ISO New England Inc., Revisions to ISO New England Transmission, Markets and Services Tariff of Buyer-Side Market Power Review and Mitigation Reforms, FERC filing, Docket No. ER22-1528-000 (March 31, 2022), https://www.iso-ne.com/static-assets/documents/2022/03/mopr_removal_filing.pdf

[25] IMM, Comments of the Internal Market Monitor, Docket No. ER22-1528-000 (April 21, 2022), https://www.iso-ne.com/static-assets/documents/2022/04/imm_comments_on_mopr_transition.pdf

1.1 Wholesale Cost of Electricity

In 2021, the total estimated wholesale market cost of electricity was $11.2 billion, an increase of $3.1 billion (38%) compared to 2020 costs.[26] While energy costs increased, a decrease in capacity costs was partially offset by higher transmission (RNL) costs. The total cost equates to $94/MWh of wholesale electricity demand served. The components of the wholesale cost over the past five years, along with the average annual natural gas price (on the right axis), are shown in Figure 1-3 below.[27]

Figure 1-3: Wholesale Costs and Average Natural Gas Prices



A description of each component, along with an overview of the trends and drivers of market outcomes, is provided below. The amount of each category in dollars, dollars per MWh of load served, and the percentage contribution of each category to the overall wholesale cost in 2021 are shown in parenthesis.

Energy ($6.1 billion, $51/MWh, 55%): Energy costs are a function of energy prices (LMPs) and wholesale electricity demand:

- Day-ahead and real-time LMPs averaged $45.92 and $44.84/MWh, respectively (simple average). Compared with 2021, prices were up by $22.60/MWh (97%) in the day-ahead market and $21.46/MWh (92%) in the real-time market.
- Supply and demand-side participants continued to exhibit a strong preference towards the day-ahead market, with 98% of the cost of energy settled on day-ahead prices.
- Natural gas prices continued to be the primary driver of LMPs and energy costs. Gas prices averaged $4.62/MMBtu, an increase of 120%, or $2.52/MMBtu, compared with 2020.

[26] In previous years, we used system load obligations and average hub LMPs to approximate energy costs. This year, we updated the methodology to reflect energy costs based on location-specific load obligations and LMPs. These changes are reflected in all five-years of data. Transmission network costs, known as regional network load (RNL) costs, are also included in the estimate of annual wholesale costs.

[27] Note that given their relative size to the other cost components, ancillary services and NCPC costs are barely visible in the graphs below.

Natural gas prices in Q1 2021 were significantly higher than the rest of the year due to colder weather, averaging $5.55/MMBtu, up 138% on Q1 2020 prices. Higher gas prices and wholesale demand in Q1 2021 drove a $0.9 billion increase in energy costs, accounting for almost 30% of the annual $3.1 billion jump.

- Changes to the supply mix helped temper the impact of higher gas prices on LMPs in 2021; there was a 536 MW reduction in average hourly net interchange, primarily over the New York (NY) interfaces. This shortfall was countered by an increase in native generation, with natural gas generation increasing by 9% or 508 MW and nuclear generation increasing by 6% (171 MW) due to fewer planned outages for nuclear generators.
- Demand (or real-time load) averaged 13,556 MW per hour, a 1.9% increase (by about 250 MW per hour) on 2020. Load increased due to reduced impacts from the COVID-19 pandemic and colder weather in Q1 2021. Temperatures averaged 33^{0}F in Q1 2021, down 3^{0}F from Q1 2020 (36^{0}F), but equal to the five-year average. As a result, average demand in Q1 was up 4%, or by 526 MW per hour.
- While weather typically explains year-over-year changes, wholesale load has trended down in recent years due to the growth in energy efficiency installations and increased behind-the-meter generation, particularly photovoltaic generation. However, weather-normalized load increased by 1% compared to 2020, averaging 13,410 MW.

Capacity ($2.2 billion, $19/MWh, 20%): Capacity costs decreased by 16%, or by $0.4 billion, due to lower auction clearing prices resulting from surplus supply conditions in FCA 11 (2020/21) and FCA 12 (2021/22). Capacity clearing prices peaked in FCA 9 (2018/19) at $9.55/kW-month, and then declined in each subsequent auction through FCA 14 (2023/24). New entry and limited resource retirements have continued to maintain a system surplus of 4-5% above the capacity requirement, applying downward pressure on prices.

Regional Network Load Costs ($2.7 billion, $23/MWh, 24%): Regional Network Load (RNL) costs cover the use of transmission facilities, reliability, and certain administrative services. Transmission and reliability costs in 2021 were $2.7 billion, $357 million (15%) more than 2020 costs. The primary driver was a 12% increase in infrastructure improvements costs.

NCPC ($0.04 billion, $0.3/MWh, 0.3%): NCPC (uplift) payments, the portion of production costs in the energy market not recovered through the LMP, totaled $35 million, an increase of $10 million (up by 35%) compared to 2020. The increase was due to higher energy prices and more local reliability commitments (though their total cost was small at $2.5 million). NCPC remained low when expressed as a percentage of total energy payments, at just 0.6%, continuing a downward trend in the share of NCPC from prior years. In a broader context, the low level of uplift is consistent with improvements in real-time price formation since the implementation of fast-start pricing and generally low levels of out-of-market commitments and dispatch.

Ancillary Services ($0.05 billion, $0.5/MWh, 0.5%): Ancillary services include costs of additional services procured to ensure system reliability, including operating reserve (real-time and forward markets), regulation, and the Winter Reliability Program.[28] In 2021, the costs of most ancillary service products and their associated make-whole payments were similar to 2020 costs. Ancillary

[28] The Winter Reliability Program ended after winter 2018, coinciding with the start of the pay-for-performance rules in the capacity market in June 2018.

service costs totaled $54 million in 2021, $1.5 million more than 2020 costs.[29] The increase was driven by higher average regulation prices.

1.2 Overview of Supply and Demand Conditions

Key statistics on some of the fundamental market trends over the past five years are presented in Table 1-1 below. The table comprises five sections: electricity demand, estimated generation costs, electricity prices, wholesale costs and the New England real-time supply mix.

[29] The ancillary services total presented here does not include blackstart and voltage costs, since these costs are represented in the RNL category.

Table 1-1: High-level Market Statistics

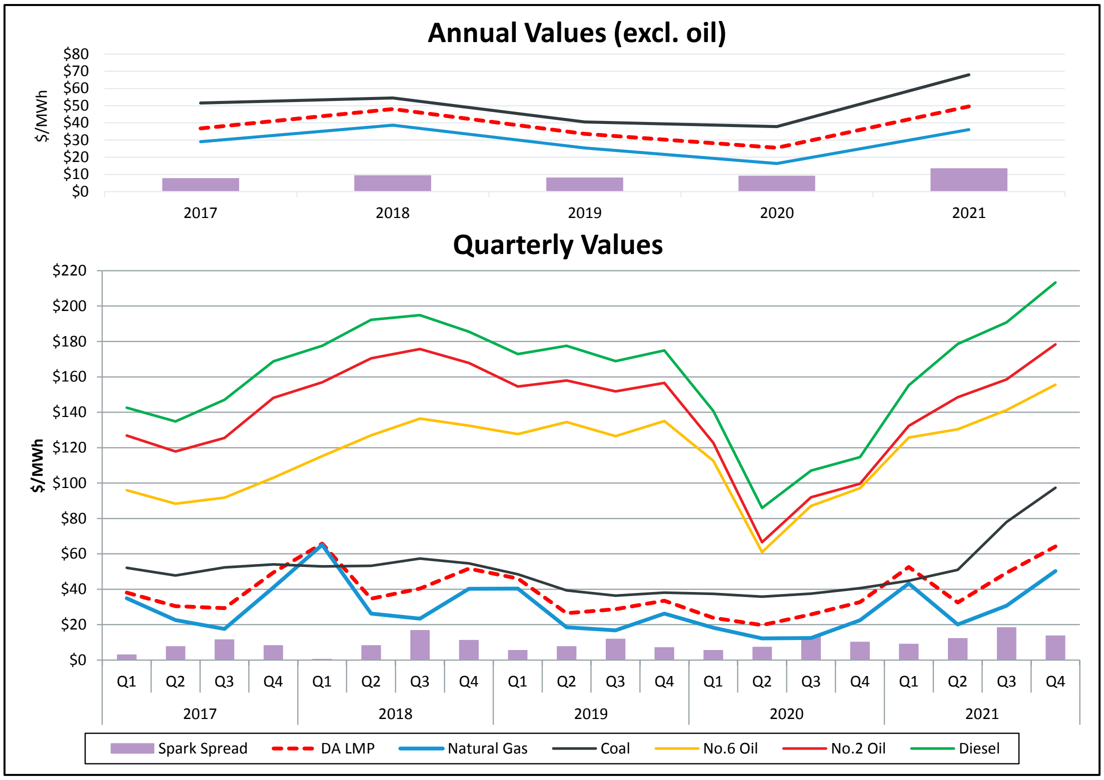
Statistic	2017	2018	2019	2020	2021	% Change 2020 to 2021
Demand (MW)						
Real-time Load (average hourly)	13,838	14,095	13,614	13,309	13,556	2%
Weather-normalized real-time load (average hourly)[a]	13,737	13,725	13,558	13,279	13,410	1%
Peak real-time load (MW)	23,968	26,024	24,361	25,121	25,801	3%
Generation Fuel Costs ($/MWh) [b]						
Natural Gas	29.02	38.61	25.41	16.34	36.07	121%
Coal	51.57	54.54	40.54	37.83	67.95	80%
No.6 Oil	94.76	127.80	130.90	89.43	138.30	55%
Diesel	148.36	187.60	173.54	112.06	184.69	65%
Hub Electricity Prices - LMPs ($/MWh)						
Day-ahead (simple average)	33.35	44.13	31.22	23.32	45.92	97%
Real-time (simple average)	33.93	43.54	30.67	23.38	44.84	92%
Day-ahead (load-weighted average)	35.23	46.88	32.82	24.57	48.30	97%
Real-time (load-weighted average)	36.15	46.85	32.32	24.79	47.34	91%
Estimated Wholesale Costs ($ billions)						
Energy	4.5	6.0	4.1	3.0	6.1	104%
Capacity	2.2	3.6	3.4	2.7	2.2	-16%
Net Commitment Period Compensation	0.05	0.07	0.03	0.03	0.04	38%
Ancillary Services	0.1	0.1	0.1	0.1	0.1	3%
Regional Network Load Costs	2.2	2.3	2.2	2.4	2.7	15%
Total Wholesale Costs	**9.1**	**12.1**	**9.8**	**8.1**	**11.2**	**38%**
Supply Mix [c]						
Natural Gas	40%	40%	39%	42%	45%	3%
Nuclear	26%	25%	25%	22%	22%	1%
Imports	17%	17%	19%	20%	16%	-4%
Hydro	7%	7%	7%	7%	6%	0%
Other[d]	5%	5%	5%	5%	5%	0%
Wind	3%	3%	3%	3%	3%	0%
Solar	1%	1%	1%	2%	2%	0.5%
Coal	1%	1%	0%	0%	0.46%	0.34%
Oil	1%	1%	0%	0%	0.19%	0.05%

[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] Provides a breakdown of total supply, which includes net imports. Note that section 2 provides a breakdown of native supply only.
[d] The "Other" fuel category includes landfill gas, methane, refuse and steam
denotes change is within a band of +/- 1%

As can be seen from Table 1-1, costs for the major fuels increased significantly in 2021, with gas prices being the key driver of the increase in energy prices. The system continues to be highly dependent on natural gas, accounting for 45% of the total supply mix. The most notable change in the supply mix was a 4% decline in imports, primarily from New York; there was a corresponding 3% increase in the share of gas-fired generation. Of the renewable generation categories (wind, solar, and hydro) only solar increased its contribution to the supply mix, and overall these resources comprised a relatively small share of the supply mix (~11%).

Energy Market Supply Costs: The trend in annual and quarterly estimated generation costs for each major fuel, along with the day-ahead on-peak LMP over the past five years, is shown in Figure 1-4 below.[30, 31]

Figure 1-4: Annual and Quarterly Generation Costs, Day-Ahead LMP and Spark Spreads (On-Peak Periods)



The cost of all major fuels increased in 2021. Gas and oil prices increased by 121% and 55% respectively, and coal prices were 80% higher than the prior year. The strong positive correlation between natural gas prices (blue line) and the LMP (dashed red line) is evident from the graph above.

The average cost of a combined-cycle natural gas-fired generator was $36/MWh in 2021, up about $20/MWh compared with $16/MWh in 2020. On-peak LMPs saw a corresponding increase of 95%. Average quarterly natural gas costs were within a wider $30/MWh range in 2021 (from $20/MWh in Q2 to $50/MWh in Q4), three times the $10/MWh range of 2020, but more in line with typical gas price range in years prior to 2020.

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30 On-peak periods are weekday hours ending 8 to 23 (i.e., Monday through Friday, excluding North American Electric Reliability Corporation [NERC] holidays.

31 Generation costs for each fuel are calculated by multiplying the fuel costs (in $/MMBtu) by a representative standard heat rate for generators burning each fuel (in MMBtu/MWh). For example, the heat rate assumed for a natural gas-fired generator is 7.8 MMBtu/MWh. The cost estimates exclude variable operation and maintenance and emissions costs.

Generator Profitability: Spark Spreads

The spark spread for a typical New England gas-fired generator increased significantly, by 58%, ($10.07/MWh vs. $15.86) between 2020 and 2021.[32] However, the implied (breakeven) heat rate decreased by just 10% year-over-year, indicating that slightly more efficient gas generation was on the margin during 2021, on average. The higher spark spread was driven by the increase in gas prices and the knock-on effect on energy prices.

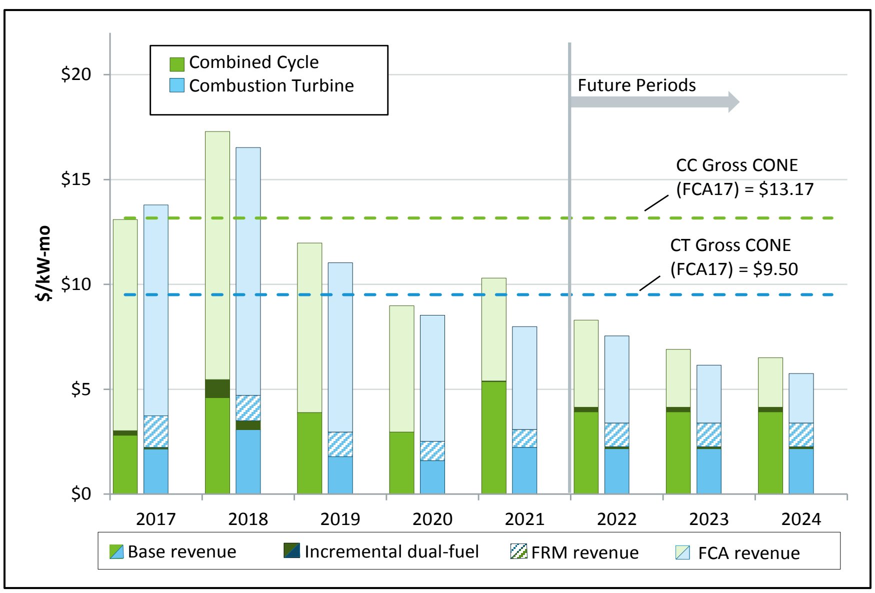
Spark spreads were highest again during Q3 in 2020 ($18.59/MWh), when more expensive, or less efficient, generators were dispatched to meet higher system demand. In contrast, Q1 spreads were again the lowest of the year, at $9.25/MWh, as higher gas prices tend to push more expensive gas-fired generators out-of-merit, and the supply mix shifts to less-expensive supply such as imports and hydro generation.

Generator Profitability: Simulation Results of Combined Cycle and Combustion Turbine Profitability

New generator owners rely on a combination of net revenue from energy and ancillary service (E&AS) markets and forward capacity payments to cover their fixed costs. The total revenue requirement for new capacity, before revenues from the energy and ancillary services markets are accounted for, is known as the Cost of New Entry (CONE), or Gross CONE.

A simulation analysis was conducted to assess whether historical energy and capacity prices were sufficient to cover Gross CONE. The results are presented in Figure 1-5 below. Each stacked bar represents revenue components by generator type and year. The analysis enables a comparison of total expected net revenue to the estimated Gross CONE for combined cycle (CC) and combustion turbine (CT) resources. If the height of a stacked bar rises above the relevant Gross CONE estimate, overall market revenues are sufficient to recover total costs.

Figure 1-5: Estimated Revenue and Profitability for New Gas-fired Generators



[32] The spark spread is the difference between the LMP and the estimated energy production cost of a gas-fired generator and is an industry standard metric of gross profits (expressed in $/MWh).

Notes: Base revenue is the net revenue from E&AS markets; i.e., energy and ancillary service revenue less variable production costs. Additional revenue to CTs in the forward reserve market and to CC and CTs with dual-fuel capability is also modelled.

Compared to 2020, the simulation results show 2021 total revenues increased by about 14% for a combined cycle (at $10.3/kW-mo) but decreased by about 6% for a combustion turbine (at $8.0/kW-mo) participating in the Forward Reserve Market (FRM).

Revenue from the capacity market (FCA revenue) decreased by 18% for both technologies, in line with the drop in clearing prices associated with FCAs 11 and 12. For the combined cycle, base revenues increased by 80% (by $2.4/kW-mo), and combined base and FRM revenue for the combustion turbine increased by 23% (by $0.6/kW-mo). These year-over-year increases were driven by greater capacity utilization and significantly higher spark spreads, which increased by 58% from the prior year. Section 3.4.1 discusses spark spreads in more detail.

Similar to 2019 and 2020, dual-fuel capability in 2021 did not add any revenue for the CT generator and added only $0.04/kW-month to net revenue for the CC generator. Like the previous two winters, Winter 2021 was relatively mild, which limited opportunities for generation on oil.

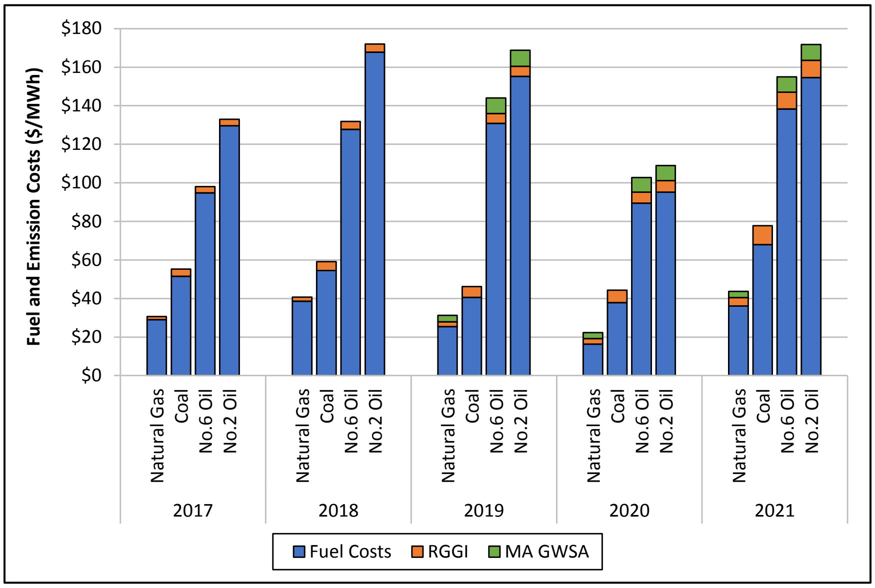
In recent years, capacity prices have generally not been high enough to support the entry of new gas-fired generation. Prices have trended downwards reflecting a system that has cleared a surplus of qualified capacity compared to the system's capacity requirement. Total revenues from the energy and capacity markets appear insufficient to incent either type of gas-fired generator to enter the region's energy market. In fact, New England has not had a new gas-fired generator clear the FCA since 2019 (FCA 13). Total revenue for a CC fell well short (by $2.9/kW-mo) of the estimated annualized revenue requirement (Gross CONE) of $13.2/kW-mo, while the total revenue from a combustion turbine was relatively closer to its Gross CONE value of $9.5/kW-mo.

Carbon Emissions Markets in New England

Carbon emissions costs have a relatively small, albeit increasing, impact on operating costs but can significantly impact profitability margins. The key driver of emission costs for all New England generators is the Regional Greenhouse Gas Initiative (RGGI), the marketplace for carbon dioxide (CO_2) credits. In addition, a CO_2 cap-and-trade program that places an annual cap on aggregate CO_2 production from fossil fuel-fired generators began in Massachusetts in 2018 as part of their Global Warming Solutions Act (GWSA).[33] Both cap-and-trade programs attempt to make the environmental cost of CO_2 explicit in dollar terms so that producers of energy consider it in their production decisions. The costs of both emissions programs for generators by fuel type (with typical efficiencies) relative to their fuel costs is shown in in Figure 1-6 below.

[33] 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 1-6: Annual Estimated Average Costs of Generation and CO_2 Emissions[34]



At current price levels, CO_2 emission programs have little effect on the economic merit order of gas, coal and oil generation as can be seen from the relatively large differences in the operating costs of each fuel. In 2021, the average estimated costs of the RGGI program increased by 51% for most fossil fuel-fired generators year-over-year: natural gas ($2.88/MWh to $4.36/MWh), coal ($6.51/MWh to $9.85/MWh), No. 6 oil ($5.77/MWh to $8.73/MWh), and No.2 oil ($5.95/MWh to $9/MWh).

Therefore for a combined cycle natural gas-fired generator, the inclusion of RGGI costs would reduce its 2021 on-peak spark spread of $15.86/MWh (as covered above) to $11.50/MWh (this is also known as a *clean* spark spread). The average estimated costs of the Massachusetts GWSA program increased 5% from 2020, adding $3.25/MWh to the estimated cost of natural-gas generation and would further reduce the clean spark spread for a Massachusetts combined cycle to just $8.25/MWh.[35]

Energy Market Demand

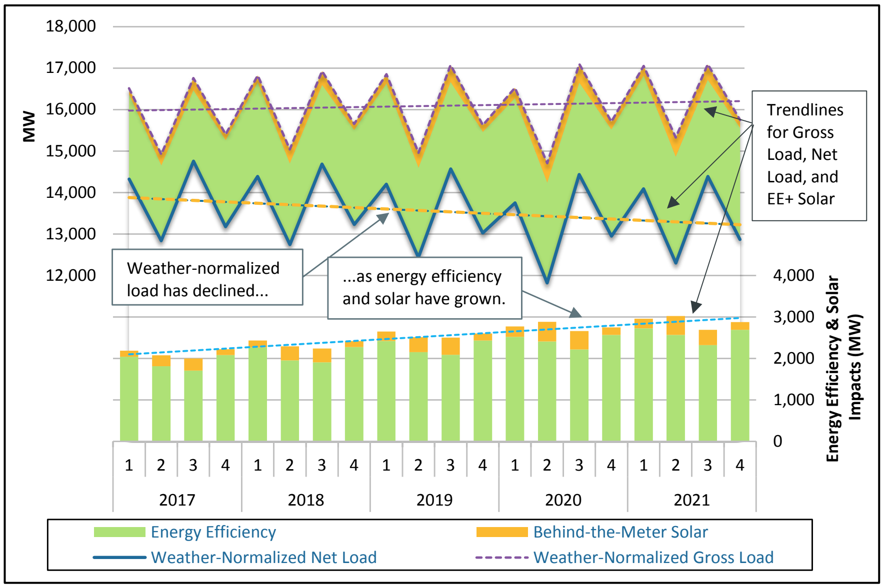
The demand for electricity is weather-sensitive and this contributes to the seasonal variation in energy prices. New England's net native electricity demand, referred to as net energy for load (NEL) averaged 13,556 MW per hour in 2021, up 2% on 2020. In 2021, weather-normalized load increased by 1.3%, the first increase since 2011. Prior to 2021, average annual weather-normalized load typically fell due to growth in energy efficiency and, to a lesser extent, behind-the-meter solar

[34] IMM standard generator heat rates and fuel emission rates are used to convert $/ton CO2 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.

[35] The market dynamics of having an explicit price on CO_2 are worth noting here. When less efficient and higher CO_2-emitting resources (than the assumed 7.8 heat rate proxy CC here) set the energy price, then the proxy CC earns a higher margin than it otherwise would absent the price on CO_2.

generation. The 2021 increase of weather-normalized load reflects electricity demand recovering after business closures largely ended prior to the start of 2021. Figure 1-7 below displays the average quarterly weather-normalized load and the estimated impact of energy efficiency and behind-the-meter solar over the past five years.

Figure 1-7: Average Quarterly Weather-Normalized Load with Energy Efficiency and Solar Impacts



Energy efficiency has the largest impact on load, reducing annual average load by an estimated 2,577 MW, a 6% increase (148 MW) compared to 2020, and a 35% increase (665 MW) compared to 2017. BTM PV generation reduced annual average load by 310 MW or nearly 11% of its estimated installed capacity (2,792 MW), representing an 8% decrease (27 MW) compared to 2020. While behind-the-meter generation decreased this year, it is still forecasted to grow in the future. By 2030, behind-the-meter solar generation is expected to reduce annual load by an average of 768 MW.[36]

Operating Reserves: The bulk power system needs reserve capacity in order to respond to contingencies, such as those caused by unexpected outages. The system reserve requirement has been relatively constant over the past five years, with an average total ten-minute reserve requirement of 1,700 MW and total thirty-minute reserve requirement of about 2,500 MW.

In 2021, the average operating reserve *margins* remained high, with a total thirty minute operating reserve margin of over 3,000 MW and a total ten-minute reserve margin of about 2,000 MW.

Imports and Exports: New England has transmission connections with both Canada and New York. Under normal circumstances, the Canadian interfaces reflect net imports of power into New England whereas the interfaces with New York can reflect net imports or net exports, depending on market conditions. While net imports have been relatively consistent over previous years, ranging from 17% to 20% of native demand, in 2021 net imports dropped to 16% of native demand. In 2021, net imports averaged 2,144 MW per hour, a drop of 536 MW from 2020. The net decrease occurred primarily at the New York North interface, where there was an increase in exports. In

[36] For more information, see ISO New England's 2021 CELT Report.

April 2021, the Indian Point nuclear plant in New York retired. This increased congestion in New York, which increased day-ahead prices there relative to New England.

The majority of import transactions continue to flow into the New England market regardless of price (i.e., are price takers), particularly over the Canadian interfaces which account for 87% of net imports. This applies downward pressure on energy prices, especially around the areas of interconnection with the New England system. In 2021, the average day-ahead prices at the Phase II (which connects New England and the Hydro-Québec control area) and New York North interfaces (the two largest ties) were 1% and 8% lower than the New England Hub price, respectively. Similarly, at the other two Canadian interfaces, New Brunswick and Highgate, average day-ahead prices were 5% and 9% lower than the Hub, respectively.

Coordinated Transaction Scheduling (CTS) with New York: The performance of CTS was broadly similar to prior years. Introduced in 2015, CTS improved the optimization of real-time power flow between New York and New England across the New York North interface. It did this by unifying the bid submission and clearing processes, reducing latency between clearing and actual flow (delivery) and eliminating transaction fees. While there are considerable economic and reliability benefits of the CTS rules, we find that there is room for improvement, specifically in the related areas of price forecasting and participant bidding.

Average real-time New England prices (at the New York North interface) were about $2/MWh higher than in New York, consistent with the 2020 price spread, and net power flowed from New York into New England 69% of the time in 2021. However, when examining the flow of power at the 15-minute interval level we find the net flow was to the higher-priced area just 56% of the time. Conversely, net flows are to the lower-priced market 44% of the time. This indicates that CTS is not effectively adjusting flows to real-time price differences, i.e., net imports are too high relative to the real-time price differences. Further, when the price difference between regions was high, on average CTS did not fully utilize the transfer capability or ramp constraint allowances to converge prices. For example, even in scenarios where price differences were between $50 and $100 per MWh, there was 150 MW of average unused interface capacity.

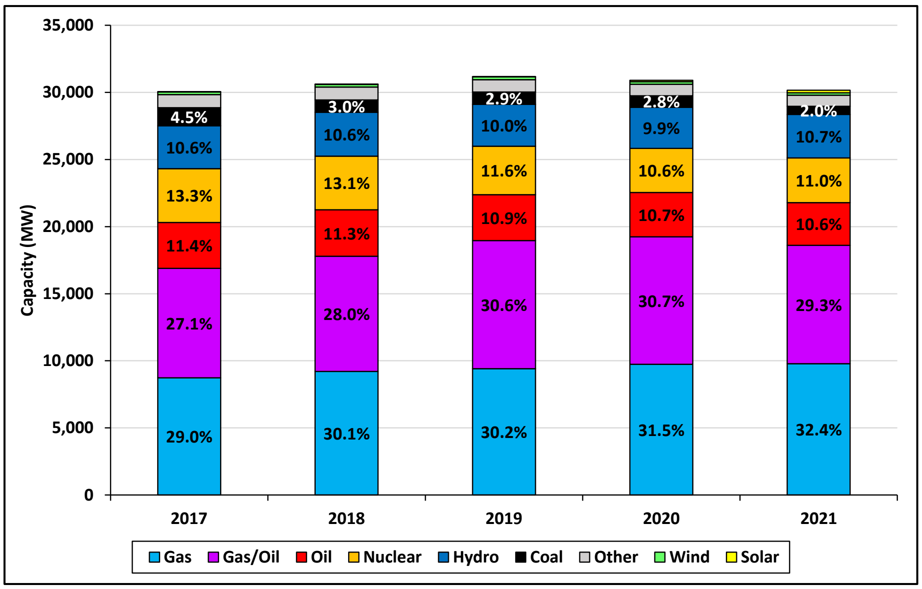
CTS scheduling is based on price forecasts from each ISO, and therefore schedules are not always economic after actual energy prices are determined. Consequently, forecast error introduces risk of clearing CTS transactions out-of-merit. One strategy to avoid this risk is to hedge real-time CTS transactions by taking on positions in the day-ahead market. Many participants acquire day-ahead schedules and offer price insensitive transactions in the real-time to match their day-ahead positions. This minimizes risk of clearing out-of-merit in real-time, but inhibits CTS from being flexible in response to real-time price difference.

Because 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 assess potential enhancements with respect to the latter (settlements), and we continue to recommend that the ISO assess improvements in price forecasting for CTS.

Capacity Market Supply and Demand: As with energy prices, there has been a strong link between capacity prices and natural gas-fired generators. Gas-fired generators have comprised the vast majority of new generation additions since the inception of the FCM. Newer, cleaner and more efficient technology, combined with low natural gas prices, increasing emissions costs, and environmental regulations have contributed to more investment in new natural gas-fired generators compared to other fossil fuel-fired generators. Further, the benchmark price in the capacity market, the net cost of new entry, is linked to the recovery of the long-run average costs of a new-entrant combustion turbine.

Supply: Three categories of capacity resources participate in the FCM. Generators make up 86% (30,011 MW in Capacity Commitment Period, or CCP, 2021/22) of total capacity with the remainder comprised of imports (3% or 1,217 MW) and demand response (10% or about 3,600 MW). Overall, demand response capacity has fluctuated in recent years, with retirements of active demand resources being offset by the new entry of passive (energy efficiency) demand resources. A breakdown of generator capacity by fuel type is shown in Figure 1-8 below.

Figure 1-8: Average Generator Capacity by Fuel Type



Notes: 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, steam, and wood.

Natural gas generation continues to be the dominant fuel source for capacity in New England. Combined, gas- and gas/oil-fired dual-fuel generators accounted for over 61% (about 18,600 MW) of total average generator capacity in 2021. There were no significant changes in capacity by fuel type in 2021. The largest year-over-year change in capacity came from gas/oil dual-fuel generators, which decreased in share from 30.7% (9,500 MW) in 2020 to 29.3% (8,800 MW) in 2021, driven largely by gas/oil generators shedding capacity obligations for one year or less in FCM reconfiguration auctions.

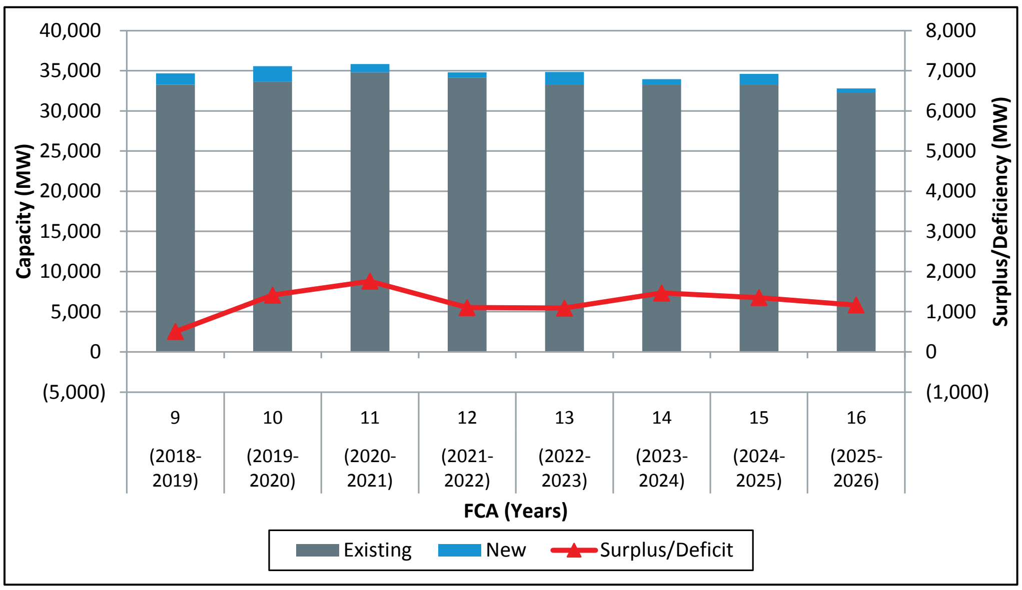
Demand: The Net Installed Capacity Requirement (NICR) for the sixteenth Forward Capacity Auction (FCA 16) was 31,645 MW.[37] The NICR decreased by 1,625 MW, or by 8%, from FCA 15, largely driven by a change in the reconstitution of passive demand resources in the ISO load forecasts. Reconstitution reflects the estimated supply provided by passive demand resources into

[37] The Net Installed Capacity Requirement (NICR) is the amount of capacity (MW) needed to meet the region's reliability requirements (after accounting for tie benefits with Hydro-Quebec). The value is grossed up to account for the amount of energy efficiency reductions participating in the FCM. Due to transmission limitations there are also local sourcing requirements (LSR) for import-constrained areas and maximum capacity limits (MCL) for export-constrained areas.

the forecasted demand of New England, and showed that the FCA 16 adjustment greatly reduced the estimated supply of passive demand resources. Additionally, battery storage resources and active demand capacity resources had updates to their modeling methodology. For the prior auction (FCA 15), NICR increased by 780 MW, or 2% compared to FCA 14, due to the introduction of transportation and heating electrification to peak load forecasts and decreased interchange tie benefits. This follows a period of relatively small changes to capacity requirements, with annual changes in a +/- 1% range.

Supply/Demand Balance: The supply and demand balance in the FCM has gone through a number of shifts in recent years. The volume of capacity procured in each auction relative to the NICR is shown in Figure 1-9 below. The stacked bar chart shows the total cleared volume in each auction, broken down between existing and new capacity resources. The red line (corresponding to the right axis) shows the level of capacity surplus or deficit relative to NICR.

Figure 1-9: Cleared and Surplus Capacity in FCA 9 through FCA 16



In FCAs 9, 10, and 11, new generation and demand response resources cleared 1,400, 1,800, and 900 MW, respectively. The new generation, along with fewer retirements, turned a 140 MW deficit in FCA 8 (not shown) into a 1,800 MW surplus by FCA 11. With lower clearing prices, the surplus declined in FCAs 12 and 13, primarily due to one-year de-lists of existing resources. The surplus rose once again in FCA 14 to 1,500 MW, driven primarily by a decrease in the NICR of almost 1,300 MW.

In FCA 15, cleared capacity rose by 665 MW over FCA 14, yet the surplus decreased slightly to 1,351 MW due to a 780 MW increase in the NICR. New battery storage projects (596 MW) and the repowering of existing gas-fired generation (334 MW) made up most of the 1,121 MW of new supply, while low clearing prices in FCA 15 prompted over 1,050 MW of existing supply to exit for one year.

The surplus fell slightly in FCA 16, down to 1,165 MW. While the Net ICR decreased by 1,625 MW, cleared capacity decreased by a greater amount of 1,810 MW. Existing capacity de-listed 1,864 MW while only 567 MW of new supply was added to the system.

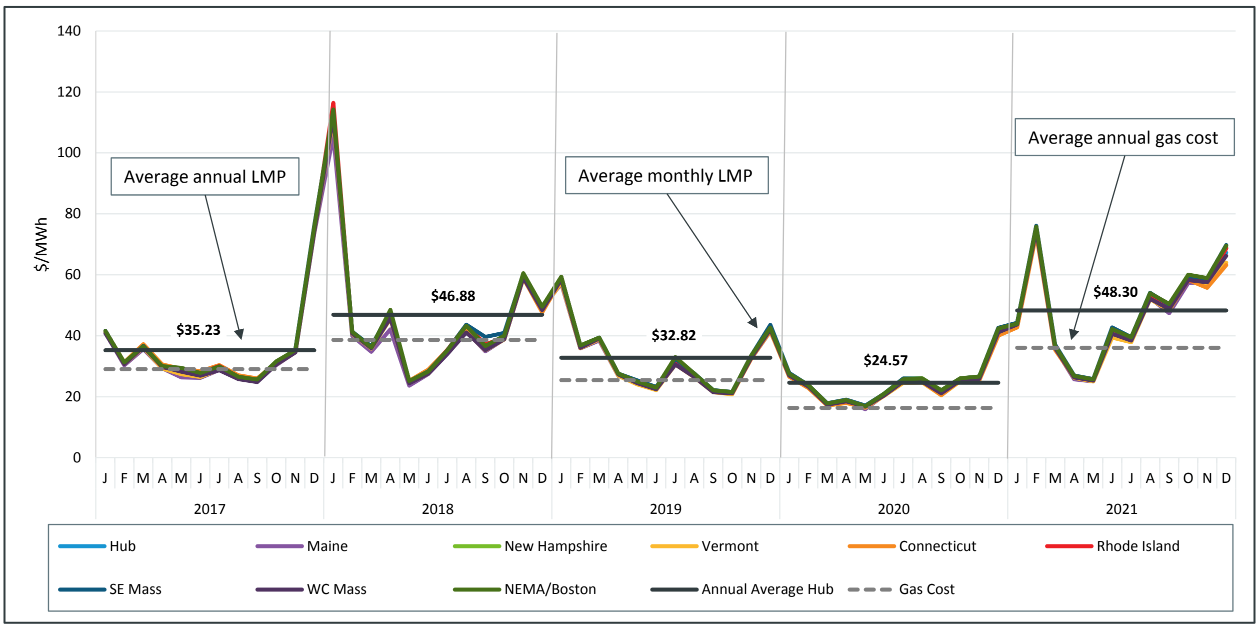
1.3 Day-Ahead and Real-Time Energy Markets

Prices: The annual real-time LMP in 2021 averaged $45/MWh (simple average). This was almost double the 2020 average of $23/MWh, which was an all-time low since standard market design was introduced in 2003. Hub prices increased by 97% in the day-ahead market and by 92% in the real-time market compared to 2020 prices.

Price differences among the load zones were relatively small in 2021, reflecting a continued trend of modest levels in both marginal losses and congestion. The average absolute difference between the Hub annual average price and average load zone prices was $0.51/MWh in the day-ahead energy market and $0.41/MWh in the real-time energy market – a difference of approximately 1.0%.

The monthly load-weighted prices across load zones over the past five years are shown in Figure 1-10 below. The black line shows the average annual *load-weighted* Hub price. The dashed gray lines show the estimated annual average gas generation cost.

Figure 1-10: Day-Ahead Energy Market Load-Weighted Prices



The graph illustrates a pattern in prices that varies considerably by year and by month, but not by load zone. In January 2018, constraints on the natural gas system resulted in large spikes in natural gas and electricity prices. 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.

Price-setting transactions: A significant proportion of the aggregate supply and demand curves are not price-sensitive. On the supply side, this is due to importers submitting fixed-priced bids, generators self-scheduling, and generators operating at their economic minimum. The first two categories are price-takers in the market. Price-takers are even willing to pay to supply power when LMPs are negative. On the demand side, load-serving entities (LSEs) submit a large amount of fixed bids. Overall, only about 30% to 40% of aggregate supply and demand can set price in the day-ahead energy market due to bidding behavior and operational constraints (limited dispatchability).

However, this amount effectively falls to about 5% on the demand side, considering that very high-priced bids (whereby the bids always clear) effectively act as fixed-priced. It is worth noting that the expected growth in energy storage devices (batteries) will likely add price-setting ability to both the demand and supply sides of the energy market.

Large volumes of unpriced supply in the market can result in low or negative pricing, particularly when demand is close to the fixed portion of the supply curve and energy provided by renewable generators is at the margin. However, the overall frequency of negative real-time prices at the Hub remains relatively low, occurring in 0.3% of hours in both 2020 and 2021. Even in Maine, which tends to have a higher frequency of negative nodal prices at export-constrained pockets with wind generation, the hourly zonal price was negative in only 0.4% of hours in 2020 and 2021. The issue of fixed supply and demand is not of particular concern to us with respect to energy market price formation since prices are generally consistent with input costs and system conditions.

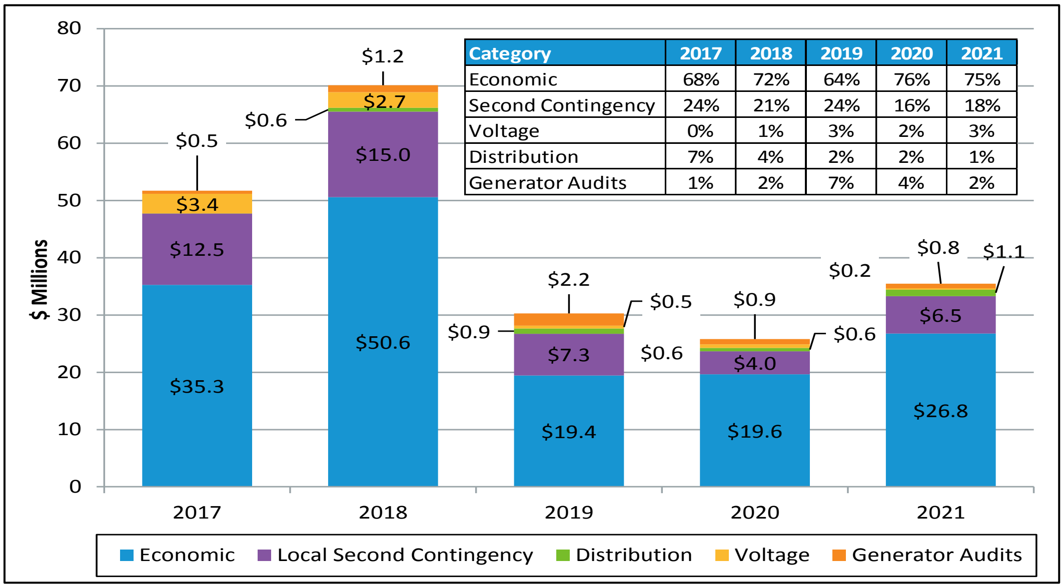
In this context of limited price-setting ability, virtual demand and supply tend to serve an important price-discovery role in the day-ahead market. Cleared virtual transactions have increased slightly over the last five years, rising from 810 MW per hour in 2017 to 966 MW per hour in 2021. Average cleared virtual supply increased by 19% and average cleared virtual demand increased by 20% over the five-year reporting period. Virtual transactions set price for about 25% of day-ahead load in 2021, comparable to prior years' statistics.

Natural gas-fired generators continued to be the dominant price-setting resources in 2021 at 52% in the day-ahead market and 83% in the real-time market. Pumped-storage units (both generators and pumps) continued to be the second largest marginal entity in real-time, at 15%. Wind generators are frequently marginal but their price-setting ability is less impactful; they are marginal for only a small share of total system load (~1% in 2021). Wind generators are often located in export-constrained areas and can only deliver the next increment of load in a small number of locations because the transmission network that moves energy out of their constrained area is at maximum capacity.

Net Commitment Period Compensation (NCPC): In 2021, NCPC (uplift) payments totaled $35.5 million, an increase of $9.7 million (up by 38%) compared to 2020. Even though total uplift payments increased in dollar terms, payments as a percentage of total energy payments decreased from 0.9% in 2020 to 0.6% in 2021, the lowest percentage level over the five-year reporting period. This continued a downward trend in payments from prior years, driven by a number of market rule changes.[38] Payments were relatively stable each quarter like in 2020, consistent with relatively unstressed system conditions and relatively low levels of out-of-market operator intervention such as posturing of resources. Annual total NCPC payments by category, as well as the percentage share of each category (inset graph), are shown in Figure 1-11 below.

[38] The elimination of day-ahead commitment eligibility for real-time NCPC (in February 2016) and the introduction of fast-start pricing (in March 2017) both applied downward pressure on NCPC costs.

Figure 1-11: Total Uplift Payments by Year and Category



Economic (first-contingency) payments made up the bulk of uplift payments, totaling $26.8 million (or 75% of total payments), an increase of $7.1 million from $19.6 million in 2020. Economic NCPC payments were only 0.4% of total energy payments, the lowest level over the past five years. Local Second Contingency Protection (LSCPR) payments to cover local reliability commitments, mostly in the day-ahead market, were $6.5 million, an increase of $2.5 million, or 63%, from 2020 payments. About 71%, or $4.6 million, of total LSCPR payments went to generators providing reliability protection during transmission outages in Maine and New Hampshire in the winter months, and in NEMA/Boston in June.

Congestion Costs/Revenue and Financial Transmission Rights: Congestion revenue was $50.1 million in 2021, a 72% increase from $29.1 million dollars in 2020. Congestion represented less than 1% of total energy costs, which was comparable to the prior four years. One of the primary drivers for the increase in congestion revenue was the increase in congestion charges that occurred at the New York - New England (NYNE) interface.[39]

The average MW-amount of FTRs held by participants rose slightly in 2021, marking the first year-over-year increase during the reporting period. The 2021 value (32,443 MW) was still 8% less than the amount in 2017 (35,452 MW). The increase in 2021 from 2020 levels may be partly related to the economic shutdown due to COVID-19, as there was a notable reduction in FTR purchases that occurred in the prompt-month auctions for April and May 2020 compared to prior years. The expectation of lower loads during the shutdown may have led to an anticipation of lower congestion.

FTRs were fully funded in 2021, as they were in the prior four years, meaning that there was sufficient congestion revenue collected in the energy market to pay FTR holders. Meanwhile, the ownership of FTRs continued to be relatively concentrated in 2021, with 61% of FTR MWs in on-peak and 64% in off-peak periods held by the top four participants. Several of these top FTR holders are financial players that do not own physical generation or serve load. After two years of

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[39] Interfaces are sets of transmission elements whose power flows are jointly monitored for voltage, stability, or thermal reasons.

losses, FTR holders made a collective profit of $25.9 million in 2021. FTR activity associated with the NYNE interface was one major reason for this increased profitability.

Energy Market Competitiveness: We apply a broad range of industry-standard economic metrics to assess the general structure and competitiveness of the energy market.[40] The metrics presented in this report include the C4 (a measure of market concentration), the Residual Supply Index, Pivotal Supplier Test, the Price-Cost Markup metric, and the Real-Time Economic Withholding metric. Each metric assesses market concentration or competitiveness with varying degrees of usefulness, but combined, can complement one another. Market power mitigation rules are also in place in the energy market, allowing the IMM to closely review underlying costs of offers and to protect the market and consumers from the potential exercise of market power.

The following metrics were calculated for the real-time energy market:

- *Residual Supply Index (RSI) and Pivotal Supplier Test (PST)*[41]
  The PST and RSI indicate whether the availably capacity of the largest supplier is required to satisfy the system's load and reserve requirements. If its capacity is required, the supplier has market power (is "pivotal"), and could be in a position to unilaterally increase prices above competitive levels through economic or physical withholding strategies.

  However, systemwide market power has been very limited in recent years. For 2021, the PST indicates that there was a pivotal supplier in just 18% of hours, and the average RSI was above 100 for the past four years, and above 90 in 99% of hours.[42] This is comparable to 2020 and 2019, and represents a significant improvement on prior years due to high supply margins and no significant changes in participant portfolios that increased market concentration.

- *C4 for supply-side participants*
  The C4 value expresses the percentage of supply controlled by the four largest companies. In 2021, the C4 in the real-time energy market was 42%, unchanged from 2020. This value indicates low levels of system-wide market concentration in New England, particularly when the market shares are not highly concentrated in any one company. No one company maintains a dominant share of on-peak supply, and the split among the top four suppliers has remained stable.

- *C4 for demand-side participants*
  The demand share of the four largest firms in the real-time energy market in 2021 was 60%, unchanged from 2020. The observed C4 values indicate relatively low levels of system-wide concentration. Further, most real-time load clears in the day-ahead market and is bid at price-insensitive levels; two behavioral traits that do not indicate an attempt to

[40] Each metric accounts for the IMM's best estimate of affiliate relationships among market participants.

[41] The RSI provides a measure of structural competitiveness by evaluating the extent to which supply, without the single largest supplier, can meet demand. This provides an indication of the extent to which the largest supplier has market power and can economically or physically withhold generation and influence the market price. A related concept is that of a pivotal supplier. If some portion of supply from a portfolio (not necessarily the largest supplier) is needed to meet demand then that supplier has market power and can withhold one or more of its resources to increase the market price.

[42] An RSI of 100 means that 100& of the system's load and reserve requirement can be satisfied without the capacity of the largest supplier.

exercise buyer-side market power (i.e., suppressing prices). The same four load serving entities comprised the top four in 2021 and 2020.

- *Real-Time Economic Withholding*
  This metric assesses the degree of economic withholding in the real-time energy market. Economic withholding occurs when suppliers offer above marginal cost in order to prevent some quantity 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.

  In 2021, the level of economic withholding was relatively low and generally in line with levels seen in past years. 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.

The competitiveness of pricing outcomes in the day-ahead energy market was assessed using the Price-Cost Markup metric:

- *Price-Cost Markup (PCM)*
  The PCM is a measure of market power that estimates the component of the price that is a consequence of offers above marginal cost.[43] In a perfectly competitive market, all participants' offers would equal their marginal costs. Since this is unlikely to always be the case, the PCM is used to estimate the divergence of the observed market outcomes from this ideal scenario.

  The PCM remained relatively low in 2021 at 8.4%, indicating that competition among suppliers limited their ability to increase price by submitting offers above estimates of their marginal cost. This indicates that offers above marginal cost increased the day-ahead energy market price by approximately 8.4%. These results are consistent with previous years and within an acceptable range given modeling and estimation error.

This subsection assesses the degree of economic withholding in the real-time energy market. Economic withholding occurs when suppliers offer above marginal cost in order to prevent some quantity 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.

In 2021, 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

[43] The Price-Cost Markup is calculated as the percentage difference between the annual generation-weighted LMPs between two scenarios. The first scenario calculates prices using actual supply offers, while the second scenario uses marginal cost estimates in place of supply offers. 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 supply curves, and calculates the difference in the resulting LMPs.

were largely unable or did not attempt to take advantage of tight system conditions by economically withholding.

The number of energy market supply offers mitigated for market power remained very low. Of 44,272 asset-hours that were evaluated for market power, only 957 asset-hours were deemed as having violated mitigation thresholds and were mitigated, representing 2% of the 44,272 asset hours.

In the absence of effective mitigation measures, participants may have the ability to unilaterally take action that would increase prices above competitive levels. While the energy market mitigation rules are in place to protect the market from such action, the rules permit a high tolerance level. For example, for system-wide market power a participant must submit supply offers in excess of $100/MWh or 300% above a competitive benchmark price, and impact price, before mitigation takes place. The thresholds are still relatively high for local constrained area market power, with tolerances of $25/MWh or 50%. The IMM believes that it is an appropriate time for the ISO to review and potentially lower these thresholds to strike a better balance between the level of possible market intervention and consumer protection.

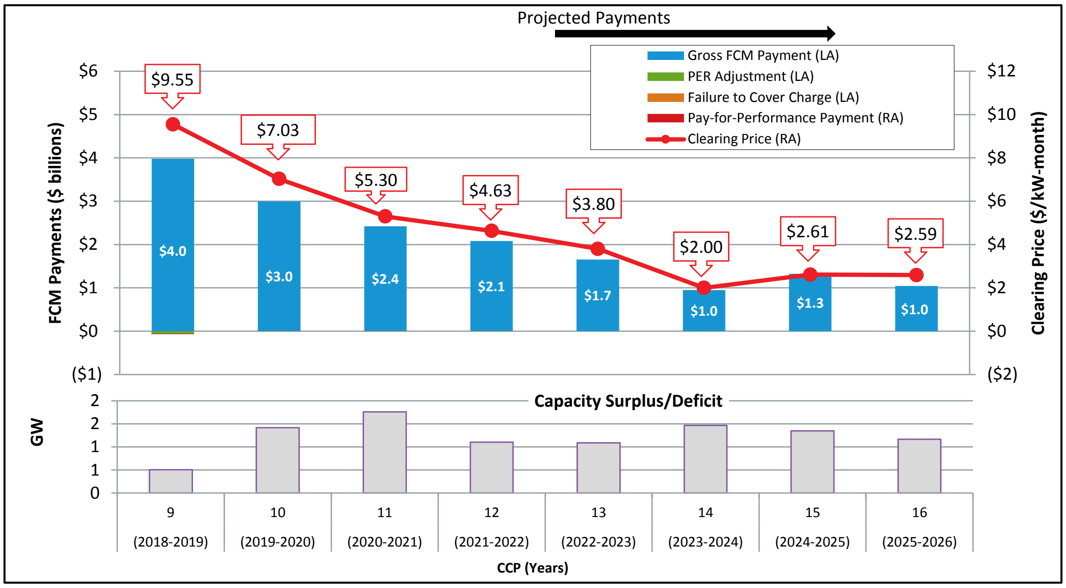
1.4 Forward Capacity Market (FCM)

Capacity prices resulting from the Forward Capacity Auctions (FCAs) have fluctuated as the number of resources competing and clearing in the auctions and the region's capacity surplus have changed. Overall, the FCM has largely achieved its design objectives of attracting new efficient resources, maintaining existing resources and encouraging the retirement of less efficient resources.

FCM Prices and Payments: Rest-of-Pool clearing prices, payments and the capacity surplus from the ninth capacity commitment period (CCP9) through CCP 16 are shown in Figure 1-12 below.[44] The graph captures the inverse relationship between capacity surplus above the Net Installed Capacity Requirement (NICR) and capacity clearing prices.

[44] Payments for future periods, CCP 10 through CCP 14, have been estimated as: $FCA\ Clearing\ Price \times Cleared\ MW \times 12$ for each resource.

Figure 1-12: FCM Payments and Capacity Surplus by Commitment Period



Beginning with FCA 9, the adoption of a system sloped demand curve improved price formation; specifically, it reduced price volatility and helped deliver more efficient price signals to maintain the region's long-run reliability criteria.

In FCA 9, the clearing price was $9.55/kW-month for all capacity resources, except for higher prices in the import-constrained zone of Southeastern Massachusetts/Rhode Island (SEMA/RI).[45] High clearing prices in FCA 9 provided price signals to the market that new generation was needed. As more capacity cleared in those auctions, prices generally declined from FCA 10 through FCA 14, with a slight uptick in FCA 15 prices. Since FCA 11, clearing prices have fallen below the dynamic de-list bid threshold price. De-list bids below this threshold are not subject to IMM review, since it is less likely for participants to successfully exercise market power given the surplus capacity conditions associated with prices in this range.

Projected payments fell for FCA 16 along with clearing prices; total payments for CCP 16 are projected to be $1.0 billion, down $0.3 billion (21%) from projected payments for CCP 15, due to a decline in total CSO and less price separation in the import-constrained Southeastern New England capacity zone.

Market Competitiveness: Two metrics are calculated to evaluate the competitiveness of the capacity market with respect to existing resources: the residual supply index (RSI) and the pivotal supplier test (PST). The results of these two complementary measures indicate that the New England capacity market can be structurally uncompetitive at both the zonal and system levels. The extent of structural competitiveness has fluctuated widely across capacity zones over the last five auctions as the capacity margin has changed. In FCA 16, the system level RSI was above 100% but the Southeastern New England (SENE) zonal level RSI was below 100% due to the retirement of the Mystic generators. There have still been few pivotal suppliers at the system level since FCA 11.

[45] Clearing prices in SEMA/RI were $17.73/kW-month for new resources and $11.08/kW-month for existing resources.

The market has both buyer- and supplier-side mitigation rules to prevent the potential exercise of market power. The buyer-side mitigation rules are also known as the Minimum Offer Price Rules (MOPR) and are designed to ensure that new supply offers in the FCA are set at competitive levels that are supported[46], consistent with market conditions and exclusive of out-of-market revenues (subsidies). In practical terms, MOPR has predominately applied to sponsored policy resources that are being developed to meet the states' environmental goals, as opposed to addressing the exercise of buyer-side market power.

Specific to the RSI and pivotal supplier metrics, existing resources are subject to a cost-review process and supplier-side mitigation. 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. In the most recent auction (FCA 16), there were no pivotal suppliers with de-list bids.

For *MOPR*, offers from about 461 resources were reviewed over the past five auctions (FCA 12-16). These offers came from 64 different lead participants and totaled 20,800 MW of qualified capacity, of which about 12,000 MW (~58%) ultimately entered the auction.[47] Generation resources accounted for the majority of new capacity reviewed, comprising 83% of the total (12,000 MW). Demand response resources accounted for the remaining 6% (1,200 MW). The IMM mitigated approximately 82% (375) of the new supply offers it reviewed, or approximately 88% by capacity (18,200 MW). Mitigation resulted in an average increase in offer prices of $4.33/kW-month (from a submitted price of $2.16/kW-mo to an IMM-determined price of $6.49/kW-mo).

For the most recent auction, FCA 16, the impact of MOPR on resource clearing was relatively small compared to the number of pre-auction IMM reviews. Prior to the auction, 62 new resources requested an offer floor price below the applicable Offer Review Trigger Price (ORTP), totaling almost 2,900 MW of capacity.[48] Of this, 43 resources (~2,400 MW) were denied (mitigated) by the IMM. Ultimately, 28 of these resources (or ~1,200 MW based on SoI, and 600 MW based on qualified capacity) participated in the auction. Of the qualified resources, five resources (or ~300 MW) did not clear in the auction as they exited at the IMM-determined prices which was above the clearing price, mostly (~ 200 MW) comprising energy storage resources. In addition, another 30 resources (totaling ~180 MWs) did not challenge their ORTP, and were removed during the auction at their respective ORTP values.

On the *seller-side*, the IMM reviewed 63 general static de-list bids from 13 different lead participants over the past five FCAs, totaling roughly 7,800 MW of capacity (an average of 1,600 MW per auction).[49] Generation resources accounted for 7,700 MW and demand response resources made up 80 MW. About 60% of bids were accepted by the IMM without any changes. Of the static de-list bids that were denied, many were voluntarily withdrawn or the bid price further reduced prior to the auction. Only de-list bids belonging to pivotal suppliers are mitigated. There were

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[46] Sufficient documentation and information must be included in the resource's FCA qualification package per Market Rule 1, Appendix A.

[47] 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.

[48] Based on Show of Interest values, which can be different that the actual qualified values determined by the system planners.

[49] 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.

active de-list bids from pivotal suppliers in FCA 13 only; the four other auctions had zero bids mitigated.

The test price mitigation rule was introduced in FCA 14, and applies to resources (above 3 MW) seeking to retire through the substitution auction. The rule is designed to address the incentive for a resource to reduce its primary auction bid below a competitive level (by factoring in the value of a severance payment) in the hopes of retaining its CSO, and subsequently trading out of it for a severance payment in the substitution auction. Without an IMM review, this behavior could have a price-suppressing impact on the primary auction.

In FCA 16, fifteen existing resources with a combined capacity of 994 MW elected to participate in the substitution auction. The weighted-average submitted test price was $4.35/kW-mo. The IMM reviewed 12 resources with a combined capacity of 993 MW and denied five resources (above the 3 MW threshold). The weighted-average IMM-determined test price was $4.10/kW-mo. All 737 MWs that obtained a CSO in the primary auction were eligible to participant in the substitution auction. However, the substitution auction did not clear any capacity obligations because its demand and supply curves did not intersect (i.e., demand bids of existing resources were too low relative to supply offers of sponsored resources).

1.5 Ancillary Services Markets

The ancillary services markets include a number of programs designed to ensure the reliability of the bulk power system, including operating reserves (forward and real-time), blackstart, voltage, and regulation. In 2021, the costs of most ancillary service products and their associated make-whole payments were higher than, or similar to, 2020 costs. Overall, ancillary services costs increased to $109 million in 2021 from $103 million in 2020.[50] The only category with a notable increase was blackstart costs, which at $35 million increased by $5.6 million, or 21%. The increase was due to blackstart fleet composition changes, coupled with the annual rate adjustment for inflation of approximately 5.7%.

Real-time Reserves: Higher energy prices throughout the year led to a $2.9 million increase in gross reserve payments in 2021, up to $13.7 million from $10.8 million in 2020. Based on higher re-dispatch costs for reserves in the co-optimization process, ten-minute spinning reserve (TMSR) payments were $10.0 million. This was $1.1 million, or 12%, higher than the $8.9 million in 2020. Payments increased despite 28% fewer hours of TMSR pricing. Ten-minute non-spinning reserve (TMNSR, $2.8 million) and thirty-minute operating reserve (TMOR,$0.9 million) payments also increased due to re-dispatch costs increasing from 2020 to 2021. Due to the "claw back" of forward reserve obligation charges, net reserve payments were $10.9 million, or 13% higher than in 2020.

Forward Reserves: Costs associated with the Forward Reserve Market (FRM) for non-spinning reserves totaled $18.9 million in 2021, down slightly from $22.9 million (by 18%) in 2020 and primarily reflecting a 33% decline in summer auction TMOR prices.

Market requirements for the quantity of procured forward reserve capacity at the system level have relied on a stable set of first and second contingencies, leading to reasonably stable requirements over the years. Local reserve zone requirements have fluctuated to a more significant degree; these

[50] This total includes voltage services and blackstart services, which are included in the regional network load (RNL) cost total in the preceding wholesale cost section of the Executive Summary (rather than the ancillary services total), since they are recovered via the Open Access Transmission Tariff.

fluctuations have reflected the availability of transmission capacity to provide external reserve support (ERS) to the local reserve zones. However, in the six most recent auctions (Summer 2019 through Winter 2021/22), external reserve support has been sufficient to eliminate the need for a local requirement in all local reserve zones.

The FRM auctions have required the offered capacity of the largest supplier to meet certain systemwide and local reserve requirements over the past ten auctions. At the system level, three auctions (Summer 2019, 2020, and 2021) revealed modest structural market power. In those instances, the residual supply index estimates indicated that the single largest FRM supplier in those auctions would need to provide at least 10% to 16% of cleared supply to satisfy the TMNSR requirement and at least 3% to satisfy the TMOR requirement.

Despite structural market power, there is no form of offer price mitigation in this market. There has also been a wide range in supply offers across participants, likely reflecting varying expectations of future reserve pricing events, penalties, and foregone energy rents associated with holding the FRM obligation. However, clearing prices and payments have been comparatively low over the past two years (than the prior three years) and stable during auctions with and without structural market power. Prices for the higher quality product, TMNSR, have averaged about $1,200 per MW-month over the prior two summers. The most recent summer 2022 auction was an exception, with TMNSR clearing prices increasing significantly to almost $7,400/MW-month, more than a 500% increase. We will include our assessment of the summer 2022 auction in our upcoming spring quarterly markets report.

Regulation: The regulation market is highly competitive with an abundance of regulation resources and relatively unconcentrated control of supply. Market participants have little opportunity to engage in economic or physical withholding. 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.

Regulation payments increased by 20% in 2021, primarily reflecting an increase in regulation capacity prices. Payments in 2021 totaled $25.3 million while 2020 payments were $21.1 million.

The average hourly regulation requirement of 90.7 MW in 2021 was slightly higher than the 89.9 MW requirement in 2020. Regulation clearing prices for capacity increased significantly from $16.12/MWh in 2020 to $19.23/MWh in 2021, reflecting an increase in the "opportunity cost" and "incremental cost saving" components of regulation capacity pricing. Regulation service prices were unchanged compared to the prior year. In 2020 and 2021, the average service price was $0.21/mile.

1.6 IMM Market Enhancement Recommendations

One 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. 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 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.

Table 1-2: Market Enhancement Recommendations

ID	Recommendation	When made	Status	Priority Ranking
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 is currently pending FERC's decision.	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 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.	Filed Comments with FERC on ORTP Recalculation (Apr 2021	The value of this recommendation is low in the context of the potential elimination of MOPR in FCA 19. IMM will reassess this recommendation pending the outcome of the MOPR elimination proposal.	Low

ID	Recommendation	When made	Status	Priority Ranking
2020-1	***Reference level flexibility for multi-stage generation*** Given that the preceding recommendation is not part of the ISO's workplan, 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.[51] 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:*** 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	Q2 2015 QMR (Oct 2015)	The projects is not in the scope of the ISO's current workplan. The IMM will continue to rely on a combination of internal data and its own market research to satisfy its monitoring needs.	Medium

[51] Similar to our findings detailed in the *Fall 2017 Quarterly Markets Report,* Potomac Economics raised issues of inefficient commitments for local reliability, depressed clearing prices, and increased NCPC charges. Potomac has recommended that the ISO expand its authority to commit combined-cycle generators in a single turbine configuration when that configuration will satisfy the underlying reliability need. See page 36 in Section III of the EMM's 2016 *Assessment of the ISO New England Electricity Markets*: https://www.iso-ne.com/static-assets/documents/2017/08/iso-ne-2016-som-report-full-report-final.pdf.

ID	Recommendation	When made	Status	Priority Ranking
	potential exercise of market power and market manipulation.			
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
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. We also note that the FRM is anticipated to sunset with the implementation of day-ahead ancillary services in Q4 2024/Q1 2025.[52]	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. [53]	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 expects to review this issue as part of the conforming changes related to the day-ahead ancillary services project.	Medium
2020-2	***Reconstitution of Regional Network Load for Behind-the-Meter (BTM) Generation (Part #1: Compliance)*** Participating Transmission Owners (PTOs) should change their current practices to comply with the express Tariff requirement to reconstitute peak demand by adding back BTM generation output for transmission charging purposes. We also recommended that the ISO consider incorporating a certification step in the data	Spring 2020 QMR (Jul 2020)	Closed. The PTOs filed, and FERC accepted, a proposal that addressed this recommendation.	High

[52] See ISO Memo, *Day-Ahead Ancillary Services: Project Scope, Status, and Timeline* (April 6, 2022), https://www.iso-ne.com/static-assets/documents/2022/04/a05_mc_2022-04-12_day_ahead_ancillary_services_memo.pdf

[53] IMM, *Factors the Internal Market Monitor Considers in Evaluating Physical Availability of Fuel for Generating Resources* (September 27, 2013), https://www.iso-ne.com/static-assets/documents/markets/mktmonmit/rpts/other/factors_imm_considers_in_eval_physical_avail_of_fuel_for_gen_res.pdf

ID	Recommendation	When made	Status	Priority Ranking
	submittal and billing process whereby the PTOs would certify that their peak load data has been reconstituted in compliance with the Tariff. Lastly, we recommended that the Tariff and operating procedures be reviewed and changed, as appropriate, to provide helpful clarifications and specificity to aid compliance going forward.		[54] See section 8.1.3 of this report for further details.	
2020-3	***Reconstitution of Regional Network Load for Behind-the-Meter (BTM) Generation (Part #2: Wider Review of the Rate Structure)*** The PTOs should engage with ISO-NE and stakeholders to review the current rate structure, including the requirement to reconstitute BTM generation. This review would evaluate the rate structure for consistency with transmission planning processes and cost drivers. It would consider the value of BTM generation (e.g., avoiding transmission system constraints and potentially reducing future transmission investment needs). We recognized that the requirement to reconstitute BTM generation may undervalue its contribution. However, not requiring reconstitution could raise equity issues that result from shifting costs to customers with less BTM generation.	Spring 2020 QMR (Jul 2020)	Closed. The PTOs filed, and FERC accepted, a proposal that addressed this recommendation. See section 8.1.3 of this report for further details.	Medium

[54] 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

Section 2
Overall Market Conditions

This section provides an overview of the key trends in wholesale market outcomes over the past five years (2017 through 2021). It covers the underlying supply and demand conditions behind those trends, and provides important context to the market outcomes discussed in more detail in the subsequent sections of this report.

2.1 Wholesale Cost of Electricity

In 2021, the estimated wholesale market cost of electricity totaled $11.2 billion, an increase of $3.1 billion (or 38%) compared to 2020 costs.[55] Energy payments increased by $3.1 billion (104%), driven by a 121% increase in natural gas prices.[56] Capacity payments declined by $0.4 billion (16%), in line with lower capacity prices in Forward Capacity Auctions (FCAs) 11 and 12. Regional network load costs were up $0.4 billion (15%), primarily due to additional infrastructure costs.

A breakdown of the wholesale electricity cost for each year, along with average natural gas prices, is shown in Figure 2-1 below. The wholesale cost estimate consists of several categories:

- *Energy*: costs incurred by participants with load obligations in the day-ahead and real-time energy markets.
- *Net commitment period compensation (NCPC):* shows total uplift costs from the day-ahead and real-time markets.
- *Ancillary services:* aggregated costs of operating reserves, regulation, and the winter reliability program (which ended in February 2018).
- *Capacity:* costs to attract and retain sufficient capacity to meet energy and ancillary service requirements through the Forward Capacity Market.
- *Regional network load (RNL):* also known as transmission costs, this category includes transmission owners' recovery of infrastructure investments, maintenance, operating, and reliability costs.

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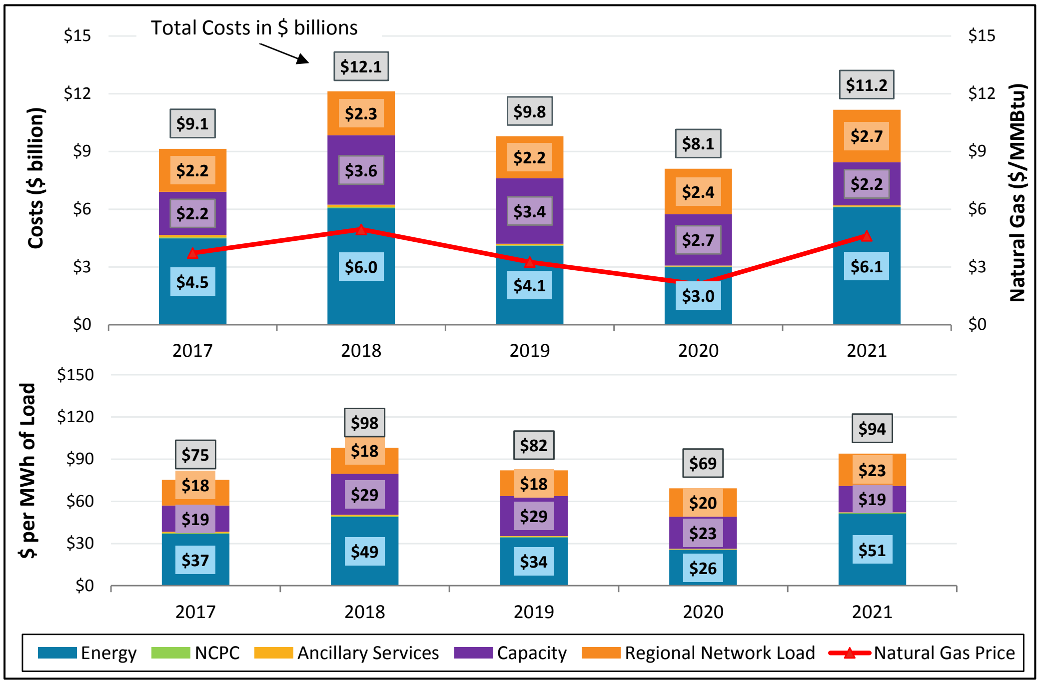
[55] In previous years, we used system load obligations and average hub LMPs to approximate energy costs. This year, we updated the methodology to reflect energy costs based on location-specific load obligations and LMPs. These changes are reflected in all five-years of data. Transmission network costs, known as regional network load (RNL) costs, are also included in the estimate of annual wholesale costs.

[56] 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 11 on D+2.

Figure 2-1: Wholesale Costs ($ billions and $/MWh) and Average Natural Gas Prices



Natural gas-fired generators, which provided 53% of total native generation, are the single largest resource type in New England. As such, natural gas prices are a primary driver of energy, ancillary services and NCPC costs. This relationship is apparent in Figure 2-1 with annual energy costs and gas prices moving in the same direction. Compared to 2020, 2021 gas prices increased by 121% and energy payments increased by 104%.

Energy costs increased by less than gas prices for three reasons. First, in 2021 there was 7% more fixed supply on the system (about 662 MW per hour in the day-ahead market). There were fewer baseload generator outages, which led to additional fixed supply from nuclear generators. Additionally, New England imported less power from New York due to planned transmission reductions and increased export transactions. This led to a need for additional native generation, which was met by natural gas-fired generators who provided 278 MW per hour of additional fixed generation up to their economic minimum.

Second, participants submitted more fixed import transactions across Canadian interfaces. Low energy prices in New England during 2020 may have increased the financial risk associated with submitting fixed, price-taking imports. As gas and energy prices rose in 2021, participant offer behavior indicated that they were more willing to submit fixed imports into New England across Canadian interfaces, which put downward pressure on energy prices.[57]

Finally, the historically low prices in 2020 made it an outlier year with a disconnect between gas (down 36%) and power (down 25%) due to relatively large non-gas impacts like more priced-

[57] Section 5.2 discusses the share of fixed and priced imports across Canadian and New York interfaces in detail.

supply (nuclear outages) and higher CO2 prices. This creates a baseline issue when comparing 2021 to 2020.[58]

Regional network load (RNL) costs also account for a large share of total costs. Transmission and reliability costs were $2.7 billion in 2021, $357 million (15%) more than 2020 costs. The primary driver of the higher RNL costs was a 12% increase in infrastructure improvement costs, which are distributed across regional network load customers that buy power.[59]

Capacity costs accounted for 20% of wholesale costs in 2021. Costs decreased by 16%, or $0.41 billion, due to lower auction clearing prices in FCA 11 (2020/21) and FCA 12 (2021/22). Capacity clearing prices peaked in FCA 9 (2018/19) at $9.55/kW-month, and then declined in each subsequent auction through FCA 14 (2023/24). Clearing prices in FCA 11 ($5.30/kW-month) and FCA 12 ($4.63/kW-month) reflect lower installed capacity requirements and increased surplus due to new entry in previous auctions.

NCPC costs totaled $35 million in 2021, an increase of 38% compared to $26 million in 2020. The increase was largely due to an additional $5.0 million (38% increase) in economic NCPC payments. Additionally, day-ahead local second contingency payments increased by $2.3 million (58% increase) between 2020 and 2021.

Ancillary service costs totaled $54 million in 2021, $1.5 million more than 2020 costs largely due to an increase in regulation costs.[60]

2.2 Supply Conditions

This section of the report provides a macro-level view of supply conditions across the wholesale electricity markets in 2021, and describes how conditions have changed over the past five years. Topics covered include the New England generation mix (Section 2.2.1), fuel and emissions market prices (Section 2.2.2), and estimates of generator profitability (Section 2.2.3).

2.2.1 Generation and Capacity Mix

This subsection provides a summary of the New England generation and capacity mix by fuel type, location, and age over the past five years. Generation and capacity mix metrics provide situational awareness that connects the reader with other important market outcomes, such as fuel prices, energy prices, and system events. In 2021, gas generation and capacity factors rose compared to 2020 due to reduced net interchange.[61]

[58] For instance, when comparing 2021 changes to other years prior to 2020, the relationship between energy and gas prices is tighter.

[59] For a breakdown of the infrastructure improvement costs and other RNL costs see https://www.iso-ne.com/participate/rules-procedures/tariff/oatt.

[60] The ancillary services total presented here does not include blackstart and voltage costs. Those costs are included in the RNL category.

[61] Section 2.2.1 focuses on native generation. Section 5 provides an explanation of interchange between New England and the bordering control areas.

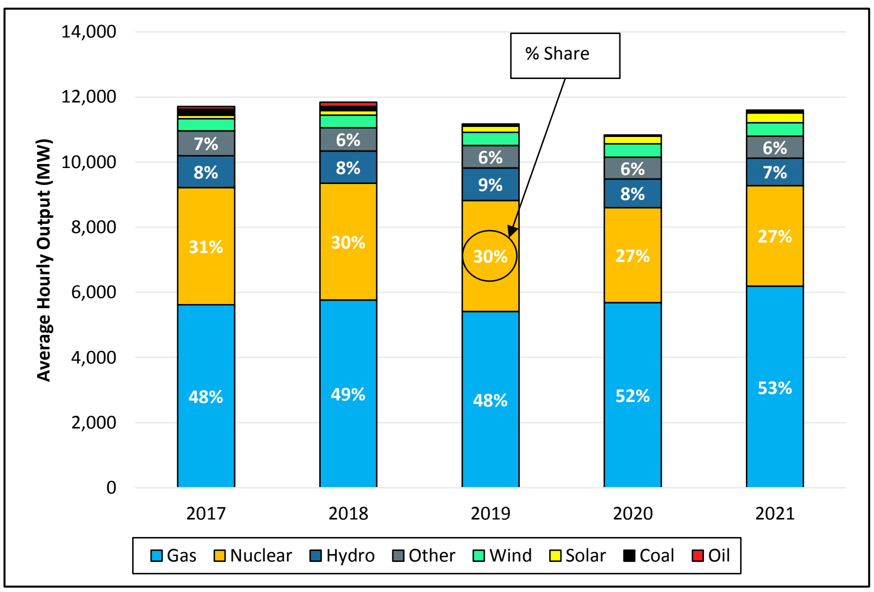
Average Generator Output by Fuel Type

There are a wide range of energy market and non-energy market related factors that impact generation output by fuel type. Some examples include:

- Tight system conditions (summer) and high gas prices (winter) typically result in more oil generation.
- Less net interchange with neighboring systems is offset by more native generation.
- Rapid changes in demand require generation that can be dispatched quickly by the ISO (pumped-storage, light fuel oil).
- State and federal policies supporting the investment in renewable generation increase the total capacity of wind and solar generation on our system.

Energy production by generator fuel type as exhibited minor changes as shown in Figure 2-2 below. Each bar illustrates annual average hourly output by fuel type. The total height illustrates average native generation by year. We include percent share of native generation to facilitate cross-year comparisons.

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

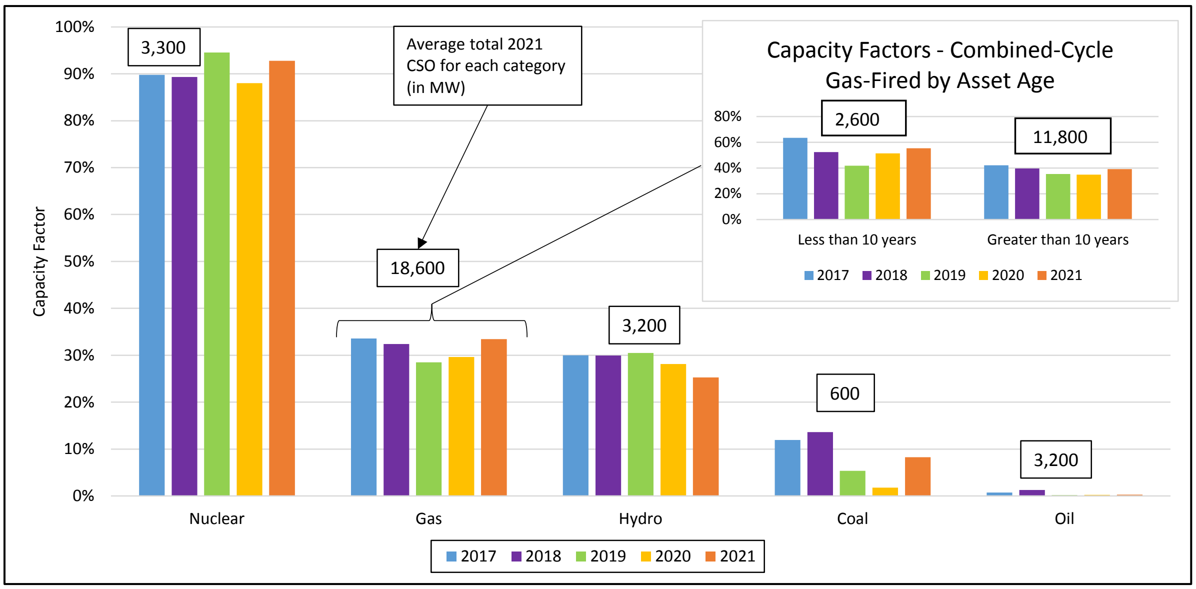


Native generation increased 766 MW in 2021 compared to 2020, on average. There was a need for more native generation because net interchange decreased by 536 MW between 2020 and 2021 and load increased by 244 MW. The decrease was primarily due lower net imports across the New York North interface (see Section 5 for more detail). As a result of lower net interchange, natural gas and nuclear generation made up a larger share of native generation. Natural gas generation increased by 9%, or 508 MW, in 2021, up to 6,191 MW from 5,683 MW in 2020. Nuclear generation increased by 6%, or 171 MW, in 2021 due to fewer planned outages. Out-of-service nuclear generation averaged 257 MW in 2021, down from 433 MW in 2020.

State and federal policies have driven an increase in solar energy production; both behind-the-meter and wholesale metered (front-of the-meter). Wholesale solar production increased by 28% in 2021, up to 303 MW in 2021, compared to 237 MW in 2020. New solar capacity resources cleared an additional 350 MW of capacity supply obligations between FCA 11 (70 MW) and FCA 15 (420 MW), indicating that solar shares of native generation will continue to grow. Section 2.3.1 discusses the impact of solar generation on load.

Capacity Factors: A capacity factor is the percentage of a generator's capacity being utilized. The capacity factor is calculated as the ratio of a resource's average hourly output over their capacity supply obligation (CSO).[62] The individual capacity factors are then summarized over the entire year for each fuel type. In 2021, capacity factors increased for almost all fuel types as native generation increased system-wide.[63] Capacity factors between 2017 and 2021 by fuel type are shown in Figure 2-3 below.

Figure 2-3: Capacity Factor by Fuel Type



Nuclear generators, which provide baseload generation, had increased capacity factors in 2021 due to increased availability. Natural gas-fired generator capacity factors increased for the second year in a row, up from 30% in 2020 to 33% in 2021. For combined-cycle gas-fired generators, capacity factors are categorized by age in the inset graph. In 2021, both age groups of combined-cycle generators had increased gas capacity factors; generators less than 10 years old maintained the larger capacity factor at 55% due their relatively higher efficiencies compared to older generators at less than 40%.

Coal-fired generators saw a significant increase in capacity factors, up from 1% in 2020 to 8% in 2021. Higher gas and energy prices increased margins for coal in the winter months, causing average hourly coal generation to increase from 15 MW in 2020 to 60 MW in 2021. Oil-fired

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[62] A capacity factor of 60% for a 100 MW generator means that the generator is producing 60 MW, on average, each hour.

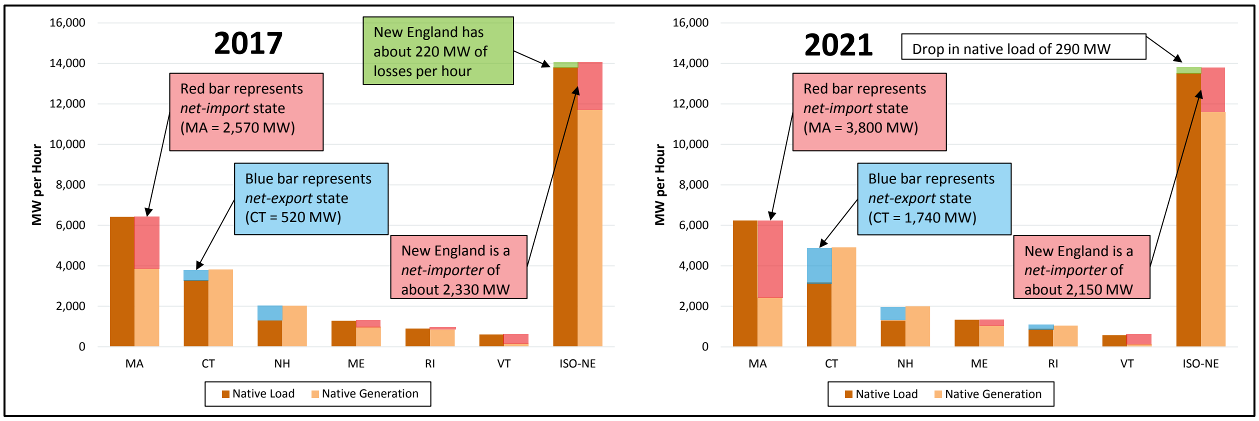
[63] Total generation from resources with CSOs (the numerator) increased by 689 MW per hour, on average, and the amount of total CSOs in the system (the denominator) decreased by 900 MW per hour, on average.

generators have had capacity factors below 1% since 2019 due to high fuel costs and the increased availability of cheaper, more efficient generation.[64]

Generation by State

A breakdown of energy production and consumption by state and aggregated across the ISO-NE market is shown in Figure 2-4 below. The state breakdown shows native energy production and consumption within each state; it does not include imports into the state from neighboring jurisdictions. Darker shaded bars show state load, while lighter shaded bars show state generation. The red bars illustrate net imports into each state, and the blue bars illustrate net exports out of the state.[65] The green bar for ISO-NE illustrates losses as energy flows through the system.

Figure 2-4: Average Native Electricity Generation and Load by State, 2017 and 2021



Note: MW values are rounded to the nearest 10 MW.

Massachusetts, the state with the most load, consumed an average of 3,800 MW per hour more than it generated in 2021, up from 2,570 MW per hour in 2017. The gap between load and generation was driven by two factors: 1) the June 2019 retirement of the 680 MW Pilgrim nuclear facility located in Southeastern Massachusetts, and 2) a decrease in generation from two existing combined-cycle generators due to relatively expensive fuel input costs.

Connecticut generated an average of 1,740 MW per hour more than it consumed in 2021, up from 520 MW per hour in 2017. New gas-fired generators built in Connecticut over the past five years, including Bridgeport Harbor 5 (510 MW) and CPV Towantic (850 MW), accounted for the majority of new generation in the state.

The final bar summarizes two key trends. First, average native load in New England fell by 290 MW per hour compared to 2017. This is largely due to the impact of energy efficiency and behind-the-meter solar generation, which is discussed in Section 2.3.1 below. Second, New England continues to be a net importer of power. In 2021, 16% of New England's electricity demand was met by energy imported from neighboring jurisdictions, or 2,150 MW per hour. Imports flow from Canada into Vermont, Massachusetts and Maine, and from New York into Vermont, Massachusetts and

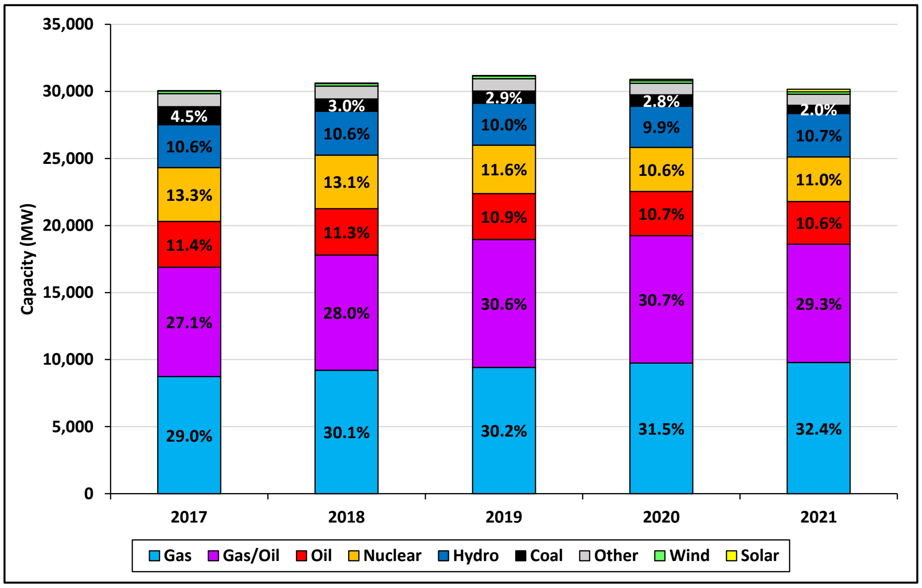
[64] A detailed discussion about the effects of input fuels and supply-side participation on electricity prices can be found in Section 2.2.2 of this report.

[65] 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.

Connecticut. This was the lowest level of net imports over the five-year period; more detail on this trend is provided in Section 2.4 below.

Capacity by Fuel Type: Capacity by fuel type provides context about the maximum capabilities of New England's fleet, rather than on actual generation. Average generator capacity by fuel type for the past five years is shown in Figure 2-5 below.[66, 67]

Figure 2-5: Average Generator Capacity by Fuel Type



Notes: 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.

Natural gas generation continues to make up the most capacity of any fuel source in New England. Combined, gas- and gas/oil-fired dual-fuel generators accounted for over 61% (about 18,600 MW) of total average generator capacity in 2021. The largest year-over-year change in capacity came from gas/oil dual-fuel generators, which decreased in share from 30.7% (9,500 MW) in 2020 to 29.3% (8,800 MW) in 2021, driven largely by the generators shedding CSO in reconfiguration auctions. The decrease in gas/oil capacity, combined with a lower aggregate CSOs, increased capacity shares for gas-fired, nuclear, and hydro generators.

Average Age of Generators by Fuel Type: As generators age, they require increased maintenance and upgrades to remain operational. Older coal- and oil-fired generators in New England also face

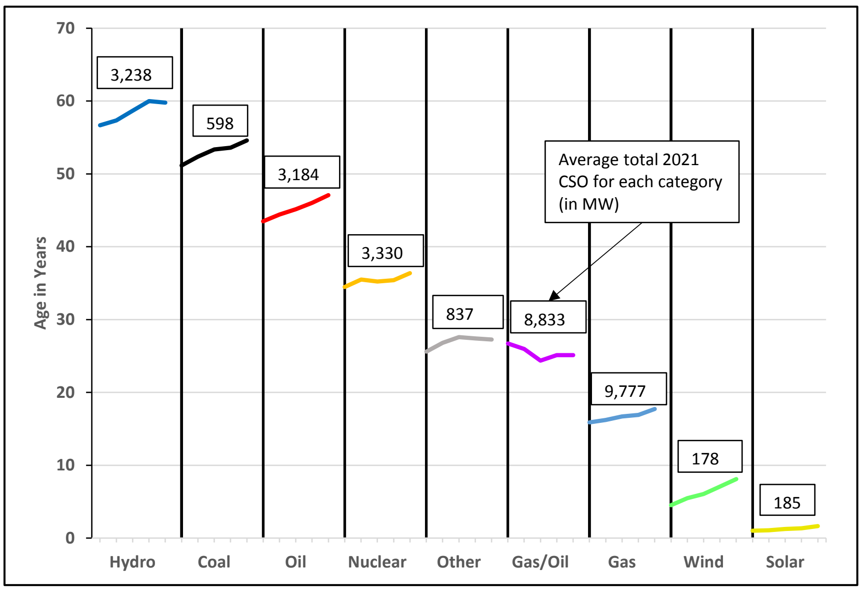
[66] For the purpose of this section, capacity is reported as the capacity supply obligations (CSO) of generators in the Forward Capacity Market, which may be less than a generator's rated capacity. A CSO is a forward contract in which the generator agrees to make the contracted capacity available to serve load or provide reserves by offering that capacity into the energy market. The capacity shown here is the simple average of all monthly generator CSOs in a given year. Analyzing the aggregated CSOs of generators shows how much contracted capacity is available to the ISO operators, barring any generator outages or reductions. Rated generator capacity is generally defined as continuous load-carrying ability of a generator, expressed in megawatts (MW).

[67] 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 gas/oil category.

other market dynamics, including higher compliance costs associated with certain 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 costs. As a result, most 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 2-6 below.[68] Each colored line represents average generator age by fuel type, from 2017 to 2021. The values are weighted by CSO for each generator within the fuel type. 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 total capacity in 2021 by fuel type.

Figure 2-6: Average Age of New England Generator Capacity by Fuel Type (2017-2021)



Note: "Other" category includes landfill gas, methane, refuse, steam, wood, and battery storage. While a significant amount of battery storage is contracted to come online in the next few years, 2021 installed capacity totaled just 23 MW.

The average age of New England's generators in 2021 ranged from two years (solar) to 60 years (hydro), with a weighted-average total system age of 30 years. Solar and wind generation remain the newest generation fuel type; both groups of generators had an average age below 10 years.

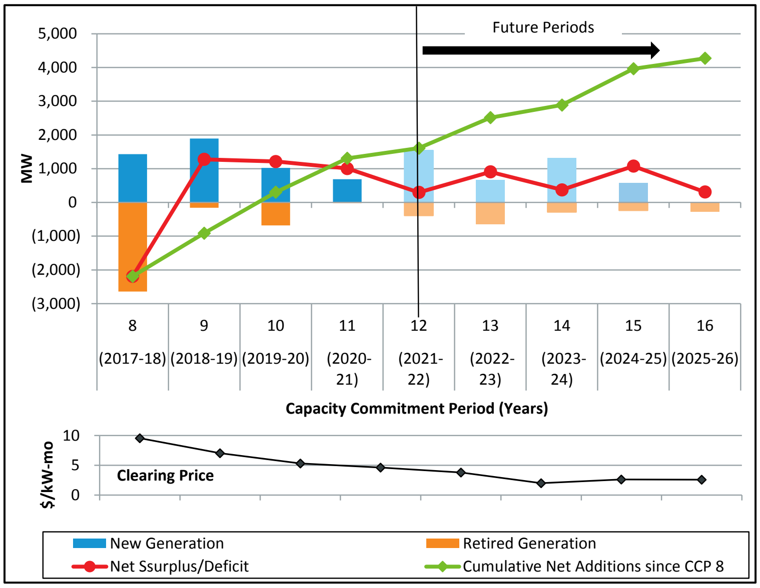
Generation Additions and Retirements: Generator additions and retirements beginning with Capacity Commitment Period 9 (CCP 9, 2018/19) are shown in Figure 2-7 below.[69] Blue bars represent new generation added through the capacity market. Orange bars represent generation that permanently retired. Future periods are years for which the Forward Capacity Auction (FCA)

[68] Age is determined based on the generator's first day of commercial operation.

[69] Capacity Commitment Periods (CCPs) start on June 1 and end on May 31 of the following year. For example, CCP 10 started June 1 2019 and ended May 31 2020. The CCP numbers correspond to the FCA numbers (e.g., FCA 10 procures capacity for delivery during CCP 10).

has taken place, but the capacity has yet to be delivered or resources retired. The FCA clearing prices (for existing rest-of-system resources) are also shown for further context.

Figure 2-7: Generation Additions, Retirements, and FCM Outcomes



In the past eight primary auctions, more capacity has been added from new generation than lost from retiring generation. While the exact surplus amounts fluctuate between commitment periods, the additions of cheaper, more efficient new capacity continue to drive down clearing prices. Existing generation nearing the end of their economic life, and facing high environmental costs, will be incentivized to retire if capacity market revenues continue to decline. In FCA 16, total retirements remained steady at 266 MW with gas-fired generation (150 MW) making up the majority of retirements. New generation declined year over year; the largest types of new capacity consisted of solar projects (208 MW) and battery storage projects (102 MW).

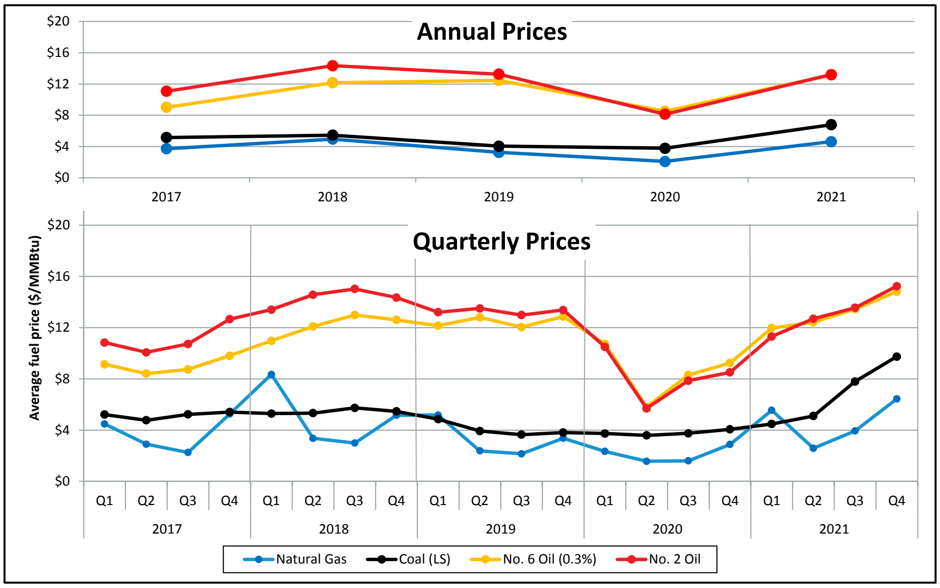
2.2.2 Generation Fuel and Emissions Costs

Input fuel costs and combustion engines' operating efficiencies are major drivers of New England's electricity prices. In 2021, average prices increased for all fuel types; natural gas (121%), No. 2 oil (62%) No. 6 oil (55%) and coal (80%). In summary, for 2021 average fuel price were:

- Natural gas: $4.62/MMBtu.
- No. 2 oil: $13.21/MMBtu.
- No. 6 oil: $13.17/MMBtu.
- Coal: $6.79/MMBtu, the highest price since 1999.

To provide context to the above fuels, natural gas-fired generators produced 53% of native electricity generation, while oil- and coal-fired generators combined produced less than 1% of that total. The annual (top) and quarterly (bottom) average prices of natural gas, low-sulfur (LS) coal, No. 6 (0.3% sulfur) oil and No. 2 fuel oil for the past five years are shown in Figure 2-8 below.

Figure 2-8: Average Fuel Prices by Quarter and Year



Natural Gas

In 2021, natural gas prices averaged $4.62/MMBtu, rebounding from record lows in 2020.[70] Natural gas prices increased by $2.53/MMBtu compared to 2020 ($2.10/MMBtu) and increased by $1.37/MMBtu compared to 2019 ($3.26/MMBtu). In 2020, natural gas demand decreased due to the COVID-19 pandemic, resulting in increased storage and lower prices.[71] However, economic conditions normalized and natural gas demand and LNG export demand both increased resulting in higher natural gas prices in 2021. Colder winter weather and higher prices at supply basins (discussed below) also contributed to higher New England natural gas prices in 2021.

Quarterly Breakdown: New England natural gas prices increased in every quarter year over year due to higher national natural gas prices. Additionally, New England saw higher prices in Q1 2021 and Q4 2021 when colder weather led to natural gas pipeline constraints and higher prices.

During Q1 2021, natural gas prices averaged $5.55/MMBtu, a 138% increase compared to Q1 2020 ($2.33/MMBtu) and a 7% increase compared to Q1 2019 ($5.18/MMBtu). In Q1 2021, temperatures averaged 33^{0}F, a 3^{0}F decrease and 2^{0}F increase from Q1 2020 (36^{0}F) from Q1 2019 (31^{0}F). The colder temperatures led to higher natural gas prices compared to 2020. Additionally, natural gas prices averaged $8.59/MMBtu during February, the highest monthly price since the January 2018 cold snap.[72] February 2021 saw higher gas prices due to colder New England weather, with temperatures averaging 29^{0}F, 5^{0}F and 1^{0}F colder than February 2020 and 2019, respectively. There were also high prices in Q1 2021 at Henry Hub ($5.14/MMBtu) and in the Marcellus Shale region ($3.18/MMBtu) as the Texas and Midwestern Cold Snap led to the second highest week of natural gas net withdrawals of all time.[73]

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

[71] See the EIA's Natural Gas Weekly Update.

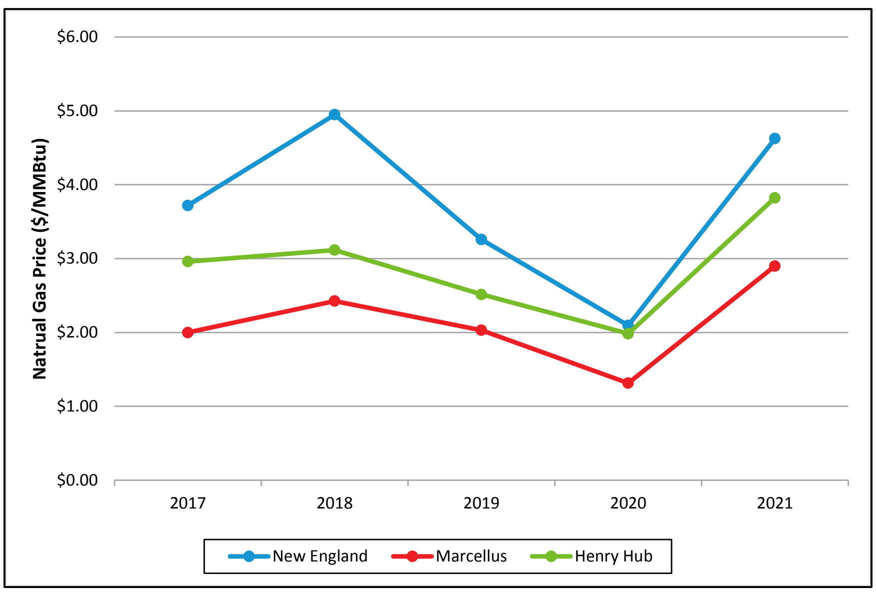
[72] For more information, see the Internal Market Monitor's 2018 Winter Quarterly Markets Report.

[73] See the EIA's Natural Gas Weekly Update.

In Q4 2021, natural gas prices averaged \$6.44/MMBtu, 124% higher than Q4 2020 (\$2.88/MMBtu) and 91% higher than Q4 2019 (\$3.37/MMBtu). Q4 2021 saw the second highest quarterly natural gas price over the last five years. Only Q1 2018 had higher natural gas prices when the 2017/2018 Cold Snap led to extreme pricing over the first week of January 2018. Higher natural gas prices occurred despite warmer weather in Q4 2021 (45^{0}F) compared to Q4 2020 (45^{0}F)[74] and Q4 2019 (42^{0}F). In the Marcellus shale region, Q4 2021 natural gas prices increased 198% compared to Q4 2020 (\$3.88/MMBtu vs. \$1.30/MMBtu). LNG injections from Canada and the Boston-area can provide additional natural gas supply and counter-flow into the New England natural gas infrastructure which delivers gas from west and south of New England. However, higher New England natural gas prices did not lead to higher LNG injections in Q4 2021. This was due to higher prices in international markets providing reduced incentives to schedule LNG deliveries into New England. In Q4 2021, LNG injections decreased by 5.17 million dth year over year (1.27 million dth vs. 6.44 million dth).

While New England is particularly exposed to high natural gas prices during periods of cold weather when the interstate pipeline becomes constrained, gas prices at supply basins also influence New England's gas price given our lack of native production. Figure 2-9 below compares annual average prices in New England (blue) to prices at Henry Hub (green) over the past five years. While Henry Hub is the predominant pricing benchmark in the United States, Figure 2-9 also includes the Marcellus trading Hub (red). 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.

Figure 2-9: New England vs. Henry Hub and Marcellus Natural Gas Prices



In 2021, natural gas prices increased at Henry Hub and at Marcellus, with both reaching their highest prices of the last five years. Prices increased at these basins due to increased domestic natural gas demand and LNG export demand, which led to lower storage levels than in prior years.

[74] Temperatures averaged 45.47^{o}F in Q4 2021 and 44.62^{o}F in 2020.

At Henry Hub, natural gas prices averaged \$3.82/MMBtu, up 93% after averaging \$1.98/MMBtu in 2020, a 25-year low.[75] While both Henry Hub and Marcellus reached their highest average prices of the last five years, average prices at New England remained below 2018 prices, when cold weather led to supply constraints and high natural gas prices. In 2021, the New England natural gas price averaged a premium of \$1.72/MMBtu compared to Marcellus, significantly lower than the premium in 2018 (\$2.52/MMBtu).

Oil

In 2021, No. 2 Oil and No. 6 Oil prices increased by 62% (by \$5.07/MMBtu) and 55% (by \$4.65/MMBtu), respectively. Oil prices increased as demand increased following the COVID-19 pandemic.[76]

Coal

In 2021, coal prices increased by 65% (\$3.01/MMBtu) year-over-year due increased global demand, including demand for coal-fired generation.[77]

Emission Prices

While fuel prices and generator operating efficiencies are the main drivers of electricity prices, emissions allowances are secondary drivers of electricity production costs for fossil fuel-fired generators. State regulations require some generators to purchase emissions allowances, and the associated emissions costs are incorporated into generator reference levels.

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

1. Regional Greenhouse Gas Initiative (RGGI), covering generators in all New England states, and
2. Electricity Generator Emissions Limits (EGEL) under the Global Warming Solutions Act (referred to as the MA GWSA program below), covering only Massachusetts generators.[78]

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. The average cost of emissions by generator fuel type for each program in the context of short-run fuel costs is illustrated in Figure 2-10.

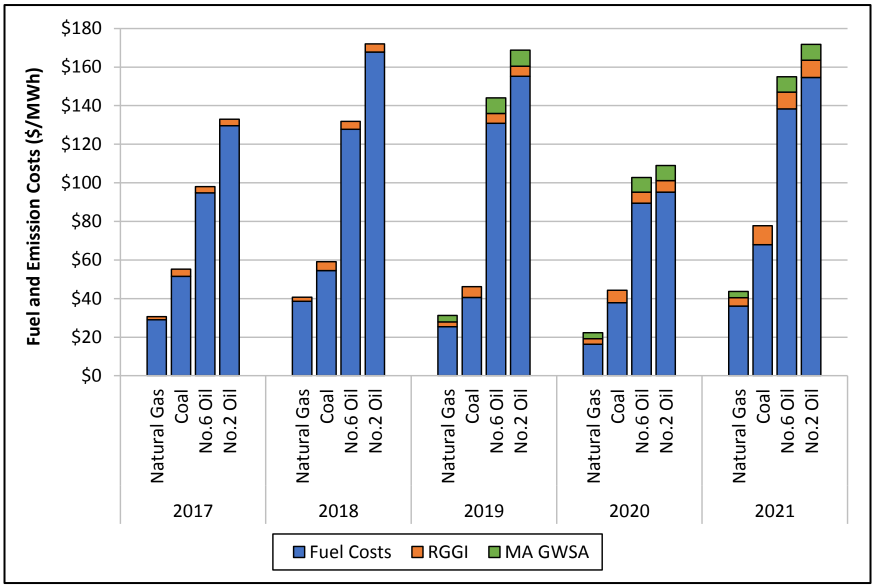
[75] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/2020-average-henry-hub-natural-gas-price-hits-lowest-level-in-25-years-62023069

[76] See the EIA's Today in Energy

[77] See the IEA's report on Coal in 2021

[78] 310 CMR 7.74: Reducing CO2 Emissions from Electricity Generating Facilities (https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774)

Figure 2-10: Annual Estimated Average Costs of Generation and Emissions[79]



The graph illustrates that the cost of emissions is still relatively low compared to fuel costs, but has grown in recent years. In 2021, the average estimated costs of the RGGI program increased by 51% for most fossil fuel-fired generators year-over-year: natural gas ($2.88/MWh to $4.36/MWh), coal ($6.51/MWh to $9.85/MWh), No. 6 oil ($5.77/MWh to $8.73/MWh), No. 2 oil ($5.95/MWh to $9/MWh). This was due to a variety of factors discussed below. The average estimated costs of the Massachusetts GWSA program increased by 5% from 2020 to $3.25/MWh. This was largely due to the end of directly allocated allowances, expectations of tighter conditions in future years, and higher emissions in Massachusetts.

Regional Greenhouse Gas Initiative Prices:

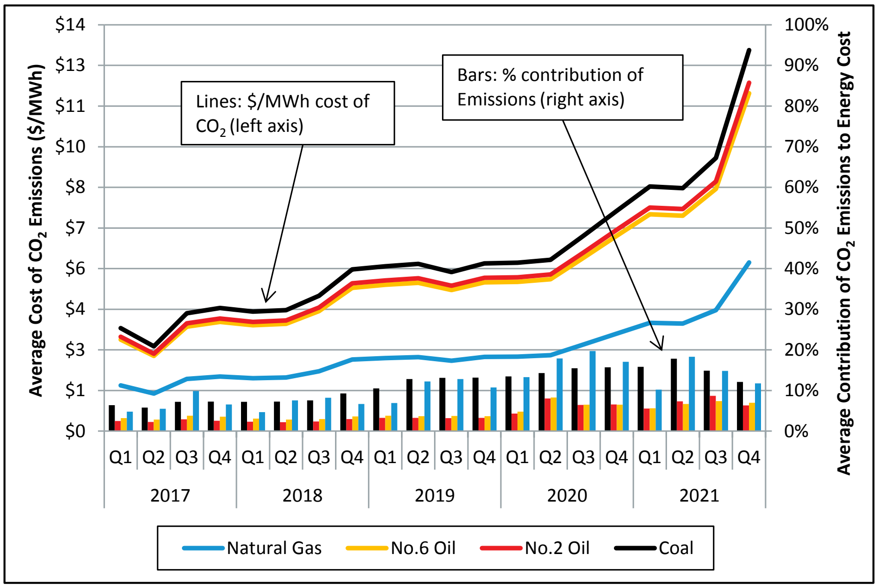
The key driver of emissions costs for generators in New England is RGGI, a marketplace for CO_2 credits in the Northeast and Mid-Atlantic regions; it covers all six New England states. RGGI operates as a cap-and-trade system, in which fossil fuel-fired generators must purchase emissions allowances equal to their level of CO_2 emitted over a specific compliance period.[80] Market prices for CO_2 credits affect the total energy costs of fossil fuel-fired generators. 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.

[79] 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.

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

The average estimated dollar per MWh costs of CO_2 emissions and their percent contribution to total variable production costs are shown in Figure 2-11 below.[81] 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.

Figure 2-11: Estimated Average Cost of RGGI CO_2 Allowances and Contribution of Emissions to Energy Production Costs[82, 83]



As shown in Figure 2-11 above, the estimated RGGI costs for generators of all fuel types increased sharply from Q2 2017 through the end of 2021, driven by an increase in the price of RGGI allowances. On August 23, 2017 prices increased after a RGGI program review placed a 30% emissions cap reduction by 2030, relative to 2020 levels (from 78.2 million short tons to 54.7 million short tons).[84,85]

RGGI allowance prices increased by 51%, on average, in 2021 (from $6.32/short ton in 2020 to $9.56/short ton in 2021). For a typical natural gas-fired generator the average estimated CO_2 cost was $4.36/MWh in 2021. This was an increase of $1.48/MWh from 2020. There are several factors potentially influencing the increase in the price of RGGI allowances:

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[81] Only fuel and CO_2 emissions 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.

[82] 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.

[83] RGGI accounts for nearly all of emissions costs

[84] RGGI Inc. RGGI States Announce Proposed Program Changes: Additional 30% Emissions Cap Decline by 2030 August, 2017. (https://www.rggi.org/sites/default/files/Uploads/Program-Review/8-23-2017/Announcement_Proposed_Program_Changes.pdf)

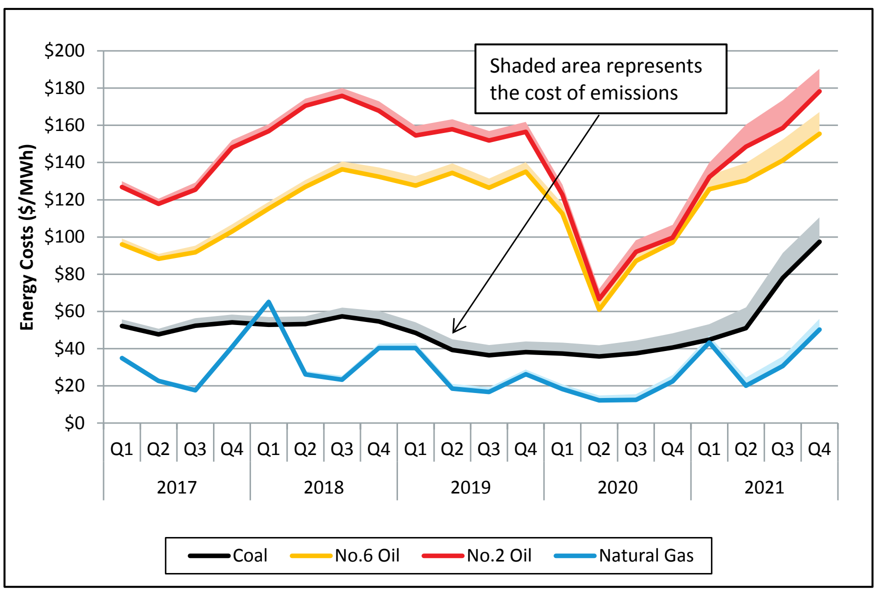
[85] https://www.rggi.org/sites/default/files/Uploads/Program-Review/12-19-2017/Principles_Accompanying_Model_Rule.pdf

- The Emission Containment Reserve (ECR) was introduced into the program. Through the ECR, allowances would be withheld from circulation to secure additional emission reductions if prices fell below an established price.[86]
- Market participants increased as Virginia joined RGGI, and Pennsylvania and North Carolina set out to join RGGI.
- Futures trading activity and participation by investors increased.[87]
- The start of the third RGGI program review began, signaling potential further emission reductions similar to the second program review in 2017.[88]

The bars in Figure 2-11 show the relative contribution of emissions allowance costs to generator energy costs. This contribution remained similar for all fuel types in 2021, although the cost of CO_2 increased 51%, on average, from the previous year. The relative impact of these higher CO_2 prices on total generator costs was offset by a 121% increase in natural gas prices from 2020 to 2021.

A wider view of the impact of RGGI CO_2 allowances on generator production costs is presented in Figure 2-12 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.

Figure 2-12: Contributions of Emissions Cost to Energy Production Costs



[86] The 2021 trigger price was $6.00 and will rise 7 % each year through 2030. (https://www.rggi.org/sites/default/files/Uploads/Market-Monitor/Quarterly-Reports/MM_Secondary_Market_Report_2020_Q4.pdf)

[87] https://www.rggi.org/sites/default/files/Uploads/Market-Monitor/Quarterly-Reports/MM_Secondary_Market_Report_2021_Q3.pdf

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

Figure 2-12 highlights that RGGI 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 GHG (310 CMR 7.74):

In January 2018, Massachusetts implemented a CO_2 cap-and-trade program.[89] The MA Global Warming Solutions Act (GWSA) program mandates additional requirements to the RGGI program, thus generators located in Massachusetts must meet both sets of 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.[90] The cap will be lowered every year until the target annual CO_2 emission rate is reached in 2050.[91]

To ensure compliance, 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.[92] The program allows generators to trade emissions allowances to meet their quotas. To incorporate the cost of these allowances into generator offers, the IMM calculates a reference level adder by valuing the allowances based on a weighted average of recent trades with the additional consideration of allowance auction results.

Allowance trading activity in 2021 increased slightly compared to 2020. At least five of the 26 participating facilities traded a total of 450,000 allowances over the course of the year.[93] The nominal increase in trading is likely a result of participants having sufficient allowance allocations to meet their compliance obligations for this program.

Reported allowance trading volumes and weighted average prices (in $/metric ton) for each month since 2019 are shown in Figure 2-13 below. The graph also shows a rolling average-weighted allowance price that illustrates the general price movement over this time.

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[89] 310 CMR 7.74: Reducing CO_2 Emissions from Electricity Generating Facilities (https://www.mass.gov/guides/electricity-generator-emissions-limits-310-cmr-774)

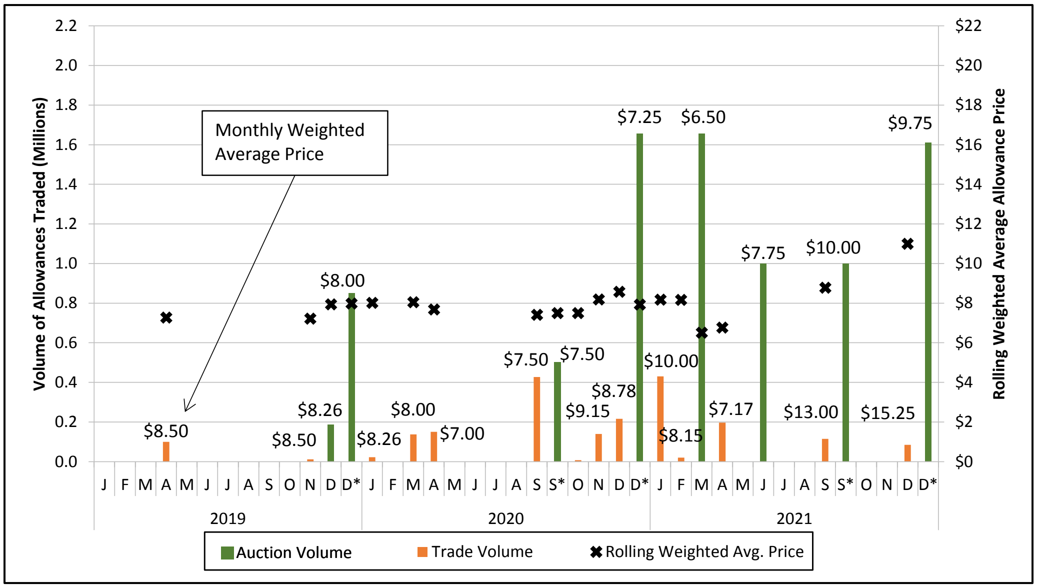
[90] Participating generators are fossil-fuel generators with a nameplate capacity of 25 MW or more. (https://www.mass.gov/doc/310-cmr-700-air-pollution-control-regulations/download)

[91] 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.

[92] For the 2018, 2019, and 2020 compliance years, 100, 75, and 50% of emissions cap was directly allocated by MassDEP. MassDEP will no longer distribute allowances through direct allocation starting 2021.

[93] The average monthly emissions for all GWSA-affected generators was 505,500 metric tons in 2021.

Figure 2-13: GWSA Allowance Trading Activity, 2019-2021



Note: Two colored bars are shown to distinguish between allowances sold at auction (green) and trades/purchases in the secondary market (orange). 2018 is excluded due to large variations in trading behavior at the start of the program. The auction volume was higher in December 2020 and throughout 2021 due to the phasing out directly allocated allowances.

In 2021, prices had a wider range of $7-$15/metric ton compared to $7-$9/metric ton in 2020. This was because the fourth year of the program (2021) marked the first year all allowances were distributed through sale at quarterly auctions. These prices also reflected expectations of tighter conditions in future years and some participants seeking to meet compliance obligations as electric load, and thus emissions increased. The increases were due to a slight rebound from the initial impact of the COVID-19 pandemic and fewer imports into the state. As the number of available allowances decreases, prices are expected to rise. If the volume of transactions remains low, participants may find it difficult to obtain additional allowances without paying significant premiums.[94]

2.2.3 Generator Profitability

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), which is conducted three-plus years in advance of the delivery year, is a critical component of moving forward with the development of a new project.[95] Developer expectations for minimum capacity revenues will be based on the cost of the project (CONE, or cost of new entry) and their expectation for net revenue from the energy and ancillary services markets. In New England, the majority of revenue to support new entry comes from the capacity market. There is an inverse relationship between expected net revenue from energy and ancillary service sales and the amount of revenue required from the capacity market in order to support new entry. As expected net revenue from energy and ancillary service sales decrease, more revenue is required from the capacity market to support new entry. The reverse is also true.

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

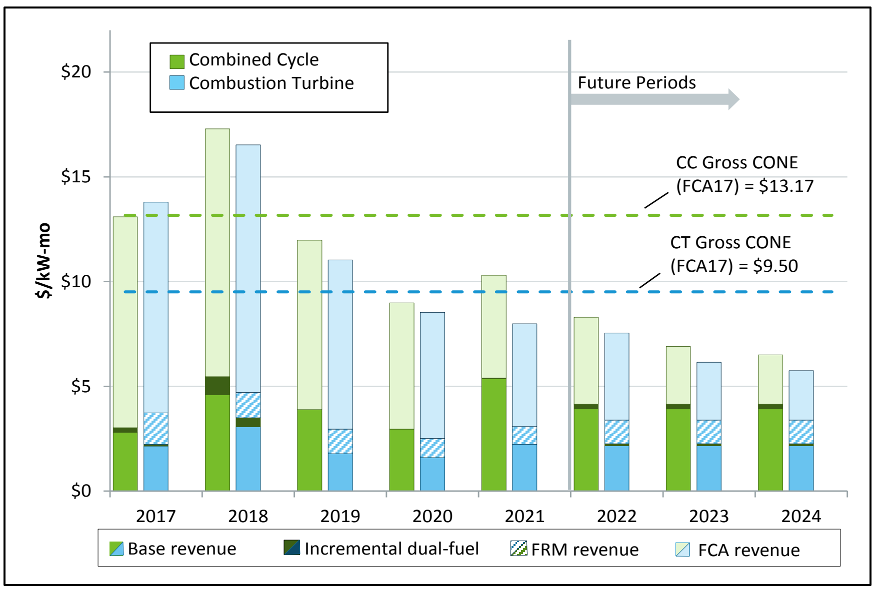
[94] https://www.mass.gov/doc/market-monitor-quarterly-report-2021-q3/download

[95] See Section 6 of this report for a discussion on the Forward Capacity Market.

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.[96]
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.[97] Last year, the simulation model was updated to explicitly include a Regional Greenhouse Gas Initiative (RGGI) cost for every short ton of CO_2 emitted. In the model, the RGGI cost for each year is the average auction clearing price for RGGI allowances in that year.[98]

Figure 2-14 shows the result of the simulations.[99] 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 2017-2021.[100] 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.

Figure 2-14: Estimated Net Revenue for New Gas-fired Generators



When compared with 2020, the simulation results show 2021 net revenues increased by approximately 82% for the combined cycle generator and approximately 23% for the combustion turbine that participates in the FRM. These year-over-year increases were driven by greater

[96] The Forward Reserve Market in discussed in detail in Section 0 of this report.

[97] 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).

[98] RGGI Auction data is available at https://www.rggi.org/auctions/auction-results/prices-volumes.

[99] The Gross CONE figures for the CC and CT gas-fired generators reflect Net CONE values of $8.80/kW-month and $5.00/kW-month with the difference between gross and net figures attributed to net revenue from energy and ancillary service sales.

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

capacity utilization and significantly higher spark spreads, which increased by 58% from the prior year.[101] Similar to 2019 and 2020, dual-fuel capability in 2021 did not add any revenue for the CT generator and added only $0.04/kW-month to net revenue for the CC unit. Like the previous two winters, winter in 2021 was relatively mild, which limited opportunities for generation on oil.

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 $3.92/kW-month, which increases to $4.15/kW-month for generators with dual-fuel capability. Under the same conditions, new combustion turbines could expect net revenue earnings from $2.71/kW-month for single-fuel generators to $2.84/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 when gas prices rise above oil prices as occurred in the winter of 2018.

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 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. While FRM auction payments have trended lower recently, this analysis shows that a new combustion turbine that is designated as an FRM resource could earn $0.58/kW-month more net revenue than the same resource might accumulate in the real-time market alone. In addition, participation in the FRM results in greater net revenue than non-participation in all five years where these revenues have been observed (not future periods).

The simulations show that average revenues for new gas-fired generators appear to be lower than benchmark estimates used to establish CONE numbers for the Forward Capacity Auctions (FCAs). The most recent CONE revisions approved by FERC estimate energy and ancillary service revenue requirements of $4.37/kW-month and $4.50/kW-month for combined cycle and combustion turbine generators respectively.[102] However, even 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 trended downwards reflecting a system that is increasingly 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 had a new gas-fired generator clear the FCA since 2019 (FCA 13).

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.

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[101] Section 3.4.1 of this report discusses spark spreads in more detail.

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

2.3 Demand Conditions

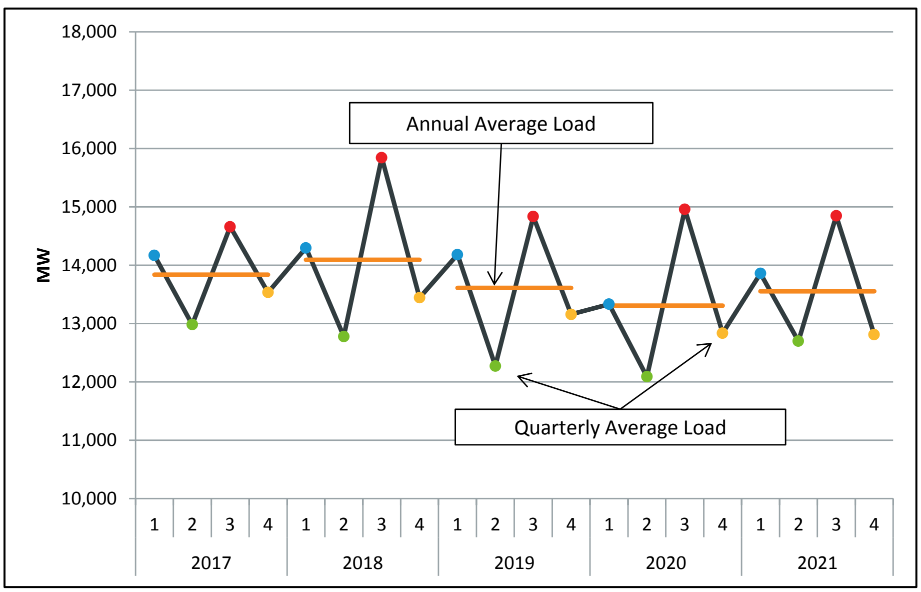
Consumer demand for electricity is a key determinant of wholesale electricity prices in New England.[103] The section focuses on wholesale demand, otherwise known as Net Energy Load (NEL).[104] Weather, economic forces, energy efficiency, and behind-the-meter solar are the primary factors influencing wholesale electricity demand over time. The following sections describe these drivers, as well as system reserve requirements and the amount of capacity needed to meet the region's reliability needs.

2.3.1 Energy Demand

In 2021, New England wholesale electricity demand (load) increased by 1.9% as demand rebounded following the COVID-19 pandemic. Typically, temperature fluctuations drive yearly differences in wholesale load, while growing energy efficiency and behind-the-meter solar generation have generally led to declining wholesale load in New England. On a weather-normalized basis, wholesale load increased by 1.3% compared to 2020, the first increase weather-normalized load since 2011. Weather-normalized load increased as impacts of the COVID-19 pandemic subsided in 2021.

Quarterly average load from 2017 to 2021 is shown in Figure 2-15 below. The solid black lines show quarterly average load and the gold line represents annual average load. The different colored dots identify each calendar quarter (Q1 – blue, Q2 – green, Q3 – red, Q4 – yellow).

Figure 2-15: Average Hourly Load by Quarter and Year



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103 The terms "load" and "demand" are used throughout this report. The term "load" typically refers to actual real-time wholesale electricity consumption. The term "demand" can have a more general meaning, but typically refers to demand that clears in the day-ahead energy market when used in that context.

104 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.

In 2021, annual average load increased by 1.9% mainly due decreased impacts from the COVID-19 pandemic. Beginning in March 2020, the New England states implemented closures to mitigate the spread of COVID-19, which generally led to decreased electricity demand during Q1 and Q2 2020. These closures largely ended by 2021, and load rebounded towards pre-pandemic levels during Q1 and Q2 2021.

In Q1 2021, average load (13,861 MW) increased by 3.9% (or 526 MW) year over year due to the waning impacts of the pandemic compared to March 2020, but also due to colder temperatures. Temperatures averaged 33^{0}F, a 3^{0}F decrease compared to Q1 2020 (36^{0}F).

During Q2 2021, average load (12,699 MW) increased by 5% (or 609 MW), with the increase largely due to the COVID-19 pandemic rather than weather. During Q2 2021, temperatures averaged 60^{0}F, a 3^{0}F increase compared to Q2 2020 (57^{0}F). While warmer temperatures typically cause lower loads during non-summer months, degree days show a better relationship between load and temperatures.[105] In Q2 2021, degree days show that weather had a mixed impact on loads as heating degree days (HDD) decreased by 238 year-over-year but Temperature-Humidity Index (THI) cooling degree days (tCDD) increased by 35 year-over-year.[106]

Demand in Q3 and Q4 2021 were comparable to the prior year. In Q3 2021, quarterly average load decreased by 0.7% (or 111 MW) due to milder weather and less air-conditioning demand. In Q3 2021, the THI increased slightly (69 vs. 68). However, the total number of tCDDs decreased from 423 in Q3 2020 to 390 in Q3 2021. Average Q4 load decreased by 0.2% (or 26 MW) year-over-year, as average temperatures increased by 1^{0}F, leading to a decrease of 80 HDDs (1,787 vs. 1,867).

New England's system load over the last five years is shown as load duration curves in Figure 2-16 below. A load duration curve depicts the relationship between load levels and the frequency that load levels occur. The red line shows 2021 and the range of gray lines (from lightest to darkest) show 2017-2020. The inset graph highlights the 5% of hours with the highest load levels for each year.

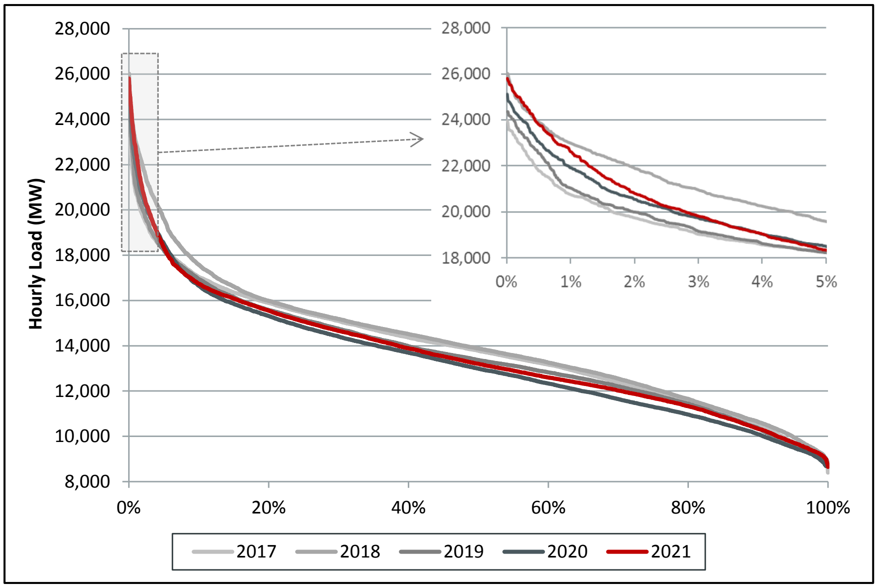
[105] Heating degree day (HDD) measures how cold an average daily temperature is relative to 65°F and is an indicator of electricity demand for heating. It is calculated as the number of degrees (°F) that each day's average temperature is below 65°F. For example, if a day's average temperature is 60°F, the HDD for that day is five.

The Temperature-Humidity Index combines temperature and dew point (humidity) into one metric that is a useful indicator of electricity demand in summer months when the impact of humidity on load is highest. The THI is calculated as 0.5 x [Dry-Bulb Temperature (°F)] + 0.3 x [Dew Point (°F)] + 15.

A THI cooling degree day (tCDD) measures how warm an average daily THI is relative to 65°F and is an indicator of electricity demand for air conditioning. It is calculated as the number of degrees (°F) that each day's average temperature is above 65°F. For example, if a day's average temperature is 70°F, the CDD for that day is five.

[106] Cooling Degree Days (CDDs) have a larger impact on load as air-conditioning demand causes a stronger relationship between changes in temperature and load.

Figure 2-16: Load Duration Curves



The 2021 load duration curve was higher in most hours compared to the 2020 load duration curve, but lower in most hours compared to 2017 – 2019. This highlights two trends in New England electricity demand. First, loads at least partially recovered following the COVID-19 pandemic as 2021 loads were higher in 95% of all hours compared to 2020. Second, wholesale load continues to decline long-term due to increases in energy efficiency and behind-the-meter solar generation.

The inset graph highlights the load duration curves during the top 5% of load levels during the year. These hours tend to occur during the summer when increased air-conditioning demand drives higher wholesale electricity demand. Therefore, weather differences tend to explain annual variations during the top 5% of hours. In 2021, the top 5% of load levels were typically higher than every year besides 2018. The higher peak loads, especially in the top 1% of all hours, occurred due to hot weather at the end of June 2021. From June 28 – June 30, temperatures peaked at an average of over 94°F, and loads averaged 25,462 MW.

In 2021, weather-normalized load increased by 1.3%, the first increase since 2011.[107] Prior to 2021, average annual weather-normalized load typically fell due to growth in energy efficiency and, to a lesser extent, behind-the-meter solar generation. However, state-mandated business closures to mitigate the spread of COVID-19 led to a larger than normal decrease in weather-normalized load during 2020. The 2021 increase of weather-normalized load reflects electricity demand recovering after business closures largely ended prior to the start of 2021. Figure 2-17 displays the average quarterly weather-normalized load and the estimated impact of energy efficiency and behind-the-meter solar over the past five years.[108]

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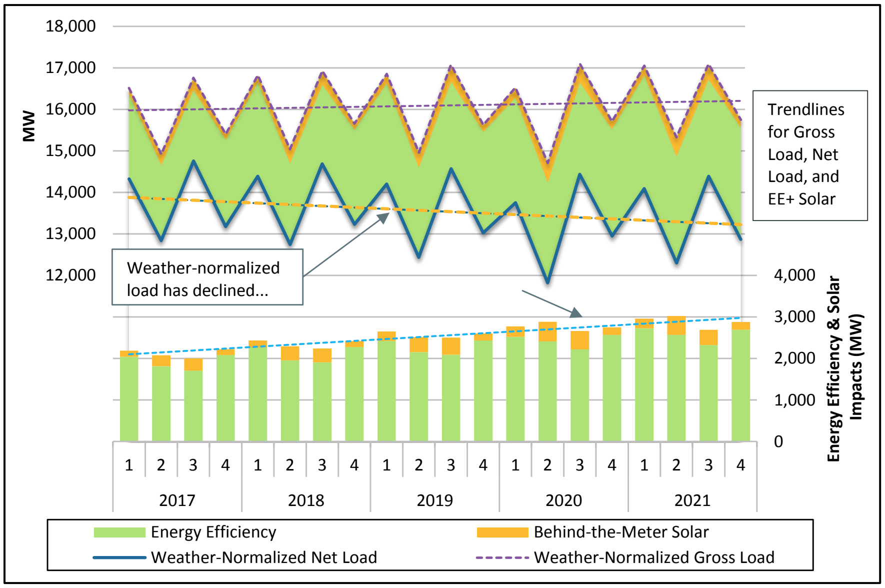
[107] Weather-normalized load adjusts observed load for the effects of weather, leap year and non-holiday weekdays.

[108] 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.

Figure 2-17: Average Quarterly Weather-Normalized Load with Energy Efficiency and Solar Impacts



Weather-normalized net load (solid blue line in Figure 2-17) fluctuates from quarter to quarter but still trended downward over the past five years despite the year over year increase in 2021. Weather-normalized *gross* load (dashed purple line), which shows load without the effects of energy efficiency and behind-the-meter solar, has continued to grow slightly since 2017. The gap between weather-normalized gross load and actual load is the combined impact of energy efficiency (green area) and behind-the-meter solar generation (gold area). Greater energy efficiency and behind-the-meter solar generation have typically helped offset the increase in gross load, causing weather-normalized load to fall.

In 2021, energy efficiency reduced annual average load by an estimated 2,577 MW, a 6% increase (148 MW) compared to 2020, and a 35% increase (665 MW) compared to 2017. Behind-the-meter solar generation reduced annual average load by 310 MW or nearly 11% of estimated installed capacity (2,792 MW). The 310 MW average load reduction was an 8% decrease (27 MW) compared to 2020.[109] While behind-the-meter generation decreased this year, it is still forecasted to grow in the future. By 2030, behind-the-meter solar generation is expected to reduce annual load by an average of 768 MW.[110] Energy efficiency and behind-the-meter solar generation impact wholesale

[109] While behind-the-meter solar generation typically increases along with increased installed capacity, several factors may have contributed to the decrease in behind-the-meter solar generation. First, the ISO receives performance data from around 5% of behind-the-meter solar installations in New England. Updates to the metering of these installations showed decreased, but more accurate, generation estimates than prior years. This would incorrectly show decreased generation when comparing to prior years which had less accurate measurements. Secondly, installations operating as behind-the-meter generation may have registered as settlement-only generators. This lowers the amount of behind-the-meter generation and increases the level of settlement-only generation. Any installation that moved "in front of the meter" would no longer reduce wholesale load, but increase wholesale load as settlement only generation is included in Net Energy for Load. Lastly, weather impacts behind-the-meter solar generation. For example, behind-the-meter solar generation n decreased by 23% in July due to increased cloud cover. However, capacity factors remained fairly similar for solar generation with revenue-quality metering when compared to 2020. This suggests the improved metering of behind-the-meter installations is largely responsible for the estimated decrease in behind-the-meter solar generation.

[110] For more information, see ISO New England's [2021 CELT Report](#).

load differently during the year. Figure 2-17 shows that energy efficiency has a greater effect during Q1 and Q4, while behind-the-meter solar generation has a greater impact during Q2 and Q3.

Energy efficiency and behind-the-meter solar generation will continue to grow and reduce gross load in the future. However, net load is forecasted to begin growing year-over-year under normal weather conditions. Net load is expected to increase as increased electrification of the grid and economic impacts will outweigh the growth in energy efficiency and behind-the-meter solar generation.

2.3.2 Reserve Requirement

Bulk power systems need reserve capacity to respond to contingencies. ISO New England's reserve requirements allow the bulk power system to serve load uninterrupted if a major transmission line or generator loss occurs.[111] The ISO maintains a sufficient amount of reserves to be able to recover from the loss of the largest single-source system contingency (N-1) within 10 minutes. This is called the total 10-minute reserve requirement. At least 25% of the total 10-minute reserve requirement must be synchronized to the power system. System operators determine the exact amount, which is referred to as the 10-minute spinning reserve (TMSR) requirement. The rest of the total 10-minute reserve requirement is met by offline generators that are capable of providing 10-minute non-spinning reserves (TMNSR).

Additionally, adequate operating reserves must be available within 30 minutes to meet 50% of the second-largest system contingency (N-1-1). This requirement can be satisfied by 30-minute operating reserves (TMOR). Lastly, the ISO adds a 30-minute replacement reserve requirement of 160 MW for the summer and 180 MW for the winter months.[112] Adding the 30-minute and replacement reserve requirements to the total 10-minute reserve requirement comprises the system total reserve requirement.

In addition to system-wide requirements, 30-minute reserves must be available to meet the local second contingency in import-constrained areas. Local TMOR requirements exist for the region's three local reserve zones – Connecticut, Southwest Connecticut (SWCT), and NEMA/Boston. Local reserve requirements reflect the need for 30-minute contingency response to provide second contingency protection for each import-constrained reserve zone. Local reserve requirements can be satisfied by resources located within a local reserve zone or through external reserve support.

Average annual local reserve requirements are shown in the right panel of Figure 2-18 below. The left panel shows the total 10-minute requirement (purple), which includes both 10-minute spinning (blue) and non-spinning reserves. The total 30-minute requirement (green) contains the total 10-minute and 30-minute requirements. The right panel shows the local 30-minute requirements for the three local reserve zones.

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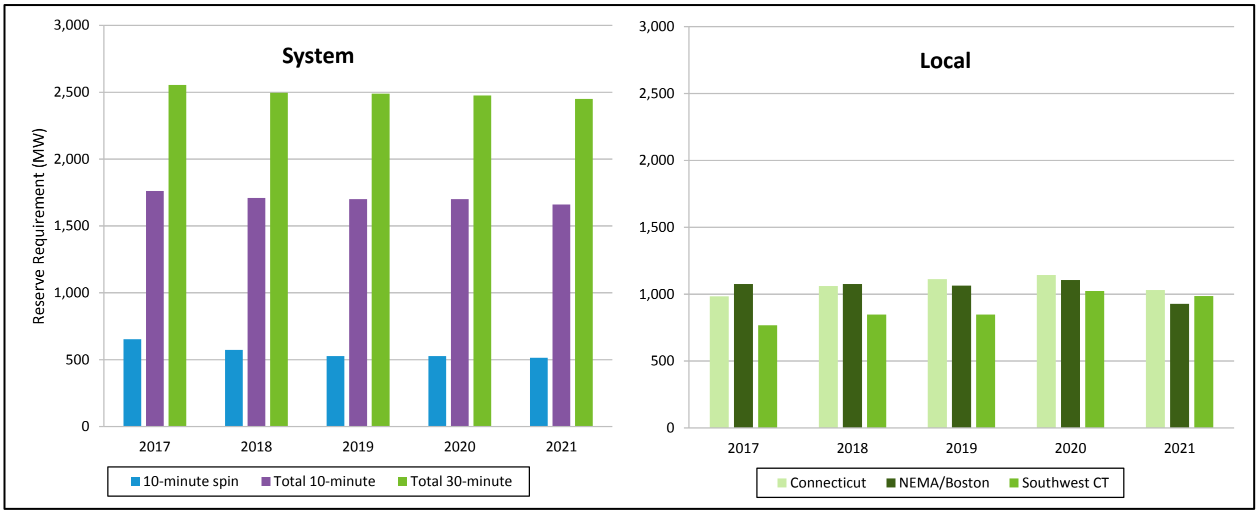
[111] Operating Procedure No. 8, Operating Reserves and Regulation (August 2, 2019), https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op8/op8_rto_final.pdf

[112] Operating Procedure No. 8 states that in addition to the operating reserve requirements, ISO will maintain a quantity of Replacement Reserves in the form of additional TMOR for the purposes of meeting the NERC requirement to restore its total 1-minute reserve requirement. ISO will not activate emergency procedures, such as OP-4 or ISO New England Operating Procedures No. 7 - Action in an Emergency (OP-7), in order to maintain the replacement reserve requirement. To the extent that, in the judgment of the ISO New England Chief Operating Officer or an authorized designee, the New England RCA/BAA can be operated within NERC, NPCC, and ISO established criteria, the replacement reserve requirement may be decreased to zero based upon ISO capability to restore the total 1-minute reserve requirement within NERC requirements.

Figure 2-18: Average System Reserve and Local 30-Minute Reserve Requirements



The average 10-minute spinning requirement was 515 MW in 2021, down 2% from 528 MW in 2020. The requirement was notably lower during the most recent three years compared to 2017 and 2018. In June 2018, market operation studies revealed that changes in New England's generation fleet and generator performance required fewer spinning reserves to be online to maintain adequate response to contingencies. As a result, the average spinning requirement decreased from 37% to 31% of the total 10-minute requirement.

The total 10-minute (1,661 MW) and total 30-minute requirements (2,449 MW) fell slightly in 2021 compared to previous years. As discussed above, the first and second largest single-source contingencies determine system reserve requirements. In 2020 and 2021, Phase II, a 2,000 MW direct current tie line connecting the Hydro-Quebec control area to New England, was the largest single-source contingency for 86% of hours. Planned transmission capability reductions in 2021 reduced the average flows over Phase II, thus reducing its size as the largest contingency by 52 MW, on average, over the course of the year, which reduced total 10-minute and 30-minute requirements.

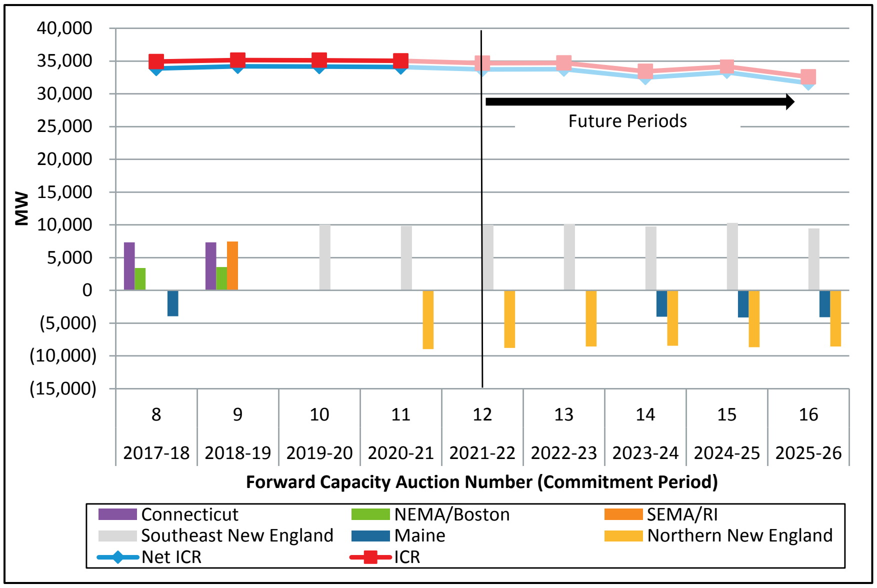
2.3.3 Capacity Market Requirements

The Installed Capacity Requirement (ICR) is the amount of capacity (expressed in megawatts) needed to meet the region's reliability requirements (including energy and reserves). 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. The ISO develops the ICR through a stakeholder and regulatory process with review and action by various NEPOOL committees, state regulators, and the New England States Committee on Electricity.

When developing the target capacity to be procured in the Forward Capacity Auction (FCA), the ISO utilizes a Net ICR. The Net Installed Capacity Requirement (NICR) is the amount of capacity needed to meet the region's reliability requirements 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 2026 are shown in Figure 2-19 below. The system ICR and Net ICR are represented as line series. LSRs (positive bars) and MCLs (negative bars) are also shown.

Figure 2-19: ICR, NICR, Local Sourcing Requirements, and Maximum Capacity Limits



The Net Installed Capacity Requirement for FCA 16 was 31,645 MW. The Net ICR decreased by 1,625 MW, or 8%, from FCA 15, largely driven by a change in the reconstitution of passive demand resources in the ISO load forecasts.[113] Reconstitution adds the estimated supply provided by passive demand resources into the forecasted demand of New England to prevent double-counting energy efficiency contribution; the FCA 16 recalculation of reconstitution greatly reduced the estimated supply of passive demand resources, contributing to the large decrease in Net ICR. Additionally, battery storage resources and active demand capacity resources had updates to their modeling methodology in the FCA 16 Net ICR calculation.[114]

Local Sourcing Requirements (LSRs) are placed on import-constrained zones due to limited import capability and generation-load imbalances. As zonal capacity approaches and falls below the LSR, additional capacity within the zone becomes increasingly valuable due to declining reliability in the local area. Starting in FCA 10, Southeast New England (SENE) was the only import-constrained zone.[115] The SENE capacity zone was modeled again in FCA 16 with an LSR of 9,450 MW, an 855 MW decrease from FCA 15 (10,305 MW).

Maximum capacity limits (MCLs) are placed on export-constrained zones due to limited export capability. These zones may procure more generation capability than can be exported to the rest of the system. Surplus capacity within the export-constrained zone becomes decreasingly valuable due to its declining contribution to system reliability. The Maine and Northern New England (NNE) capacity zones were modeled as separate export-constrained capacity zones for FCA 16, marking

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[113] For more information on the changes to passive demand resource reconstitution, see https://www.iso-ne.com/static-assets/documents/2020/10/eef2021_eeinitiative.pdf.

[114] All inputs and changes in the Net ICR can be found in the associated filing to FERC: https://www.iso-ne.com/static-assets/documents/2021/11/icr_for_fca_16.pdf

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

the third auction applying the updated nested capacity methodology that is detailed in Section III.12.2.2 of the Tariff. The MCLs were 4,095 MW in Maine, and 8,555 MW in Northern New England; which includes Maine, Vermont, and New Hampshire.

2.4 Imports and Exports (External Transactions)

New England transacts power with its neighboring control areas of New York, Hydro Québec, and New Brunswick over the transmission lines that interconnect the regions. The transmission lines that connect the ISO-NE system with its neighboring control areas are often referred to as external interfaces. External transactions allow competitive wholesale markets to serve load at a lower cost by displacing more-expensive native generation when cheaper imported power is available. Exporting generators also benefit when there are no willing buyers of their power in their own region, but there are customers willing to purchase their energy in another region.

In the day-ahead and real-time energy markets, participants can profit from the difference in energy prices (or price spread) between two regions. ISO-NE's role is to schedule external transactions and coordinate the flow of power across the interfaces. The interface's energy price (produced by ISO-NE) represents the value of energy at that location in the New England market, *not in the neighboring area.* An external transaction has two components: 1) an import in one control area at that control area's price and 2) an export in the neighboring area at that control area's price. The ISO-NE market settles the part of the transaction that occurs in the New England market; the neighboring control area settles the corresponding transaction on its side of the interface.

Market participants can use external transactions to fulfill contractual obligations to buy or sell power (e.g., a power purchase agreement) or to import energy and collect credits for renewable power.[116] Participants submit external transactions at specific locations known as external nodes, which are affiliated with specific external interfaces. The nodes represent trading and pricing points for a particular neighboring area. A pricing node may correspond to one or more transmission line(s) that connect the control areas.

New England's six external nodes are listed in Table 2-1 below, along with the commonly used external interface names. These names will be used throughout this section. There are three interfaces with New York, two with Hydro Québec and one with New Brunswick. The table also lists each interface's import and export total transfer capability (TTC) ratings. The operational ratings can be different for import and export capabilities at the same interface due to the impact of power transfers in each direction on reliability criteria.

[116] A Renewable Energy Certificate represents an amount of energy generated by a renewable energy source. These certificates can be bought by energy providers for the purposes of satisfying their Renewable Portfolio Standard. The generator selling these certificates must produce the amount of energy associated with their purchased RECs.

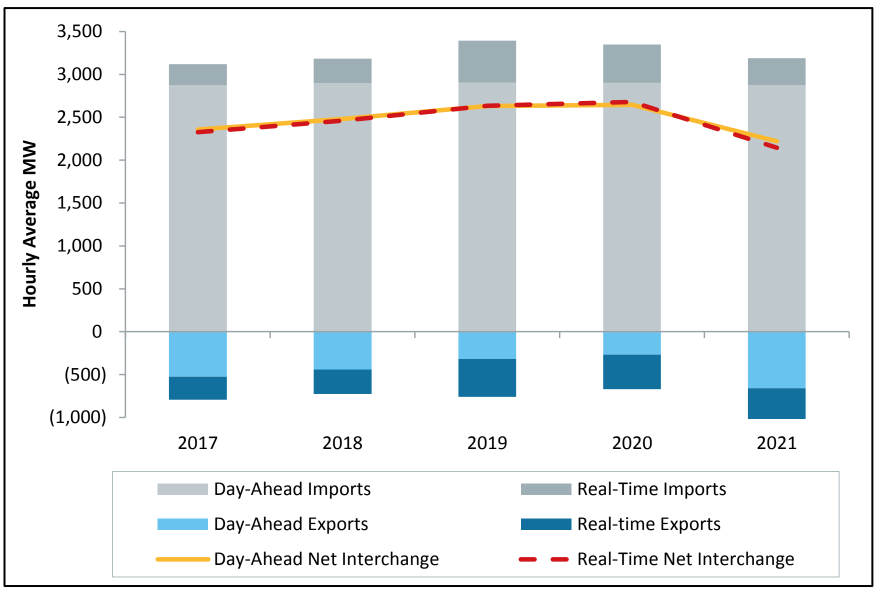
Table 2-1: External Interfaces and Transfer Capabilities

Neighboring area	Interface name	External node name	Import capability (MW)	Export capability (MW)
New York	New York North	.I.ROSETON 345 1	1,400 - 1,600	1,200
New York	Northport-Norwalk Cable	.I.NRTHPORT138 5	200	200
New York	Cross Sound Cable	.I.SHOREHAM138 99	346	330
Hydro Québec (Canada)	Phase II	.I.HQ_P1_P2345 5	2,000	1,200
Hydro Québec (Canada)	Highgate	.I.HQHIGATE120 2	225	170
New Brunswick (Canada)	New Brunswick	.I.SALBRYNB345 1	1,000	550
Total			**5,171 – 5,371**	**3,650**

Net Interchange

The average hourly system-wide, or pooled, imports, exports, and net interchange (imports minus exports), from the day-ahead and real-time markets for 2017 through 2021 are shown in the line series of Figure 2-20 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 2-20: Hourly Average Day-Ahead and Real-Time Pool Net Interchange



New England continued to be a net importer of power in 2021; real-time net imports averaged 2,144 MW each hour, meeting 16% of New England's wholesale electricity demand. The hourly average real-time net interchange increased every year between 2017 and 2020 but decreased in 2021, as shown by the dashed red line series. Average net interchange was significant lower (20% or 536 MW per hour) than in 2020. This was due to the compounding effect of lower imports and higher exports. Real-time imports decreased by 161 MW (5%) per hour, on average, from 2020 to 2021, while real-time exports increased by 375 MW (56%) per hour. The net decrease occurred primarily at the New York North interface, where there was an increase in exports. In April 2021, one of New York's large nuclear generators, Indian Point 3, retired. This increased congestion in

New York which drove up day-ahead prices there. We discuss the decrease in interchange with New York in more detail in Section 5.

New England imports significantly more power from the Canadian provinces (87% of total net imports) than it does from New York (13%). Across all three Canadian interfaces (i.e., Phase II, New Brunswick, and Highgate) the real-time net interchange averaged 1,860 MW per hour in 2021, which was just 16 MW less than the average interchange in 2020. The real-time net interchange across the three interfaces with New York (i.e., New York North, Cross Sound Cable and Northport-Norwalk) averaged 285 MW per hour in 2021, 520 MW less than the average 2020 net interchange.

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 with 2%).[117] Although additional import and export transactions are scheduled in real-time relative to day-ahead (shown by the darker colored bar series), the volumes of incremental real-time import and export schedules almost offset each other. For the first time since 2018, New England's net imports were lower in real-time market than cleared in the day-ahead, shown by the dashed red line falling below the solid yellow line.

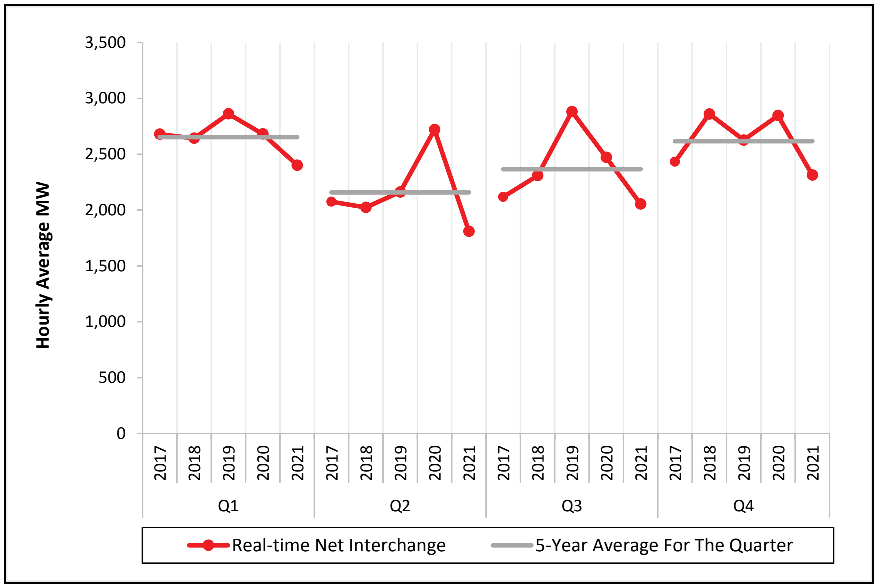
In 2021, average real-time net interchange was less than day-ahead net interchange by 3.4% (i.e., less power was imported in real-time than planned for in the day-ahead market). The main driver behind less net interchange in the real-time was higher prices in New York. Over the Coordinated Transaction Scheduling (CTS) interface, participants flowed more exports to New York in the real-time. One possible explanation for this shift in behavior was higher prices in New York due to the retirement of Indian Point 3. In order to ensure these transactions flowed in the real-time, participants bid them at low or fixed prices. Over the two non-CTS interfaces, participants continued to flow power to New York to profit from the larger price differences between the control areas.

Net Interchange by Quarter

The hourly average real-time system-wide net interchange value is plotted by calendar quarter for 2017 through 2021 in Figure 2-21 below. The red line series illustrates each quarter's hourly average net interchange; the five-year average for each quarter is shown in gray.

[117] 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 2-21: Hourly Average Real-Time Pool Net Interchange by Quarter



As illustrated in Figure 2-21, there is seasonal variation in system net interchange, with the highest net imports occurring in Q1 and Q4, which on average are the highest-priced quarters in New England due to high gas prices. This trend in quarterly real-time net interchange aligns with the trend we observe in the seasonal variation of the day-ahead Hub price. This variation is further illustrated by movement in the five-year average (gray lines) from a high during late winter (Q1) when heating demand and natural gas-fired generators compete for constrained gas supply, to a low during the spring (Q2) when temperatures are moderate, and loads and natural gas prices are typically at their lowest levels. The average net interchange climbs during the summer (Q3) when New England loads are typically highest, and moves to a second peak at the start of winter (Q4) when heating demand once again begins to put upward pressure on natural gas and electricity prices. Fuel prices are discussed more in Section 2.2.2.

As covered above, in 2021 there was a decrease in real-time net interchange in every quarter relative to 2020. Further, each of the quarterly observations in 2021 fell below the five-year average. This was driven by low net-interchange over New York North, with was the lowest in the reporting period for Q2 and Q4, and increases in exports over Northport-Norwalk and the Cross Sound Cable. Relative to 2020, the greatest decrease in quarterly average net interchange occurred in Q2. In Q2 2021, the average net interchange was 909 MW (33%) per hour less than in Q2 2020, primarily due to an increase in exports over the New York North interface. This shift in net interchange aligns with the retirement of the Indian Point 3 nuclear generator in New York. Participants captured the higher day-ahead price in New York, caused by this retirement and subsequent congestion, and submitted real-time exports bids at fixed or low-prices to ensure the power-flow in the real-time.

The decrease in net interchange was the smallest in Q1. The Q1 2021 average hourly net interchange was 280 MW less than in Q1 2020. This decrease was driven by a lower net interchange over the Cross Sound and Northport-Norwalk Cables. Average prices on the New York (NY) side of both of these interfaces were much higher than their New England counter-parts in 2021. The NY premium over the Cross Sound Cable increased from $2.44 in 2020 to $5.45 in 2021, a 124% increase. Similarly, The NY premium over the Northport-Norwalk Cable increased from

$1.60 in 2020 to $2.37 in 2021, a 48% increase. These higher NY prices incentivized participants to flow more power from New England into New York.

Section 3
Day-Ahead and Real-Time Energy Market

This section covers energy market outcomes, including the drivers of prices, market performance, competitiveness and market power mitigation.

The day-ahead and real-time energy markets are designed to ensure wholesale electricity is supplied at competitive prices, while maintaining the reliability of the power grid. Competitive energy market prices that reflect the underlying cost of electricity production are key to achieving both design goals. If suppliers can inflate prices above competitive levels, buyers will be forced to pay uncompetitive prices that exceed the cost of supplying power. On the other hand, if market prices are deflated (priced below production cost), suppliers lose the incentive to deliver power when it is needed. Further, investment in new, economically viable projects is hindered by deflated prices, hurting the short-term and long-term reliability of the New England power grid. Competitive energy market prices send the correct market signals, resulting in efficient buying and selling decisions that benefit consumers and suppliers alike.

In 2021, total day-ahead and real-time energy payments more than doubled from 2020 levels. This reflected a large increase in underlying primary fuel prices, most notably natural gas. The average Hub price was $45.92/MWh in the day-ahead market, up by 97% on 2020, and consistent with the 121% increase in natural gas prices as the pace of economic recovery outpaced increases in gas production at supply basins.

When energy prices are too low to cover production costs, resources receive NCPC payments in addition to energy payments; high levels of NCPC can be symptomatic of price formation issues or gaps in the market design. In 2021, uplift payments totaled $35.5 million, an increase of $9.7 million (38%) compared to 2020. However, payments as a percentage of total energy payments remained low, and decreased from 0.9% in 2020 to 0.6% in 2021, the lowest percentage level over the five-year reporting period. This is consistent with improved price formation in the real-time energy market since the implementation of fast-start pricing rules in 2017, and with the generally low levels of operator out-of-market or unpriced actions, which can result in high levels of uplift and can signal gaps in the market design and/or market clearing processes.

Under certain system conditions, suppliers can have local or system-wide market power. If suppliers exploit market power opportunities by inflating energy offers, uncompetitive market prices can result. To diminish the impacts of market power, energy market mitigation measures are applied when market power is detected; an uncompetitive generator offer is replaced with an IMM calculated competitive offer (i.e., reference level) consistent with the generator's cost of energy production.

Overall, day-ahead price-cost markups (i.e., the premium in market prices resulting from differences in generator offers and marginal costs) were within reason and market concentration levels, on average, remained reasonably low. Energy supply portfolios with structural market power in the real-time market remained low for the third consecutive year, declining from a third of hours in 2018, to 15% in 2019, 17% in 2020, and 18% in 2021. The reduction in the number of intervals with pivotal suppliers is consistent with a number of market trends, including a higher reserve surplus, and lack of scarcity conditions over the past two years, and the commissioning of new entrant generators.

The energy market has an extensive set of rules to identify and mitigate the impact of uncompetitive offers at times when structural market power exists. However, the mitigation measures for system-level market power in the real-time energy market provide suppliers a considerable degree of deviation from competitive marginal-cost offers before the mitigation rules trigger and mitigate a supply offer. Our analysis indicates that lower thresholds would not have had a significant impact on offer mitigation over the past few years since the market has generally been competitive, particularly due to surplus supply conditions. However, in our opinion, it remains an appropriate time for the ISO to revisit and potentially lower the mitigation thresholds, which will strike a better balance between protecting consumers and administratively intervening in the market as the supply margin contracts in future years.

3.1 Overview of the Day-Ahead and Real-Time Energy Markets

This section provides an overview of the day-ahead and real-time energy markets.

ISO-NE administers its wholesale energy market using a two-settlement system. The first settlement takes place in the day-ahead energy market. This is a *forward* market where market participants buy and sell power for the following operating day. The day-ahead market is often considered a *financial* market because there is no physical requirement that the energy bought and sold in this market be consumed or delivered in real-time.[118] The second settlement occurs in the real-time energy market. This is a *spot* market that coordinates the dispatch of resources in real-time based on actual power system conditions. The real-time market is a *physical* market because the transactions that occur in this market correspond to actual power flows.

Participants that are interested in purchasing electricity can submit hourly *demand bids* into the day-ahead energy market. These bids indicate the maximum price a buyer is willing to pay in order to purchase a certain quantity of electricity. Demand bids with bid prices greater than the locational marginal price (LMP) clear in the day-ahead market. Participants that are interested in selling electricity can submit *supply offers* into the day-ahead energy market.[119] These offers indicate the minimum price the seller is willing to accept in order to sell a certain quantity of electricity. Supply offers with offer prices less than the LMP clear in the day-ahead market.

Clearing a demand bid or a supply offer in the day-ahead market results in an initial settlement (i.e., the day-ahead settlement) and creates a financial obligation for the buyer or seller. For example, a generator that clears a 100 MW supply offer in the day-ahead market at a price of $50/MWh would be *credited* $5,000 in the day-ahead settlement. This generator receives a payment because it has financially obligated itself to provide power in real time on the following day. This obligation requires the generator to deliver in real time every megawatt it sold forward or else purchase power at a replacement price (i.e., the real-time price). Physical delivery in real time results in the second settlement for the generator (i.e., the real-time settlement). For example, if the generator provides no energy in real time and the real-time price of energy is $75/MWh, then the generator

[118] However, the day-ahead market is not completely separated from the physical market as the commitments made in the day-ahead energy market form the basis of the operating plan that is used in real-time. Reliability commitments in the day-ahead market also flow through to real-time.

[119] In general, resources with a capacity supply obligation (CSO) obtained through the Forward Capacity Market are required to submit supply offers into the day-ahead energy market of a magnitude at least equal to the megawatt amount of CSO they hold. The obligations associated with assuming a CSO create a linkage that ties the energy market to the capacity market, which is discussed in more detail in Section 6.

would be *charged* $7,500 in the real-time settlement. The net outcome from the two settlements would be a charge of $2,500 to the generator for not delivering on its obligation.

One of the primary reasons for this two-settlement design is that it affords participants a way to reduce their exposure to real-time energy price volatility. Unexpected events like transmission or generator outages can lead to high real-time energy prices. However, buyers and sellers who bought or sold energy in the day-ahead market are not exposed to these extreme real-time prices so long as they do not deviate from their day-ahead market obligations. This is because real-time energy prices apply only to deviations from day-ahead market obligations.

For example, consider a load-serving entity (LSE) that purchases 100 MW of electricity in the day-ahead market at a price of $50/MWh. This purchase creates a charge to the LSE of $5,000 in the day-ahead settlement. If the real-time price is $75/MWh and the real-time load for the LSE is 110 MWs, then the real-time settlement would result in an additional charge of $750. This is because the real-time price only applies to the 10 MW deviation. The net outcome from the two settlements would be a charge of $5,750 to the LSE. If the LSE had not participated in the day-ahead market, then it would have been charged $75/MWh for all 110 MWs of its real-time load. This would have resulted in a charge of $8,250 to the LSE. Effectively, the LSE has partially insulated itself from the higher real-time prices by participating in the day-ahead market.

As the day-ahead energy market is a financial market, participants may submit *virtual demand* bids (decrement bids) or *virtual supply* offers (incremental offers) into this market. As the name implies, virtual demand bids and supply offers are not backed by physical power. Collectively known as *virtual transactions*, these instruments allow participants to take financial positions in the day-ahead market with the expectation that the associated power will not be delivered or consumed in real-time. The participant can use this tool to speculate on day-ahead to real-time price differences or as a hedging instrument to manage to manage its exposure. ISO-NE's wholesale energy market benefits from virtual transactions through their ability to enhance competition (reduce market power), increase liquidity in the day-ahead market, and improve price convergence between the day-ahead and real-time markets. Virtual transactions are discussed in more detail in Section 4.1.

The day-ahead market purchases enough physical and virtual supply to meet physical and virtual demand.[120] In order to determine which bids and offers clear, the day-ahead market uses a clearing algorithm with the objective of maximizing social surplus, while respecting transmission constraints. The day-ahead market results form the basis of the ISO Control Room's operating plan for the following day. In the day-ahead market, virtual bids and offers can be submitted at a nodal level, zonal level or at the Hub.[121] However, supply offers from generators must be submitted at the nodal location where that generator is electrically interconnected, and non-virtual (physical)

[120] Operating reserves, described in Section 7, are not explicitly purchased through the day-ahead market. Operating reserves are procured in the Forward Reserve Market (see Section 0), and actual spot market procurement occurs in the real-time energy market where reserve procurement is co-optimized with energy procurement.

[121] Nodes, zones, and the Hub are points on the New England transmission system at which locational marginal prices (LMPs) are calculated. *Internal* nodes are individual pricing points (*pnodes*) on the system. An *external* node is a proxy location used for establishing an LMP for electric energy received by market participants from, or delivered by market participants to, a neighboring balancing authority area. *Zones* are aggregations of internal nodes within specific geographic areas and include both load zones and demand response resource (DRR) aggregation zones. The *Hub* is a collection of internal nodes intended to represent an uncongested price for electric energy that is used to facilitate energy trading. The Hub LMP is calculated as a simple average of LMPs at 32 nodes, while zonal LMPs are calculated as a load-weighted average price of all the nodes within the respective zone.

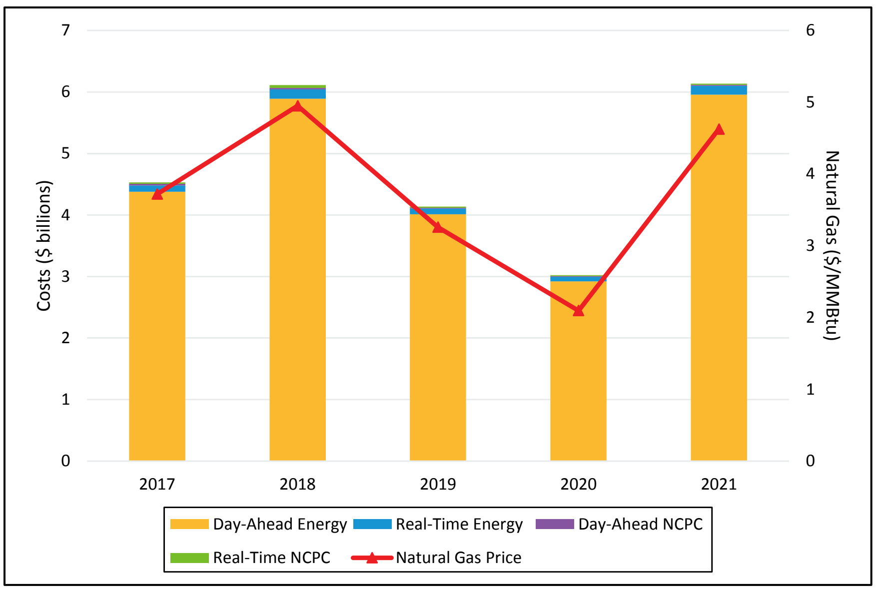
demand bids are submitted at a zonal level. All results are hourly in the day-ahead market. The results are usually posted no later than 1:30 p.m. the day before the operating day.

The real-time energy market can be thought of as a "balancing market," settling the differences between positions (production or consumption) cleared in the day-ahead energy market and actual production or consumption in the real-time energy market. The ISO coordinates the production of electricity to ensure that the amount produced moment to moment equals the amount consumed, while respecting transmission constraints. While resources continue to make supply offers in real-time, the demand is the actual physical load. In real-time, the ISO produces LMPs every five minutes for each location on the transmission system at which power is either withdrawn or injected.

3.2 Energy and NCPC (Uplift) Payments

Energy payments are strongly correlated with natural gas prices in New England and comprise the vast majority of payments to supply resources in the energy markets. When energy prices are too low to cover production costs, resources receive NCPC (also known as uplift) payments in addition to energy payments.[122] Energy and NCPC payments for each year (billions of dollars), by market, along with the annual average natural gas price ($/MMBtu), are shown in Figure 3-1 below.

Figure 3-1: Energy Payments, NCPC, and Natural Gas Prices



Energy payments more than doubled compared to 2020, up to $6.1 billion in 2021 from $3.0 billion in 2020. As discussed above, natural gas prices are a key driver of energy payments. Natural gas prices averaged $4.62/MMBtu in 2021, up 121% from $2.10/MMBtu in 2020. The day-ahead market continued to account for the vast majority of energy payments (98%). This is because the majority of demand and supply clears in the day-ahead, while the real-time market settles on deviations from the day-ahead market.

NCPC totaled $35.5 million, a $9.7 million increase from $25.8 million in 2020. This was largely due to an increase in payments to cover generator economic commitments and dispatch ("economic"

[122] NCPC is explained in more detail in Section 3.5.

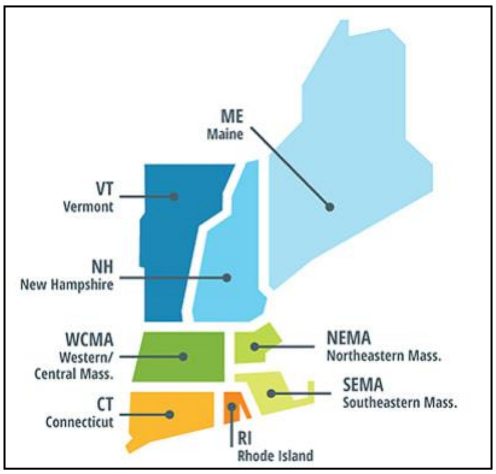
NCPC), which increased by $5.2 million, and is in-line with higher production costs associated with higher gas prices. In addition, payments for local reliability reasons ("local second contingency protection" NCPC) increased by a modest $2.5 million.

3.3 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 over the review period. An important overall outcome for energy prices in 2021 was an increase in annual average Hub prices compared to earlier years; annual real-time market LMPs averaged $45/MWh in 2021, compared to an all-time low for prices in 2020 of $23/MWh.[123] Prices in both the day-ahead and real-time energy markets were almost double the year-earlier prices.

All energy prices have a locational dimension. In this section, prices are differentiated geographically by "load zone" (as shown in Figure 3-2 below) and the "Hub". The Hub represents a collection of selected pricing nodes that are intended to indicate "reference" prices for energy transactions.

Figure 3-2: ISO New England Pricing Zones

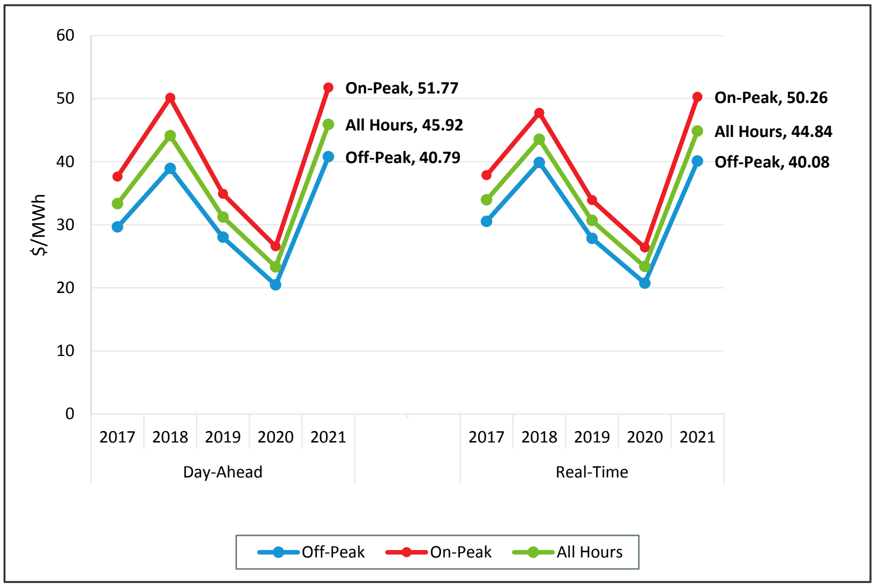


3.3.1 Hub Prices

An illustration of energy market prices in the day-ahead and real-time markets, from 2017 to 2021, is provided in Figure 3-3 below.

[123] The 2020 LMPs were the lowest in the 18 years since standard market design was introduced in 2003.

Figure 3-3: Annual Simple Average Hub Price



In 2021, the simple annual average Hub price (in all hours) was $45.92/MWh in the day-ahead market and $44.84/MWh in the real-time market. Hub prices increased by 97% in the day-ahead market and by 92% in the real-time market compared to 2020 prices, on average.[124] These price changes are consistent with observed market conditions, including input fuel costs, load levels, and generator operations. Average natural gas prices increased significantly in 2021, rising by approximately 121% compared to 2020. The increase in gas prices largely explains the increase in LMPs between 2020 and 2021, with gas generators setting price during 83% of pricing intervals in the real-time energy market. A small increase in average 2021 loads (approximately 2%) also contributed to the increase in LMPs.

Pricing by time-of-day (i.e., on-peak and off-peak) in 2021 exhibited the same trend when compared with 2020; average on-peak prices increased by 95% in the day-ahead market and 91% in the real-time market, while average off-peak prices increased by 100% in the day-ahead market and 93% in the real-time market, respectively.[125]

Average Hub LMPs for all hours in the real-time energy market were lower than LMPs for the day-ahead market in 2021, with a -$1.08/MWh (-2.3%) difference. During both on-peak and off-peak hours, Hub LMPs also were lower in the real-time energy market than the day-ahead market: -$1.50/MWh (-2.7%) for the on-peak period and -$0.71/MWh (-1.7%) for the off-peak period. Over the review period, average real-time prices tended to be lower than day-ahead prices, with 2017 and 2020 as exceptions. In 2017, higher average real-time prices occurred during a period of very cold weather in the latter part of December 2017; [126] while real-time energy market prices were

[124] These prices represent a simple average of the hourly-integrated Hub LMPs for each year and time-period, respectively.

[125] 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.

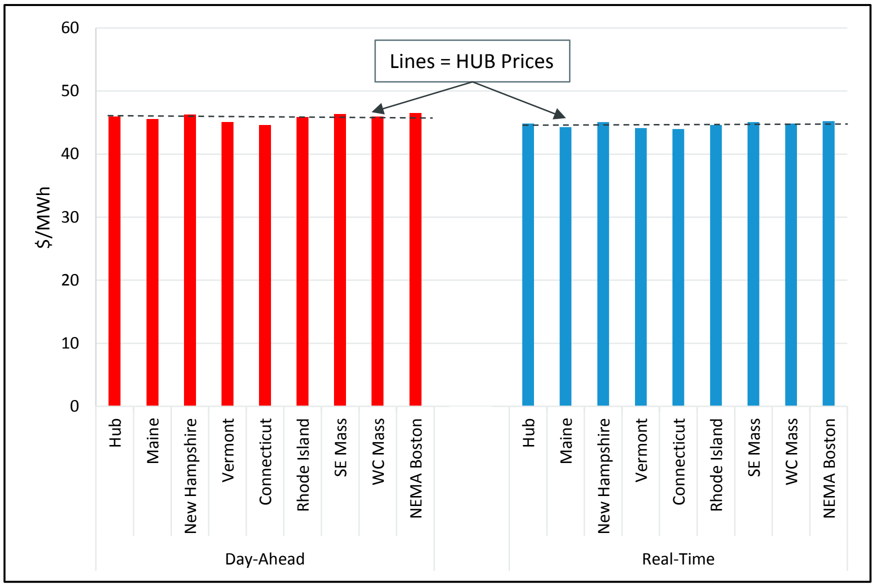
[126] While both day-ahead and real-time prices were relatively high in December 2017, as a result of cold weather and elevated fuel prices, tight system conditions and unexpected factors in the real-time market resulted in higher overall prices. These factors included reductions in imports in mid-December because of a partial transmission outage, and very cold weather and high loads levels, combined with unexpected generator outages, during the final week of the month. These factors led to an average real-time premium of $9/MWh.

slightly higher than day-ahead prices in 2020, the difference was negligible, with a $0.06/MWh real-time market premium.

3.3.2 Zonal Prices

This section describes differences among zonal prices. Within the day-ahead and real-time energy markets, price differences among load zones result from energy "losses" and transmission congestion that vary by location.[127] In 2021, price differences among the load zones were relatively small, as shown in Figure 3-4 below.

Figure 3-4: Simple-Average Hub and Load Zone Prices, 2021



The relatively small price differences between the load zones were the result of modest levels of both marginal losses and congestion. The average absolute difference between the annual average Hub price and load zone prices was $0.51/MWh in the day-ahead energy market and $0.41/MWh in the real-time energy market – a difference of approximately 1.0%.

The Connecticut load zone had the lowest overall average prices in the region in 2021. Connecticut's prices averaged $1.32/MWh (2.9%) and $0.87/MWh (1.9%) lower than the Hub prices for the day-ahead and real-time markets, respectively. Most of the difference in average prices between Connecticut and the Hub resulted from the imputed cost for transmission losses that is included in the LMP; losses represented about 66% of the price difference in the day-ahead market and 85% of the difference 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 $0.61/MWh and $0.41/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

[127] The loss component of the LMP is the marginal cost of additional losses resulting from supplying an increment of load at the location. In addition to the loss and congestion components, the LMP also includes an energy component that does not vary by location. New England is divided into the following eight load zones used for wholesale market billing: Maine (ME), New Hampshire (NH), Vermont (VT), Rhode Island (RI), Connecticut (CT), Western/Central Massachusetts (WCMA), Northeast Massachusetts and Boston (NEMA), and Southeast Massachusetts (SEMA).

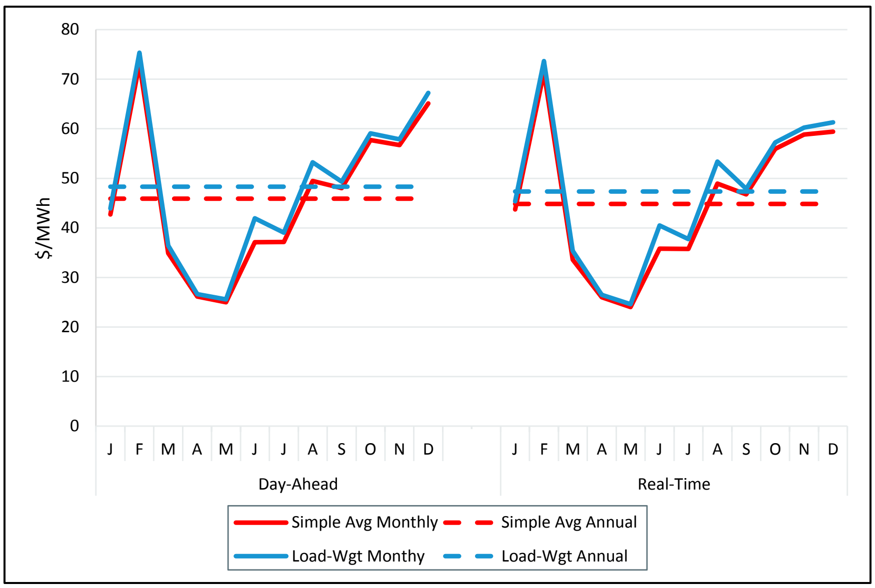
zone, losses represented the bulk of the price difference between the Hub and NEMA: 85% and 100% in the day-ahead and real-time markets, respectively. The average congestion component in NEMA was quite low in both markets for 2021.

3.3.3 Load-Weighted Prices

While simple-average prices are an indicator of actual observed energy prices within the ISO's markets, load-weighted prices are a better indicator of average prices that load-serving entities (LSEs) pay for energy.[128] The amount of energy consumed in the markets can vary significantly by hour. Load-weighted prices reflect 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 $48.30 and $47.34/MWh in the day-ahead and real-time markets in 2021, respectively. Monthly load-weighted and simple average prices for 2021 are provided in Figure 3-5.

Figure 3-5: Load-Weighted and Simple Average Hub Prices, 2021



As expected, load-weighted average prices were higher than simple-average prices in 2021. The differences range from approximately 2% to 12%, depending on the month and energy market (day-ahead and 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.

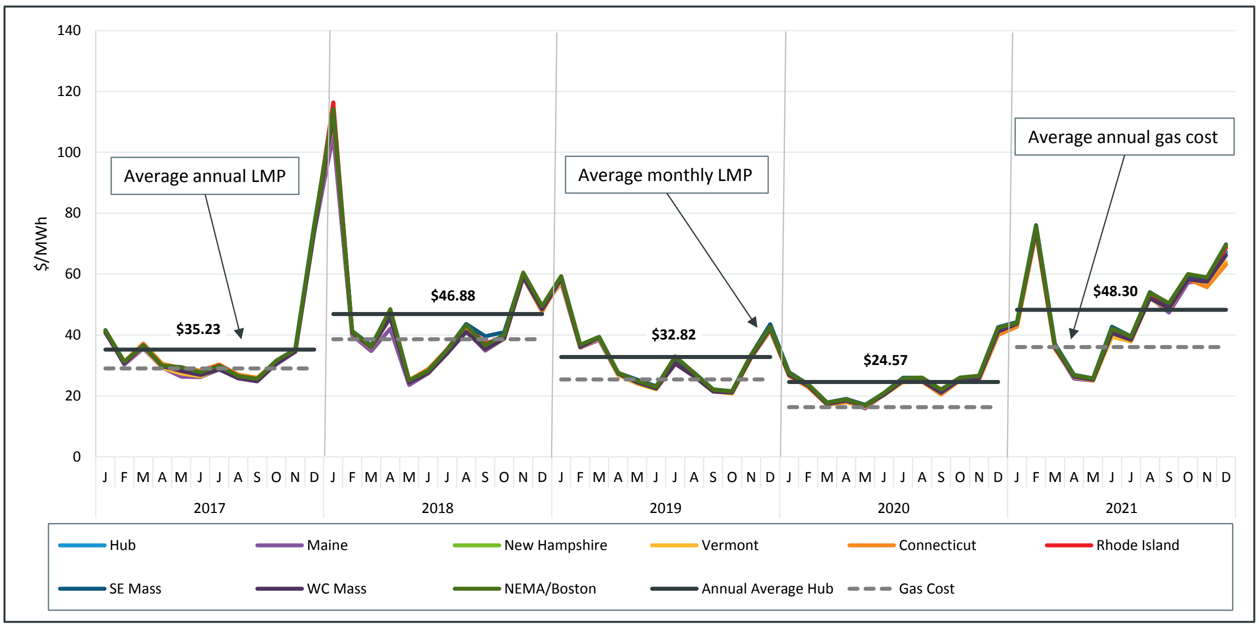
In 2021, hourly load variability had the least impact on average prices paid by wholesale consumers in April, when simple- and load-weighted average prices differed by just 2% in both the day-ahead

[128] 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.

and real-time markets. Summer months exhibited the greatest impact of load variability on average prices paid by wholesale consumers. In the day-ahead and real-time energy markets, the largest difference occurred in June: $4.82/MWh (12%) in the day-ahead market and at $4.67/MWh (12%) in real-time.

Monthly day-ahead load-weighted prices across load zones over the past five years are shown in Figure 3-6 below. The figure illustrates significant monthly variability in LMPs, particularly during winter months with fuel price volatility. The black lines show the average annual load-weighted Hub prices and highlight the degree of variability in prices throughout the year when compared to monthly prices. The dashed grey lines show the annual average cost of natural gas, providing a benchmark for linking annual fuel price variation to LMPs.

Figure 3-6: Day-Ahead Load-Weighted Prices



Load-weighted energy prices by load zone from 2017 to 2021 indicate a pattern that varies considerably by year and by month, but typically not by load zone. Very high pricing occurred in January 2018. This is consistent with varying weather patterns and natural gas prices over the period, and reasonably uniform load shapes across load zones. Winter periods with high fuel prices and summer months with elevated load variability 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. Additionally, in December, a frequently binding transmission constraint (the NE West-East constraint) resulted in lower prices in the Connecticut zone. Spark spreads were also higher in 2021; see Section 0 for a discussion of spark spreads over the review period.

3.3.4 Fast Start Pricing: Impact on Real-Time Outcomes

On March 1, 2017, the ISO implemented fast-start pricing to improve price formation and performance incentives in the real-time energy market. This subsection provides an update on the impact assessment provided in the Summer 2017 Quarterly Markets Report, which also contained a detailed discussion of fast-start pricing's purpose and mechanics.[129] We find the impact of the fast-start pricing rules in 2021 was broadly similar to our prior analysis. The results indicate that fast-start pricing is broadly working as intended. In summary, under fast-start pricing:

- Real-time energy prices have more effectively reflected fast-start resource commitment costs
- Uplift payments have decreased
- Reserve pricing is higher and more frequent due to fast-start pricing mechanics

Since the ISO implemented fast-start pricing, the market clearing software performs separate dispatch and pricing optimization processes. The following is a high-level description of each:

- The dispatch process is similar to the process before fast-start pricing. The dispatch optimization respects all resources' operational constraints when determining least-cost dispatch instructions.
- The pricing process is designed to better reflect fast-start resources' commitment costs in LMPs. The pricing process relaxes some physical fast-start resource constraints – allowing these resources to set price in more circumstances.[130] Additionally, commitment costs are converted to per-MW values and added to fast-start energy offers.

The following table details estimates of fast-start pricing impacts. The *Fast-Start Pricing* column details actual outcomes – with dispatch instructions from the dispatch process and prices from the pricing process. The *Non-Fast-Start Pricing* column provides an estimate of counter-factual outcomes if fast-start pricing had not been implemented. Non-fast-start pricing outcomes are estimated using prices produced by the dispatch software. These prices are not used in settlement.

[129] 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

[130] Specifically, fast-start pricing relaxes resources' economic minimum and down-ramp constraints, allowing these resources to set price in their entire physically-dispatchable range *and* below their physical minimum output.

Table 3-1: Fast-Start Pricing Outcome Summary, 2021

	Fast-Start Pricing (Actual Outcomes)	Non-Fast-Start Pricing (Counterfactual Outcomes)	Difference
System LMP ($/MWh)[131]	$44.68	$42.06	$2.62 (6%)
Real-Time Energy Payments ($, Millions)[132]	$141.9	$123.9	$18.0 (15%)
NCPC Payments ($, Millions)[133]	$20.2	$29.1	-$8.9 (-31%)
Reserve Prices ($/MWh)[134]	$1.55	$ 0.56	$0.99 (177%)
Reserve Payments ($, Millions)[135]	$13.7	$3.2	$10.5 (327%)
Percent of Intervals with Reserve Pricing (%)	15.3%	8.4%	6.9% (82%)
Intervals Fast-Start Resource Marginal[136]	25.5%	8.6%	16.9% (197%)

Fast-start pricing resulted in a higher frequency of price-setting fast-start resources. Fast-start resources set price about a quarter of the time in 2021, compared with less than 10% of the time in the counter-factual non-fast-start-pricing case. Fast-start pricing increased the average annual system LMP by 6% and real-time energy payments from load by 15% over the course of 2021.

Fast-start pricing decreased real-time NCPC paid to generators and asset-related demand (ARDs) by 31%, in line with stated fast-start pricing goals. Breaking down the reduction further, fast-start pricing reduced commitment-out-of-merit (COOM) and dispatch-out-of-merit (DOOM) NCPC by 43%. COOM and DOOM NCPC are paid to resources that do not recover their costs when following ISO commitment or dispatch instructions. The decrease in COOM and DOOM NCPC was offset by Rapid Response Pricing Opportunity Cost (RRPOC) NCPC. RRPOC payments remedy the misaligned incentives produced by the separation of dispatch and pricing processes. Because these concepts were introduced with the implementation of fast-start pricing, RRPOC NCPC was not necessary prior to the change. RRPOC NCPC compensates resources for following dispatch instructions when they are incentivized to deviate from their desired dispatch points (DDPs) due to fast-start pricing mechanics.

[131] The system LMP shown here is the energy component of the LMP in each interval.

[132] 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). Using this methodology, the actual value of real-time payments is $143.4 million.

[133] 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 in 2021 were $19.7 million.

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

[135] 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.

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

Fast-start pricing had a substantial impact on reserve pricing and payments. Reserve pricing occurred in 82% more intervals than in the counterfactual dispatch case. In other words, when reserves were priced in 2021, almost half of the time there was no physical scarcity of reserves. Overall, average reserve prices were 177% higher in the pricing case than in the dispatch case and payments were 327% higher.

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, and
- Compensate market participants with on-line and fast-start generators for the increased value of their product when the system is short of reserves.

Fast-start pricing can result in reserve pricing even when reserve margins positive (above zero) and there is no redispatch of resource required to provide additional reserve capacity. This is apparent in the 6.9% of intervals that there is positive reserve pricing, when no resources are being dispatched down to provide reserves (i.e., there is no reserve pricing in the dispatch run).[137]

Figure 3-7, below, shows reserve prices output from the pricing and dispatch software on April 17, 2021, the day with the largest difference in reserve pricing frequency between the pricing and dispatch case during 2021. The pricing software, on top and in orange, represents the fast-start pricing (actual) case. The dispatch software, on the bottom and in blue, represents the non-fast-start-pricing (counter-factual) case.

[137] 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 have *not* been dispatched down to provide reserves. RRPOC NCPC, not reserve pricing, is the mechanism through which the market compensates these resources.

Figure 3-7: Reserve Prices in the Pricing vs. Dispatch Software on April 17, 2021

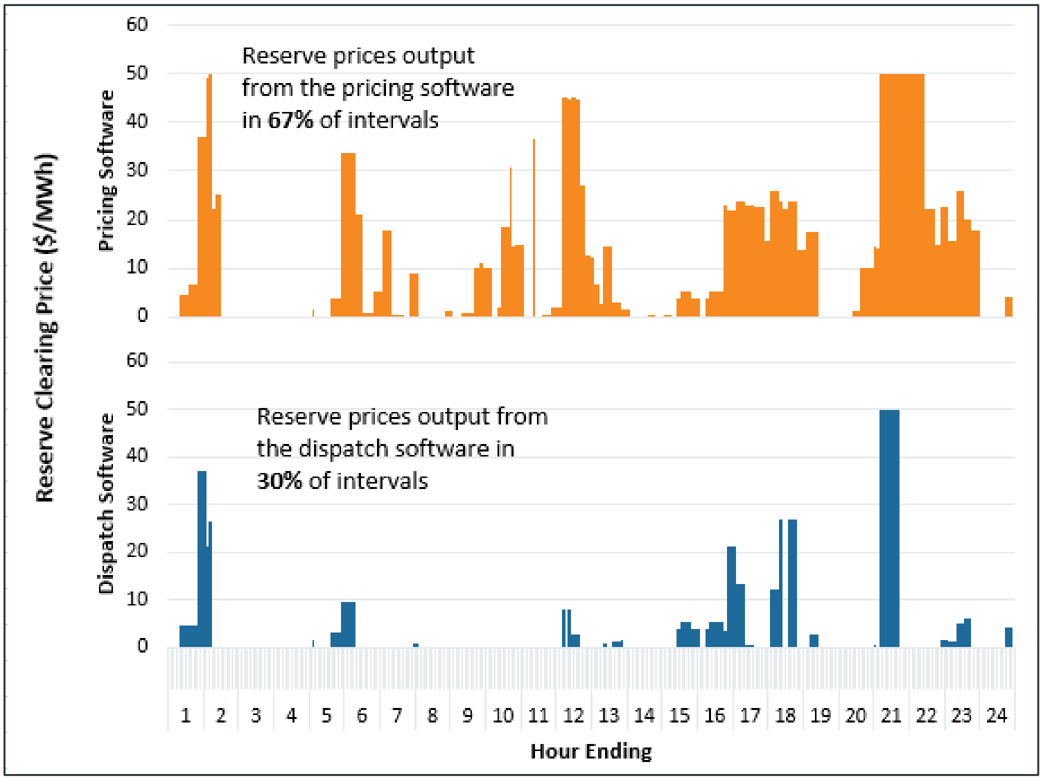


Figure 3-7 shows that fast-start pricing can have a substantial impact on the frequency of non-zero reserve prices. On this day, April 17, fast-start pricing generated reserve prices in more than double the five-minute intervals as in the counter-factual case. The difference between the two cases, 37% of intervals, represents the percentage of time during the day reserve prices were generated in which there was no reserve scarcity (i.e., the dispatch software did not hold back resources for reserves when they otherwise were economic to provide energy).

3.3.5 Energy Price Convergence between the Day-Ahead and Real-Time Market

This section focuses on four aspects of price convergence.[138] First, we describe the importance of price convergence as a signal of market efficiency. Second, we review the degree of price convergence in recent years by looking at the day-ahead price premium at the Hub. Third, we examine the drivers that influence energy price convergence, including the factors that cause real-time and day-ahead prices to differ. Lastly, we assess the role virtual transactions can play in relation to price convergence.

Importance of Price Convergence

Price convergence is an important metric because it can indicate how well the day-ahead market anticipated real-time conditions. The objective of the real-time energy market is to provide least-cost dispatch while meeting load and reliability requirements. The day-ahead energy market serves an important role in achieving this ultimate goal because it can help produce a least-cost schedule that reliably meets expected load in advance of real time.

[138] Other metrics for assessing price convergence are presented in Section 4.1.4.

Scheduling generators in the day-ahead market is advantageous because it allows for more flexibility in generator selection. After the day-ahead market closes and as the real-time market approaches, the number of generators the ISO can commit and dispatch shrinks. This is because longer-lead time generators, which can require several hours to start up, often cannot be dispatched in response to sudden or transient supply needs in the real-time market. Thus, in real time, there is a greater reliance on fast-start generators, which are often more expensive.

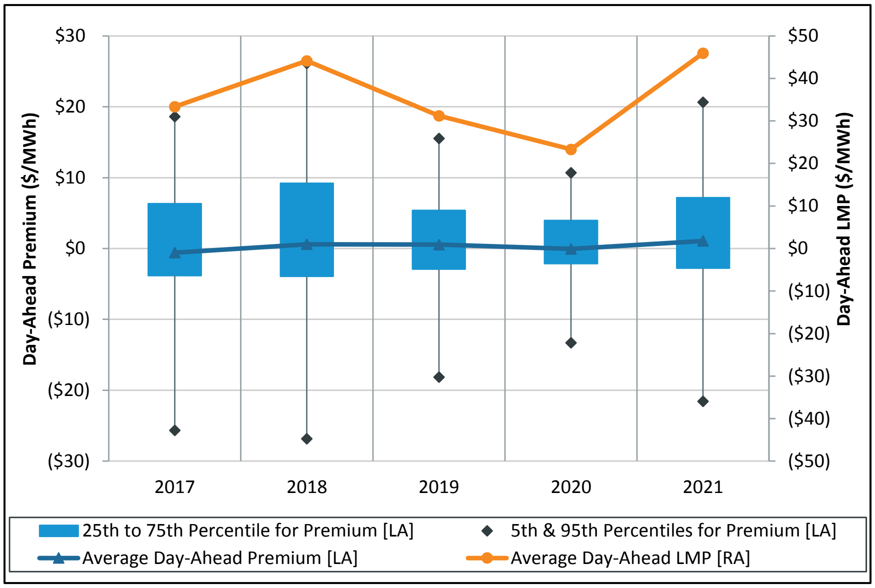
We can consider an example to see how price convergence serves as a signal that the day-ahead market is accurately anticipating real-time conditions. Consider a day where real-time load is exceeds the day-ahead cleared demand. To satisfy this increase in load, the ISO would need to commit additional (and often more expensive) fast-start generators in real time. The resulting real-time price would be greater than (sometimes much greater than) the day-ahead price. On the other hand, if participants had forecasted high real-time load, they would have cleared more demand in the day-ahead market, raising the day-ahead price. Meanwhile, additional generator commitments in the day-ahead market would have removed the need to dispatch expensive fast-start generators in the real-time market, lowering the real-time price. Thus, if the day-ahead market had better anticipated real-time conditions, the day-ahead and real-time prices would have been better aligned.

Day-Ahead Price Premium

The day-ahead market will almost never perfectly anticipate real-time conditions. Similarly, day-ahead energy prices will almost never perfectly match real-time energy prices. However, over a longer period, the average prices from the day-ahead market should begin to align more closely with the average prices from the real-time market. 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) over time. Figure 3-8 shows the distribution of the day-ahead price premium at the Hub using a box-and-whiskers diagram along with the annual average day-ahead Hub LMP (orange line) for 2017–2021.[139]

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

Figure 3-8: Day-Ahead Hub LMP Premium and Average Day-Ahead Hub LMP



The day-ahead premium at the Hub averaged $1.08/MWh in 2021 (i.e., the day-ahead Hub price averaged $1.08/MWh more than the real-time Hub price). This represents a moderate increase from 2020 when the day-ahead premium was -$0.06/MWh. In fact, the 2021 premium is the largest day-ahead premium observed over the reporting period. Between 2017 and 2020, the average day-ahead premium had been as low as -$0.58/MWh (in 2017) and as high as $0.59/MWh (in 2018). However, it is worth noting that the average day-ahead LMP at the Hub in 2021 ($45.92/MWh) was also the highest value of the reporting period. When expressed as a percent of the average day-ahead LMP, the 2021 premium (2.3%) is considerably more in line with previous years, whose values ranged between -1.7% (in 2017) and 1.8% (in 2019).

An increased amount of variability in the 2021 day-ahead premium relative to the last two years is also evident in Figure 3-8. The blue boxes, which denote the range between the 25th and 75th percentiles for the day-ahead premium (i.e., the interquartile range), show that for half of all hours in 2021, the day-ahead Hub premium was between -$2.78/MWh and $7.19/MWh. The range in 2021 ($9.97/MWh) was larger than in the previous two years ($6.10/MWh in 2020 and $8.31/MWh in 2019). The whiskers in the figure show the 5th and 95th percentiles for the day-ahead Hub premium, which were -$21.55/MWh and $20.64/MWh, respectively, in 2021. Similar to the interquartile range, the range between the 5th and 95th percentiles in 2021 ($42.18/MWh) was considerably larger than the range in both 2020 ($24.00/MWh) and 2019 ($33.67/MWh).

While the widening price ranges in 2021 might suggest worsening price convergence, it is important to note that, over time, these percentiles generally track the average day-ahead LMP and therefore are not of particular concern (orange series, right axis). 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.[140] Similarly, differences between day-ahead and real-time prices tend to

[140] The average price of natural gas in New England was $4.62/MMBtu in 2021, compared to only $2.10/MMBtu in 2020.

be larger when gas prices are higher. This is because the cost difference between two gas-fired generators with different heat rates is greater when gas prices are higher.[141]

Drivers of Price Divergence

A well-functioning energy market does not require day-ahead and real-time prices to be equal all the time. Rather, it requires the day-ahead clearing reflects an unbiased expectation of the real-time conditions given all the information that was available at the time. This, in turn, would result in day-ahead prices that represent an unbiased expectation of real-time prices. Of course, despite efforts to predict and anticipate real-time conditions in the day-ahead market, real-time conditions usually differ from day-ahead expectations. This will lead to price differences.

Ultimately, day-ahead and real-time prices are determined by energy supply, energy demand, and reliability actions taken by the ISO. Thus, when day-ahead and real-time prices do vary, it is often the result of shifts in supply and demand conditions. For example, if a generator clears an energy supply offer in the day-ahead market but experiences an unplanned outage in real-time, the available system supply falls and real-time prices will likely rise. In another example, higher-than expected temperatures on a summer day can translate to greater real-time loads and higher real-time prices.

In addition to unforeseen changes between day-ahead and real-time conditions, market participants may prefer transacting energy in one market over another. For example, a supplier with a gas-fired generator may prefer to sell power in the day-ahead market; receiving an operating schedule the day before expected physical delivery allows the supplier to better manage its natural gas purchase and delivery for the following day. Similarly, a load-serving entity may want to limit its exposure to more volatile real-time prices by purchasing load in the day-ahead market.[142] While most load and generation clear in the day-ahead market, some participants might have a preference for the real-time market. For example, intermittent generators may prefer to clear in the real-time market when the environmental factors that influence their ability to generate are more certain.

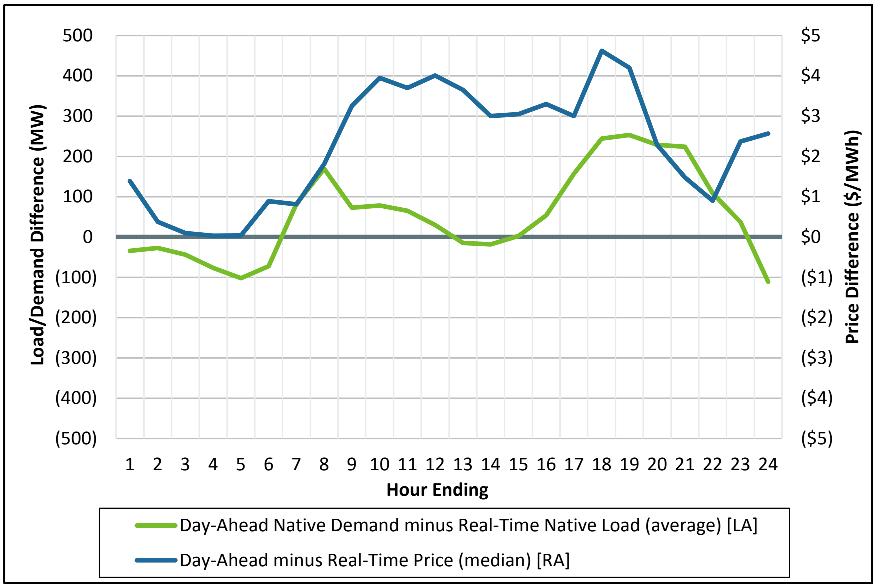
Looking at the relationship between load deviations and energy market prices can provide information about the extent to which changes in load across markets are associated with changes in prices across markets. The relationship between load deviations and energy market price differences is depicted in Figure 3-9. The green line depicts the average difference between day-ahead native demand and real-time metered native load (i.e., day-ahead demand minus real-time load) during 2021 by hour of the day (hours ending 1–24). This series is measured on the left axis ("LA"). The blue line shows the median difference between day-ahead and real-time Hub prices

[141] 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).

[142] The vast majority of load clears in the day-ahead market. In 2021, 100.4% of real-time load cleared in the day-ahead market.

(i.e., day-ahead Hub price minus real-time Hub price) during 2021 by hour of the day.[143] This series is measured on the right axis ("RA").

Figure 3-9: Deviations in Day-Ahead and Real-Time Native Demand and Hub Price by Hour, 2021



The deviations in day-ahead native demand and real-time native load correlate modestly well with the difference in day-ahead and real-time Hub prices. In general, the hours with higher day-ahead native demand compared to real-time native load (e.g., HE 7-12, 15-23) also tend to be the hours with higher day-ahead prices relative to real-time prices. However, this relationship breaks down somewhat during the middle part of the day and late at night. For example, during hours ending 13 and 14, day-ahead native demand is less than real-time native load but day-ahead prices maintain a premium over real-time prices. It is possible that this premium exists during daytime hours because of uncertain real-time load conditions, which are increasingly impacted by the growth in solar generation.[144] This type of generation is particularly sensitive to changes in environmental factors (e.g., changes in locational cloud cover, weather, and ambient air temperature). As these environmental factors can change quickly in New England, so too can the production from solar generation, which in turn can lead to increased variability in the real-time price of energy. Consequently, market participants may be willing to pay a premium to transact in the day-ahead energy market as a way to avoid this real-time price volatility.

Role of Virtual Transactions in Price Convergence

As discussed in more detail in Section 4, virtual transactions play a critical role in improving market efficiency and price convergence. Virtual traders seek to profit from differences between day-ahead and real-time prices. Generally, profitable virtual transactions help improve day-ahead commitment so that it more closely matches the real-time needs. For example, consider a virtual trader who anticipates that higher-than-forecasted temperatures will cause real-time load and prices to be much higher than others expect. The trader submits a virtual demand bid, and it clears

[143] While the median difference is shown in Figure 3-9 (to remove the impact that extreme observations may have had), the mean difference looks quite similar. The mean difference is shown in Figure 3-10.

[144] The growth in solar generation is discussed in more detail in Section 2.2.

in the day-ahead market. If the real-time price is higher than the day-ahead price, the trader profits (ignoring charges and other costs). Although the trader's motivation was profit, the virtual transaction may have helped improve the day-ahead commitment; by clearing the virtual demand bid, the day-ahead market may have committed some additional physical generation in the day-ahead market that could serve the higher real-time load. Additionally, the cleared virtual demand would have worked to raise the day-ahead price, while the additional committed generation may have lowered the real-time price (by precluding the need to call upon higher-cost, fast-start generation), thereby helping to converge prices between the markets.

Although hourly price differences continue to offer profitable opportunities for virtual transactions, Net Commitment Period Compensation (NCPC) charges allocated to virtual transactions diminish the profitability and frequency of these opportunities. In ISO-NE, real-time economic NCPC costs are assigned to real-time deviations.[145] Virtual transactions are assigned these charges because, by their very nature, these transactions create real-time deviations as they represent demand bids and supply offers that are not expected to materialize as physical consumption or delivery in real time.[146]

The impact of NCPC charges on virtual transaction profitability is demonstrated in Figure 3-10 below, which shows, by hour, the average day-ahead to real-time price difference at the Hub (blue line) together with the average hourly NCPC charges (black dashed lines) in 2021. On a gross profit basis, when price differences are positive (i.e., DA LMP > RT LMP), it is profitable for virtual supply to clear.[147] Conversely, when price differences are negative (i.e., DA LMP < RT LMP), it is profitable for virtual demand to clear. The dashed black lines show the annual average NCPC charge to virtual supply (positive value) and virtual demand (negative value). Where the blue line falls between the two dashed black lines (red circles), on average, neither virtual supply nor virtual demand is profitable on a net profit basis as the NCPC charges are greater than the day-ahead to real-time price difference. Conversely, where the blue line falls outside the dashed lines, on average, virtual supply or demand is profitable on a net profit basis (green circles). The gray bars show the interquartile range (i.e., the middle 50 percent) of the day-ahead to real-time price difference at the Hub.

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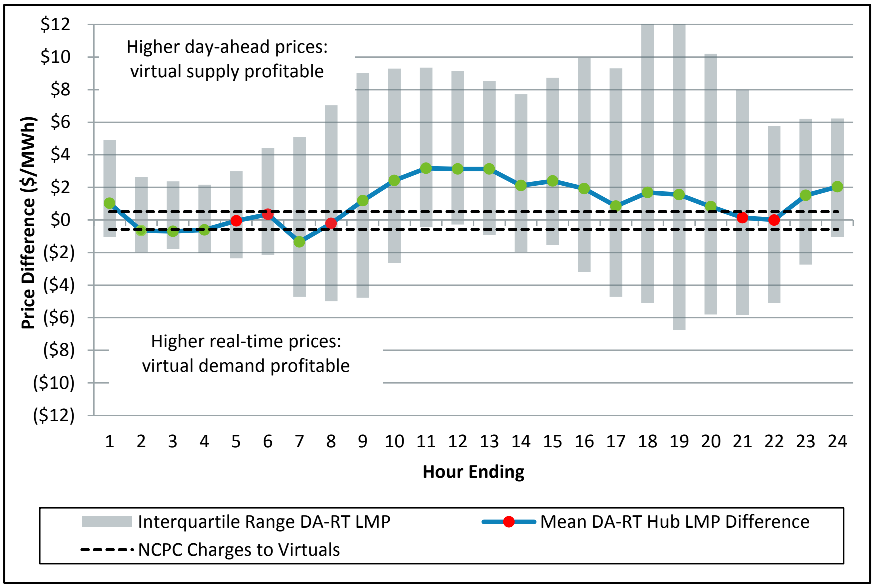
[145] While virtual supply is always treated as a full deviation for the purposes of allocating real-time economic NCPC charges, the treatment of virtual demand is more complex. For more detailed information about how real-time economic NCPC charges are allocated, please see ISO-NE's calculation summary document: https://www.iso-ne.com/static-assets/documents/2017/02/rt_ncpc_calculation_summary.pdf.

[146] While both virtual demand and virtual supply are obligated to pay a portion of real-time economic NCPC (keeping in mind the information from the preceding footnote), virtual demand is also obligated to pay a portion of day-ahead economic NCPC (as these charges are assigned to day-ahead load obligation). As such, the NCPC charges assigned to virtual demand exceed those assigned to virtual supply. In general, the average real-time NCPC charge rate is considerably higher than the average day-ahead NCPC charge rate. See Section 4.1 for more information about virtual transactions and NCPC.

[147] In this section, gross profit refers to profit before accounting for NCPC charges, while net profit refers to profit after accounting for NCPC charges.

Figure 3-10: Hourly Day-Ahead to Real-Time Price Differences and NCPC Charges, 2021



Relatively large day-ahead to real-time price differences combined with modest NCPC charges contributed to create profitable opportunities for virtual transactions at the Hub in 2021, particularly for virtual supply. NCPC charges averaged around $0.50/MWh for virtual transactions in 2021, meaning that on average price differences needed to exceed this amount in order for virtual transactions to be profitable on a net profit basis. One notable period where it would have been profitable to clear virtual supply is between HE 9 and HE 20. During this stretch of 12 consecutive hours, the day-ahead prices were, on average, above real-time prices and this difference exceeded the average NCPC charge for virtual supply. In fact, the average day-ahead premium was often much larger than this charge rate (for example, between HE 11 and HE 13, the average day-ahead premium was greater than $3.00/MWh).

Given the large average day-ahead premiums at the Hub in some hours during 2021, it would have been profitable for virtual traders to clear more virtual supply, and yet this did not occur. It is possible that virtual transaction activity was hindered to some degree by uncertainty over NCPC charges. Because a participant cannot know the NCPC charge in advance, the expectation of a charge (and possibly a large charge) likely diminishes the incentive for a virtual participant to capture these price differences. While the average real-time NCPC charge in 2021 was only around $0.50/MWh, this value exceeded $5.00/MWh at times over 2021. Additionally, the interquartile range gives us insight into the price difference uncertainty faced by virtual traders; the fact that the first quartile is negative for every hour (not just the daylight hours) indicates clearing virtual supply would have resulted in a loss at least 25% of the time in every hour, even before considering NCPC charges.

3.4 Drivers of Energy Market Outcomes

Many factors can provide important insights into long-term market trends. For example, underlying natural gas prices can explain, to a large degree, movements in energy prices. Other factors, such as load forecast error or notable system events can provide additional insight into specific short-term pricing outcomes. This section covers some of the important factors that provide context to energy market outcomes. The section is structured as follows:

- Generation costs (Section 3.4.1)
- Supply-side participation (Section 3.4.2)
- Reserve Adequacy Analysis (RAA) Commitments (Section 3.4.3)
- Load and weather conditions (Section 3.4.4)
- Demand bidding (Section 3.4.5)
- Load forecast error (Section 3.4.6)
- Reserve margin (Section 3.4.7)
- System events (Section 3.4.8)
- Reliability commitments (Section 3.4.9)
- Congestion (Section 3.4.10)
- Marginal resources (Section 3.4.11)

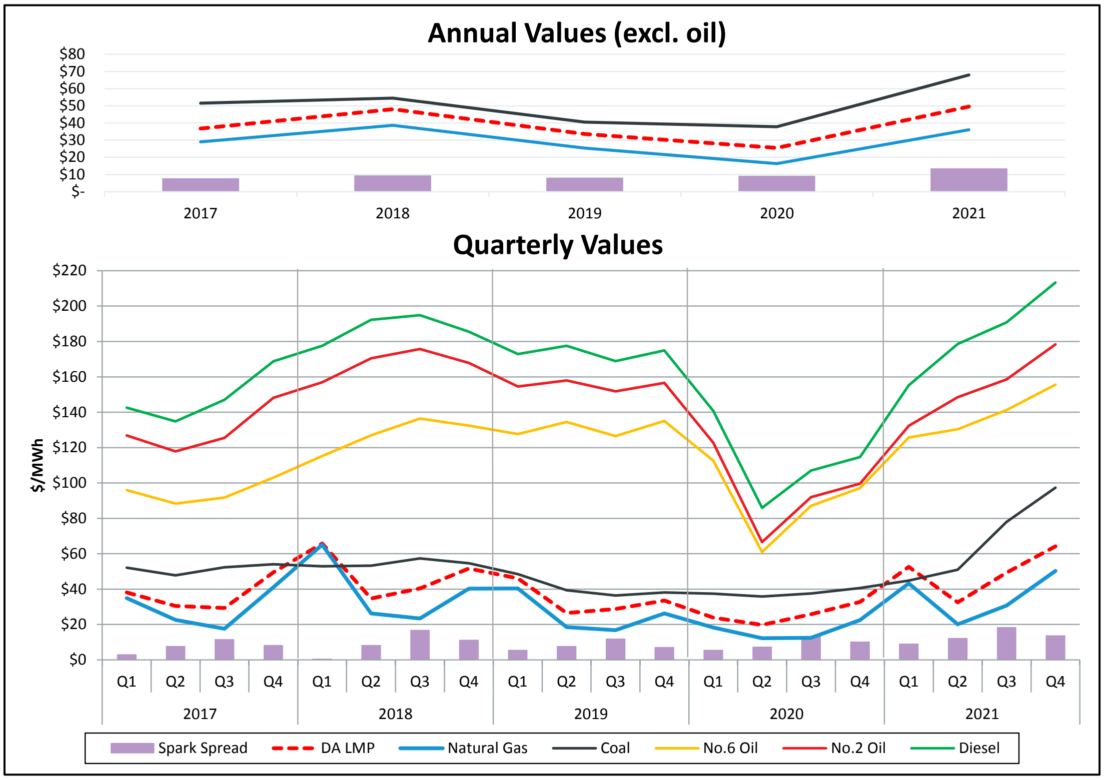
3.4.1 Generation Costs

Day-ahead and real-time electricity prices in New England continue to be closely correlated with the estimated cost of operating a natural gas-fired generator. As discussed later in Section 3.4.11 one or more marginal resources determine the price of electricity in any given time interval. In a competitive, uniform clearing price auction, a resource's offer price should reflect its variable production costs. For fossil fuel-fired generators, the variable costs are largely determined by fuel prices and operating efficiencies (heat rates). Since natural gas-fired generators set price more frequently than generators of any other fuel type in New England, a positive correlation exists between electricity prices and the estimated marginal cost of a typical natural gas-fired generator.

One way to understand the relationship between electricity prices and fuel costs is to compare the variable costs of different fuel types to the wholesale price (LMP). Quarterly average on-peak, day-ahead LMPs and estimated generation costs of various fuel types (assuming standard heat rates), and spark spreads (or the estimated profitability of a natural gas-fired generator) are shown below in Figure 3-11.[148]

[148] 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 LMP and the fuel cost of a gas-fired generator with a heat rate of 7.8.

Figure 3-11: Estimated Generation Costs and On-Peak LMPs



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.[149]

In New England, natural gas-fired generators are the dominant price setters (83% in real-time) and supply over 50% of native generation. Therefore, it is worth reviewing trends in industry-standard profitability metrics for gas-fired generators. Such metrics include implied heat rates and spark spreads across a range of efficiencies applicable to the New England fleet of natural gas-fired generators.

Table 3-2 shows the annual average day-ahead on-peak LMP and natural gas price; these are the key inputs into the implied heat rate (or breakeven point) calculation for natural gas-fired generators. 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 a new entrant combined cycle gas-fired generator.

[149] 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.

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
2017	37.64	3.69	10,188	14.06	11.78	**8.82**	8.08	4.39	0.69
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

The table shows that the spark spreads for a typical New England gas-fired generator (7,800Btu/kWh) increased significantly, by 58% ($15.86/MWh vs. $10.07/MWh). The implied (breakeven) heat rate decreased by just 10% (11,247 Btu/kWh vs. 12,558 Btu/kWh) year-over-year, indicating that a slightly more efficient gas generation was on the margin on 2021 on average. The higher spark spread was driven by the increase in gas prices and the knock-on effect on energy prices.[150] In 2021, the typical gas generator earned the equivalent of $3.45/MWh (the implied heat rate minus its heat rate of 7,800) per dollar of gas (i.e., $3.45/MWh x $4.6/MMBtu = $15.86/MWh). This compares to $4.76/MWh for each dollar of gas in 2020 (i.e., $4.76/MWh x $2.12/MMBtu = $10.07/MWh).

Note that the spark spreads do not include emissions costs (e.g., Regional Greenhouse Gas Initiative), which increase generator costs. RGGI costs for an average combined cycle gas-fired generator increased by $1.48/MWh in 2021 (from $2.88/MWh to $4.36/MWh) leading to higher generation costs.[151]

New England's reliance on natural gas

A number of market forces influence the relationship between New England's natural gas and electricity markets, including:

- The rise of natural gas-fired generators over the past 25 years.[152]

[150] For example, assume the implied heat rate was 10,000 MMBtu/MWh in both 2020 and 2021. Given the natural gas prices, 2020 LMPs would average $21.20/MWh ($2.12/MMBtu x 10,000 Btu/kWh) in 2020 and $46.00/MWh ($4.60/MMBtu x 10,000 Btu/kWh). Since we estimate a heat rate of 7,800 Btu/kWh for standard efficiency gas-fired unit, the estimated cost of natural gas-fired generation would be $16.54/MWh ($2.12/MMBtu x 7,800 Btu/kWh) in 2020 and $35.88/MWh ($4.60/MMBtu x 7,800 Btu/kWh) in 2021. This means the spark spreads (or LMP minus estimated cost of generation) would average $4.66/MWh ($21.20/MWh minus $16.54/MWh) in 2020 and $10.12/MWh ($46.00/MWh minus $35.88/MWh) in 2021. In this example, the increase in natural gas prices caused the increase in spark spreads.

[151] Spark spreads that include the cost of CO_2 emissions are known as clean spark spreads.

[152] During the 1990s, the region's electricity was produced primarily by oil-fired, coal-fired, and nuclear generators, with very little gas-fired generation. In 1990, oil-fired and nuclear generators each produced approximately 35% of the electricity consumed in New England, whereas gas-fired generators accounted for approximately 5%. Coal-fired generators produced about 18% of New England's electricity. In contrast, by 2021, oil- and coal-fired generators combined produced less than 1% of electricity generated in New England. Natural gas-fired generators produced 53%.

ISO New England, *Addressing Gas Dependence* (July 2012), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/strategic_planning_discussion/materials/natural_gas_white_paper_draft_july_2012.pdf.

- An aging and declining fleet of nuclear, oil- and coal-fired generators, many of which were constructed during the 1960s and 1970s.
- Increased production of domestic shale gas from the Marcellus Shale region leading to long-term decreases in natural gas prices.
- Constraints on the natural gas system due to high heating demand during winter months and greater demand from a larger fleet of natural gas-fired generators. Limited additional gas pipeline capacity has been developed to alleviate these constraints due to regulatory, political and market challenges.

The first three factors listed above have resulted in gas-fired generators supplying a much higher proportion of electricity in New England than ever before. However, during winter months, gas-fired generators must compete with heating demand, which can constrain gas pipeline capacity over periods with peak gas demand. Consequently, the reliability of New England's wholesale electricity grid partially depends on the owners and operators of natural gas-fired generators effectively managing natural gas deliveries during contemporaneous periods of high gas and electric power demand. Also, reliability increasingly depends on the region's oil fleet having sufficient oil inventory to operate when the gas network becomes constrained. During these periods, oil-fired generation can be cheaper than gas-fired generation, leading to oil-fired generators being dispatched more frequently.

One of the challenges identified in the ISO's Strategic Planning Initiative is the region's reliance on natural gas-fired generators.[153] Over the past few years the ISO has undertaken a number of related initiatives, including the following:

- Redesigning Forward Capacity Market performance penalties with the pay-for-performance (PFP) capacity market design, which began June 1, 2018.[154]
- Introducing the Winter Reliability Program, which was in place until PFP was implemented in 2018.
- Allowing the ISO to share information concerning the scheduled output of natural gas-fired generators with the operating personnel of the interstate natural gas pipeline companies serving New England.
- Introducing changes to the energy market design, including improving price signals for fast-start resources, accelerating the closing time of the day-ahead energy market (May 2013) and introducing energy market offer flexibility (December 2014).
- Increasing the procurement of ten-minute non-spinning reserves in the Forward Reserve Market to account for generator non-performance.
- Including an Energy Market Opportunity Cost (EMOC) adder in energy market reference levels for generators that maintain an oil inventory. Beginning in December 2018, EMOC adders allow participants to reflect the value of limited fuel in the mitigation process so that it can be preserved for hours when it is most economic and needed to alleviate tight system conditions.

[153] See the ISO's "Strategic Planning Initiative Key Project" webpage at http://www.iso-ne.com/committees/key-projects/implemented/strategic-planning-initiative.

[154] See Section 6.2 for information on pay-for-performance.

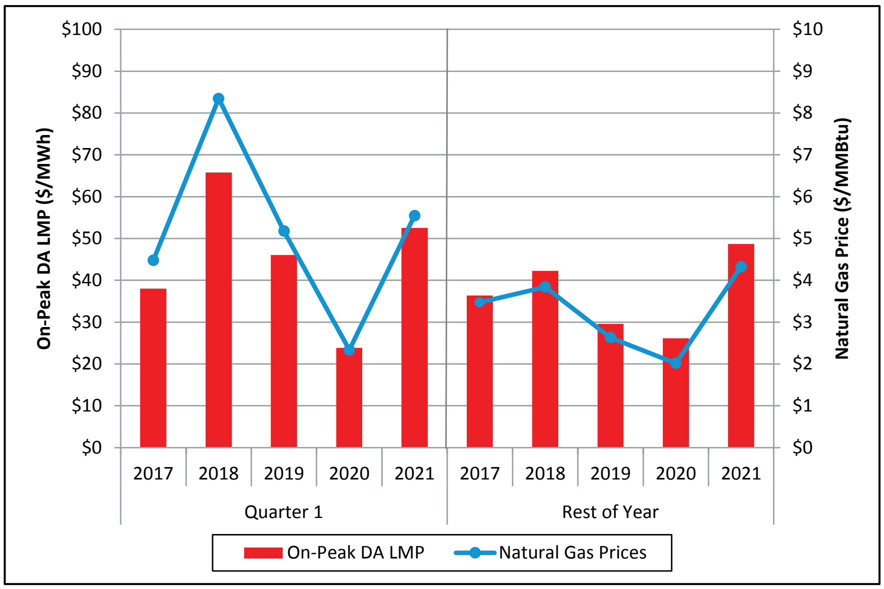
- Establishing Operating Procedure 21 (OP21) which includes the collection of information on generator-level fuel availability and winter readiness along with the publication of a 21-day energy assessment forecast.[155]

- Establishing a two-year program, known as the Interim Compensation Treatment program, to compensate generators for providing secure energy for winter 2023/24 and 2024/25.

Relationship between natural gas and electricity prices

Average annual day-ahead on-peak LMPs (left axis) and natural gas prices (right axis) from 2017 to 2021 are shown in Figure 3-12 below. Since cold weather in the first quarter (Q1) can cause higher natural gas prices and electricity prices, Q1 is shown separately from the rest of the year.

Figure 3-12: Average Electricity and Gas Prices for Q1 Compared with Rest of Year



Colder temperatures in Q1 tend to cause higher natural gas prices and LMPs than the rest of the year. In Q1 2021, gas prices averaged $5.55/MMBtu compared to $4.32/MMBtu during the rest of the year. The higher Q1 natural gas prices led to higher LMPs compared to the rest of the year. On-peak day-ahead LMPs averaged $52.50/MWh, 8% higher than the rest of the year ($48.68/MWh). Compared to prior winters, colder weather in Q1 2021 resulted in the second highest natural gas prices and day-ahead, on-peak LMPs over the five-year period. Only Q1 2018 saw higher LMPs and natural gas prices, when a cold snap during the start of the quarter led to high average natural gas prices ($8.35/MMBtu) and higher LMPs ($65.75/MWh).

Higher gas prices and colder weather, especially during February 2021, resulted in more LNG injections into the New England interstate gas system than the prior year. When the primary natural gas pipelines (which flow from west and south) become constrained, LNG deliveries can provide counter flow (or injections from the east and north). This helps alleviate natural gas constraints and puts downward pressure on natural gas prices. LNG injections into New England during Q1 2021 increased by 24% compared to Q1 2020, rising from 16.2 million Dth to 20.1

[155] See ISO New England Operating Procedure No. 21 for more information.

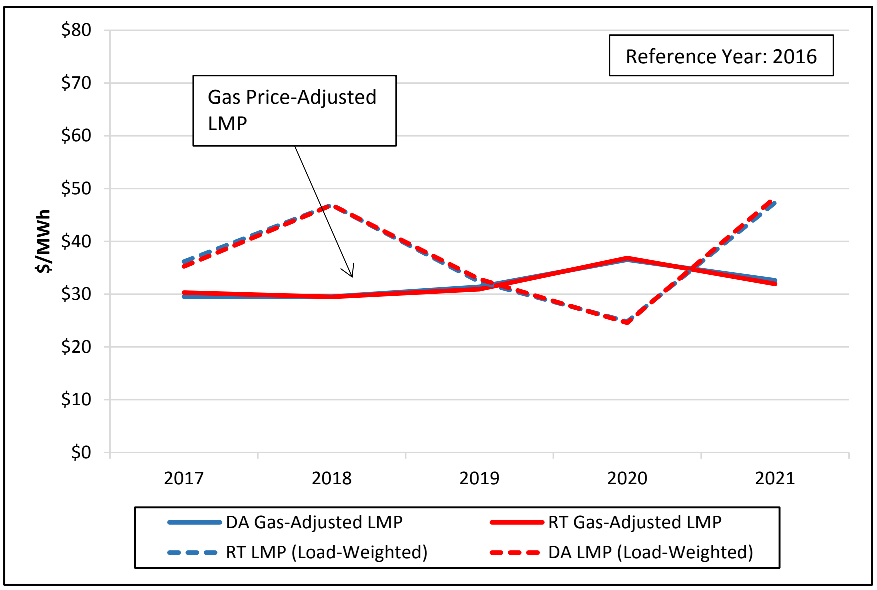
million Dth. The year-over-year increase equates to the amount of natural gas necessary to run a 230 MW standard heat rate natural gas-fired generator for the entire quarter.

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.

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. The day-ahead (blue solid) and real-time (red solid) gas-price adjusted LMPs, along with the day-ahead (blue dashed) and real-time (red dashed) load-weighted LMPs (unadjusted) from 2017 to 2021 are shown in the Figure 3-13 below.

Figure 3-13: Annual Average Natural Gas Price-Adjusted LMPs



On a gas price-adjusted basis, day-ahead and real-time prices decreased by 11% (from $36.52 to $32.60/MWh) and 14% (from $36.84 to $31.90 /MWh), respectively, on average. With the exception of 2020, the day-ahead and real-time gas price-adjusted LMPs were within a relatively narrow band ($29-$32/MWh). This indicated that gas prices had a relatively large impact on the LMP. The previous year was 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.

Energy Market Opportunity Costs

Beginning December 1, 2018, energy market reference levels have included an energy market opportunity cost (EMOC) adder for resources that maintain an oil inventory.[156] The update was

[156] https://www.iso-ne.com/static-assets/documents/2018/10/a7_memo_re_energy_market_opp_costs_for_oil_and_dual_fuel_revised_edition.pdf

motivated by concerns that, during sustained cold weather events, generators were unable to incorporate opportunity costs associated with the depletion of their limited fuel stock into their energy supply offers due to the risk of market power mitigation. Such an event arose during winter 2018 - which resulted in ISO operators posturing oil-fired generators to conserve oil inventories. During cold weather events, the inclusion of opportunity costs in energy offers enables the market to preserve limited fuel for hours when it is most needed to alleviate tight system conditions.

We calculate generator-specific EMOC adders with a mixed-integer programming model that was developed by the ISO and runs automatically each morning. For a given forecast of LMPs and fuel prices, the model seeks to maximize an oil-fired generator's net revenue by optimizing fuel use over a seven-day horizon, subject to constraints on fuel inventory and asset operational characteristics. Opportunity costs produced by the model are available to participants an hour before the day-ahead market closes and, since December 2019, a real-time opportunity cost update is available at 6:30 pm, on the day prior to real-time operation. The real-time update of the opportunity cost calculation is based on data that is available after the day-ahead market closes but prior to the start of the real-time market. This calculation incorporates updated fuel price forecasts to produce more accurate opportunity costs for the real-time market.

While the calculation of EMOCs is complicated and dependent on a number of variables (gas and oil price forecasts, fuel inventory levels, and generator characteristics), it is possible to develop a general sense about when EMOCs are likely to occur. Primarily, we should expect to see EMOCs for a generator when oil prices are forecasted to be close enough to gas prices that an oil-fired generator would be in merit long enough to physically exhaust their oil-fired inventory. This type of scenario would typically occur during an extended period of very cold weather when demand for natural gas is highest because natural gas is used for both heating and electricity generation in New England. Table 3-3 below displays EMOC summary statistics from the months of December 2021 to February 2022.

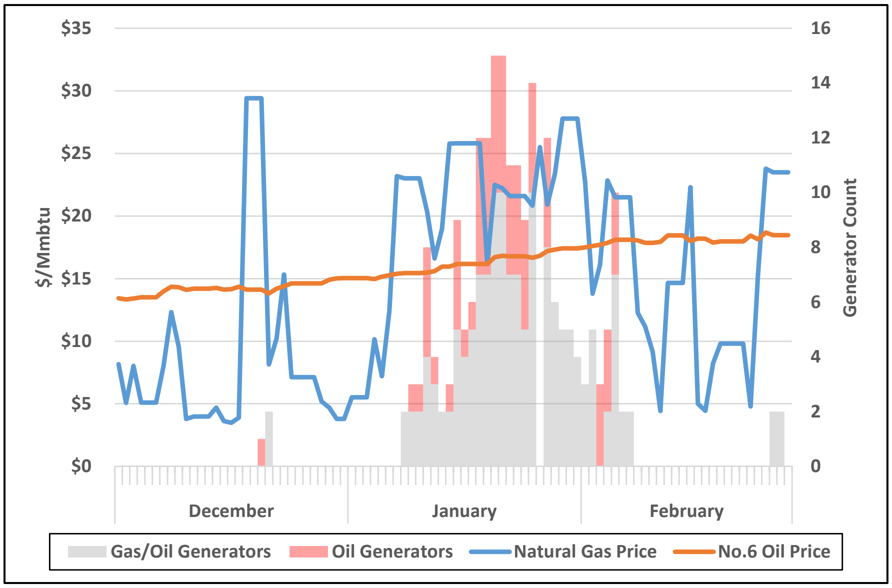
Table 3-3: EMOC Summary Statistics (Dec 2021 - Feb 2022)

Market Type	Generator Count	Avg. EMOC ($/MWh)	Avg. NG Price ($/MMBtu)	Avg. Oil Price ($/MMBtu)
Day-Ahead	18	$19.14	$22.07	$16.73
Real-Time	18	$18.11	$22.63	$16.85

From December 1, 2021, to February 28, 2022, eighteen generators received EMOC adders for their oil inventories in both the day-ahead and real-time market. Thirteen of the assets were dual-fuel capable while the remaining five generate on oil only. The EMOC adders were split across 34 days and 18 different generators in the day-ahead market, averaging around $19/MWh. In the real-time market, EMOC adders either continue from their DA value or can be updated using updated fuel prices. Across 28 days where DA EMOC adders were active, eight different assets received updated RT EMOC adders, and averaged around $18/MWh.

Figure 3-14 below displays the distribution of resources receiving EMOC adders in the day-ahead market from December 2021 to February 2022. The natural gas and No.6 oil prices (left axis) are imposed over the count of generators receiving non-zero EMOC adders (right axis). Gas/oil-fired generators are shown with gray shading; oil-only generators are shown with red shading.

Figure 3-14: Day-Ahead Non-Zero EMOC Generator Count and New England Fuel Prices[157]



Due to New England's dependence on natural gas generation, increases in natural gas prices typically increase energy market prices, making oil-fired generation economical and incentivizing dual-fuel generators to switch to the lower-priced fuel of oil. Both actions deplete oil reserves and increase the likelihood of an EMOC adder applied to reference levels. From December 2021 to February 2022, prolonged periods of higher natural gas prices were highly correlated with occurrences of EMOC adders. The second half of January 2022 saw the largest count of non-zero EMOC adders, with 15 generators affected on January 20 and 21.

We analyzed whether participants incorporated EMOC price adders in their offer prices during Winter 2022 by comparing MW-weighted offer prices to reference levels for all hours of December 2021 to February 2022. We expected this ratio to remain relatively consistent if participants were including the EMOC adder in their offers. Oil-only generators clearly did not demonstrate behavior of incorporating the adder into their offers, while results for dual-fuel generators remained inconclusive.

In addition to our internal analysis, we surveyed a selection of participants directly on EMOC adder usage. The participants' responses confirmed that the EMOC adder did not play a significant role in the development of their offers as they remained confident in their fuel reserves during all prolonged periods of high energy prices. The calculation of the EMOC adder does not consider restocking past a seven-day horizon and, consequently, may overstate the opportunity cost of burning oil. Therefore, we would only expect participants to take advantage of the EMOC adder when fuel delivery is less certain during extreme winter conditions.

Overall, the EMOC adder has worked as intended and is an important tool that allows participants to reflect the economic value of limited energy inventory in their supply offers and can thereby enhance price formation. We will continue to review the reasonableness of the computed adders over time and as more data becomes available.

[157] A data error accounts for the missing asset count on January 26, 2022.

3.4.2 Supply-Side Participation

In 2021, unpriced supply made up around 70% of total supply in the energy market, a level similar to previous years in the reporting period. 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).[158]
- **Generation-up-to economic minimum** from economically-committed generators is the portion of output that 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 economic minimum 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[159] transactions.

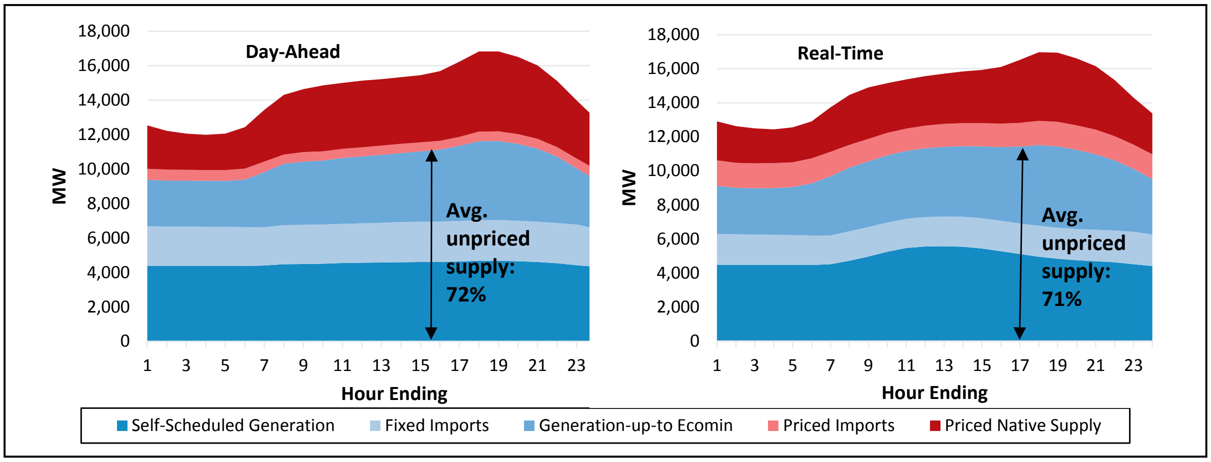
There are some nuances to the priced imports category in terms of price-setting ability. Unlike unpriced supply, priced imports are not price-taking (i.e., suppliers are not willing to sell at any price), and priced imports regularly set price in the day-ahead market. However, priced imports rarely set price in real-time because the tie-lines are scheduled in advance of the delivery interval 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 2021 is provided in Figure 3-15 below.

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

[159] 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.

Figure 3-15: Day-Ahead and Real-Time Supply Breakdown by Hour Ending, 2021



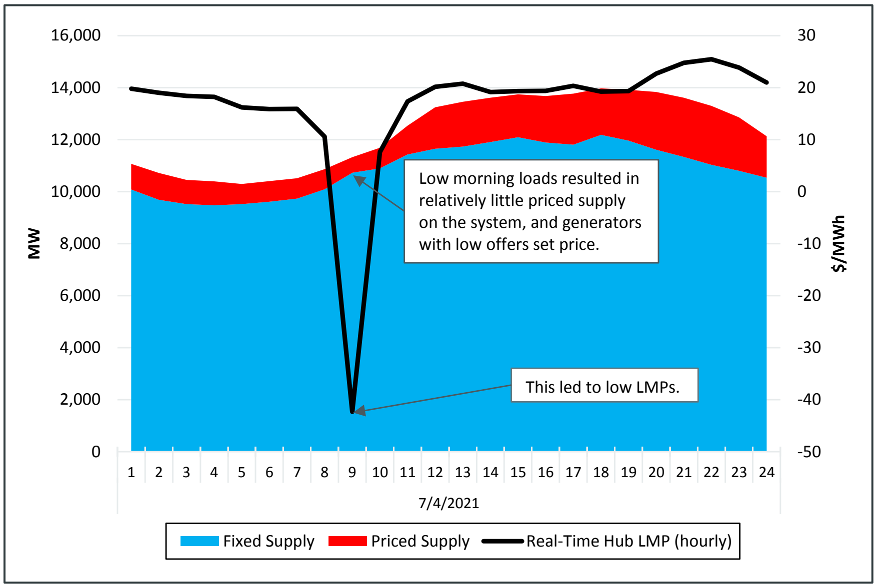
Over the course of a day, the share of supply from self-scheduled generation (the largest component of unpriced supply) and fixed imports tends to be fairly stable. In real-time, average hourly self-scheduled generation was slightly higher during midday, due to output from settlement-only solar generators (SOGs). These smaller generators do not clear in the day-ahead market because they are not modeled generators in the market nor centrally dispatched by the ISO control room. They participate in the settlement process of the energy market only.

In both markets, the daily ramp-ups in load are typically met by additional supply from generation-up-to EcoMin and priced supply. Priced supply averaged 29% of total supply over all hours in real-time in 2021, with its share peaking in hours ending (HE) 18-21 at 32-33%. On average, unpriced supply made up 72% and 71% of total supply in the day-ahead and real-time markets, a small increase compared to 2020 shares. The small increase was due to a greater share of up-to EcoMin generation on the system, as more online generation was needed due to higher loads and less imports in 2021.[160] Priced imports decreased by about 270 MW and 570 MW in the day-ahead and real-time markets, respectively, while up-to EcoMin generation increased by 360 MW and 370 MW. The higher loads in 2021 also led to more priced native supply on the system, an increase of 220 MW and 280 MW in the day-ahead and real-time markets, respectively.

The large amount of unpriced supply can have important implications for real-time pricing outcomes because it increases the likelihood of low or negative prices. An example of this is illustrated in Figure 3-16 below, which shows unpriced and priced supply along with the Hub LMP for July 4, 2021. Unlike the figure above, this figure includes all imports in the fixed supply category for convenient illustrative purposes.

[160] The metrics in this section focus on the supply side and therefore do not account for exports, which increased in 2021, leading to further decreases in net interchange. Section 5 discusses net interchange.

Figure 3-16: Priced and Unpriced Supply vs. Real-Time LMP, July 4, 2021



In the morning hours of July 4, real-time loads were relatively low. 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 with negative offers, resulting in negative prices. The 5-minute Hub LMP ranged from -$98 to -$50/MWh from 08:10 to 08:45, and the hourly price averaged -$42.30/MWh from 8am to 9am.

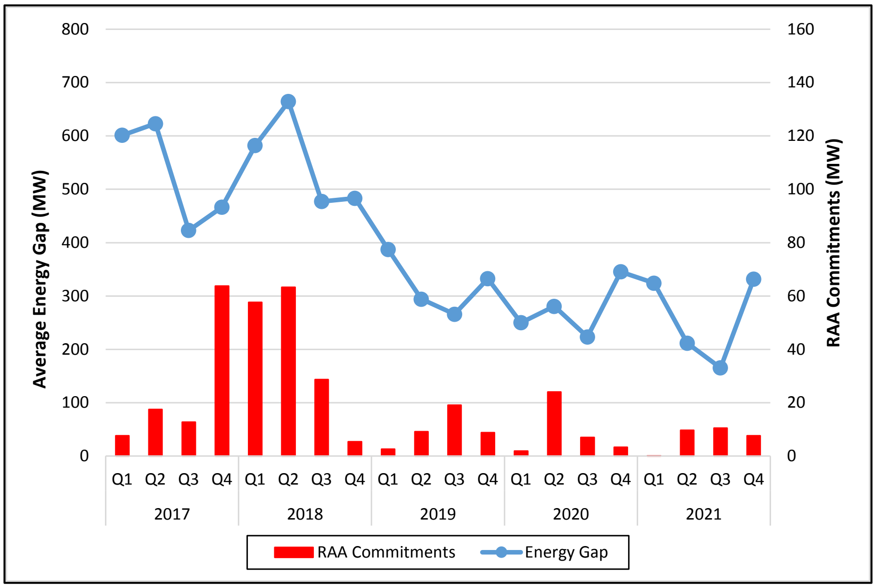
In situations like this, there is very little generation with price-setting capability on the system. The combination of low loads with large amounts of unpriced generation can thus bring about a sudden drop in prices, to low or even negative levels. However, the overall frequency of negative real-time prices at the Hub remains relatively low. Negative prices at the Hub occurred in 0.3% of hours in both 2020 and 2021. Even in Maine, which tends to have a higher frequency of negative nodal prices at export-constrained pockets with wind generation, the hourly zonal price was negative in only 0.4% of hours in 2020 and 2021.

3.4.3 Reserve Adequacy Analysis Commitments

The day-ahead market is a forward financial market that clears at the intersection of participant submitted supply offers and demand bids. However, the commitment, dispatch and pricing outcomes in the day-ahead market may not always reflect expected real-time conditions. For example, load-serving entities may 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. After the day-ahead market and the re-offer period close, the ISO performs the Reserve Adequacy Analysis (RAA) to meet these capacity and reserve constraints. If the day-ahead market satisfies the expected real-time requirement, additional generators will not need to be committed in the RAA process. Conversely, if the day-ahead market did not clear enough supply to meet the ISO's forecasted demand and reserve, additional generators may be required.

The difference between the amount of physical cleared generation (i.e., no virtual supply) in the day-ahead market compared to the expected real-time load and reserve requirement (the energy gap), along with the commitments made in the RAA are shown in Figure 3-17 below.[161] Large energy gaps are more likely to result in more RAA commitments. By comparing the quarterly average energy gap to the additional commitments made in the RAA, we can derive insights into different outcomes between each market.[162]

Figure 3-17: Average Quarterly RAA Generator Commitments and the Day-Ahead Energy Gap



RAA commitments remained very low in 2021, with the RAA process committing 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. In the day-ahead market, load-serving entities cleared more demand than what they consumed in the real-time market, on average, in 2021.[163] Therefore, additional RAA commitments were not typically necessary as over-clearing of demand in day-ahead market led to sufficient levels of physical supply. Overall, the low levels of RAA commitments was in line with strong price convergence between the day-ahead and real-time market in 2021.[164]

3.4.4 Load and Weather Conditions

Load is a key determinant of day-ahead and real-time energy prices. Higher loads generally requires costlier generation to be dispatched, resulting in higher prices. Weather, economic factors and energy efficiency measures tend to drive changes in wholesale electricity load. Behind-the-meter photovoltaic generation plays a small, but increasing, role in declining wholesale load. In future years, the electrification of heating and transportation sectors will play a growing role in increasing wholesale load.[165]

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[161] The RAA bridges the gap between the day-ahead and the real-time market by committing any additional generation need to meet load and reserves. The day-ahead market closes at 10:30 am and results are published by 1:30 pm prior to the operating day. The RAA process is completed by 5:30 pm following the day-ahead market re-offer period (1:30 pm to 2:30 pm).

[162] Additional commitments include non-fast start and non-local second contingency protection commitments.

[163] See Section 3.4.5 for more information on high levels of demand clearing in the day-ahead market.

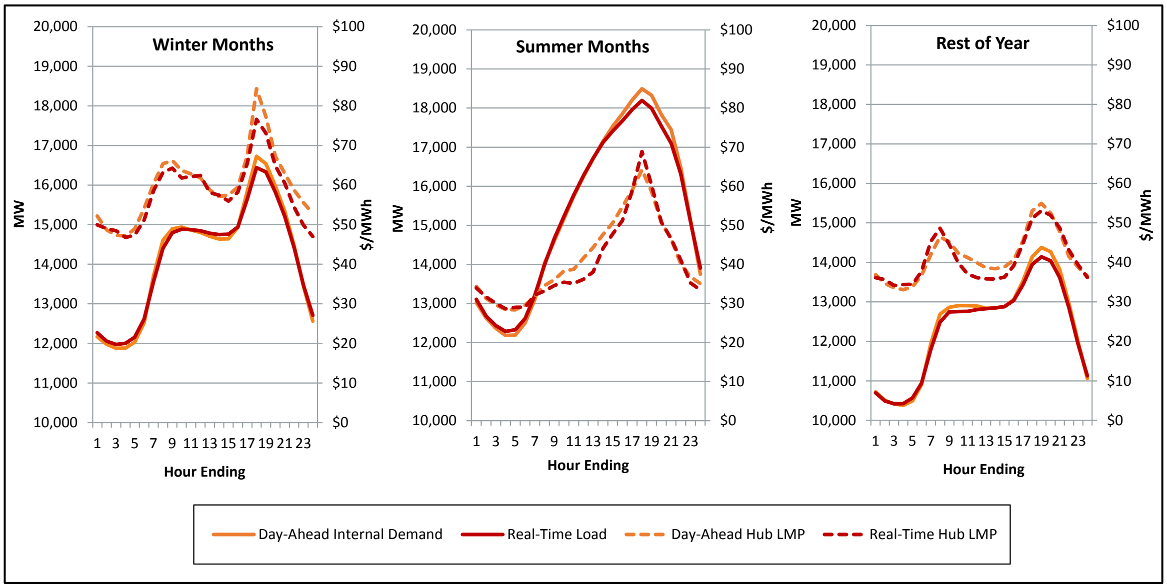
[164] See Section 3.3.5 on Energy Price Convergence between the Day-Ahead and Real-Time Market.

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

Demand/Load Statistics

The strong connection between energy prices and load is particularly evident over the course of the operating day. Lower prices typically occur in hours with lower loads, and higher prices typically occur in hours with the higher loads. Figure 3-18 below depicts the average time-of-day profile for both day-ahead demand and real-time load compared to day-ahead and real-time LMPs for 2021. Since load curves have different shapes during different seasons, the figure is broken into three panels: winter (December, January, February), summer (June – August) and rest of year

Figure 3-18: Average Demand and LMP by Hour, 2021



Note: 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, a constrained New England interstate gas pipeline system leads to elevated gas and energy prices compared to the rest of the year, despite lower demand levels than the summer months. During the summer, load often climbs throughout the day as air conditioning demand rises. 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. Figure 3-18 also shows a clear, positive correlation between demand and prices in both the day-ahead and real-time markets. The figure 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 3.4.6.

Net Energy for Load (NEL) averaged 13,556 MW per hour in 2021, a 1.9% increase (247 MW) compared to 2020. New England's native electricity load is shown in Table 3-4 below.[166]

[166] 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.

Table 3-4: 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)
2017	121,217	13,838	23,968	120,668	13,737
2018	123,471	14,095	26,024	120,560	13,725
2019	119,254	13,614	24,361	118,772	13,558
2020	116,906	13,309	25,121	116,322	13,279
2021	118,749	13,556	25,801	117,473	13,410

Note: *Weather-normalized* results are an estimate of load if the weather were the same as the long-term average.[167]

In 2021, load increased due to reduced impacts from the COVID-19 pandemic and colder weather in Q1 2021. During the year, load reached a peak of 25,801 MW, which occurred in HE 16 on June 29, when temperatures reached nearly 95^{0}F, the hottest weekday over the reporting period. This was 2.7% (or 680 MW) higher than the peak load in 2020, and the highest peak load since 2018 (26,024 MW).[168]

Declining weather-normalized load reflects the long-term trend of declining load due to increased energy efficiency and behind-the-meter solar generation. However, weather-normalized load averaged 13,410 MW, a 1.0% (or 131 MW) increase compared to 2020, and the first annual increase since 2010. This increase highlights the depressing impact of the COVID-19 pandemic on load in 2020. After 2021, the ISO forecasts average load will increase each year, given declining impacts of energy efficiency and behind-the-meter (BTM) solar generation and growth in electrification of transportation and heating.

Impact of Weather

Weather is the primary driver of load in New England. In 2021, changes in temperatures contributed to higher loads than in 2020. 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.[169] Quarterly average and five-year average temperatures for 2017 through 2021 are illustrated in Figure 3-19 below.[170] The first quarter, Q1 (January-March), is shown in blue, Q2 (April-June) is green, Q3 (July-September) is red and Q4 (October-December) is yellow. Average quarterly load is shown in black.

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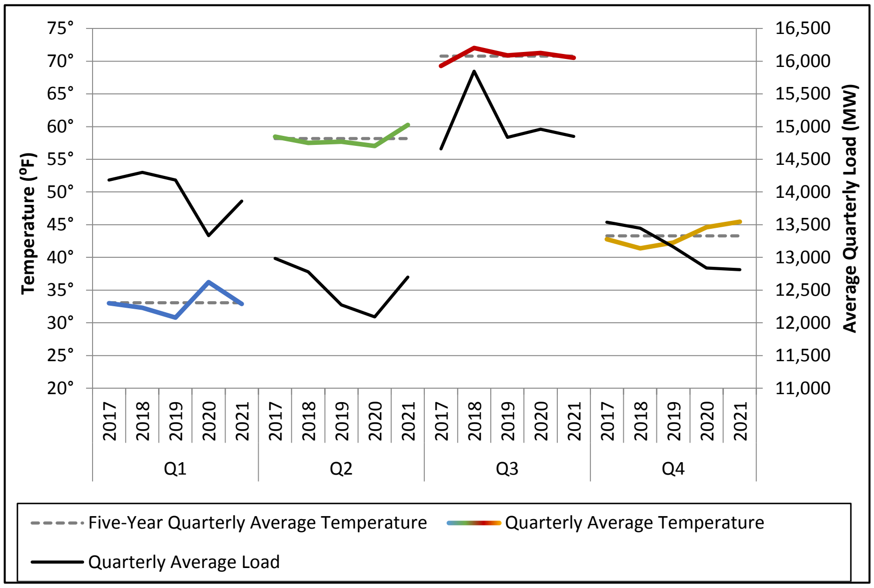
[167] Weather-normalized load estimates what load would if monthly total heating degree days and cooling degree days were in line historical averages. The estimate also factors in differences non-holiday weekdays and leap days.

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

[169] 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.

[170] 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.

Figure 3-19: Seasonal vs. Five-Year Average Temperatures



Quarterly average temperatures in 2021 were either warmer than (Q2 and Q4), or equal to (Q1 and Q3) their historical five-year averages. Q2 and Q4 2021 saw warmer temperatures year-over-year, and warmer temperatures when compared to their historical 5-year average. In Q1 2021, temperatures averaged 33^{0}F, down 3^{0}F from Q1 2020 (36^{0}F), but equal to the five-year average. The colder temperatures led to an increase in Heating Degree Days (HDD) (2,896 vs. 2,616) and, along with the reduced impacts of the pandemic, contributed to higher loads. In Q2 2021, temperatures averaged 60^{0}F, a 3^{0}F increase compared to Q2 2020 (57^{0}F) and the warmest Q2 over the last 5 years. While warmer temperatures resulted in 238 fewer HDDs (687 vs. 926), it also led to an increase of 35 THI Cooling Degree Days (tCDD) compared to Q2 2020 (138 vs. 103) and higher loads.[171] During Q3 2021, average temperatures decreased by nearly 1^{0}F compared to Q3 2020, from 71^{0}F to 70^{0}F. However, the weather was more humid throughout the summer and the THI increased from 68 in Q3 2020 to 69 in Q3 2021. In Q4 2021, temperatures averaged 45^{0}F, 1^{0}F warmer than Q4 2020 and 2^{0}F warmer than the 5-year average (43^{0}F).[172]

Average quarterly load by time of day (hour endings 1-24) is shown in Figure 3-20 below. Temperature changes affect load differently throughout the year. Lower temperatures in the winter (Q1) typically result in higher loads while lower temperatures in the summer (Q3) typically result in less air conditioning demand and therefore lower loads. The shape of the load curve differs by quarter. In the summer, load typically rises throughout the day to a single peak in the late

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[171] Heating degree day (HDD) measures how cold an average daily temperature is relative to 65°F and is an indicator of electricity demand for heating. It is calculated as the number of degrees (°F) that each day's average temperature is below 65°F. For example, if a day's average temperature is 60°F, the HDD for that day is five.

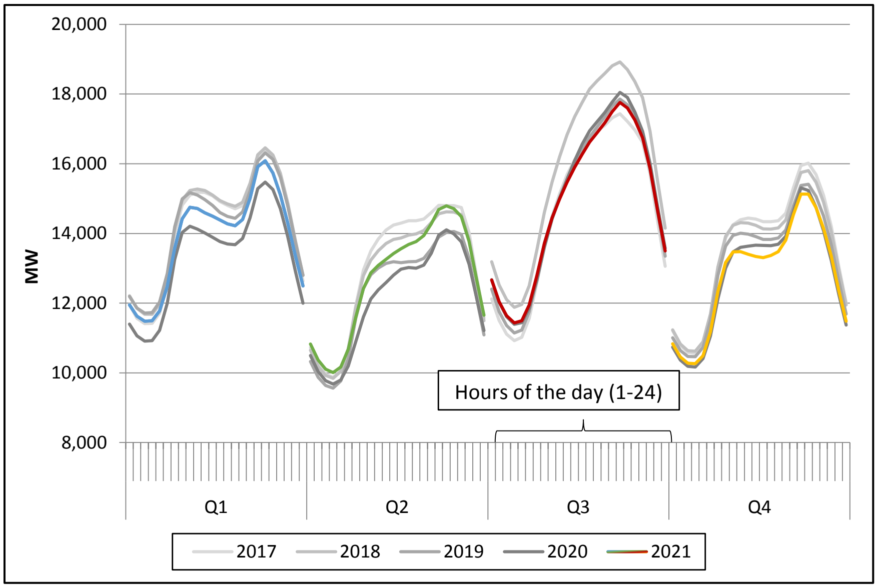
The Temperature-Humidity Index combines temperature and dew point (humidity) into one metric that is a useful indicator of electricity demand in summer months when the impact of humidity on load is highest. The THI is calculated as 0.5 x [Dry-Bulb Temperature (°F)] + 0.3 x [Dew Point (°F)] + 15.

A THI cooling degree day (tCDD) measures how warm an average daily THI is relative to 65°F and is an indicator of electricity demand for air conditioning. It is calculated as the number of degrees (°F) that each day's average temperature is above 65°F. For example, if a day's average temperature is 70°F, the Cooling Degree Day (CDD) for that day is five.

[172] Temperatures averaged 45.5°F in Q2 2021 and 44.6°F in Q2 2020.

afternoon/early evening, then declines as temperatures decline. When the weather gets colder, there are typically two load peaks: one after the morning ramp, and the second during the evening.

Figure 3-20: Average Quarterly Load Curves by Time of Day



Compared to 2020, quarterly average load was substantially higher in every hour during Q1 and Q2 2021 as impacts from the COVID-19 pandemic largely subsided. Additionally, the Q2 2021 average load curve had no morning peak or midday trough, as load climbed throughout the afternoon. This was due to a combination of warmer weather in June 2021 and less behind-the-meter solar generation, both of which caused increased load during the middle of the day.[173] During Q3 and Q4 2021, the average load curves are more similar to the load curves in prior years.

3.4.5 Demand Bidding

The amount of day-ahead cleared demand, along with the ISO's reserve adequacy analysis (RAA), determines generator commitment decisions for the operating day.[174] In this section, we examine native day-ahead cleared demand (i.e., delivery within the New England jurisdiction, which excludes exports).[175]

Native demand consists of cleared fixed, price-sensitive, virtual, and pumped-storage demand bids. Fixed demand bids indicate that participants are willing to pay the market-clearing price, regardless of cost. Participants that submit price-sensitive demand bids are only willing to pay if the market-clearing price is below their bid price. Virtual demand bids are submitted by

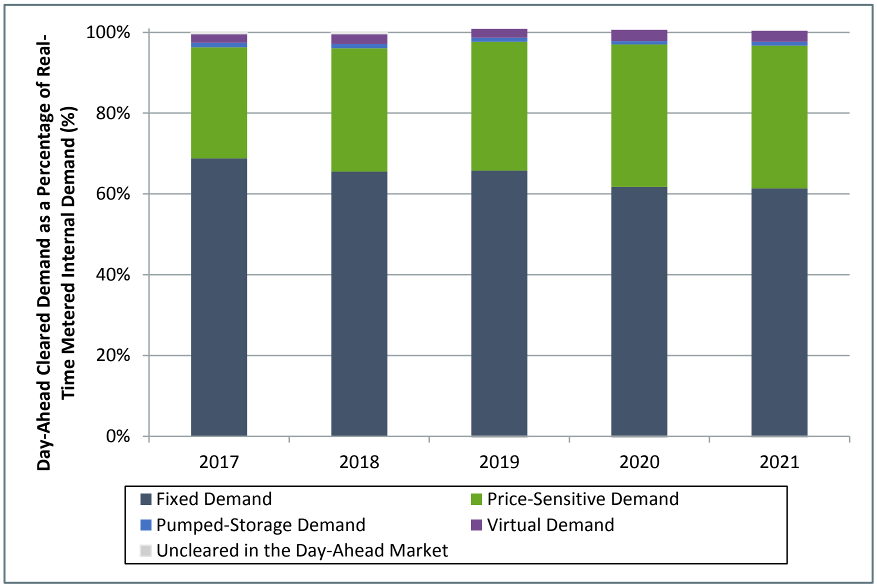
[173] Behind-the-meter solar generation decreased in 2021 compared to 2020. However, the decrease exists for two reasons: 1. A notable amount of behind-the-meter generation likely moved in front of the meter, registering as a settlement-only generators. (SOG). SOGs count towards the calculation of load, or Net Energy for Load, which is the total energy needed to meet load. 2. Improved measuring of real-time performance of behind-the-meter solar installations led to more accurate, but lower generation estimates.

[174] 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 3.4.3.

[175] Exports are not included as this section focuses on demand participation within New England. Exports are discussed in Section 2.4 and Section 5.

participants that do not represent any physical demand and aim to profit on the difference between the day-ahead and real-time prices. Pumped-storage demand bids are submitted by asset-related demand resources. Day-ahead cleared demand by bid type as a percentage of real-time load is shown below in Figure 3-21.[176]

Figure 3-21: Day-Ahead Cleared Demand as a Percentage of Real-Time Load by Bid Type



Overall, in 2021 participants cleared over 100% of their real-time requirements in the day-ahead market, with a modest decrease compared to 2020 (100.4% vs. 100.6%). However, it should be noted that this metric varies by time-of-day with hours of over- and under-clearing as discussed in Section 3.3.5.

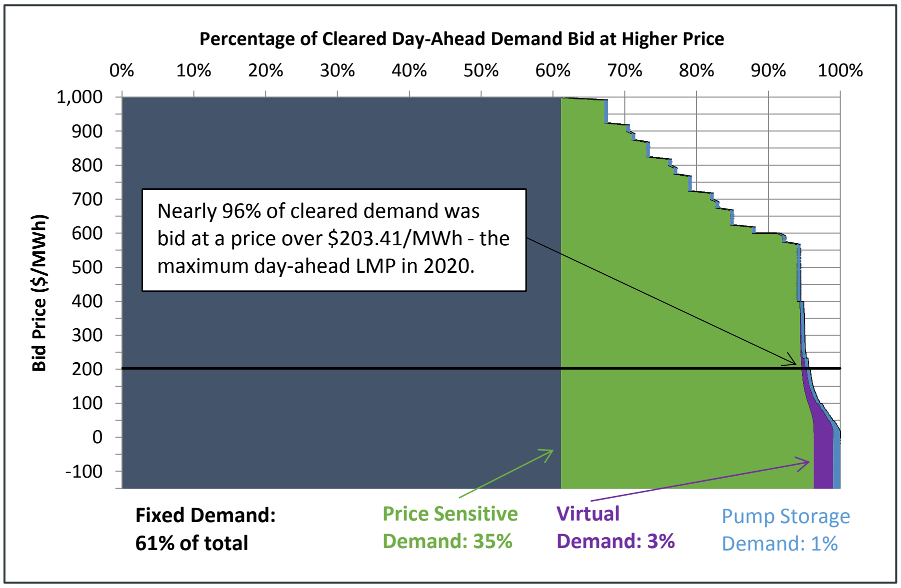
Fixed day-ahead cleared demand averaged 61.4% of real-time load in 2021, a 0.4% decrease from 2020 (61.8%). In 2021, price-sensitive demand bids accounted for 35.3% of real-time load, which was unchanged from 2020. Virtual demand as a percentage of real-time load, decreased slightly from 2.8% to 2.7% year over year. Lastly, pumped-storage demand accounted for 1.0% of real-time load, which increased by 0.2% from 2020 as one generator returned in Fall 2021 following a long-term outage.

Although price-sensitive demand bids are submitted with a MW quantity and corresponding price, the majority of bids are priced significantly above the LMP. In addition, pumped-storage demand can self-schedule in the day-ahead market. Such transactions are, in practical terms, fixed demand bids. High bid prices are not limited to internal demand bids; Section 5 examines the breakdown between priced and fixed external transactions.

Cleared internal demand bids by price are shown in Figure 3-22 below. The bid prices are shown on the vertical axis, and the percentage of cleared bids that were willing to pay at each bid price are shown on the horizontal axis. For example, nearly 96% of cleared day-ahead demand was willing to pay more than $203.41/MWh, the maximum day-ahead hub LMP in 2021.

[176] 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 3-22: Components of Day-Ahead Cleared Demand as a Percentage of Total Day-Ahead Cleared Demand



Generally, demand in New England is 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 35% 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.

3.4.6 Load Forecast Error

The ISO produces several different load forecasts, ranging from 10-year projections to short-term forecasts made within the operating day. This section focuses on the *day-ahead load forecast*: the daily forecast made around 9:30 am that projects hourly load for the next operating day and is published on ISO website.[177] This forecast is the ISO's last load projection prior to the close of the day-ahead market. 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.[178, 179] 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

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[177] 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.

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

[179] Additionally, the reserve adequacy analysis (RAA) process uses the ISO's load forecasts to make supplemental generator commitment decisions. During the RAA process, the ISO may determine that, based in part on their load forecast, the day-ahead market scheduled insufficient capacity. In these situations, the ISO will commit additional generators over what cleared in the day-ahead market to satisfy real-time load and reserve requirements. These commitments do not happen often, but when they occur, they impact *real-time* market outcomes. See Section 3.4.3 above.

to forecast. The increasing amount of behind-the-meter solar generation (discussed in more detail below) also added to the difficulty of accurately estimating load even in short time horizons.

The mean absolute percent error (MAPE) of the ISO's day-ahead load forecast (over the past five years) by time of year is shown in Figure 3-23 below. Months are partitioned into four groups based on the ISO's monthly load forecast goal (shown as dashed lines). Prior to 2018, the ISO had a MAPE goal of 2.6% for the summer months (Jun. – Aug.) and 1.5% MAPE for the other months.[180] In 2018, the ISO revised its goals to 1.5% MAPE in January–April and October–December; 1.8% in May and September; 2.6% remained the goal for months June–August.[181]

Figure 3-23: ISO Day-Ahead Load Forecast Error by Time of Year

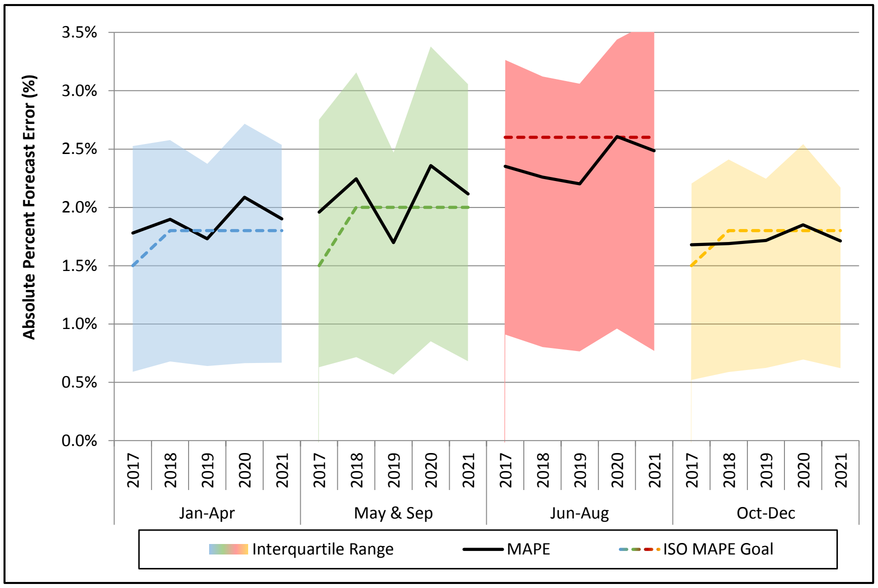


Figure 3-23 shows that 2021forecast error and volatility decreased compared to 2020, but remained generally higher than levels in prior years. In 2021, the MAPE for all four groups decreased by between 0.12% (Jun. – Aug.) and 0.24% (May & Sep.) compared to 2020. The MAPE decreased this year following an increase in 2020 due to the challenges of forecasting load during the COVID-19 pandemic. In March 2020, the COVID-19 pandemic caused lower loads than the ISO forecasted as state-level mandates led to business closures across the region. During Summer 2020, the COVID-19 pandemic caused higher loads due to increased residential air conditioning usage.[182] At a monthly level, the ISO's 2021 monthly forecast missed the monthly goal in five months, down from six months in 2020, but higher than one month in 2019.

[180] Mean absolute percent error (MAPE) is the average of the hourly absolute percent errors across all hours (on-peak and off-peak). The absolute percent error is calculated as | ([forecast load] – [actual load]) / [actual load] |.

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

[182] For more information see the Estimated Impacts of COVID-19 on ISO New England Demand.

Impact of Behind-The-Meter Solar

The growth in behind-the-meter (BTM) solar generation in recent years has made forecasting particularly challenging especially at more granular levels.[183] For one, it is challenging to estimate the location and installed capacity of thousands of small-scale solar installations around New England. Second, forecasting cloud cover at a granular level is notoriously difficult.[184] With more than an estimated 4,500 MW of behind-the-meter and settlement-only solar generation, changes in cloud cover or snowfall can have a significant impact on pricing.

For example, when less solar generation occurs than what was forecasted, the ISO may need to commit more expensive generators to meet real-time load. Since forecasted BTM solar generation is an important input for load forecasting and continues to grow in the region, accurate solar forecasting will become increasingly crucial. In recent years the ISO has made significant investments to better forecast BTM solar generation.[185] The relationship between the daily average BTM solar forecast and the system level load forecast is shown below in Figure 3-24.

Figure 3-24: Impact of BTM Solar on Load Forecast Error[186]

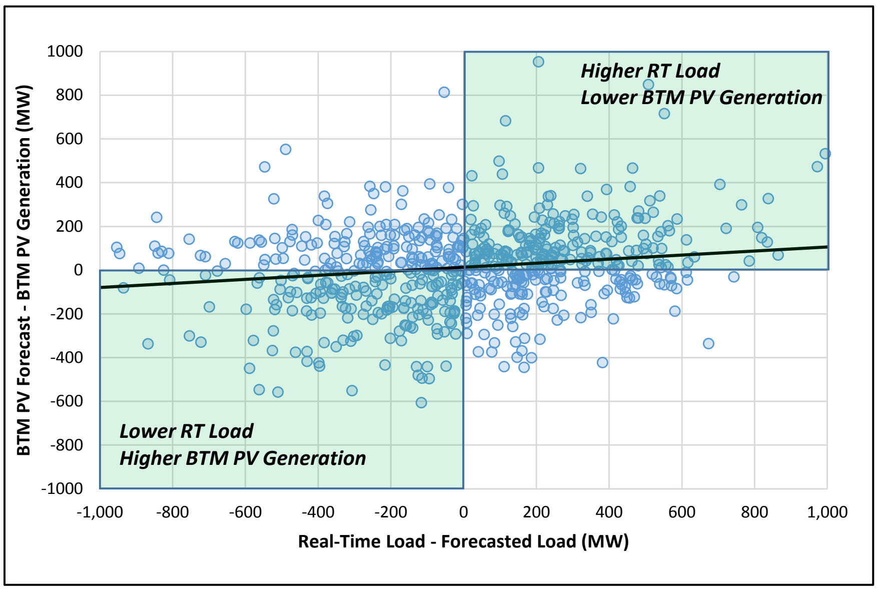


Figure 3-24 shows that BTM solar forecast error generally causes a greater load forecast error. When there is less BTM solar generation than forecasted, system load is typically higher than the

[183] By the end of 2021, New England had an estimated 4,509 MW of solar generation that did not have real-time telemetry with the ISO, up 506 MW from 4,003 MW at the end of 2020. This includes both behind-the-meter solar generation and settlement-only solar generation, neither of which are visible to the ISO operators. Settlement-only differs from behind-the-meter because it participates in the settlement process of the energy market, while behind-the-meter does not participate in the energy market.

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

[185] 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/

[186] The IMM received solar forecasting data beginning in Q1 2019. Therefore, the underlying data show all of 2020 and a majority of 2019, but not the entire year.

ISO's load forecast and vice versa. However, this relationship does not always hold as other factors, like temperature, impact load forecasting.

The Interaction between Forecast Error and Pricing Outcomes in 2021

When the ISO's load forecast differs from real-time load, the forecast error can provide insight into energy market outcomes, including divergence between day-ahead and real-time cleared demand and prices. ISO load forecast error tends to be consistent with the market's forecast error. That is, when the ISO's load forecast is greater than actual load, the day-ahead market tends to commit more generation than is required to satisfy actual real-time load. This can result in depressed real-time prices as more expensive generators are backed down from their day-ahead schedules.

Alternatively, when actual loads are greater than the ISO's forecast, fewer generators are committed in the day-ahead market than are needed in real-time. This can result in real-time prices exceeding day-ahead prices because more expensive generators (than what cleared in the day-ahead) are required. Often there is a smaller selection of generators to choose from due to start-up time constraints, and expensive fast-start generators may be required to serve actual load.

The statistical relationship between average daily load forecast error and price divergence is shown in Figure 3-25 below.

Figure 3-25: Price Separation and Forecast Error Relationship

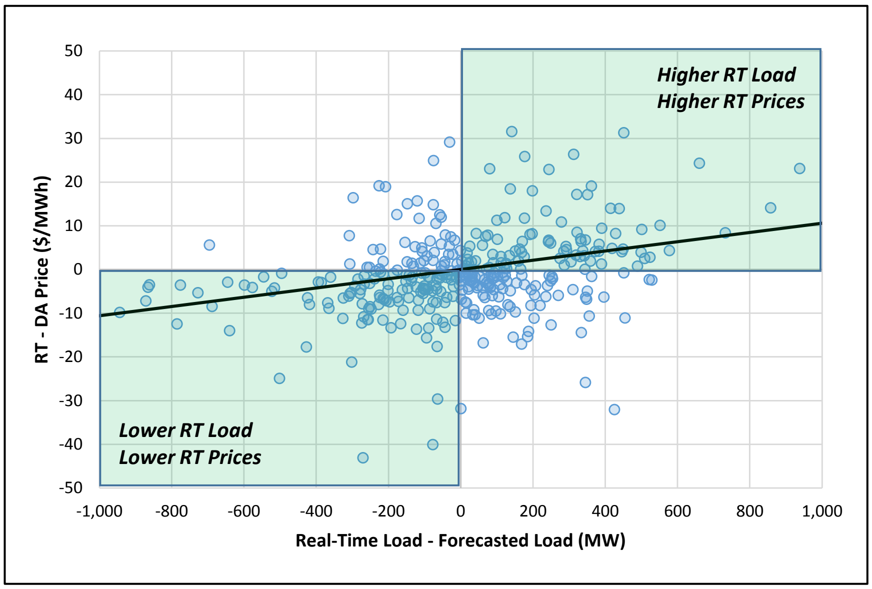


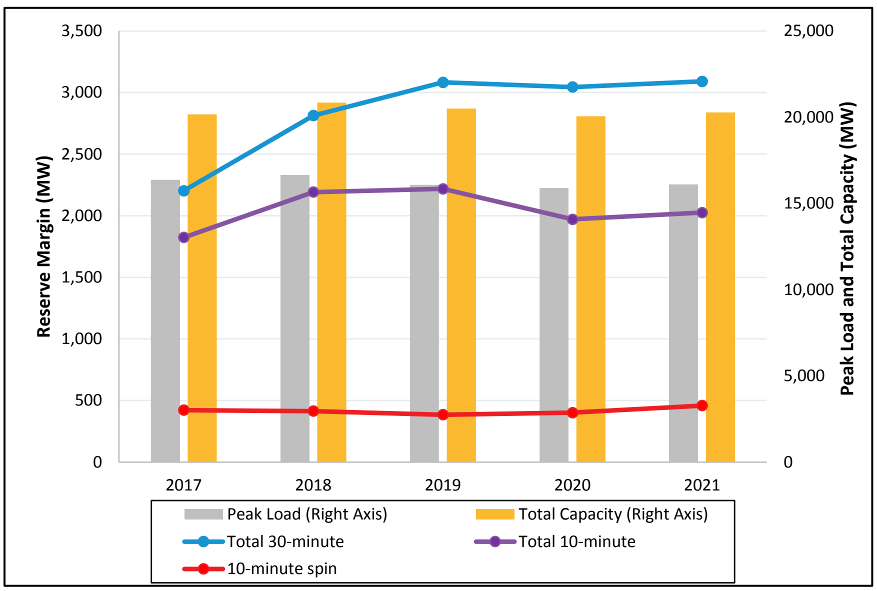
Figure 3-25 illustrates that in 2021 there was a positive correlation between forecast error and price separation between the day-ahead and real-time markets. In other words, when real-time loads were higher than day-ahead forecasted demand, real-time prices tended to be higher than day-ahead prices, and vice versa.

3.4.7 Reserve Margins by Reserve Product

The real-time reserve margin measures additional available generation capacity over the load and reserve requirements.[187, 188] If the margin is low, the ISO may need to commit additional generators or reposition (or redispatch) generation to meet load and reserves, resulting in elevated LMPs. Additionally, the energy market is more susceptible to market power when system conditions are tight.

The annual average margins for 10-minute spinning reserves (red line), total 10-minute reserves (purple line), and total 30-minute reserves (blue line) are shown in Figure 3-26 below. The margins are equal to the amount of reserves provided in excess of the corresponding reserve requirement. The bars represent the annual average of New England load (gray bar) and total available capacity (orange bar) during the peak hour of each day. Combined, these bars provide context on the difference between load and available capacity during the tightest conditions throughout the year, which is when reserve margins are typically at their lowest.

Figure 3-26: Reserve Margin, Peak Load, and Available Capacity



The reserve margins increased slightly year over year, which reflects the decline in reserve requirements (discussed in Section 2.3). The total 10-minute and 30-minute margins increased modestly by 55 MW (3%) and 46 MW (2%) in 2021 compared to 2020, consistent with the 39 MW (2%) and 27 MW (1%) decreases in the respective reserve requirements. The relationship load and capacity provides insight into how much additional energy is available to provide reserves when conditions are tight. As loads increase, the market commits available capacity, which can reduce the amount of offline (total 10-minute and total 30-minute) reserves available, thereby reducing the reserve margin. Average daily peak loads increased by 213 MW in 2021, from 15,898 MW in 2020

[187] 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 $Supply + Reserve\ Margin = Demand$

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

to 16,109 MW in 2021. This is consistent with higher loads discussed in Section 3.4.4. Over the same period, average daily available capacity increased 219 MW.

The 10-minute spinning margin increased by 57 MW or 14% in 2021, averaging 459 MW compared to 401 MW in 2020. Two factors drove the increase. First, new battery storage generators provided additional 10-minute spinning reserves. When battery storage generators are synched to the grid, they provide constant spinning reserves, as long as they are not dispatched to their maximum output. Second, in-merit gas-fired generators provided additional energy (discussed in Section 2.2.1) in 2021 due lower net interchange. Since external transactions do not provide reserves, additional online gas-fired generation led to more dispatchable 10-minute spinning reserves.

3.4.8 System Events During 2021

Conditions were relatively benign in 2021, with no capacity scarcity conditions[189] or instances of prolonged cold or hot temperatures putting the system under significant stress. There were days where storms or unplanned outages affected the system, but these events were not as impactful as certain occurrences in previous years.

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

- Number of OP4 and M/LCC 2 Events
- Reserve Deficiency Events

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)[190] 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)[191] establishes criteria and guidelines for actions during capacity deficiencies. There are eleven actions described in the procedure which the ISO can invoke as system conditions worsen.

The number of instances for each type of event during the reporting period is detailed in Table 3-5 below.

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[189] A scarcity condition is any five-minute interval when system cannot meet reserve requirement – the system is deficient in reserves. For Pay-for-Performance (PFP) purposes, this is a deficiency of 10-minute non-spinning reserve (TMNSR), and/or 30-minute operating reserve (TMOR).

[190] For more information on M/LCC2, see https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/mast_satllte/mlcc2.pdf

[191] 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 3-5: OP-4 and M/LCC 2 Event Frequency

	2017	2018	2019	2020	2021
# of OP-4 Events	0	1	0	0	0
# of M/LCC 2 Events	7	7	0	3	6

While there have not been any OP-4 events since 2018, the ISO implemented six M/LCC 2 events in 2021.

Three of the M/LCC2 events in 2021 occurred due to the threat of severe storms that struck the region in July, August, and October. Overall, these events had relatively minimal impacts on system infrastructure and the energy market. The August event was the most notable. M/LCC 2 was in effect from August 20 to August 23 due to hurricane Henri, which caused approximately 140,000 customer outages at the peak of the storm. Most customer outages occurred in Rhode Island, where the storm made landfall. For comparison, during August 2020, tropical storm Isaias resulted in 1.2 million customer outages in New England and a load forecast error of nearly 4,000 MW, with actual loads coming in substantially below the forecast.

The other three M/LCC 2 events occurred due to potential capacity deficiencies on days in June, August, and October. Despite the circumstances, there were no capacity scarcity conditions (shortage events) in 2021. Over these three days, supply was relatively tight and 46-70% of real-time pricing intervals saw at least one pivotal supplier.[192] Participants were subject to general threshold energy mitigation, and there were numerous structural and conduct test failures, but no impact test failures. This indicates that although participants had market power, their supply offer behavior did not increase LMPs beyond mitigation thresholds.[193] The bullet points below provide additional detail on these events.

June 28*:*

- The daily high temperature forecast was 92°F, and the peak load forecast was 24,497 MW, the highest load forecast of 2021 up to that point.
- One generator tripped around 08:30, and another experienced a forced reduction around 13:45. The real-time load obligation was greater than what cleared in the day-ahead market during the afternoon and evening peak due to fewer net imports in real-time.
- M/LCC 2 was in effect from 14:30-22:00.
- The 5-minute real-time Hub LMP peaked at $308/MWh during the 15:05, 15:10, and 15:15 pricing intervals.
- Eighty-five minutes of non-spinning reserve pricing occurred between hour ending (HE) 15 and 18. Operators manually committed generators to maintain operating reserves during that period.

August 25:

- The control room forecasted tight system conditions going in to the operating day due to the expectation of higher loads and dew points. Load peaked at 23,440 MW during HE 18 and temperatures peaked at 89°F during HE 17. While temperatures were similar to

[192] These pivotal supplier figures were calculated using the method described in Section 3.7.3, which differs from the pivotal supplier calculation performed by the mitigation process.

[193] A supply offer fails the impact test for general threshold energy mitigation if there is an increase in the LMP greater than 200% or $100/MWh, whichever is lower.

expected values, actual loads came in about 640 MW greater than the load forecast during the peak hour.

- Two generators tripped in the morning, and produced 0 MW in real-time for several hours during the afternoon and evening despite clearing over 400 MW combined in the day-ahead market. Additionally, multiple gas-fired generators experienced gas pressure issues and produced less than their day-ahead schedules (160-460 MW deviation from HE 13-21, or 9-22% less than the day-ahead cleared amount).
- M/LCC2 was in effect from 13:00-22:00.
- The 5-minute real-time Hub LMP peaked at $506/MWh during the 17:35 and 17:40 pricing intervals.
- Non-spinning reserve pricing occurred for 195 minutes around the evening peak. Reserve pricing peaked at $428/MWh during the 17:35 and 17:40 pricing intervals.

October 14:

- Going into the operating day, around 10,000 MW of generation was out of service (mostly planned outages), including significant baseload generator capacity. October is a shoulder season month, when many planned maintenance activities occur.
- The highest loads of the month (October 2021) were forecast for HE 19, at 15,720 MW.
- A generator tripped at 10:30, and another tripped around 13:30. These issues resulted in a loss of about 670 MW of capacity, with no anticipated resolution timeframe.
- Given that the expected margin at peak was only 500 MW and loads were running close to the forecast, there could have been reliability issues if the generator outages persisted.
- The control room declared M/LCC2 from 15:00-22:00.
- Real-time Hub LMPs peaked at $134/MWh during the 21:20, 21:25, and 21:30 pricing intervals.
- Reserve prices peaked at $37/MWh during the 14:35, 14:40, and 14:45 pricing intervals. There was no non-spinning reserve pricing.

Negative Reserve Margins

Negative reserve margins are indicative of stressed system conditions. In these instances, the system does not have enough available supply to meet the reserve requirements necessary to maintain system reliability. In particular, negative *non-spinning* reserve margins result in very high real-time energy prices, because reserve prices reach the Reserve Constraint Penalty Factor (RCPF) of $1,000/MWh for thirty minute operating reserve (TMOR) and/or $1,500/MWh for ten-minute non-spinning reserve (TMNSR).[194] The number of hours with negative non-spinning and spinning reserve margins are presented in Table 3-6 below.

[194] Section 7.1.1 provides additional information on Reserve Constraint Penalty Factors.

Table 3-6: Frequency of Negative Reserve Margins (System Level)[195]

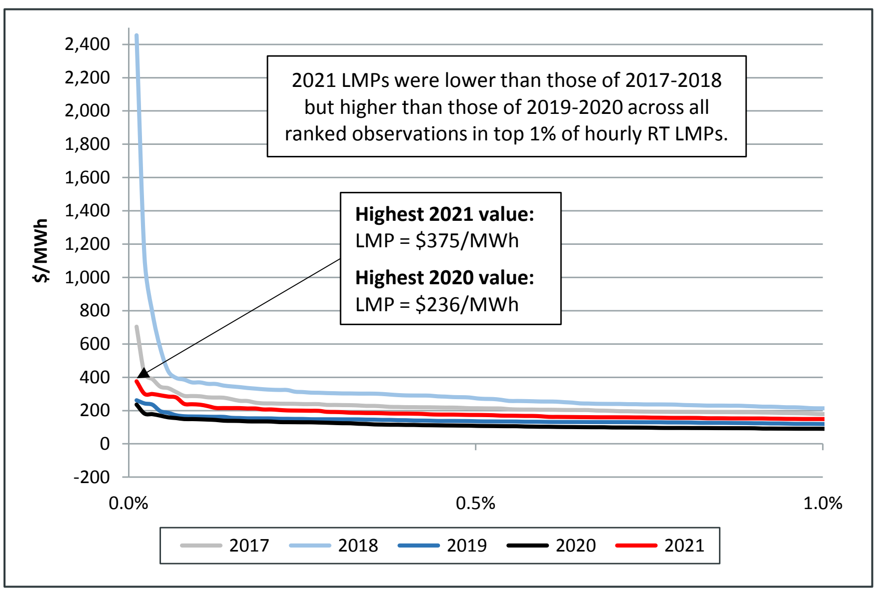
Year	Hours of Negative Total30 Margins	Hours of Negative Total10 Margins	Hours of Negative Spinning Reserve Margins
2017	0.6	0.0	57.0
2018	2.7	0.9	68.1
2019	0.0	0.0	25.9
2020	0.0	0.0	14.4
2021	0.0	0.0	26.8

Unlike the first two years in the reporting period, the TMNSR and TMOR margins did not fall below 0 in 2019-2021. Shortages of ten-minute spinning reserves were more frequent than in 2020 but similar to 2019. The spinning reserve shortages occurred across 33 days throughout the year in 2021 due to a variety of factors, such as tight system conditions caused by higher real-time loads or unplanned outages. 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.

Frequency of extreme energy prices at the Hub

High real-time LMPs can indicate stressed system conditions, as higher-cost generation is required to meet load and reserve requirements. The duration curves in Figure 3-27 below show the top 1% of hourly real-time LMPs ranked from high to low over the past five years.

Figure 3-27: LMP Duration Curves for Top 1% of Real-Time Hours



[195] The calculations in this table come from the pricing and 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.

This figure shows relatively modest levels of real-time Hub LMPs in the top 1% of hours in 2021, indicating a lack of scarcity pricing throughout the year. LMPs were lower than 2017-2018 LMPs but higher than 2019-2020 LMPs across the top 1% of ranked observations. This trend persisted across most of the remaining 99% of observations. In 2017 and 2018, there were periods of tight system conditions that resulted in high non-spinning reserve pricing and high LMPs. No comparable events occurred in 2019-2021. In 2021, LMPs were generally higher than in 2019 and 2020 due to higher natural gas prices.

3.4.9 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.[196] To meet 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. Such reliability commitments can be made in both the day-ahead and real-time markets. The ISO may also 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.

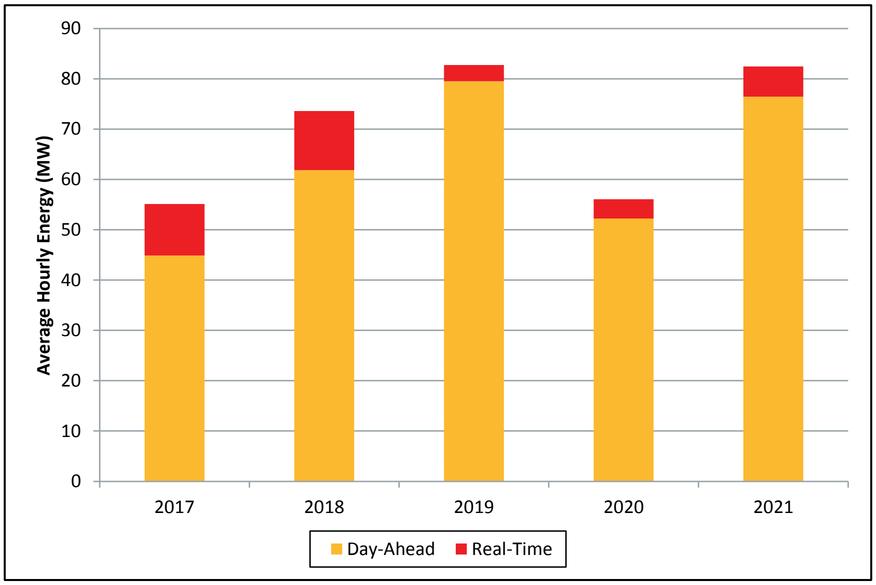
Reliability Commitments

Reliability commitment decisions are often "out-of-merit", meaning they are not based on the economics of a generator's offer. When this happens, lower-cost generators that would otherwise have been economically committed (if the reliability need had not existed) are displaced. Consequently, overall production costs increase in the market. If LMPs are insufficient to cover the out-of-merit generator's costs, NCPC payments will be made to the out-of-merit generator. The impact on consumer costs (i.e., the LMP) is less straightforward. Often, the more-expensive reliability-committed generator will operate at its economic minimum and the LMP will be set by a less expensive generator.

The real-time average hourly energy output (MW) from reliability commitments during the peak load hours (hours ending 8-23) for 2017 through 2021 is shown in Figure 3-28 below. The figure also shows whether the commitment decision was made in the day-ahead or real-time market.

[196] 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 3-28: Average Hourly Energy Output from Reliability Commitments, Peak Load Hours



Reliability commitments remain a relatively small component of total system generation, at less than 0.4%, on average. This indicates that the market solution produces in-merit commitments and dispatch that meet the system's reliability needs to a large extent. Over the review period, reliability commitments were relatively low, averaging just 70 MW per hour. Commitments continue to be more common in the day-ahead market as a percentage of total reliability commitments.

In 2021, the ISO's reliability commitments averaged 82 MW per hour. The vast majority (96%) of these commitments occurred for Local Second Contingency Reliability Protection (LSCPR). Special-Constraint Resources (SCR) and voltage support resources accounted for 3% and 1% of reliability commitment resources, respectively.[197] Almost two-thirds of all reliability commitments (66%) occurred in Maine and SEMA-RI; the remainder were in NEMA (13%) and New Hampshire (19%). These reliability commitments primarily reflected a need for additional on-line generation in areas with transmission upgrades and outages, to ensure local reliability. The 2021 increase in reliability commitments (from 56 to 82 MW per hour, on average) resulted from transmission work related to the "west-east" constraint in December 2021; that month accounted for 31% of the reliability commitment hours in 2021.

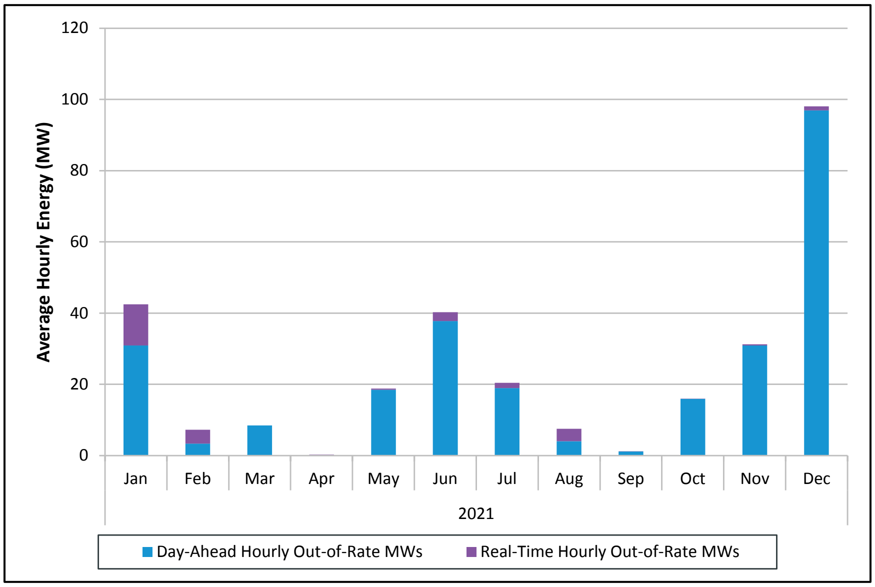
In terms of reliability commitment-hour increases for other years, the 2019 increase in overall reliability commitments resulted from local reliability commitments in Maine and SEMA between May and December, to support planned transmission work. The 2018 increase in reliability commitments resulted from outages during transmission upgrade work in the NEMA/Boston, Rhode Island and SEMA zones.

A monthly breakdown of reliability commitments made during 2021 is shown in Figure 3-29 below. The figure shows the out-of-rate energy for reliability commitments during the peak load hours in 2021, by market and month. Out-of-rate energy includes reliability commitment output that is

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

offered at a higher price than the LMP, and, therefore, would not likely have been committed or dispatched in economics.

Figure 3-29: Day-Ahead and Real-Time Average Out-of-Rate Energy from Reliability Commitments, Peak Load Hours, 2021



Of the roughly 82 MW of average hourly output from generators committed for reliability, about 24 MW (on average) was out-of-rate. This is a relatively small amount of out-of-rate energy (in the context of average hourly load of over 13.6 GW in 2021) that was served by more expensive generation to meet a reliability need. Figure 3-29 shows that the greatest amount of out-of-rate energy from reliability commitments occurred in January, June, and December; these commitments supported planned transmission outages in Maine, SEMA-RI, and the "east-west" constraint. The LSCPR reliability commitments explain the pattern and magnitude of the out-of-rate commitments. As noted earlier, approximately 96% of all reliability commitments were for LSCPR in 2021.[198] Out-of-rate commitments require uplift payments, to ensure that operating costs are recovered. NCPC payments to generators providing LSCPR in 2021 were approximately $6.5 million; while this represented 18% of total uplift payments for the year, it represented just 0.1% of total energy payments.

As shown in the two figures above, a large majority of the 2021 reliability commitments were made in the day-ahead market. This helps minimize surplus capacity and the amount of economic generation that is displaced in the real-time operating day, which could otherwise lead to price suppression and poor price formation. If a reliability requirement is known prior to the clearing of the day-ahead market, commitments can be made in the day-ahead market to meet the requirement.

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

[198] Local second contingency protection reliability (LSCPR) commitments are made for import-constrained subareas, 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.

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.

Posturing Actions

In addition to committing off-line, out-of-merit generators to ensure local reliability, the ISO may limit the output of potentially in-merit generators to ensure either system-wide or local reliability. Limiting the output of generators is called "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. Generators may be postured either on-line or off-line. When generators are postured on-line, it is often at the generator's economic minimum; the generator provides operating reserves while postured, but is only available for manual dispatch above the posturing level in the event of a system contingency. Generators postured off-line, if fast-start capable, also provide either 10- or 30-minute operating reserves.

Because posturing removes potentially in-merit generation from economic dispatch, postured generators may be financially worse-off as a result of the ISO's actions, unless the ISO provides uplift payments to compensate for foregone profitable dispatch. Postured generators are eligible to receive NCPC for any foregone profits that occurred during the posturing period. Generally, the postured generator's remaining energy is compared to its economic dispatch opportunities during the posturing period. NCPC is provided for the net profits of optimal economic dispatch that would have occurred absent posturing, compared to the profitability of the actual dispatch that occurred during the posturing period.[199]

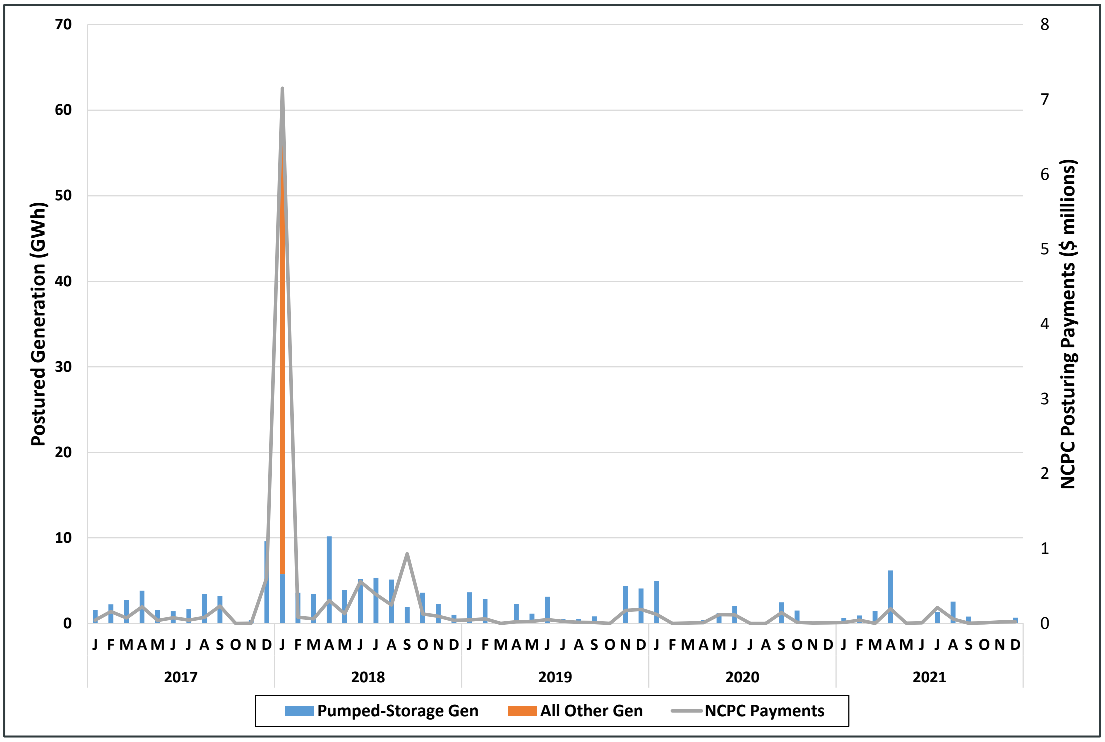
Postured energy (GWh) and NCPC payments by month are shown in Figure 3-30 below.[200] The bars indicate the postured energy obtained (the amount of energy constrained down) from pumped-storage generators and all other types of generators.[201]

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

[200] 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.

[201] 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.

Figure 3-30 Monthly Postured Energy and NCPC Payments



As indicated in the figure above, pumped-storage generators are frequently postured throughout the year. In 2021, only pumped-storage generators were postured, and posturing levels were relatively low, at 15 GWh in total, compared to other years in the review period.[202] Only in January 2018 have non-pumped-storage generators been postured. The posturing in January 2018 involved a number of oil-fired generators, with limited fuel, being postured during a prolonged cold snap period that resulted in significant 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 throughout 2021, with approximately $0.6 million in total payments (accounting for 1.6% of all NCPC payments in 2021). 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 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.

3.4.10 Congestion

This section provides an overview of how congestion occurs in an electrical transmission system and how it affects LMPs. It then compares the amount of congestion revenue in New England in 2021 against historical levels of congestion revenue over the last five years. In general, New England has experienced low levels of congestion revenue in recent years, especially when

[202] For context, the total supply/load in 2021 was approximately 119,000 GWh.

considered relative to total energy market payments. Subsequently, this section explores where congestion occurred geographically in the New England transmission system over the past year. It concludes by looking at some of the most frequently binding transmission constraints in New England in 2021.

Overview of Transmission Congestion

The ISO models the operational limits of transmission elements as constraints in the economic optimization that it administers to determine the least-cost way of producing electricity. When the power flowing through a transmission element reaches its modeled limit in this optimization process, the constraint associated with that transmission element is said to "bind" and the transmission system experiences congestion. Much like a traffic jam on a highway, congestion in a transmission system represents a bottleneck: a location where the limited capability of some element has impeded the optimal flow in the system. In the case of transmission congestion, a transmission element has limited the extent to which the least-expensive generation can meet load in the system. Transmission congestion is important because it imposes additional costs on the power system. Higher-cost generation must be dispatched in order to help meet load, which raises the price of energy (i.e., the LMP) in the area where the higher-cost generation has been dispatched.

The Congestion Component

Recall, that at every node in the New England power system, the LMP represents the marginal cost of serving an additional megawatt (MW) of load at that location at the lowest cost to the system. This price reflects not only the cost to produce the energy, but also the cost to deliver it to that specific location. Both line losses and transmission congestion can make it more expensive to deliver energy to certain parts of the transmission system.

Accordingly, ISO-NE separates the LMP into three components: the energy component, the loss component, and the congestion component. The energy component is the same for all locations in the power system. The loss component reflects the dispatch of additional generation because some electric energy is lost during transmission. The congestion component reflects the additional system costs when transmission constraints prevent the use of the least-cost generation to meet the next increment of load.

The decomposition of LMPs into these three components is done in order to determine how much of the difference in LMPs at two locations is due to losses versus transmission congestion. This is only necessary so that the ISO is able to provide market participants with a means of hedging specifically against transmission congestion. Financial transmission rights (FTRs) are the financial instrument that the ISO offers to market participants to help them manage transmission congestion risk. Locational differences in the congestion component serve as the basis for determining the value of these rights. FTRs are covered in more detail in Section 4.2.

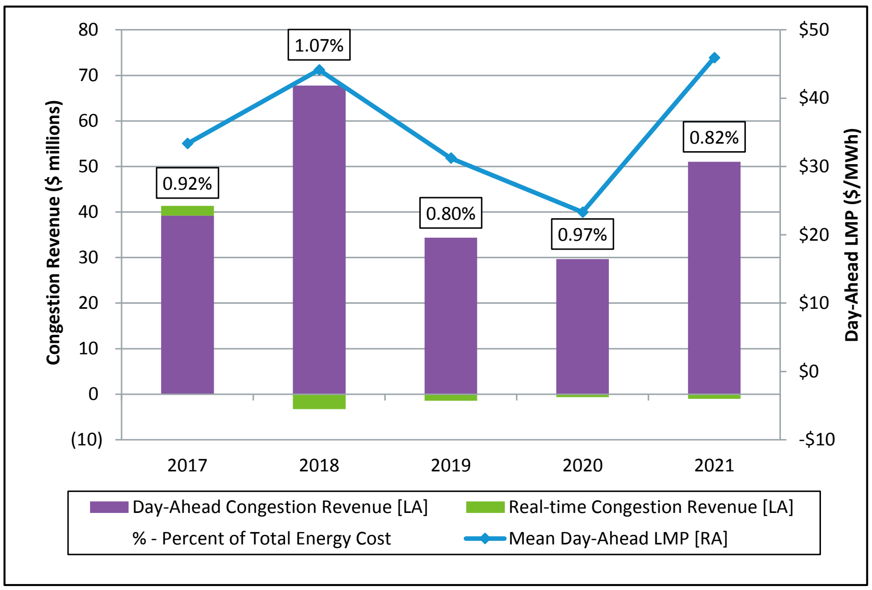
Congestion Revenue

The ISO settles the day-ahead and real-time energy markets by calculating charges and credits for all market activity that occurs at each pricing location (node) in the system. Energy market settlement is performed on each of the three components of the LMP separately. By design, the settlement based around the congestion component does not balance. The congestion charges are expected to exceed the congestion credits, and the surplus revenue is called congestion revenue.

The ISO collects congestion revenue in both the day-ahead and real-time energy markets and this revenue forms the basis of the congestion revenue fund, which is used to pay FTR holders.

Over the last five years, congestion revenue has been small relative to total energy market payments. This can be seen in Figure 3-31 below, which shows the congestion revenue in New England by market and year between 2017 and 2021. The purple bars represent the day-ahead congestion revenue, and the green bars represent the real-time congestion revenue. Bars with a positive value indicate that the congestion charges exceeded the congestion credits for that year in that market, while bars with a negative value indicate that congestion credits exceeded the congestion charges. 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.[203] This figure also depicts the annual average day-ahead Hub LMP (blue line).

Figure 3-31: Average Day-Ahead Hub LMP, Congestion Revenue Totals and as Percent of Total Energy Cost



Total day-ahead and real-time congestion revenue was $50.1 million in 2021. This represents a 72% increase from congestion revenue in 2020 ($29.1 million). The day-ahead congestion revenue totals tend to be strongly correlated with the average day-ahead LMP.[204] The congestion revenue in 2021 represents less than 1% of total energy costs, which was comparable to other years in the reporting period. The majority of the congestion revenue came from the day-ahead market. Because the real-time market is a balancing market, the congestion that occurs in real-time only affects

[203] Some of these percentages are slightly different from those from the corresponding figure in the 2020 Annual Markets Report as the IMM is using a new methodology for calculating energy market payments in this year's report.

[204] As congestion components reflect the marginal values of binding transmission constraints, they tend to be higher when energy prices are higher. To see this, we can consider an example of an export-constrained area where the marginal resource is setting the area's LMP at $0/MWh. If the marginal resource outside the export-constrained area is setting that area's price at $35/MWh, then the marginal value of the binding constraint would be -$35/MWh, reflecting the fact that if one more MW could flow over the binding constraint, then one MW priced at $35/MWh could be replaced by one MW priced at $0/MWh. It is straightforward to see that the marginal value of this binding constraint would double if the marginal resource outside of the export-constrained area were setting the price at $70/MWh instead of $35/MWh. Congestion charges, which are based on the congestion component, would also increase in this example.

deviations from day-ahead schedules. Consequently, the magnitude of congestion revenue in the real-time market is small relative to the congestion revenue in the day-ahead market. In 2021, the real-time congestion revenue amounted to -$1.0 million, while the day-ahead congestion revenue totaled $51.1 million.

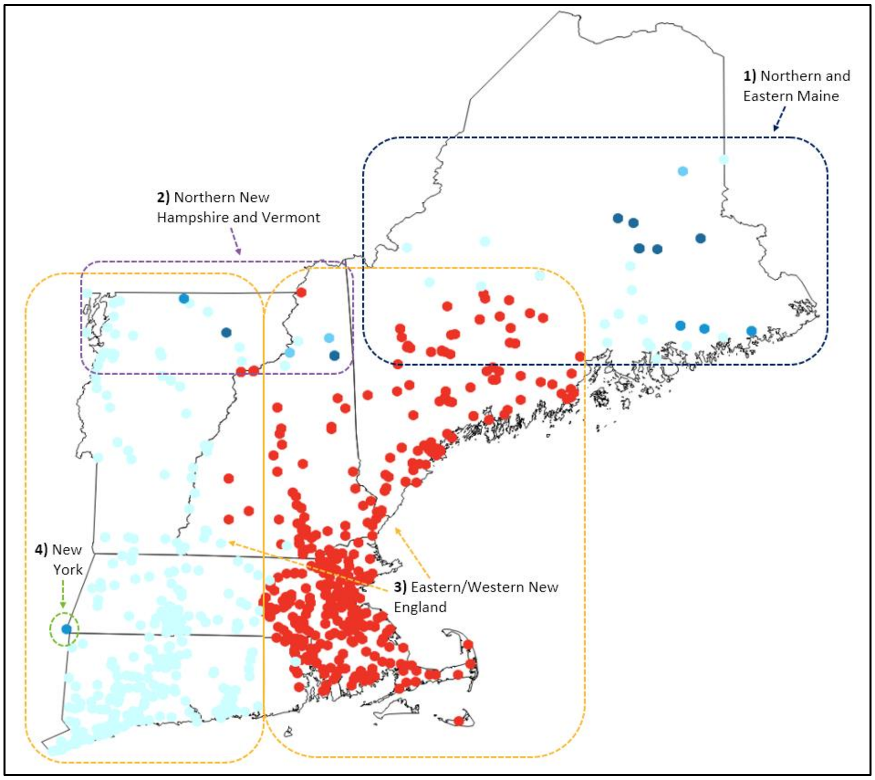
Congested Areas in New England

The New England nodes most affected by transmission congestion in the day-ahead market in 2021 are shown in Figure 3-32 below.[205] The colors of the nodes indicate the average day-ahead congestion component in 2021. Blue dots represent locations that had a negative average day-ahead congestion component in 2021. The darker the blue, the lower the average day-ahead congestion component (i.e., the more negative the congestion component). Locations that are "upstream" of a binding constraint have a negative congestion component.[206] Generally, these are areas where there is an imbalance of generation relative to load and there is insufficient transmission capability to export the excess energy. Meanwhile, red dots represent locations that had an average day-ahead congestion component that was positive in 2021. Locations that are "downstream" of a binding constraint have a positive congestion component. These are often areas where there is an imbalance of load relative to generation and there is insufficient transmission capability to import the additional needed energy.

[205] This figure only includes nodes that had an average day-ahead congestion component of greater than or equal to $0.10/MWh or less than or equal to -$0.10/MWh in 2021.

[206] More specifically, a negative congestion component occurs when a location has a positive shift factor to a binding constraint, while a positive congestion component occurs when a location has a negative shift factor to a binding constraint. In simple terms, shift factors measure how injections of energy at different locations impact the flow of energy over a transmission constraint.

Figure 3-32: New England Pricing Nodes Most Affected by Congestion, 2021



Several patterns of congestion have been highlighted in Figure 3-32 and each of them is discussed in detail below:

1) **Northern and Eastern 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). Many of the interface constraints that are used to manage parts of this broad geographic area bound frequently in the day-ahead market in 2021 (see Table 3-7 below).[207] This includes the Keene Road Export (KR-EXP) interface. The nodes behind this interface constraint had the lowest average day-ahead congestion components (-$9.45/MWh) of any location in 2021. Congestion associated with the KR-EXP interface was particularly notable during Fall 2021 when an extended transmission outage reduced the capability of this interface. Further, a new wind generator located in the coastal region of eastern Maine reached commercial operation in late 2020 and the additional generation from this unit contributed to the congestion in this region in 2021.[208]

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. This combination of imports and abundant wind energy often contribute to congestion at the Sheffield + Highgate Export (SHFHGE)

[207] Interfaces are sets of transmission elements whose power flows are jointly monitored for voltage, stability, or thermal reasons.

[208] The congestion in this coastal region of Maine was often associated with the EPPING_T59BHE-2 line constraint.

interface. As shown in Table 3-7, this interface was the third most frequently binding interface constraint in the day-ahead market in 2021. Two other interfaces used to manage the output from specific wind resources within the SHFHGE interface – SHEF and KCW – were also frequently binding in the day-ahead market. Meanwhile, New Hampshire had several locations that were among those having the lowest average congestion components in the day-ahead market in 2021. Two constraints that contributed to the congestion in New Hampshire were: 1) the Burgess Generation (BURG) interface, which bound frequently in the fall as a result of planned transmission work, and 2) the PARIS O154 line, which bound periodically throughout the whole year.

3) **Eastern/Western New England**: One of the more prominent patterns in Figure 3-32 is the negative congestion in the entire western half of New England and the positive congestion in most of the eastern half of New England. This is largely the result of the New England West-East (NE_WE) interface constraint. This constraint manages power flows from western New England, where there is abundant generation as well as power coming in from New York, to eastern New England, where some of the larger load centers are located. This constraint began binding more frequently in the second half of 2021 in part because of planned transmission work that reduced its capability. The impact of this constraint was widely spread geographically, with the majority of the locations in western New England having an average day-ahead congestion component in the range of -$0.20/MWh to -$0.45/MWh. Meanwhile, the majority of the locations in the eastern half of New England had an average day-ahead congestion component between $0.10/MWh and $0.30/MWh. Given the broad geographic impact, this constraint had a large impact on FTR target allocations in 2021. Target allocations are presented in more detail in Section 4.2.

4) **New York**: The NYNE interface was the second most frequently binding interface constraint in ISO-NE's day-ahead market in 2021. This interface is a collection of seven lines that control the flow of power between New York and New England. As discussed in Section 5, New England typically imports power over this interface. This constraint frequently binds 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) or when there are reductions in the interface limit. When this constraint binds, it is reflected in the congestion component of the .I.ROSETON 345 1 pricing node, which is ISO-NE's external node for trading across the NYNE interface. The average day-ahead congestion component at .I.ROSETON 345 1 was -$2.11/MWh in 2021. This constraint is discussed in more detail toward the end of this section.

The Most Frequently Binding Interface Constraints

The 10 interface constraints that bound most frequently in the day-ahead market in 2021 are listed in Table 3-7 below. Interface constraints can often have a larger impact on congestion revenue when they bind than individual transmission elements because they likely affect more load and generation. Also included in the table is the average marginal value ($/MWh) of each constraint when it bound in the day-ahead market in 2021.[209] Lastly, this table includes a location column, which places the constraints in the areas defined in Figure 3-32.

Table 3-7: Most Frequently Binding Interface Constraints in the Day-Ahead Market, 2021

Constraint Name	Constraint Short Name	% of Hours Binding	Average Marginal Value of Constraint ($/MWh)	Location
Keene Road Export	KR-EXP	27.4%	-$31.69	1
New York - New England	NYNE	15.5%	-$11.41	4
Sheffield + Highgate Export	SHFHGE	10.1%	-$5.41	2
Burgess Generation	BURG	6.9%	-$46.94	2
Orrington - South	ORR-SO	5.0%	-$17.90	1
New England West-East	NE_WE	3.8%	-$11.48	3
Kingdom Wind Generation	KCW	2.9%	-$38.65	2
Sheffield Wind Generation	SHEF	2.6%	-$68.48	2
Bingham Wind Generation	BNGW	2.5%	-$26.34	1
Oakfield Wind Generation	OAKW	2.5%	-$37.71	1

Outside of the New England West-East interface, nearly all of the most frequently binding interface constraints in the day-ahead market in 2021 were associated with small geographic areas where transmission capacity limited the ability of (mostly) intermittent generation to export power to the rest of the system. Consequently, many of these constraints are reflective of fairly localized congestion. This was the case for the KR-EXP interface constraint, the most frequently binding interface constraint in the day-ahead market in 2021. This interface consists of a line and a transformer that control flows through the Keene Road substation. There are several intermittent generators (specifically, hydro and wind) located at nearby substations whose power flows through this interface. When the KR-EXP interface constraint bound, the average day-ahead congestion revenue was $8,977 per hour.[210] Meanwhile, the average day-ahead congestion revenue was only $4,641 per hour in the hours when this constraint was not binding. Although the constraint only bound in 27.4% of hours in 2021, the congestion revenue within these hours comprised 42.2% of the total day-ahead congestion revenue.

The second most frequently binding interface constraint in the day-ahead market in 2021 was the New York - New England (NYNE) interface constraint. As mentioned above, this interface is a collection of seven lines that controls the flow of power between the New York and New England control areas. The average day-ahead congestion revenue was $17,573 per hour when this interface was binding, compared to $3,671 per hour in the hours when it was not binding. Although the

[209] The marginal value provides an indication of the extent to which the transmission system is limiting the ability to minimize the cost of electricity production. For example, a marginal value of -$10/MWh indicates that system production costs could be reduced by $10 if the limit of the binding transmission constraint were increased by one MW for one hour. The more negative the marginal value of the binding transmission constraint, the more the production costs could be reduced if the constraint were relaxed.

[210] Identifying the contribution of each binding constraint on the amount of congestion revenue it generates in an hour is complex because multiple constraints can be binding at one time. Comparing the average congestion revenue when a constraint is binding against when it is not binding can give us a helpful (but not perfect) sense of the constraint's impact on congestion revenue.

interface was only binding in 15.5% of hours, the congestion revenue within these hours comprised 46.8% of the total day-ahead congestion revenue. The relationship between the congestion at the NYNE interface and financial transmission rights is discussed in more detail in Section 4.2.5.

3.4.11 Marginal Resources

The LMP at each pricing location is set by the cost of the next megawatt of supply the ISO would dispatch (or the next MW of demand the ISO would back down) to meet an incremental change in load at that location. The supply offer or demand bid that sets price is considered "marginal."

Ranking supply offers from lowest to highest offered price creates a supply curve or "supply stack" with the relative position of each generator in the stack largely determined by the relative cost of different fuels (gas, oil, coal, etc.). On the demand-side, for the day-ahead market, ranking demand bids from highest to lowest produces the demand curve. The intersection of the supply and demand curves determines the market-clearing price and the quantity of MWs that clear.[211] The individual offer or bid located at the intersection of the supply and demand curves sets the market price and that offer/bid is said to be marginal.

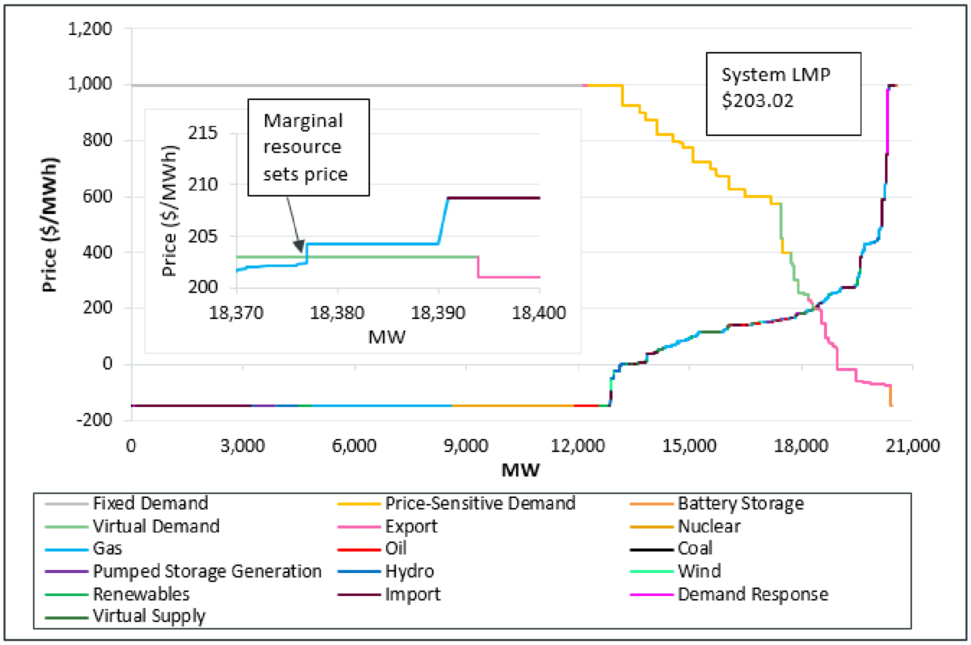
An Example

An example of a demand bid setting the price in the day-ahead market (hour ending 18 on December 20, 2021) is shown in Figure 3-33 below. This was the highest-priced hour in the day-ahead market in 2021. The curve that ascends from -$150/MWh in the bottom left corner to about $1,000/MWh in the upper right corner shows the supply stack, where supply offers are ranked from lowest to highest. The large section of supply at -$150/MWh mostly consists of self-scheduled generation, fixed imports, and generation up-to economic minimum, all of which are not eligible to set price and are treated as fixed supply in this example. The demand curve, which descends from $1,000/MWh in the upper left to about -$150/MWh in the lower right, consists of day-ahead demand bids, with a large section of fixed demand bids at the offer cap of $1,000/MWh.[212]

[211] This is a crude simplification of the optimization that occurs to clear the day-ahead market, but it accurately describes the essence of optimization's goal to maximize social welfare by bringing supply and demand in balance.

[212] Negative $150/MWh for fixed supply and $1,000/MWh for fixed demand are chosen for illustrative purposes only.

Figure 3-33: Day-Ahead Supply and Demand Curves – December 20, 2021, Hour Ending 18



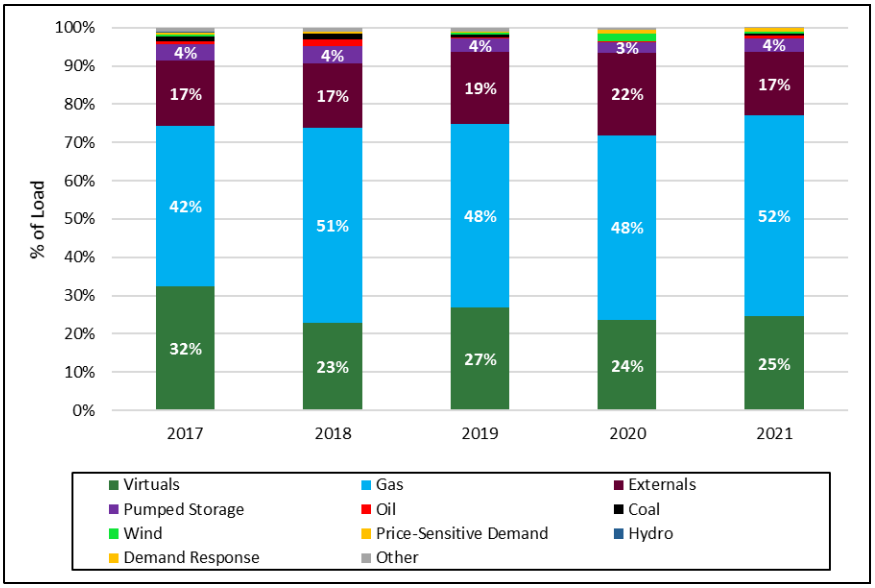
At the intersection of the supply and demand curves, which is highlighted in the inset graph of Figure 3-33, a virtual demand bid of $203.02/MWh intersects with the supply curve at about 18,377 MW. The virtual demand bid was split by the supply curve. Therefore, the virtual demand bid only cleared 19 MW out of its full offered quantity of 33 MW. The virtual demand bid is therefore marginal, as an incremental MW of demand would be served by reducing the cleared demand from this demand bid by one MW. As a result, this virtual demand bid sets the market-clearing price at $203.02/MWh.

In cases where transmission constraints are binding and energy cannot flow freely, there will be more than one marginal resource. For example, if transmission lines are limiting the amount of generation exported from a given area, that area is *export-constrained*. Transmission limitations do not allow for resources within this area to serve the next MW of load outside of the export-constrained area. In this case, there will be a marginal resource that could serve the next increment of load inside the export-constrained area, and at least one other marginal resource that serves incremental load outside the export-constrained area.

Marginal Resources in the Day-Ahead Market

As illustrated in the example above, many different types of transactions can be marginal in the day-ahead market, including: virtual transactions, price-sensitive demand bids, price-responsive demand, asset-related demand, generator supply offers, and external transactions. The percentage of load for which each transaction type was marginal over the past five years is illustrated in Figure 3-34 below.

Figure 3-34: Day-Ahead Marginal Resources by Transaction and Fuel Type

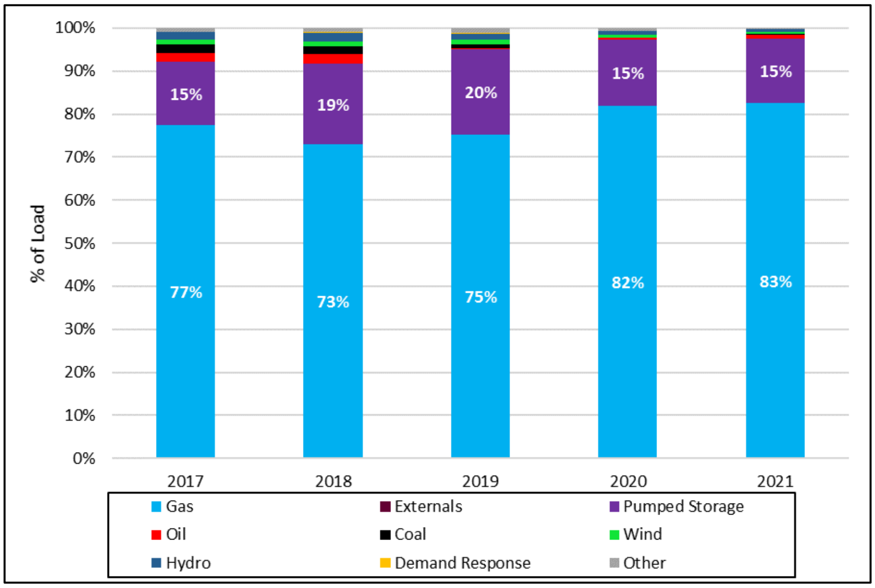


In the day-ahead market, price-setting fuel frequencies in 2021 were similar to previous years. Natural gas (52%), virtual transactions (25%), and external transactions (17%) continue to set price for a majority of load (94%) in the day-ahead market. The most notable change from 2020 was a 5% reduction in the percentage of load served by marginal external transactions. The New Brunswick interface accounted for three percentage points of the total decrease in marginal external transactions. External transactions are discussed further in Section 5.

Marginal Resources in the Real-time Market

In the real-time market, only physical supply, pumped-storage demand, price-responsive demand, and external transactions can set price. In reality, 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 3-35 below.

Figure 3-35: Real-Time Marginal Resource by Fuel Type



The mix of resources that set price in 2021 was very similar to the 2020 mix. Natural gas was the marginal fuel for 83% of load in the real-time market in 2021. Gas-fired generators are typically the lowest-cost fossil fuel type generator and thus typically operate much more often than coal- or oil-fired generators. Pumped-storage units (both generators and demand) are the second largest marginal resource, setting price for 15% of load in 2021.[213] Because they are online relatively often and priced close to the margin, they can set price frequently. They are also often called upon when conditions are tight due to their ability to start up quickly and their relatively low commitment costs compared with fossil fuel-fired generators.

The remaining transaction types were marginal for less than 5% of load in 2021. Although wind generators are frequently marginal, they are usually marginal for only a small share of total system load (less than 1% in 2021). 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.

3.5 Net Commitment Period Compensation (or Uplift)

This section provides an overview of Net Commitment Period Compensation (NCPC) payments. It covers payment types, drivers, and trends over the past five years.

Generators are eligible for NCPC or *uplift* payments when they follow ISO dispatch instructions and are unable to recover their operating costs through day-ahead or real-time energy prices. Uplift is also paid to generators for "lost opportunities", i.e., situations in which a generator foregoes opportunities for additional energy market revenue by following ISO instruction. This typically occurs when the market clearing software, or the ISO operators, restrict a generator's output below

[213] 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 2021, pumped storage generation set price about 10% of the time and pumped storage demand set price about 5% of the time.

its economically optimal level. In other words, the uplift rules are designed to incentivize generators to follow ISO's operating instructions so they are no worse off financially than the generator's next best alternative (of not following instructions).[214]

In 2021, uplift payments totaled $35.5 million, an increase of $9.7 million (38%) compared to 2020. Table 3-8 below details the continuing downward trend in payments as a percentage of energy costs over the reporting horizon.

Table 3-8: Uplift Payments as a Percent of Energy Costs

	2017	2018	2019	2020	2021
Day-Ahead NCPC	0.6%	0.4%	0.3%	0.3%	0.3%
Real-Time NCPC	0.5%	0.7%	0.4%	0.5%	0.3%
Total NCPC as % Energy Costs	**1.2%**	**1.2%**	**0.7%**	**0.9%**	**0.6%**

Even though total uplift payments increased in dollar terms, payments as a percentage of total energy payments decreased from 0.9% in 2020 to 0.6% in 2021, the lowest percentage level over the five-year reporting period. The increase in total uplift payments was significantly less than the increase in energy payments, which doubled due to a 120% increase in gas prices.

The relatively low level of NCPC is consistent with improved price formation in the real-time energy market since the implementation of fast-start pricing rules in 2017, and with the generally low levels of operator out-of-market or unpriced actions.

3.5.1 Uplift Payment Categories

Generators that operate at the ISO's instruction may be eligible for one of the following types of uplift depending on the reason for ISO commitment:

- **Economic/first-contingency NCPC ("Economic")**[215]:

  At a high level, economic NCPC is paid to generators that were committed and/or dispatched in economic merit order to satisfy the system's load and reserve requirements. The subcategories of economic NCPC are:

  - *Out-of-merit NCPC:* Provided to a generator committed and/or dispatched in economic merit order to satisfy system-wide load and reserves in a least cost manner. Payments are calculated to cover the commitment and energy components of the supply offer (i.e., start-up, no-load and energy costs) not recovered through the LMP.

[214] The terms "generators" or "generation" are used in this section in a broad sense; in practice, external transactions and pumped-storage demand also receive certain types of NCPC payments, but the vast majority of payments are made to generators.

[215] A system's *first contingency* (N-1) is the loss of the power system element (facility) with the largest impact on system reliability. A *second contingency* (N-1-1) takes place after a first contingency has occurred and is the loss of the facility that at that time has the largest impact on the system.

- *External NCPC:* Payments made to external and virtual transactions that relieve congestion at the external interfaces, and for external transactions that are unable to recover as-offered costs due to price forecast error.[216]
  - *Dispatch lost opportunity cost NCPC (DLOC):* Payments provided to a resource that is instructed by the ISO to run at levels below its economic dispatch point.
  - *Posturing NCPC:* Payments provided to a resource that follows an ISO instruction to alter its output from its economically-optimal dispatch level in order to create additional reserves.
  - *Rapid-response pricing opportunity costs (RRPOC):* Payments provided to a resource that follows an ISO instruction not to operate at its economic dispatch point when fast-start generators are setting the LMP.

- **Local second-contingency protection NCPC:** Payments made to a generator committed to provide local operating reserve support in a transmission-constrained area to ensure local reliability needs.
- **Voltage reliability NCPC**: Payments made to a generator that is dispatched to provide reactive power for voltage control or support.
- **Distribution reliability NCPC:** Payments made to a generator committed to support local distribution networks, also known as special constraint resource or SCR payments.
- **Generator performance auditing NCPC**: Payments made to a generator that is operating to satisfy the ISO's performance auditing requirements.[217]

3.5.2 Uplift Payments for 2017 to 2021

Uplift payments increased by $9.7 million (38%) in 2021, from $25.8 million in 2020 to $35.5 million in 2021. This was the first increase in total annual payments since a downward trajectory from 2018; a significant driver then was a cold snap at the beginning of January, which resulted in higher economic NCPC payments for the year.

Economic payments make up most (almost three quarters) of the annual increase, up by $7.2 million from $19.6 million in 2020 to $26.8 million in 2021. Local second-contingency protection increased by $2.5 million, from $4.0 million in 2020 to $6.5 million in 2021. Distribution reliability payments also increased in 2021, rising from $0.6 million in 2020 to $1.1 million. The drivers of these changes are discussed further below.

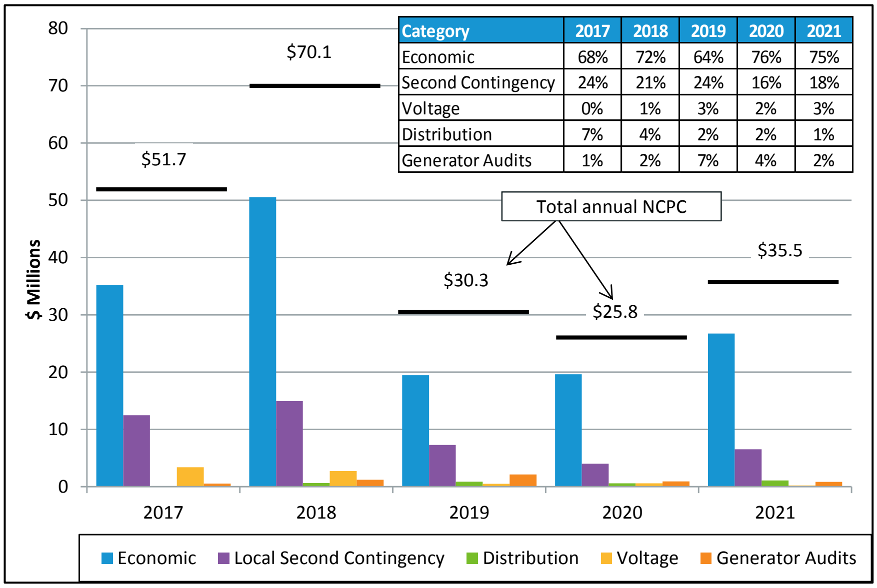
Uplift Payments by Category

Over the past five years, most uplift payments have covered the operating costs of generators committed and dispatched in economic merit order (economic or first contingency), as shown in Figure 3-36 below. The inset table shows the percentage share of total uplift for each category by year. The black lines above the bars correspond to total annual uplift payments for that year.

[216] See Section 5.3 for further detail on external transaction uplift payments.

[217] Eligibility for payment under this uplift category includes: Performance audits of on-line and off-line reserves and for seasonal claimed capability audits initiated by the ISO rather than the participant, and dual-fuel testing.

Figure 3-36: Total Uplift Payments by Year and Category



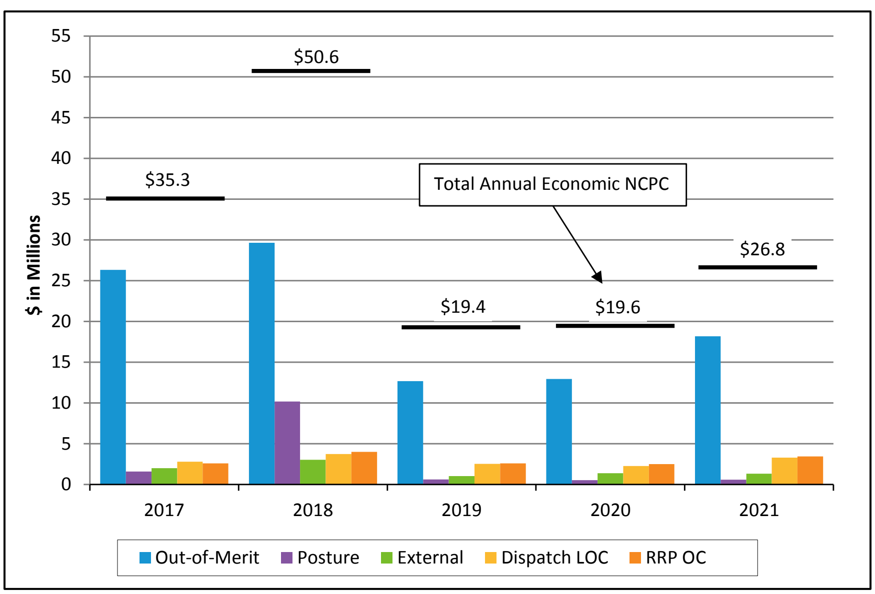
Category	2017	2018	2019	2020	2021
Economic	68%	72%	64%	76%	75%
Second Contingency	24%	21%	24%	16%	18%
Voltage	0%	1%	3%	2%	3%
Distribution	7%	4%	2%	2%	1%
Generator Audits	1%	2%	7%	4%	2%

As can be seen from the graph, economic uplift continues to comprise the majority of payments (75% of total payments in 2021), followed by local second contingency (18%). The remaining categories covering reliability services (voltage, distribution) and auditing costs, make up a relatively small share (6% together) of uplift.

Economic Uplift Sub-Categories

In the economic uplift category, out-of-merit and external uplift payments were the only sub-categories that increased in 2021. A breakdown of economic uplift by year and by sub-category is shown in Figure 3-37 below. The black lines above the bars correspond to total annual uplift payments for that year.

Figure 3-37: Economic Uplift by Sub-Category



Out-of-merit uplift continue to make up the majority of total economic payment at $18.2 million, increasing by $5.2 million (41%). The opportunity cost categories of uplift (posturing, dispatch LOC and RRP OC) comprised a similar share of economic NCPC than prior years.[218] Although 2021 payments were higher than in 2020, the payments were still well below the high payment totals seen in 2018 ($29.7 million) driven by the cold snap in January. Overall, most economic payments in 2021 ($19.8 million or 56%) occurred in the real-time market, consistent with the average over the prior four years, 57% of payments occurred in the real-time market.

Reliability Uplift Payments

Local Second Contingency Protection (LSCPR) payments made up the second largest category of uplift at $6.5 million, or 18% of total uplift payments. This is a modest increase of $2.5 million from 2020, and is consistent with the low level of reliability commitments required to support local system contingency needs over the past few years.[219]

The majority (93%) of these payments continued to be made in the day-ahead market to support planned transmission line outages with out-of-market generator commitments. In January and December 2021, high-voltage line outages coupled with a generator maintenance outage led to reliability commitments in Maine and New Hampshire. Similarly, a high voltage line and electric bus outage led to commitments in NEMA/Boston in June. These three months accounted for ~72% of the total LSCPR payments.

Distribution reliability protection payments increased by just $0.5 million in 2021; all distribution payments were made in the real-time market. Approximately 64% of 2021 payments were made to two oil-fired generators on Cape Cod that were committed to support distribution reliability in the SEMA load zone from June through August when loads were highest. Also, during a three-day period at the beginning of February 2021, planned distribution maintenance along with high forecasted loads led to the distribution reliability commitment of a single generator in Rhode Island. This commitment totaled $0.3 million or 23% of total distribution payments.

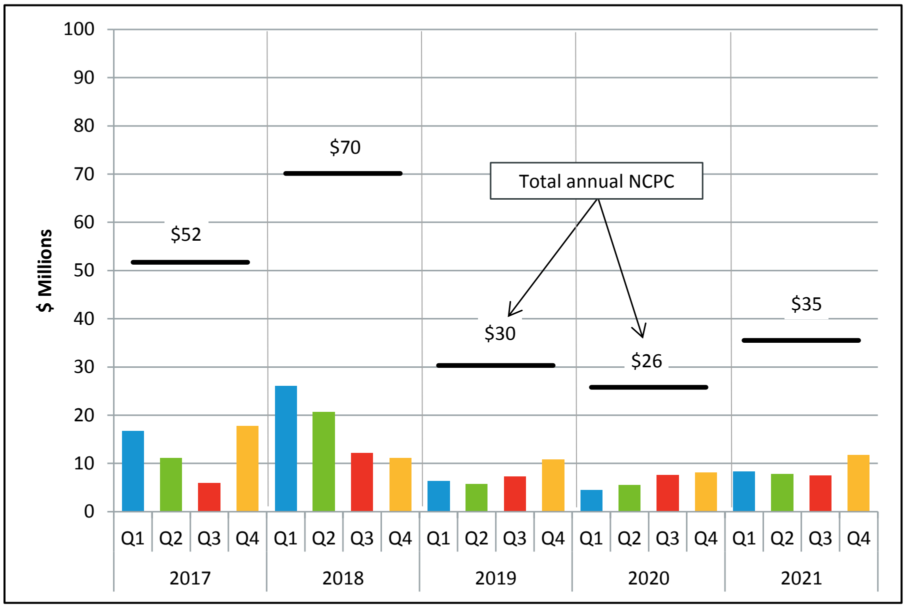
Uplift Payments by Quarter

Uplift payments can vary significantly by season for a number of reasons, including fluctuating fuel prices, diverse load conditions, the timing of major transmission or generator outages, and other factors. Quarterly total uplift payments for 2017 through 2021 are shown in Figure 3-38 below. The colored bars illustrate the quarterly uplift totals (Q1 is blue, Q2 is green, Q3 is red, and Q4 is yellow) and the black lines above the bars correspond to total annual uplift payments for that year.

[218] See Section 3.4.9 for further details on reliability commitments and posturing actions. See Section 5.3 for further details on external transaction uplift payments.

[219] See Section 3.4.9 for further details on reliability commitments and posturing actions.

Figure 3-38: Total Uplift Payments by Quarter

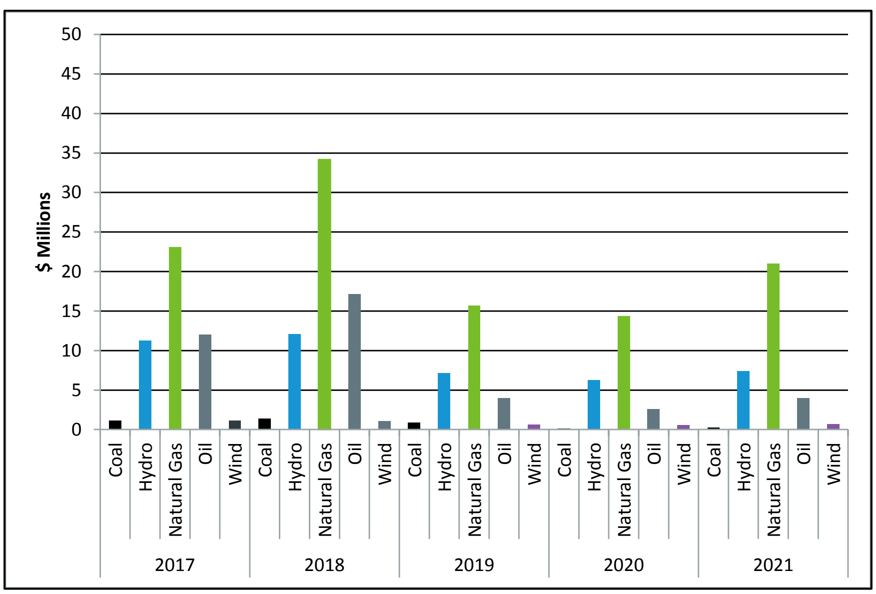


Similar to 2020, uplift payments by quarter continued to flatten out in 2021. The highest 2021 total uplift payment occurred in Q4, while the remaining three quarters were consistent across quarters at approximately $8 million each quarter. The slight variations across quarters was driven by reliability payment fluctuations. The increase in Q4 uplift payments was due to higher LSCPR payments, described above.

Uplift by Fuel Type

Total uplift payments by generator fuel type are shown in Figure 3-39 below.

Figure 3-39: Total Uplift Payments by Generator Fuel Type



The distribution of uplift payments by fuel type in 2021 is almost identical to 2020. Natural gas-fired and hydro generators received the majority (85%) of uplift payments because of their locational importance, both in the supply stack and geographically. These generators are often neither the least- nor most-costly generators, but are needed to ensure the reliable operation of the power system and are more economic to commit than very costly generators. Given some operational inflexibility (such as minimum run times), these generators may need to operate during hours when energy market prices do not allow them to fully recover their production costs.

Pumped-storage generators (part of the hydro category) continued to be the only fuel type that received posturing uplift payments ($0.6 million) in 2021. This is consistent with 2020 and 2019 but differs from 2018 when oil-fired generators received uplift credits during a cold snap. In 2021, coal-fired generators received the smallest amount of uplift in the reporting period, 0.7% ($0.2 million) of total uplift. Oil-fired generators received 1% more uplift in 2021 compared to 2020, up from 11% ($2.6 million) in 12% ($4.0 million). Lastly, wind generators first started receiving relatively small amounts of uplift in 2017 and have received a steady 2% of total uplift payments (between $0.2 million and $1.1 million) every year since. These payments are mainly comprised of dispatch lost opportunity cost payments, which are paid when resources are instructed to run at levels below their economic dispatch point.

3.6 Demand Response Participation in the Energy and Capacity Markets

On June 1, 2018, the ISO implemented the Price-Responsive Demand (PRD) program to integrate demand response resources into the day-ahead and real-time energy markets in order to comply with FERC Order 745 (Demand-Response Compensation in Organized Wholesale Energy Markets).[220] This program allows demand response resources to submit demand reduction offers into the day-ahead and real-time energy markets. With the program change, the ISO now commits and dispatches demand resources in the energy market based on economics, with these resources being eligible to set price. Demand resources also provide operating reserves, in a manner similar to traditional generators. Along with energy market integration, the capacity market now treats active demand resources similarly to other resources, with demand response capacity resources having a must-offer obligation in the energy market.

In 2021, 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 2021; on average, 95% of offers have been priced above $200/MWh since the program's implementation;
    - Given offer prices, dispatch of these resources averaged just 5.6 MW in the day-ahead energy market and 6.4 MW in the real-time energy market in 2021;[221]
    - These resources also provided operating reserves in 2021, averaging 0.4 MW per hour of ten-minute reserves and 299 MW per hour of thirty-minute reserves; and,

[220] Prior to June 1, 2018, demand response resources participated in the ISO's energy markets (1) as emergency resources activated during OP4 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.

[221] The data are annual averages for all hours in the year, including hours with 0 MWs of dispatch.

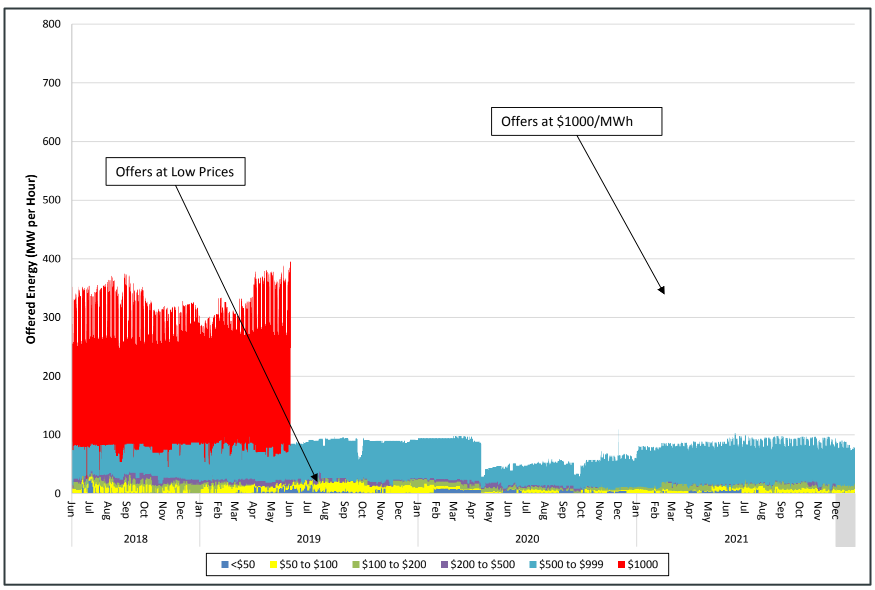
- With low dispatch levels and infrequent thirty-minute reserve pricing in 2021, energy revenues totaled just $1.7 million in the day-ahead energy market, while energy and reserve revenues totaled $0.8 in the real-time energy market and NCPC payments totaled 0.2 million for both markets.

- PRD resources represented a modest amount of overall capacity procured in the ISO's forward capacity market:
  - PRD resources provided approximately 502 MW of capacity supply obligation (CSO) on average in calendar year 2021, an increase of 64 MW over the prior calendar year;
  - PRD resources accounted for 1.5% of CSOs acquired in FCA 12; and,
  - Capacity payments provided to these resources totaled approximately $29 million in 2021.[222]

3.6.1 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).[223] 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.

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 83% in 2020. In most hours, only the lower tiers of offered capacity ($200/MWh or less) have a reasonable likelihood of being

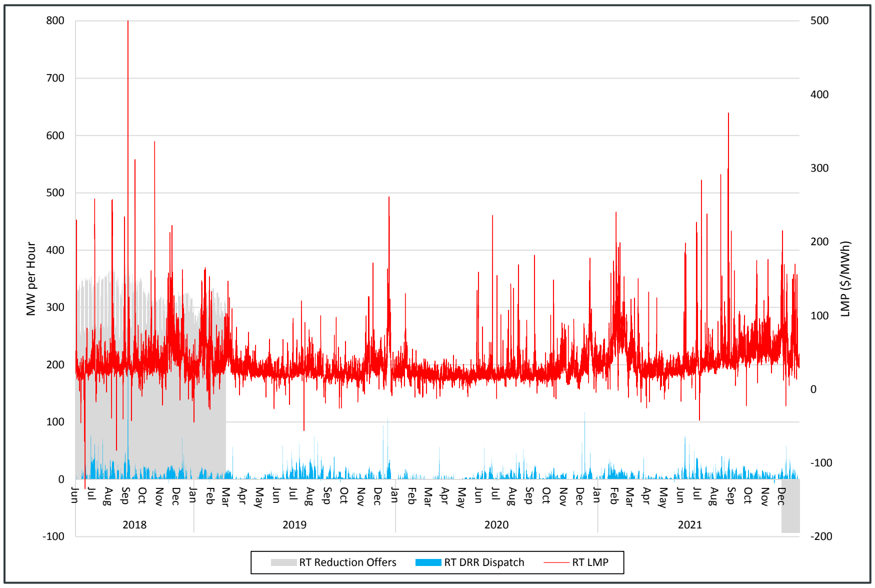
[222] This is a simple estimate that assumes all obligations received the primary auction clearing price.

[223] 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.

dispatched in the real-time energy market; these offers did not exceed 10% of offered demand reduction capacity in any hour of 2020 or 2021, and averaged just 4% of offered capacity.[224]

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-ahead energy market, relative to resources' offered reductions and hourly energy prices since the implementation of PRD in 2018.

Figure 3-41: Demand Response Resource Dispatch in the Real-Time Energy Market[225]



The maximum hourly quantity of demand response capacity dispatched in the real-time energy market was 75.7 MW in 2021 and 117 MW in 2020. While demand resources were dispatched frequently in the real-time market – in 52% of hours in 2021 and 36% of hours in 2020 – the dispatch level was very small, averaging just 6.4 MW in 2021 and 4.3 MW in 2020.

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. 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.[226] 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). In 2021, DRRs provided only 0.4 MW per hour, on average, of ten-minute operating reserves, but provided substantially more in thirty-minute operating reserves (TMOR), averaging 299 MW per hour. In 2020, ten-minute reserve designations were not substantially different, equaling 0.9 MW on

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224 Energy prices in the real-time market exceeded $200/MWh in just 0.3% of pricing intervals in 2021 and 0.2% over the review period.

225 The right vertical axis (LMPs) has been truncated to improve the figure's legibility. During the September 3, 2018 shortage event, real-time LMPs exceeded $500/MWh. The truncation obscures the magnitude of those prices, which reached as high as $2,677/MWh.

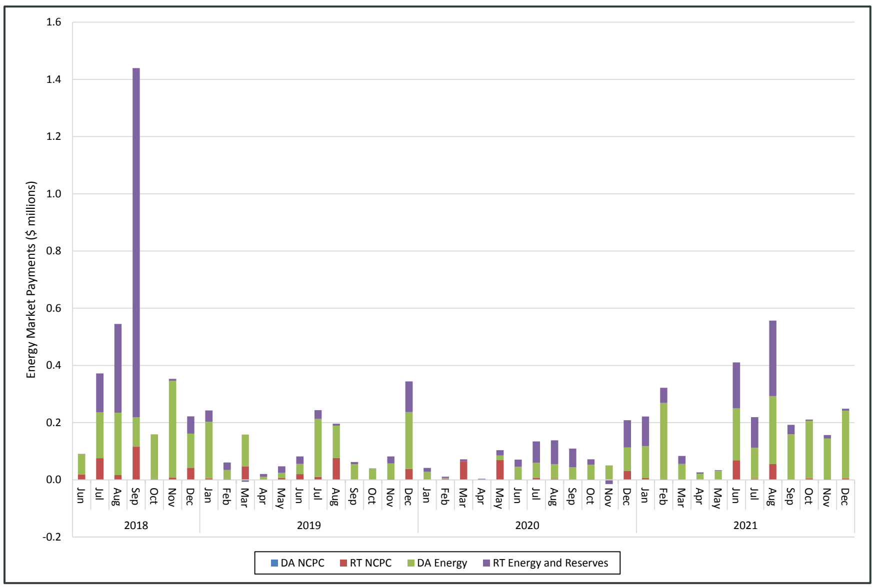
226 These operating constraints are: total start-up time (including notification time) of less than or equal to 30 minutes, minimum time between reductions and a minimum reduction time of less than or equal to 1 hour, and a "claim 30" (30-minute reserve capability) greater than 0.

average; thirty-minute operating reserves (TMOR) for 2020 equaled 266 MW per hour – 13% less than in 2021 (partially as a result of new capacity added in 2021).

3.6.2 NCPC and 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-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.[227] Payments for NCPC represent just 10% of total energy market compensation for DRRs, and total energy payments for 2021 were only $2.7 million. (This compares to energy market payments of $6 billion for all resources during the full year.) Except for the elevated real-time energy market payments in August and September 2018 (resulting from a few hours of high reserve prices [August] and the capacity scarcity event [September]), day-ahead market payments have been the largest source of energy market revenue for DRRs over the review period.[228] The somewhat elevated winter and summer energy payments to DRRs resulted from periods of higher energy prices that resulted in increased dispatch.

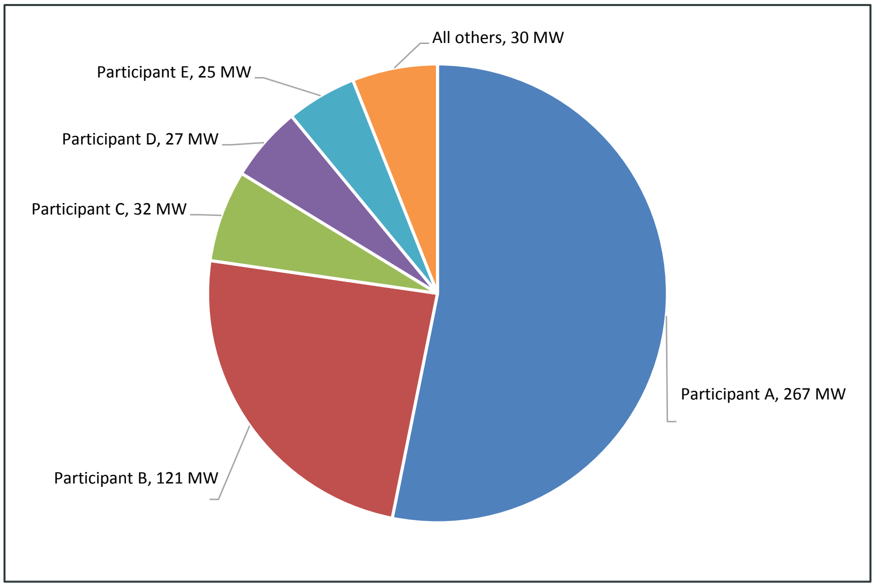
[227] Energy market payments include payments for MWh provided to satisfy the energy market's energy and reserve needs (labelled "DA Energy" and "RT Energy and Reserves" in the figure) and uplift payments when energy and reserve revenues are insufficient to cover all of the costs of providing energy and reserves (labelled "DA NCPC" and "RT NCPC" in the graph).

[228] Earlier versions of the graph did not include operating reserve revenues. Except for August and September 2018 (with operating reserve payments of approximately $200,000 per month), the inclusion of those revenues does not have a material impact on the previously-presented data.

3.6.3 Capacity Market Participation under PRD

For the Forward Capacity Market, DRRs had capacity supply obligations (CSOs) totaling approximately 502 MW in 2021, up by 64 MW (15%) compared to 2020.[229] These resources are called "Active Demand Capacity Resources" (ADCR) for capacity market purposes. All active demand resources with capacity market obligations are required to offer "physically available" capacity into the day-ahead and real-time energy markets.[230] Figure 3-43 indicates the CSO by participant for ADCRs.

Figure 3-43: CSO by Lead Participant for Active Demand Capacity Resources



Just nine participants had CSOs in calendar year 2021; the two largest participants accounted for approximately 77% of ADCR capacity supply obligations. Capacity market compensation for the delivered obligations has totaled about $29 million, or about 11 times the amount of energy market compensation received by these resources.[231]

3.7 Market Structure and Competitiveness

Administering competitive wholesale energy markets is one of ISO New England's three critical roles. A competitive energy market is crucial to ensuring that consumers are paying fair prices that incent short-run and long-run investment that preserves system reliability. This section presents an evaluation of energy market competitiveness in New England. It covers (1) opportunities to

[229] The CSO estimate indicates the average capacity supply obligation for the calendar year.

[230] The relationship between demand response resources (DRRs) and active demand capacity resources (ADCRs) is somewhat complicated. DRRs are mapped to ADCRs. More than one DRR can be mapped to an ADCR, which holds the capacity supply obligation. To satisfy the ADCR's capacity supply obligation, DRRs mapped to an ADCR need to offer demand reductions into the energy market at an aggregate level consistent with the parent ADCR's capacity supply obligation.

[231] The FCM compensation estimate focuses just on the payments for the actual obligation that these resources needed to deliver in 2021. It does not take into account any payment gains or losses that might have occurred from altering obligations through FCM bilateral and reconfiguration activities.

exercise market power, (2) the market impact of uncompetitive (i.e., above cost) offers, and (3) measures to prevent the exercise market power.

Opportunities for market participants to exercise market power are examined using several metrics: the C4, the pivotal supplier test (PST), and the residual supply index (RSI). The C4, the combined market share of the four largest participants, is a measure of market concentration. In this section it is applied to both supply and demand to assess the level of structural competition in New England. Both the PST and RSI are widely used metrics to identify potential opportunities for the largest supplier to exercise market power at any given time. The RSI represents the percentage of demand that can be met without energy from the largest supplier's portfolio of generators. If the value is less than 100%, the largest supplier is necessary to meet demand and could potentially exercise market power, if permitted. Further, if the RSI is less than 100%, there is one or more pivotal suppliers.

The Day-Ahead Price-Cost Markup is presented to estimate the *impact* of uncompetitive offer behavior in the day-ahead energy market. To produce the Day-Ahead Price-Cost Markup generator offers are replaced with estimates of each generator's marginal cost and LMPs are re-simulated. The resulting value is an estimate of the LMP premium that is attributable to generators marking up their offers above marginal cost.

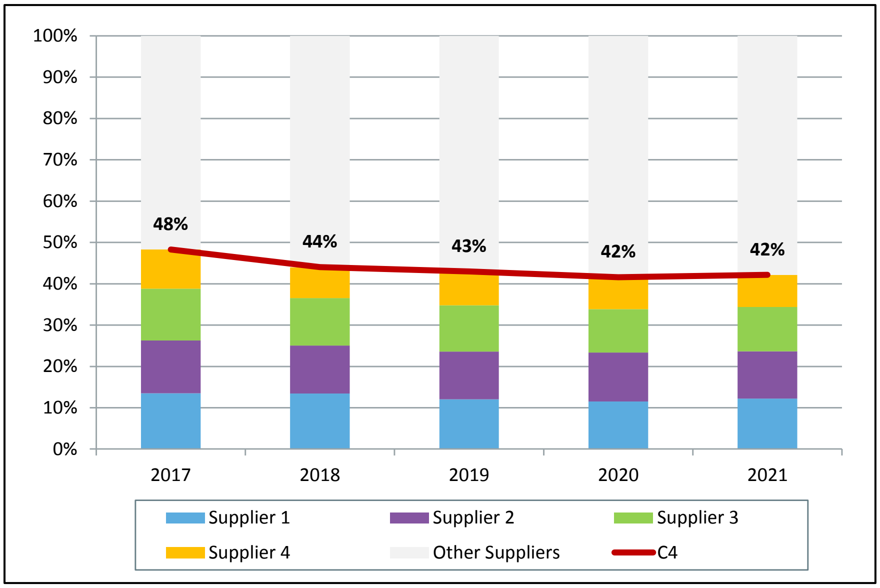
The IMM administers market power mitigation rules in the energy market to prevent potentially harmful effects of the exercise of market power. Mitigation is discussed at the end of this section.

3.7.1 C4 Concentration Ratio for Generation

This subsection analyzes supplier market concentration among the four largest firms controlling generation and scheduled import transactions in the real-time energy market. This 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.

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. As shown in Figure 3-44 below, the C4 value for 2021 remained at 42% from the prior year and remained below the average for 2017–2020 (i.e., 44.2%).

Figure 3-44: Real-time System-wide Supply Shares of the Four Largest Firms

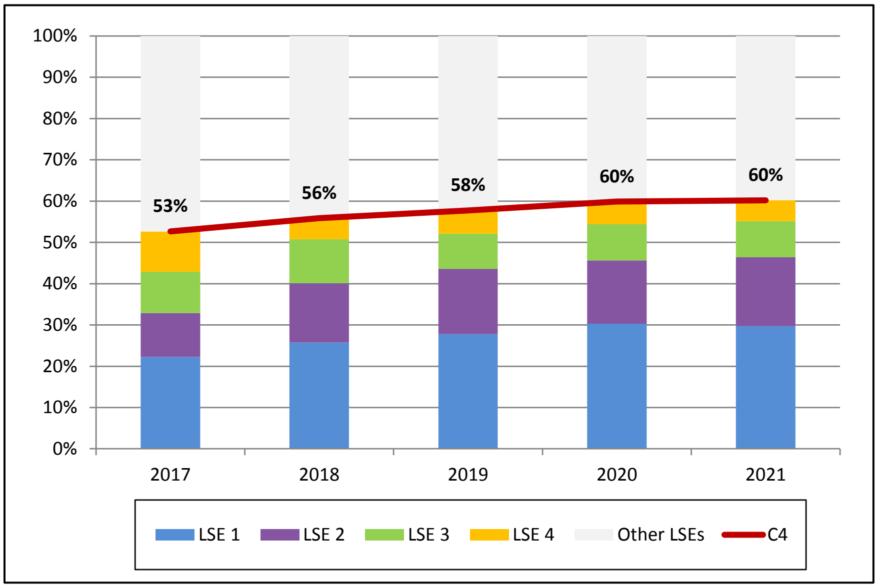


The C4 values of the last five years range between 42-48%, indicating low levels of system-wide market concentration in New England, particularly because the market shares are not highly concentrated in any one company. In 2021, the total on-peak supply of generation and imports was about 66,200 GWh, of which about 27,900 (42%) came from the four largest suppliers. The red C4 trend line in Figure 3-44 shows no clear trend in the concentration ratio over the past five years. No one company maintains a dominant share of on-peak supply, and the split among the top four suppliers has remained stable.

3.7.2 C4 Concentration Ratio for Load

This section takes the same C4 metric discussed in the previous section and applies it to real-time load. The C4 for load measures the market concentration among the four largest load-serving entities (LSEs) in the real-time energy market. It also accounts for any affiliations among different LSEs. Figure 3-45 presents the results of the market share of the four largest LSEs along with the rest of market share during on-peak hours.

Figure 3-45: Real-time System-wide Demand Shares of the Four Largest Firms



Note: 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.

In 2021, the real-time load obligation (RTLO), or the amount of electricity purchased, was 60,769 GWh.[232] Overall, the four largest LSEs served 60% (36,595 GWh) of total load, equivalent to their share in 2020. The red C4 trend line in Figure 3-45 shows that the total load share of the four largest LSEs has increased slightly over the past five years. The increase is largely due to one participant obtaining a larger share of load over the last five years.

The C4 analyses presented here and in the previous section do 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 raise prices for their generation would come at a cost to their load position. Any actions that would suppress prices for load would come at a cost to their generation position.

The observed C4 values presented above indicate relatively moderate 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 any energy market bidding behavior that would suppress prices. Over 100% of demand clears in the day-ahead market and the aggregate demand curve is relatively price-insensitive around expected LMPs (see Section 3.4.5 on Demand Bidding).

3.7.3 Residual Supply Index and the Pivotal Supplier Test[233]

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). Both

[232] 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.

[233] 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.

of these widely-used metrics identify instances when the largest supplier has market power.[234] 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 exercise market power if permitted. Further, if the RSI is less than 100, there is one or more pivotal supplier. 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[235] to the sum of each participant's total supply that is available within 30 minutes.[236] 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 3-9 below.

Table 3-9: Residual Supply Index and Intervals with Pivotal Suppliers (Real-time)

Year	% of Intervals With At Least 1 Pivotal Supplier	RSI
2017	55.7%	99.6
2018	30.7%	103.6
2019	14.7%	106.4
2020	16.6%	106.9
2021	18.0%	106.0

There were significantly fewer five-minute intervals with pivotal suppliers in 2019-2021 than in 2017-2018. This indicates that suppliers faced relatively more competition during the three most recent years compared to the two earlier years. The reduction in the number of intervals with at least one pivotal supplier was driven higher total 30-minute reserve margins in 2019-2021.

Higher supply margins are evident in the higher level of 30-minute operating reserves in 2019-2021 compared to the other years in the reporting period. Supply margins can fluctuate for several

[234] 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.

[235] 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*]

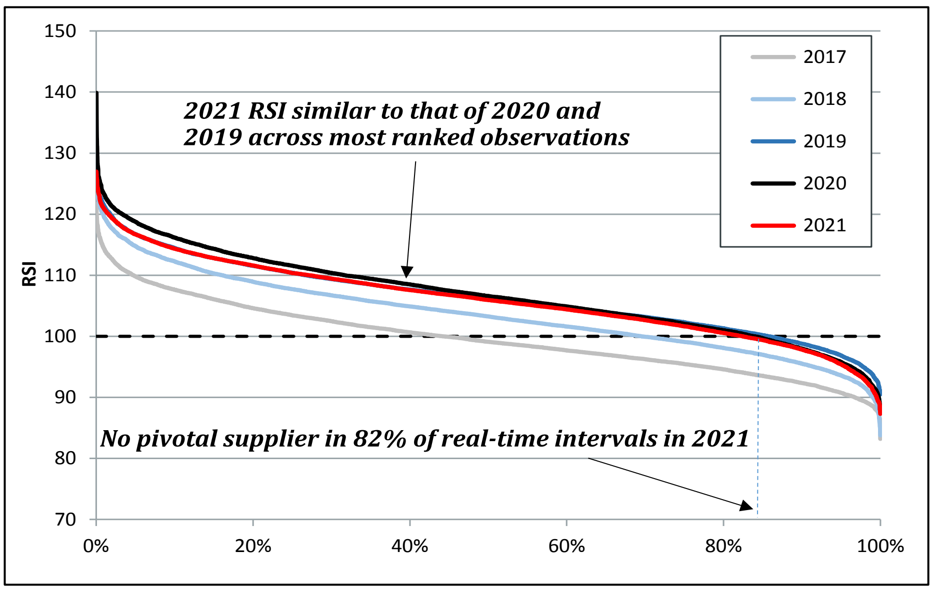
[236] This is different from the pivotal supplier test performed by the mitigation software, which does not consider ramp constraints when calculating available supply for each participant. Additionally, the mitigation software determines pivotal suppliers at the hourly level.

reasons, including generator outages, resource additions or retirements, and changes in the reserve requirement. In 2019, the average total 30-minute reserve surplus was 3,086 MW, up from 2,200-2,810 MW during 2017-2018. The increase was driven by additional off-line reserves from new generators and demand response resources. In 2020 and 2021, the average total 30-minute reserve surpluses were similar to the 2019 value, at 3,050 and 3,090 MW, respectively. Section 3.4.7 provides additional information on reserve margin trends. When reserve margins are higher, it is less likely that the available capacity of any one supplier is needed to satisfy load and reserve requirements.

There were no significant changes in participant portfolios from 2019-2021. Market concentration and opportunities to exercise market power can increase if participants with large capacity volumes merge, but no notable activity occurred during the past three years. The C4 concentration ratio for generation, discussed in Section 3.7.1, was 42% in 2021, the same value as in 2020.

Duration curves that rank the average hourly RSI over each year in descending order are illustrated in Figure 3-46 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 3-46: System-wide Residual Supply Index Duration Curves



Like the pivotal supplier statistics, Figure 3-46 shows that there was greater availability of competitive supply in 2019-2021 compared to the earlier two years in the reporting period. The RSI was above 100 in 82% of real-time intervals in 2021, which was very similar to the 2020 result (84%).

3.7.4 Day-Ahead Price-Cost Markup[237]

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

[237] This section was titled "Lerner Index" in previous reports. The name was changed to better reflect the methodology behind the metric.

costs. 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. Since market competition incentivizes participants to offer at marginal cost, the price-cost markup provides insight into market power and competitiveness. Uncompetitive offers priced above marginal cost can distort prices and impact generator commitment decisions, leading to inefficient market outcomes.

To calculate price-cost markup, the IMM simulated the day-ahead market clearing using two scenarios:[238]

- 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.[239]

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.

[238] 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.

[239] 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.

The annual day-ahead price cost markup values from the simulation are shown in Table 3-10 below.

Table 3-10: Day-Ahead Price-Cost Markup, %

Year	Price-Cost Markup
2017	4.9
2018	4.9
2019	6.6
2020	7.6
2021	8.4

The 2021 price-cost markup for the day-ahead energy market remained relatively low (below the most strict mitigation threshold of 10%) at 8.4%. This indicates that offers above marginal cost increased the generation-weighted day-ahead energy market price by approximately 8.4%. This result is similar to 2020, and is consistent with normal year-to-year variation given modeling and estimation error.[240] This indicates that competition among suppliers in the day-ahead market limited their ability to inflate LMPs by submitting offers above marginal cost.

This analysis also calculated 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 by increasing offer markups during those times. There was no meaningful correlation between the price-cost markup and the supply margin in 2021, indicating that the day-ahead market remained competitive even when the ISO expected supply margins to be low and market power was present.

3.7.5 Real-Time Economic Withholding

This subsection assesses the degree of economic withholding in the real-time energy market. Economic withholding occurs when suppliers offer above marginal cost in order to prevent some quantity 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).[241]

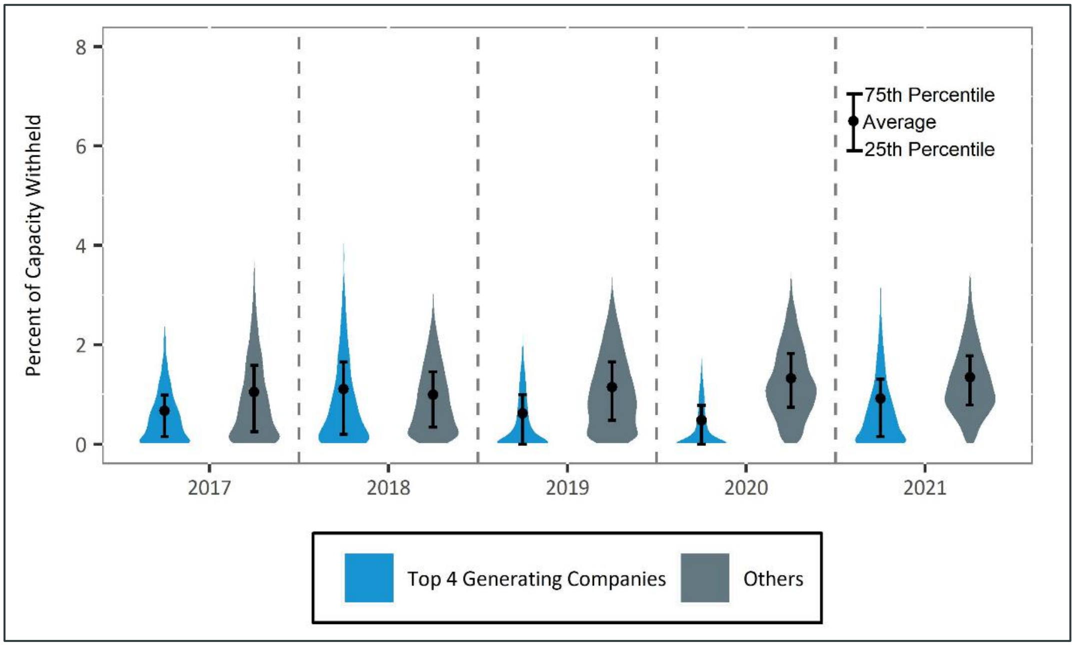
In cases where the quantity offered exceeds the quantity that was economic, the withheld MWs are set to zero (i.e., withheld MWs cannot be negative). This analysis considers only non-fast-start generators that are online and all fast-start generators (online or offline), and it does not assess potential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

[240] 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.

[241] 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.

Hourly economic withholding (as a percent of capacity) during on-peak hours in each of the past five years is summarize in Figure 3-47 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.

Figure 3-47: Hourly Real-time Economic Withholding During On-Peak Hours



Note: The curves depict the distribution of hourly real-time economic withholding observed during each year; the wider sections of each curve indicate the levels of withholding that occurred more frequently, while the thinner sections imply lower frequently.

In 2021, 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.

3.8 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.[242] Under certain conditions, the IMM will mitigate generator 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

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

pricing (LMPs) and uplift payments (NCPC) from participant offers that appear to overstate a generator's operating costs.

Appendix A of the ISO's Market Rule 1 outlines the circumstances under which we may mitigate energy market supply offers.[243] These circumstances are summarized in Table 3-11 below.

Table 3-11: Energy Market Mitigation Types

Mitigation type	Structure test	Conduct test threshold	Impact test
General Threshold Energy (real-time only)	Pivotal Supplier	Minimum of $100/MWh and 300%	Minimum of $100/MWh and 200%
General Threshold Commitment (real-time only)	Pivotal Supplier	200%	n/a
Constrained Area Energy	Constrained Area	Minimum of $25/MWh and 50%	Minimum of $25/MWh and 50%
Constrained Area Commitment (real-time only)	Constrained Area	25%	n/a
Reliability Commitment	n/a	10%	n/a
Start-Up and No-Load Fee	n/a	200%	n/a
Manual Dispatch Energy	n/a	10%	n/a

We administer seven types of ex-ante supply offer mitigation, and apply up to three criteria when determining whether to mitigate a supply offer.[244] The criteria are:

- *Structural test:* Represents a determination that market circumstances may confer an advantage to suppliers. This may result from (1) a supplier being "pivotal" (i.e., load cannot be satisfied without that supplier) or (2) a supplier operating within an import-constrained area (with reduced competition).
- *Conduct test:* Represents a determination that the financial parameters of a supply offer appear to be excessively high, relative to a benchmark offer value (a "reference" value).[245] The conduct test applies to all mitigation types.
- *Impact test:* Represents a determination that the original supply offer would have a significant impact on energy market prices (LMPs).[246] This test only applies to general threshold energy and constrained area energy mitigation types.

There is one additional mitigation type specific to dual-fuel generators not listed in Table 3-11 above or summarized in Figure 3-48. Dual-fuel mitigation occurs after-the-fact (ex-post) in cases

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[243] See Market Rule 1, Appendix A, Section III.A.5.

[244] Ex-ante mitigation refers to mitigation applied prior to the finalization of the day-ahead schedules and real-time commitment/dispatch. There is one additional mitigation type specific to dual-fuel generators not listed in the summary Table. Dual-fuel mitigation occurs after-the-fact when the supply offer indicates a generator will operate on a higher-cost fuel than it actually uses (e.g., if offered as using oil, but the generator actually runs using natural gas). This mitigation will affect the amount of NCPC (uplift) payments the generator is eligible to receive in the market settlements.

[245] See Market Rule 1, Appendix A, Section III.A.7, regarding the determination of reference values.

[246] For a description of the application of these mitigation criteria (tests), see Appendix A, Section III.A.5.

where the supply offer indicated a generator would operate on a higher-cost fuel than it actually used (e.g., if offered as using oil, but the generator actually ran using natural gas). This mitigation will affect the amount of NCPC payments the generator is eligible to receive in the market settlements. A discussion of this mitigation type is provided at the end of this section.

Energy Market Mitigation Frequency

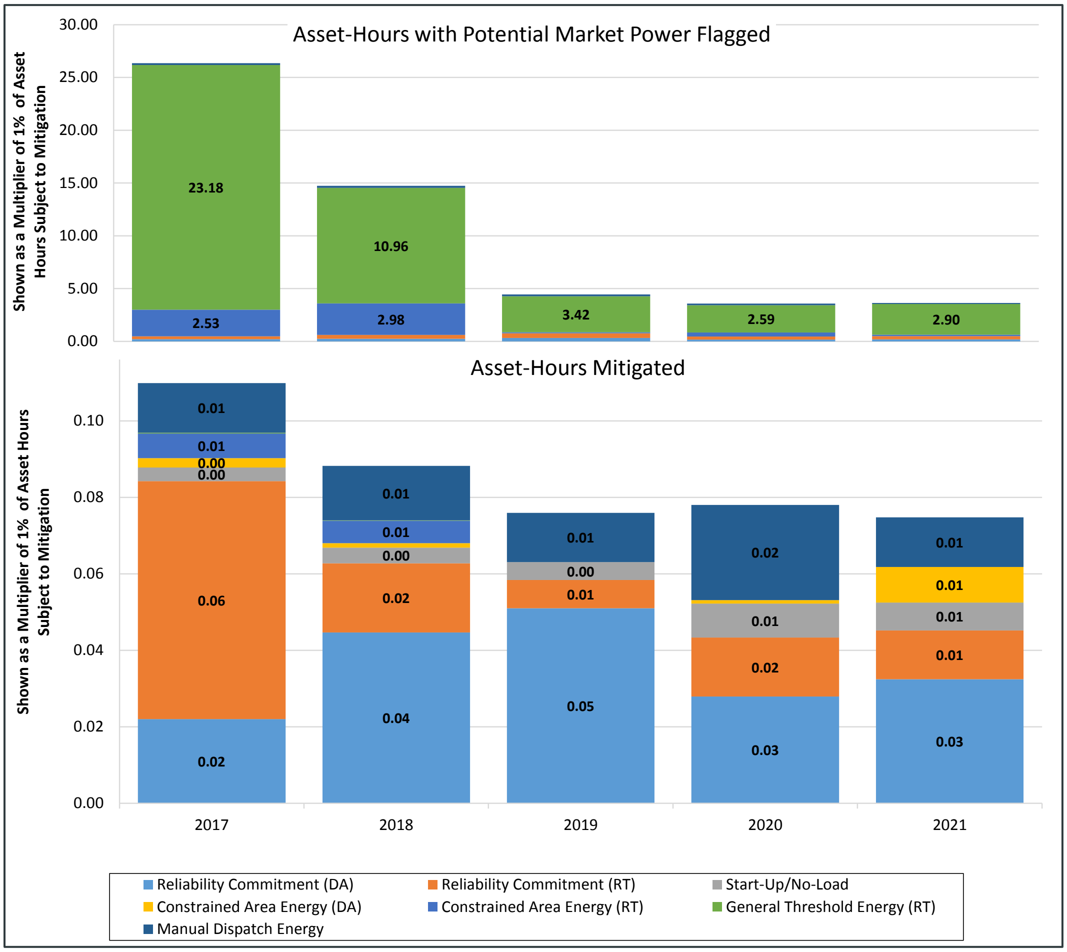
Energy market supply offers are mitigated only when an offer has failed all applicable tests for a particular mitigation type. This section summarizes three types of mitigation data: "structural test" failures, generator commitment or dispatch hours, and mitigation occurrences. The structural test represents an initial condition for applying conduct and market impact mitigation tests for generators in constrained areas or associated with pivotal suppliers (general threshold energy mitigation). For other mitigation types, the commitment or dispatch of a generator triggers the application of the conduct test, when determining whether to mitigate a supply offer.

An indication of mitigation frequency, relative to opportunities to mitigate generators, is illustrated in Figure 3-48 below.[247] 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.[248]

[247] 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.

[248] The reporting in this section has been updated, to align it with IMM's reporting of mitigation outcomes in the Quarterly Markets Report.

Figure 3-48: Energy Market Mitigation[249]



On average, approximately 1.2 million asset-hours of ISO-committed generation are subject to the IMM's mitigation rules each year. In 2021, the total asset-hours reached 1.3 million asset-hours, with approximately 44,000 asset-hours (3.4%) failing structural tests; scaling results to 1% of total asset hours, there were approximately 13,000 asset-hours (1% of 1.3 million) subject to mitigation by the IMM. Structural test failures scaled to 1% equal 3.4 (i.e., 44,000/13,000), the height of the 2021 bar graph in "asset hours with potential mitigation flagged" in Figure 3-48.

Mitigation asset-hours represented a very small fraction of potential asset hours subject to mitigation. In the figure, day-ahead reliability commitment mitigation totaled just 415 asset-hours for 2021, equaling 0.03 of asset-hours scaled to 1% (i.e., 415/13,000).

In general, the data in Figure 3-48 indicate that mitigation occurs very infrequently relative to the initial triggers for potential mitigation: ISO commitment and operation of a generator and energy

[249] Because the general threshold commitment and constrained area commitment conduct tests resulted in only eight asset hours 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.

market mitigation thresholds (i.e., structural test failures, commitment or dispatch). The highest frequency of mitigation occurs for reliability commitments (light blue or orange shading); this results from a relatively tight conduct test threshold, with any participant supply offer more than 10% above the IMM's reference offer value being mitigated. General threshold (pivotal supplier) mitigation and constrained area mitigation (green, dark blue, and yellow shading) have had the lowest mitigation frequency at close to 0% over the review period. 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 (such as local second contingency protection).[250] These commitments frequently reflect the reliability needs associated with transmission line outages and upgrades, as well as very localized distribution system support. Over the review period, Maine and Southeastern Massachusetts Rhode Island (SEMA-RI) have had the highest frequency of reliability commitment asset-hours, 33% and 32% respectively in the day-ahead energy market. This is consistent with transmission upgrades that occurred in SEMA-RI over the review period, and with the frequency of localized transmission issues within Maine. Reliability commitment mitigations also occurred most frequently in Maine and SEMA-RI; 45% of mitigations occurred in Maine and 35% occurred in SEMA-RI in the day-ahead market.[251] Overall, reliability mitigations declined significantly since 2019 (172 asset-hours). This decrease resulted from both a decline in reliability commitment asset-hours (decline from 3,765 to 2,439 asset-hours) and of mitigated offers in Maine and SEMA-RI (decline of 540 to 250 asset-hours).

Start-up and no-load (SUNL) commitment mitigation: This mitigation type, like reliability commitments, occurs based on a generator's commitment and does not rely on a structural test failure. It uses a very high conduct test threshold (200% applied to the start-up, no-load, and offer segment financial parameters) to guard against the potential commitment of generators that are not covered by other mitigation types and that appear to have grossly over-stated their commitment costs (relative to reference values).[252] Grossly over-stated commitment costs are likely to lead to unnecessary uplift payments. These mitigations occur very infrequently and may reflect a participant's failure to update energy market supply offers as fuel prices fluctuate. Almost all of the generators (greater than 99%) subject to this mitigation over the review period had natural gas as a primary fuel type, and generators associated with just three participants accounted for 83% of these mitigations. There were just 93 asset-hours of SUNL mitigation in 2021.

Constrained area energy (CAE) mitigation:[253] This mitigation type applies three tests prior to mitigation: structural, conduct and market impact. With relatively tolerant conduct and market impact test thresholds, the frequency of mitigation is low relative to the frequency of structural test failures. The frequency of mitigation given a structural test failure (i.e., generator located in an

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[250] 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.

[251] 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.

[252] 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.

[253] 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.

import-constrained area) in the real-time energy market has been approximately 0% (of structural test failure asset-hours) over the review period, as only 136 asset-hours of CAE mitigation have occurred in the real-time energy market and only 170 asset-hours of mitigation have occurred 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. Over the review period, 69,000 asset-hours of structural test failures occurred; most of the failures occurred prior to 2019 (89%, 61,000 asset hours). The 2021 failures totaled just 1,887 asset-hours of failure and were located predominantly in Connecticut and SEMA. The higher levels of structural test failures prior to 2019 reflected transmission work in a number of load zones and a prolonged cold snap in 2018, both resulting in localized transmission congestion.

General threshold energy mitigation: This mitigation type also applies three tests prior to mitigation. This mitigation type has the lowest frequency of any mitigation type, because it also has the most tolerant conduct test and market impact thresholds of any mitigation type. General Threshold energy mitigation occurred for only three asset-hours over the review period. This happened in spite of the highest frequency of structural test failures (i.e., pivotal supplier asset-hours) for any mitigation type (totaling 483,000 asset-hours) for the review period. As expected, structural test failures tend to occur for lead market participants with the largest portfolios of generators. Five participants accounted for 68% of the structural test failures over the review period. The frequency of pivotal supplier asset-hours has decreased significantly since 2018; 2017 and 2018 accounted for 78% of structural test failures. The decline in asset-hours for pivotal suppliers resulted principally from higher supply margins in later periods; the decline did not result from significant changes in participant portfolios.

Manual dispatch energy mitigation: Manual dispatch energy mitigation can occur when a generator is manually dispatched by the ISO. Behind reliability commitment mitigation, this mitigation type occurs with the second highest frequency of any mitigation type (accounting for 18% of mitigations over the review period). Like reliability commitment mitigation, manual dispatch energy mitigation has a relatively tight conduct test threshold (10%). The dispatch hours for this mitigation type, shown in Figure 3-48, simply refer to asset-hours of manually-dispatched generators in the real-time energy market. As these data indicate, manual dispatch is relatively infrequent in the real-time energy market, with typically fewer than 2,000 asset-hours occurring each year. Combined-cycle generators have the highest frequency of manual dispatch (88%); 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. In 2021, there were 1,328 asset-hours of manual dispatch and 166 asset-hours of mitigation.

Dual-fuel ex-post mitigation: Dual-fuel mitigations occur relatively infrequently. They accounted for just 522 asset-hours of mitigation over the review period, and typically total fewer than 100 asset-hours of mitigation per year. In 2021, only 33 asset-hours of dual-fuel mitigation occurred. Dual-fuel mitigations were at a relatively high level in 2020, with 335 asset-hours. This resulted from two participants using third-party software to adjust their energy market offers. The third-party software incorrectly stated the fuel type associated with energy market offers entered into the ISO's data systems. This resulted in the need to mitigate generator offers after the fact, to ensure that uplift payments were not overstated.

Section 4
Virtual Transactions and Financial Transmission Rights

This section discusses trends in the use of two important financial instruments in the wholesale electricity markets: virtual transactions and financial transmission rights (FTRs).

The first instrument is a virtual transaction. Virtual transactions are financial bids and offers that allow participants to take a position on differences between day-ahead and real-time prices. Virtual transactions can improve market performance by helping converge day-ahead and real-time market prices. That is, virtual transactions can help ensure that the forward day-ahead market reflects expected spot prices in the real-time market, especially where systematic or predictable price differences may otherwise exist between them. 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.

In general, participants cleared similar levels of virtual transactions in 2021 compared to the prior three years. However, cleared volumes remained higher than 2017 as market rule changes and lower uplift charges have created profit opportunities for virtual transactions. Virtual supply transactions yielded high net profits in 2021, but virtual demand transactions resulted in large net losses. Virtual transactions are discussed in more detail in Section 4.1

The second type of financial instrument is a financial transmission right or "FTR". These rights provide participants with physical generation or load in New England's energy markets a way to manage the risks associated with transmission congestion in the day-ahead market. They also provide market participants a way to speculate on locational congestion differences in the day-ahead market. FTRs are purchased through ISO-administered auctions. Participants' expectations of congestion in the day-ahead market play a large role in the volume of FTRs that they choose to purchase in these auctions and the price that they pay for these rights.

While the average MW volume of FTRs in effect per hour in 2021 (32,443 MW) rose slightly from the level observed in 2020 (31,550 MW), the ISO was able to fully fund this volume of FTRs. The excess revenue that remained in the Congestion Revenue Fund (CRF) at the end of the year ($7.0 million) was distributed to those entities that had paid congestion costs during the year. In aggregate, FTR holders made a profit of $25.9 million in 2021. This is in contrast to the prior two years when FTR holders collectively lost $0.8 million (in 2020) and $10.5 million (in 2019). One important factor for this change in profitability was driven by participants' expectations for congestion over the New York – New England (NYNE) interface, which was one of the most frequently binding transmission constraints in the day-ahead market in 2021. Trends in FTRs are discussed in Section 4.2 below.

4.1 Virtual Transactions

The first subsection (4.1.1) provides an overview of virtual transactions and describes how they can benefit the wholesale energy market. However, transaction costs can hinder the benefits of virtual transactions. One of these costs comes in the form of Net Commitment Period Compensation (NCPC) charges. This is the topic of subsection 4.1.2. The third subsection (4.1.3) examines virtual transaction profitability and how NCPC charges affected that profitability.

One of the primary benefits virtual transactions can provide is to improve market efficiency, which, in this case, means achieving the necessary real-time generator commitments at the lowest possible cost. Market participants can, by pursuing profitable opportunities, use virtual transactions to converge day-ahead commitments closer to real-time commitments. Improved price convergence reflects this improved commitment convergence. The relationship between price convergence and virtual transaction volumes is examined in subsection 4.1.4. Lastly, subsection 4.1.5 summarizes several energy market rule changes over the last five years that likely had an impact on the use of virtual transactions.

Key Takeaways

In general, the volume of cleared virtual transactions in 2021 remained steady compared to levels from 2018 through 2020, but increased compared to levels from 2017. Cleared transactions rose from 810 MW per hour in 2017 to 966 MW per hour, on average, in 2021. Average cleared virtual supply increased by 19% (from 499 MW to 594 MW) and average cleared virtual demand increased by 20% (from 311 MW to 372 MW) over the five-year period. The increase in cleared virtual transactions was partially related to relatively low real-time economic NCPC charge rates over the reporting period. From 2017 through 2020, this rate averaged about $0.65/MWh, and averaged only $0.53/MWh in 2021. The charge rate ($0.53/MWh) did increase slightly compared to 2020 ($0.46/MWh). Despite the slight increase, virtual supply transactions still made an average net profit of $1.58/MWh in 2021. However, virtual demand transactions made a net loss of $1.83/MWh during the past year.

4.1.1 Virtual Transaction Overview

In the day-ahead energy market, participants submit virtual demand bids and virtual supply offers to profit from differences between day-ahead and real-time LMPs. One of the primary design goals of virtual transactions is that they can improve the day-ahead dispatch model to better reflect real-time conditions.[254] Virtual demand bids and supply offers that clear in the day-ahead market (based on participants' expectations of future real-time system conditions) can help improve the generator commitments made in the day-ahead market. To see this, we consider two examples.

In the first example, over-commitment in the day-ahead market leads to systematically *higher* day-ahead prices absent virtual transactions. In this case, virtual suppliers (who are profitable when day-ahead prices are higher than real-time prices) can offer supply at lower prices than physical generation, consequently displacing some of it. The cheaper cleared virtual supply offers drive the day-ahead price downward toward the real-time price. In the second example, under-commitment in the day-ahead market leads to systematically *lower* day-ahead prices. In this case, virtual demand (which is profitable when real-time prices are higher than day-ahead prices) clears at higher prices than physical demand, and more expensive generation must be committed to meet demand. This drives the day-ahead price higher and more in line with the real-time price. In general, profitable virtual transactions improve price convergence.

Virtual bids and offers can be submitted at any pricing location on the system during any hour. Virtual transactions clear in the day-ahead market like other demand bids and supply offers (see

[254] Virtual transactions provide other market benefits than those discussed here. One of the most significant benefits is their ability to mitigate both buyer-side and seller-side market power through enhanced levels of competition. Additionally, virtual transactions increase the liquidity of the day-ahead market, which allows more participants to take forward positions in the energy market. Further, participants can use them as a way to manage/hedge the price risks associated with delivering or purchasing energy in the real-time energy market.

Section 3 for more information). The ISO settles virtual transactions based on the quantity of cleared virtual energy and the difference between the hourly day-ahead and real-time LMPs at the location. Cleared virtual supply offers make a "gross" profit if the day-ahead price is greater than the real-time price (sell high, buy back low), and cleared virtual demand bids make a gross profit if the day-ahead price is less than the real-time price (buy low, sell back high).

4.1.2 Virtual Transactions and NCPC

The ISO allocates the following NCPC charges to cleared virtual transactions:[255]

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.
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.

In general, this section refers to "net" profit as the total profit after levying these two NCPC charges. These charges effectively serve as "transaction costs" for virtual transactions, reducing a virtual transaction's profit. Transaction costs can undermine price convergence when the expected magnitude in day-ahead to real-time price difference does not provide an adequate risk-adjusted return to offset the transaction costs.[256] For example, if the expected spread (or gross profit) is $1/MWh and the magnitude of NCPC charges (transaction cost) is uncertain, but may be greater than $1/MWh, then NCPC charges can discourage virtual participation, thus inhibiting price convergence. For the past number of years, the IMM has recommended reviewing the allocation of NCPC charges to virtual transactions to ensure the charges are consistent with principles of cost causation and do not present a barrier to price convergence.[257]

4.1.3 Virtual Transaction Profitability

Virtual transactions profit from spreads between day-ahead and real-time prices. However, NCPC charges can make otherwise profitable virtual transactions into unprofitable transactions on a net basis. This limits the ability of virtual transactions to close the spread between day-ahead and real-

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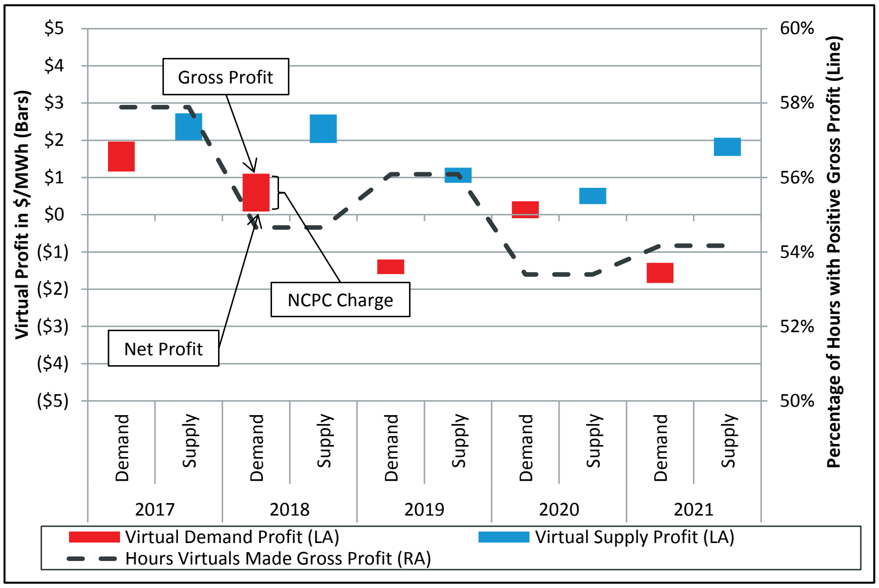
[255] Virtual transactions can also incur NCPC charges associated with congestion at the non-CTS (coordinated transaction scheduling) external interfaces. These charges are transfers between the participants causing the congestion and those relieving the congestion and are only applied to transactions that clear at these 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. However, they are accounted for in the determination of net profitability for virtual transactions in Table 4-1 and Table 4-2. The NCPC credits associated with alleviating congestion at these external interfaces are also accounted for in the determination of net profitability in these two tables.

[256] NCPC charges to cleared virtual transactions are calculated after the market has cleared. However, participants most likely have a sense of what their expected exposure to NCPC charges is before submitting their virtual transactions. Relationships drawn in this section presume participants are able to fairly accurately predict exposure to NCPC charges, which may not always be the case given the variability of such charges and the lack of information available to the participant in advance.

[257] For more information on recommended market design changes, see Section 8.1.

time prices.[258] Figure 4-1 illustrates the profitability of virtual transactions along with the impact of NCPC charges on profitability. The figure displays the average annual gross and net profit of virtual transactions since 2017 (left axis). The bars are categorized by year and 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. The net profits consider real-time economic NCPC charges for both virtual demand and virtual supply as well as day-ahead economic NCPC charges for virtual demand. Additionally, the dashed black line shows the percentage of hours each year in which virtual transactions were profitable on a gross basis (right axis).[259]

Figure 4-1: Average Annual Gross and Net Profits for Virtual Transactions



In 2021, only virtual supply made a gross profit, while virtual demand made a gross loss. Virtual supply made an average annual profit of $2.07/MWh, the highest gross profit since 2018 ($2.69/MWh) and $1.35/MWh greater than gross profit in 2020 ($0.72/MWh). Virtual demand lost an average of $1.29/MWh in gross profit, the lowest profit level over the reporting period and $1.65/MWh lower than 2020 ($0.36/MWh). The large difference in profit for virtual supply and virtual demand is consistent with the higher LMPs and a larger day-ahead price premium in 2021 ($1.08/MWh). Virtual transactions profited in 54% of all hours in 2021, a slight increase from 2020 (53%).

Average NCPC charges for virtual transactions increased slightly compared to 2020 (from $0.46/MWh to $0.53/MWh). NCPC charges largely remained in line with charges in the prior two years and well below levels prior to 2019 when generators received higher levels of NCPC payments. In 2021, virtual supply stayed profitable after the netting of NCPC charges, making a net

[258] The NCPC charges to cleared virtual transactions are calculated after the market has cleared. However, participants most likely have a sense of what their expected exposure to NCPC charges is before submitting their virtual transactions. Relationships drawn in the analysis here presume participants are able to fairly accurately predict exposure to NCPC charges, which may not always be the case given the variability of such charges and the lack of information available to the participant in advance.

[259] 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.

profit of $1.58/MWh, on average. Virtual demand made a net loss of $1.83/MWh, the largest net loss over the last five years.

Most Profitable Locations for Virtual Demand

The top 10 most profitable locations for virtual demand in 2021, after accounting for transaction charges and all relevant NCPC charges/credits, are shown in Table 4-1 below.[260] These locations are ranked by total net profit over the course of the year. The table also includes information about the volume of submitted and cleared MWhs of virtual demand bids at each location, the profitability per MWh and the number of participants submitting virtual demand bids at each location.

Table 4-1: 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
UN.BERLN_NH13.8BURG	Gen Node	42,084	14,294	$91	$85	$6.38	$5.93	9
AR.BEARSWMP13.8BSW2P	ARD Node	1,275	1,275	$37	$37	$28.89	$28.80	1
UN.BEARSWMP13.8BSW1	Gen Node	4,177	2,490	$32	$31	$12.97	$12.47	2
UN.BELFAST 34.5GEOR	Gen Node	30,640	29,564	$45	$30	$1.52	$1.02	2
.I.HQHIGATE120 2	Ext Node	29,338	1,227	$(8)	$28	$(6.54)	$23.15	3
UN.POTTER 13.8POT2	Gen Node	4,066	1,643	$15	$14	$9.01	$8.30	6
LD.SOTHNGTN13.8	Load Node	24,849	8,608	$8	$4	$0.95	$0.49	5
UN.WYMAN_HY13.8WYM1	Gen Node	341	277	$4	$3	$13.65	$12.58	3
UN.OAKFIELD34.5OAKW	Gen Node	27,905	8,332	$8	$3	$0.97	$0.42	8
LD.SONO 13.8	Load Node	419	419	$4	$3	$9.65	$8.29	1

The top 10 most profitable locations consisted mostly of nodes with low total profits and low trading activity during 2021. No location had a net profit over $85 thousand compared to 26 such locations for virtual supply. Additionally, eight of the top ten locations cleared less than one MW per hour on average throughout 2021. The most profitable node for virtual demand was UN.BERLN_NH13.8BURG, a location associated with a biomass generator in New Hampshire. Participants profited at this node during October 2021 and November 2021, when the Burgess Generation (BURG) interface bound frequently due to planned transmission work. At times, this interface would bind in the day-ahead market but not in the real-time market, leading to higher real-time prices and profit opportunities for virtual demand.

Unlike other profitable locations, virtual transactions at .I.HQHIGATE120 2 made a net profit despite losing money on a gross basis. This node represents the Highgate interface that connects New England to the Hydro Quebec control area. Typically, transaction costs associated with virtual transactions reduce profits. However, participants made a larger net profit at this location as they received external credits for relieving congestion at the external interface in the day-ahead market. Therefore, participants made a net profit of $28 thousand despite losing over $8 thousand on a gross basis.

[260] For more information about the additional charges for virtual transactions, see Schedule 2 of the ISO Funding Mechanism.

Most Profitable Locations for Virtual Supply

The top 10 most profitable locations for virtual supply in 2021, after accounting for transaction costs and NCPC charges/credits, are shown in Table 4-2 below. Again, these locations are ranked by total net profit.

Table 4-2: 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
.H.INTERNAL_HUB	Hub	999,761	773,360	$1,427	$1,017	$1.84	$1.31	22
.Z.SEMASS	Load Zone	476,380	407,311	$847	$637	$2.08	$1.56	13
UN.BULL_HL 34.5BLHW	Gen Node	180,852	119,269	$613	$553	$5.14	$4.64	16
.Z.MAINE	Load Zone	808,366	532,542	$779	$515	$1.46	$0.97	15
UN.BINGHAM 34.5BNGW	Gen Node	172,807	121,330	$549	$487	$4.53	$4.01	14
.Z.NEWHAMPSHIRE	Load Zone	298,321	252,792	$531	$406	$2.10	$1.61	11
.Z.NEMASSBOST	Load Zone	317,226	293,015	$522	$374	$1.78	$1.28	14
UN.BULL_HL 34.5HANW	Gen Node	73,021	57,121	$337	$309	$5.90	$5.40	11
.Z.RHODEISLAND	Load Zone	177,525	146,417	$352	$281	$2.40	$1.92	11
UN.BULL_HL 34.5WEVW	Gen Node	99,037	65,575	$301	$269	$4.58	$4.10	10

The 10 most profitable locations for virtual supply in 2021 fell into two major location types: (1) the Hub and load zones or (2) locations where wind power generators interconnect. On average, day-ahead LMPs were higher than real-time LMPs at the Hub and load zones in 2021. Therefore, participants made substantial profits by selling higher priced supply in the day-ahead market and buying out of their supply obligation at lower real-time prices at the hub and eight load zones.[261]

While virtual supply was profitable at all load zones, the five load zones in the top ten are located in the eastern half of New England. These five load zones saw larger profits than the other three load zones partly due to the New England West-East interface binding in the day-ahead market.[262] When that constraint binds, the eastern portion of New England experiences positive congestion pricing, resulting in higher LMPs compared to western New England. However, the New England West-East interface bound more frequently in the day-ahead market than the real-time market.[263] When this happens, LMPs in the eastern half of New England tend to be higher in the day-ahead market than the real-time market, leading to greater profit opportunities for virtual supply. While participants make larger profits at the Hub and load zones, profits per MWh tend to be lower due to the larger volumes and larger number of participants who trade virtual transactions at these nodes.

The rest of the top ten consisted of locations associated with wind power generation. All wind generators are part of the set of resources known as DNE dispatchable generators, or DDGs (these are generators that operate under the Do Not Exceed (DNE) dispatch rules discussed below). These locations tend to be the most profitable given the opportunity virtual participants have to take

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[261] .Z.WCMASS, .Z.VERMONT AND .Z.CONNECTICUT ranked 17, 22 and 23 in the most profitable locations for virtual supply.

[262] See Section 3.4.10 for more information about transmission congestion.

[263] See Section 3.4.10 for more information on the New England West-East Interface.

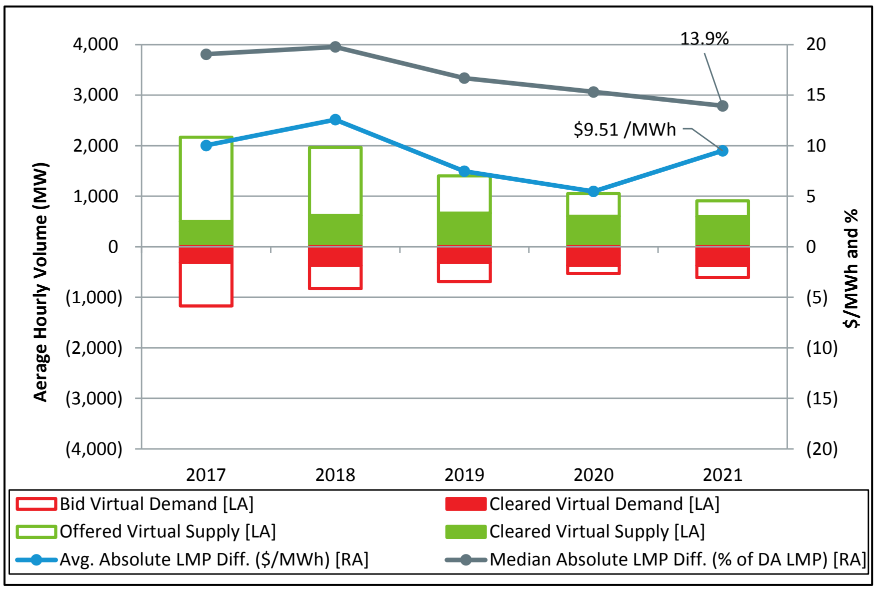
advantage of the difference between day-ahead and real-time supply offers by DDGs. Wind generators often submit higher priced day-ahead supply offers, but will generate at low or even negative real-time prices. Virtual supply participants fill this gap by clearing virtual supply at prices more in line with real-time expectations, particularly on windy days. These locations were competitive in 2021 with between 10 to 16 different participants offering virtual supply over the course of the year.

4.1.4 Price Convergence and Virtual Transaction Volumes

The relationship between the volume of virtual transactions and the level of price convergence is shown in Figure 4-2 below. This figure presents two measures of price convergence:[264]

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 4-2: Virtual Transaction Volumes and Price Convergence



The measures of price convergence provide a mixed picture about the level of convergence between day-ahead and real-time prices in 2021 compared to prior years. The average absolute price difference between the day-ahead and real-time Hub prices (blue line) was $9.51/MWh in 2021, the first increase since 2018. Between 2017 and 2020, this measure fluctuated between $5.48/MWh (in 2020) and $12.58/MWh (in 2018). However, the decrease in median absolute day-ahead to real-time difference (gray line) occurred due to higher LMPs as the difference decreased when viewed as a percentage of the day-ahead LMP. Price convergence fell to its lowest level of the last five years as measured by the median absolute price difference between day-ahead and real-time Hub prices as a percent of the day-ahead Hub price (gray line). The median difference (as a percentage of the

[264] 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.

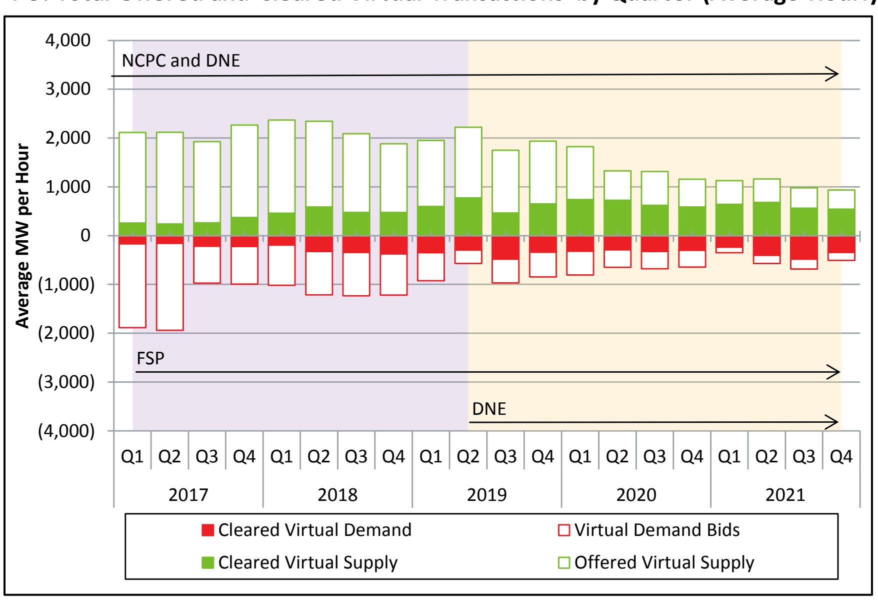
day-ahead Hub price) fell to 13.9% in 2021, down from the 15.3% observed in 2020. Section 3.3.5 discusses price convergence in more depth.

The figure also shows that, in general, the quantity of submitted virtual transactions fell over the last five years, while the level of cleared virtual transactions increased. In 2021, participants submitted an average of 1,517 MWs of virtual transactions per hour. This represents just a 4% decrease from the 1,579 MWs of virtual transactions that were submitted, on average, per hour in 2020, and a 55% decrease from the 3,339 MWs that were submitted, on average, per hour in 2017. One participant contributed significantly to the decrease in submitted virtual transactions. In 2017 and 2018, this participant submitted an average of 1,025 MWs per hour, but submitted less than 10 MW per hour in 2021. However, cleared virtual transactions have generally increased over the last five years, rising from 810 MW per hour in 2017 to 966 MW per hour in 2021, on average. In fact, 64% of submitted virtual transaction MWs cleared in 2021, the highest level of the last five years. Both cleared virtual supply and cleared virtual demand increased over the last five years with virtual demand increasing by 20% (311 MW per hour to 372 MW per hour, on average) and virtual supply increasing by 19% (from 499 MW per hour to 594 MW per hour, on average) in this five-year period.

4.1.5 The Impact of Market Rule Changes

Over the last five years, numerous energy market rule changes have been implemented that have impacted profit-making opportunities for virtual transactions. Among the relevant changes are: (i) modifications to the real-time commitment NCPC credit calculation, (ii) the implementation of Do-Not-Exceed (DNE) dispatch rules, and (iii) the implementation of Fast-Start Pricing (FSP). The periods when the latter two market rule changes (i.e., FSP and updated DNE rules) took effect are depicted in Figure 4-3 below. The NCPC credit calculation and the initial implementation of DNE rules that occurred in 2016 are not shown. This figure also shows the average hourly virtual transaction volumes by quarter over the period from 2017 through 2021, with virtual supply as positive values (in green) and virtual demand as negative values (in red). The market rule changes are discussed in more detail below.

Figure 4-3: Total Offered and Cleared Virtual Transactions by Quarter (Average Hourly MW)



Changes to NCPC rules (2016)

In February 2016 (pre-dating the reporting horizon), real-time economic NCPC payments made to generators with day-ahead commitments were eliminated, reducing the total pool of real-time economic NCPC. The average real-time NCPC charge was approximately $0.53/MWh in 2021 versus $2.79/MWh in 2015. The decrease in this average charge rate was mainly driven by three factors: the February 2016 rule change, other market rules changes discussed below, and lower energy costs.[265] The lower real-time economic NCPC equated to reduced transaction costs for virtual transactions. This may partly explain the sustained increase in cleared virtual transaction volumes that has occurred over the reporting period.

Do-Not Exceed Dispatch Rules (2016)

Beginning in May 2016 (pre-dating the reporting horizon), certain wind and hydro generators became dispatchable under the DNE Dispatch rules. Under this change, DNE dispatchable generators (DDGs) can set price in the real-time energy market. DDGs tend to offer higher-priced energy in the day-ahead market due to a combination of factors, such as uncertainty about environmental and production conditions and terms under their power purchase agreements. Consequently, these generators often clear less day-ahead energy compared to their real-time production. In real-time, when there is more production certainty, these generators often reduce their offers and frequently set price.

This creates the opportunity for virtual supply to take advantage of the difference in day-ahead and real-time offer behavior. Since the implementation of DNE, virtual supply has frequently cleared and been profitable (see most profitable locations above) in the day-ahead energy market in geographic areas with DDGs. In the real-time energy market, DDGs have frequently been marginal in these same areas. Cleared virtual supply increased after this rule change when into effect.

Beginning in June 2019 (tan shaded area), the ISO implemented a requirement that all DDGs with Capacity Supply Obligations (CSOs) must offer the full amount of their expected hourly capability into the day-ahead energy market. This requirement reduced, but did not eliminate, the opportunity for virtual transactions to participate in the day-ahead market in geographic areas with DDGs to the same extent they did before this requirement went into effect. This is because this rule triggered more participation from intermittent power generators in the day-ahead market.

Fast-Start Pricing

In March 2017 (purple shaded area), new Fast-Start Pricing (FSP) rules went into effect. These changes more accurately reflect the cost of operating higher cost fast-start generators in the real-time market. The day-ahead market does not apply the FSP mechanics. Consequently, this increases real-time energy market prices relative to day-ahead prices when fast-start generators are needed, which may create more opportunities for virtual demand to converge prices.

[265] This subsection references 2015 since it was the last full calendar year without the changes to NCPC rules.

In the case of DNE and FSP, virtual transactions provide an important service to the market as they help converge day-ahead and real-time prices by when a systematic divergence may otherwise occur due to behavioral and design differences between the markets.

4.2 Financial Transmission Rights

This section summarizes outcomes and provides insights related to Financial Transmission Rights (FTRs). The first subsection (4.2.1) provides an overview of FTRs and details how participants can purchase and sell FTRs in the various ISO-administered auctions.[266] It also discusses how FTRs can be used either as a financial tool to hedge the risk of transmission congestion for physical supply or demand, or as a completely speculative instrument. The next subsection (4.2.2) summarizes the volume of FTRs purchased and sold and explores the auctions in which these transactions occurred. Subsection (4.2.3) explores the funding of FTRs, subsection (4.2.4) assesses the concentration of FTR ownership, and the final subsection (4.2.5) examines the profitability of FTR holders in recent years. This last subsection gives special attention to FTR paths that source from ISO-NE's external node for trading across the New York - New England (NYNE) interface.[267]

Key Takeaways

The average MW-amount of FTRs held by participants rose slightly in 2021, marking the first year-over-year increase during the reporting period. However, the 2021 value (32,443 MW) was still 8% less than the amount in 2017 (35,452 MW). In 2021, FTRs were fully funded, as they were in every other year covered in this report. Meanwhile, the ownership of FTRs continued to be relatively concentrated in 2021 with the top four participants holding 61% of FTR MWs in the on-peak period and 64% in the off-peak period. There were 35 unique FTR holders in both the on-peak and off-peak periods in 2021, which were the lowest values of the previous five years. After two years of losses, FTR holders made a collective profit of $25.9 million in 2021. FTR activity associated with the NYNE interface was one major reason for this increased profitability. Profit for FTRs sourcing from .I.ROSETON 345 1, ISO-NE's external node for trading across the NYNE interface, increased by $10.7 million between 2020 (-$0.9 million) and 2021 ($9.8 million).

4.2.1 FTR Overview

FTRs provide participants with a way to hedge or speculate on transmission congestion in New England's day-ahead energy market. Transmission congestion occurs when the power flowing across a transmission element reaches the limit of what that element can reliably carry. When this happens, the power system must be re-dispatched away from the least-cost solution that had existed in the absence of that limiting element. Re-dispatching resources incurs additional production costs on the power system because the most economic generation is not able to provide all the needed energy. The energy market reflects the impact of transmission congestion through the congestion component of the LMP. FTRs, whose value depends on the congestion component, provide participants with a mechanism to manage their exposure to transmission congestion.

[266] See ISO-NE Manual for Financial Transmission Rights (Manual M-06) and Section III.7 of ISO-NE Market Rule 1 for detailed information about the operation of ISO-NE's FTR market

[267] 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.

Eligible bidders can obtain FTRs by participating in ISO-administered auctions for annual and monthly products. There are separate auctions for on-peak and off-peak hours.[268] The FTRs awarded in the two annual auctions have a term of one calendar year (i.e., January 1 to December 31), while the FTRs awarded in one of the monthly auctions have a term of one month.[269] FTRs can be purchased in all auctions, but can only be sold in the second annual auction or the monthly auctions as only FTRs that are owned (i.e., have been purchased) can be sold by participants (i.e., there is no short selling). Table 4-3 below summarizes five important elements in a bid to purchase an FTR.

Table 4-3: Elements of an FTR Bid

Element	Description
Path	FTRs are defined between two points (i.e., pricing nodes): 1) the point of injection (or the "source") and 2) the point of withdrawal (or the "sink")
Price	The $/MW value the participant is willing to pay to acquire the FTR
MW-amount	The size of the FTR (in MWs) the participant is willing to buy
Term	The monthly or annual period to which the FTR applies (e.g., November 2021)
Period	The hours in which the FTR applies (i.e., on-peak or off-peak)

As a result of the Balance of Planning Period (BoPP) project that ISO-NE implemented on September 17, 2019, market participants now have more opportunities to reconfigure their monthly FTR positions following the two annual auctions. Prior to the implementation of this project, market participants could only purchase or sell FTRs for a specific month in the auction that occurred during the month immediately prior to that effective month. For example, under the old design, if a market participant wanted to buy FTRs that would be effective for December 2021, it had to wait until the monthly auction that took place in November 2021. Under the BoPP design, ISO-NE now administers monthly FTR auctions for not just the next month (now called the *prompt-month* auction), but also for all the other months remaining in the calendar year (called the *out-month* auctions). This means that a participant that wants to buy December 2021 FTRs no longer has to wait until November 2021; it can purchase these FTRs in any of the out-month auctions that take place earlier in the year.[270]

Once FTRs are awarded, target allocations for each FTR are calculated on an hourly basis depending on the term (e.g., December 2021) and period (i.e., on-peak or off-peak) of the FTR. Target allocations are calculated by multiplying the MW amount of the FTR by the difference in the day-ahead congestion components of the FTR's sink and source locations. Positive target allocations occur when the congestion component of the sink location is greater than the congestion component of the source location in the day-ahead energy market. Positive target allocations represent revenue to FTR holders. Negative target allocations, which occur when the congestion component of the sink location is less than the congestion component of the source location in the

[268] On-peak hours are defined by the ISO as hours ending 8-23 on weekdays that are not NERC holidays. The remaining hours are off-peak hours.

[269] Information about the percent of the network made available in each FTR auction can be found in Section III.7.1.1 of Market Rule 1.

[270] Importantly, the out-month auctions do not make more network capacity available than was made available in the second annual auction (in contrast to the prompt-month auctions, which do make additional capacity available). However, additional FTR purchases can still occur in these out-month auctions on paths that were not completely subscribed in the second annual auction, as the result of other participants making countervailing FTR purchases, or as the result of FTR sales.

day-ahead energy market, represent a charge to FTR holders. Payments to FTR holders with positive target allocations come from day-ahead and real-time congestion revenue and from FTR holders with negative target allocations.[271]

Hedging vs. Speculating

To understand how an FTR could be used to hedge congestion risk, we can consider a simple example of a load-serving entity (LSE) located in an import-constrained area (i.e., an area prone to positive congestion). To manage price risk, the LSE could decide to enter into an annual contract to buy energy at the day-ahead Hub price as there are likely to be many counterparties that would enter into a contract settled at this location. However, the LSE would still bear congestion risk, as it is not serving load at the Hub, but rather in an area prone to positive congestion. In order to manage this risk, the LSE could choose to participate in the annual on- and off-peak FTR auctions. Purchasing an FTR from the Hub to the zone where it serves energy in both these auctions would entitle the LSE to the difference in the congestion components at these locations over the course of the year. The positive target allocations that accrued to these FTRs would offset the day-ahead congestion charges that the LSE incurred while serving load in this import-constrained area. The cost required to hedge this congestion risk would be the price the LSE paid to purchase the FTRs.

Participants can also purchase FTRs as a completely speculative instrument. For example, a market participant that has no load or generation position may want to purchase an FTR solely because it expects a certain amount of positive target allocations to accrue along a specific path.[272] This transaction would be profitable if the participant is able to purchase the FTR at a cost that is less than the revenue realized from holding the FTR. Such activity is not without risk, as expected patterns of congestion may not actually appear in the day-ahead market. In such cases, FTRs can quickly change from being a financial benefit to a financial obligation that requires payment. This sort of trading is considered speculative because it is an attempt to profit by engaging in a risky financial transaction that is not tied to any physical position in the ISO-NE marketplace. ISO-NE permits speculative trading in FTR auctions because it provides liquidity and competition to the market.

Supply and Demand

Participants' expectations of day-ahead congestion drives their demand for FTRs. If participants expect less day-ahead congestion than in prior years, their need to purchase FTRs to hedge against this congestion may decrease. The volume of FTR purchases is particularly dependent on the variability of participants' expectations of congestion. For example, if all participants have the same expectation for congestion in a certain year, the set of FTR paths that they bid on is likely to be limited. This may result in fewer FTRs being purchased. Additionally, participants may be unwilling

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[271] Congestion revenue is discussion in more detail in Section 3.4.10.

[272] This example is for a *prevailing flow* FTR, which is an FTR whose path is defined in the direction that congestion is expected to occur based on FTR auction clearing prices. The holder of a prevailing flow FTR pays to acquire that FTR and then expects to receive positive target allocations as congestion occurs in the day-ahead energy market. Alternatively, a speculator could acquire a *counterflow* FTR. An FTR purchased at a negative price in an auction is called a counterflow FTR because its path is defined in the opposite direction that congestion is expected to occur based on the FTR auction clearing prices. The auction pays the counterflow FTR holder to take on this counterflow position, and this position will generally be profitable to the counterflow FTR holder if the total negative target allocations for this FTR are less than this payment from the auction.

to take counterflow FTR positions if they hold comparable outlooks.[273] On the other hand, if participants have a diverse range of expectations for congestion, the set of FTR paths on which they bid is likely to be larger, and more participants may be willing to take counterflow positions.

The supply side of the FTR market is predominantly dependent on the physical capability of the transmission system. The amount of FTRs awarded by the ISO in each auction depends on a market feasibility test that ensures that the awarded set of FTRs respects the transmission system's limits under normal and post-contingent states.[274] 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 (i.e., that the positive target allocations are fully funded). We look at the funding of FTRs more closely later in this section.

4.2.2 FTR Market Volume

More FTRs (by MWs) were in effect per hour, on average, in 2021 than in 2020, marking the first year-over-year increase in the five-year reporting period. This trend can be seen in Figure 4-4, which shows the average MW volume of FTRs that were in effect each hour by year between 2017 and 2021 as black diamonds.[275] 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.[276] FTR purchases are depicted as positive values, while FTR sales are depicted as negative values.

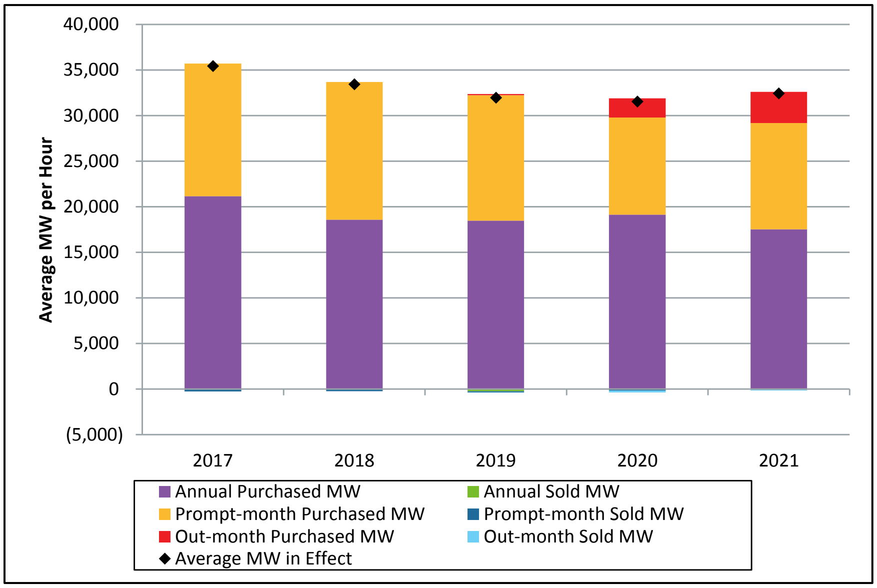
[273] The purchase of counterflow FTRs is important because it impacts the supply of FTR MWs. This is because every MW purchased on a counterflow path (say from B to A) allows participants to buy more MWs of the prevailing flow path (in this case, A to B).

[274] A post-contingent state refers to the power flow that exists after a contingency is evaluated in the market feasibility test. See Section III.7.3.10 of Market Rule 1 for more information about the FTR feasibility test.

[275] 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.

[276] The hourly-weighted average MW 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.

Figure 4-4: Average FTR MWs in Effect per Hour by Year



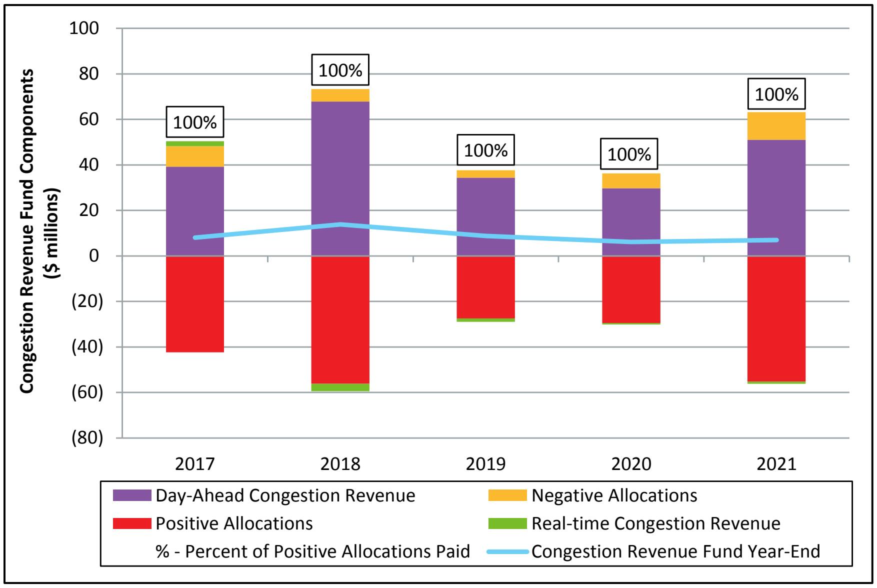
Market participants had an average of 32,443 MWs of FTRs in effect per hour in 2021, representing a modest 3% increase from the average amount of FTRs in effect in 2020 (31,550 MW). This increase was primarily the result of additional purchases in the prompt-month and out-month auctions compared to the prior year. Average prompt-month FTR purchases rose by 10% in 2021 (11,668 MWs per hour) compared to 2020 (10,644 MWs per hour), while average out-month FTR purchases increased by 60% in 2021 (3,412 MWs per hour) compared to 2020 (2,131 MWs per hour). On the other hand, average FTR purchases in the annual auctions decreased by 8% between 2020 and 2021, falling from 19,138 MWs per hour to 17,519 MWs per hour. FTR sales averaged only 156 MWs per hour in 2021. In general, FTR holders sell very few FTRs each year, as can be seen below the horizontal axis in Figure 4-4.

4.2.3 FTR Funding

In each of the last five years, the ISO collected sufficient congestion revenue from the energy market and from negative target allocations to fully pay all the positive target allocations (i.e., positive target allocations were fully funded every year). Consequently, the congestion revenue fund (CRF) has ended each of the previous five years with a surplus.[277] This can be seen in Figure 4-5 below, which depicts the year-end CRF balance as a blue line. This figure also shows the different components that determined the year-end balances, depicting positive target allocations as negative values (as these allocations represent outflows from the CRF) and negative target allocations as positive values (as these allocations represent inflows into this CRF). Also shown in this figure is the percent of positive target allocations that were paid each year (indicated by the number above each stacked column).

[277] The CRF balance is defined here as the $\sum$[day-ahead congestion revenue + real-time congestion revenue + abs(negative target allocations) – positive target allocations]. The congestion revenue fund is discussed in more detail in Section 3.4.10.

Figure 4-5: Congestion Revenue Fund Components and Year-End Balance by Year



The CRF year-end balance in 2021 ($7.0 million) was in-line with values observed during the prior four years.[278] While positive target allocations rose significantly in 2021 ($55.2 million) from their 2020 value ($29.5 million), this was matched by a similar year-over-year increase in day-ahead congestion revenue, which rose to $51.1 million in 2021 from $29.7 million in 2020. However, real-time congestion revenue, which has been negative in four of the last five years, sank from -$0.6 million in 2020 to -$1.0 million in 2021. A major reason for the fund surplus in 2021 was the amount of negative target allocations ($12.1 million). This represents an 84% increase from the level observed in 2020 ($6.6 million) and a 270% increase from the level observed in 2019 ($3.3 million). One transmission constraint from the day-ahead market that led to a significant amount of negative target allocations in 2021 was the New England West-East (NE_WE) interface (Section 3.4.10 contains more information about this constraint).

As indicated by the label in Figure 4-5, positive target allocations were fully funded in 2021. It is worth noting that there were several months in 2021 (specifically February, October, and November) when positive target allocations were not fully funded during the initial month-end settlement. However, the underfunding that occurred in these three months was remedied at the end of the year as there was sufficient revenue in the fund (from excess collections in other months of the year) to make these allocations whole. ISO-NE then allocated the remaining year-end fund surplus ($7.0 million) to the entities that paid congestion costs during the year in a proportion to the amount of congestion costs they paid.[279]

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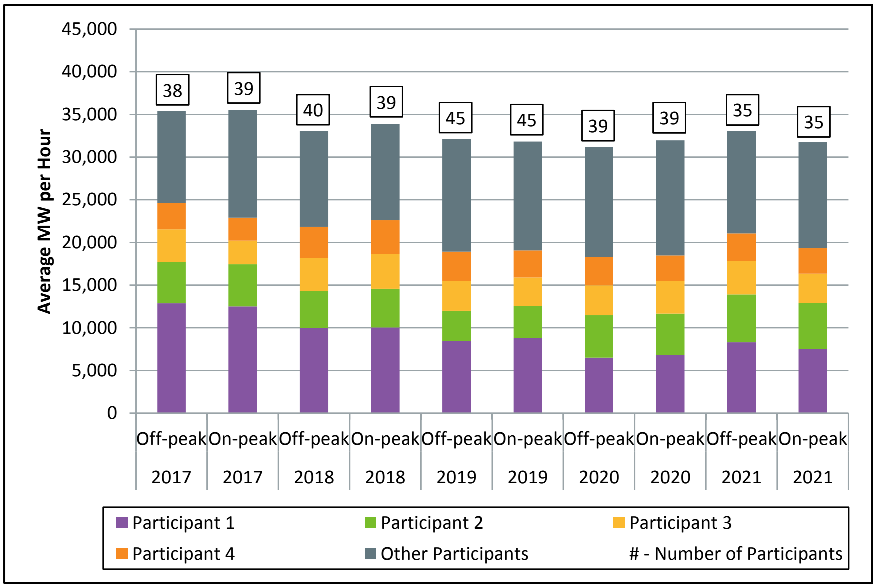
[278] This total represents the balance in the congestion revenue fund after fully funding any FTRs that had been underfunded during any month in the year.

[279] See Section III.5.2.6 of Market Rule 1 for more information about the distribution of excess congestion revenue. In practice, ISO-NE Settlements determines which participants incurred more congestion charges than congestion credits for the year across the day-ahead and real-time energy markets (i.e., had net negative congestion charges) and allocates the excess congestion revenue at year end to these participants pro-rata based on the magnitude of the net negative congestion charges. In 2021, the participants that received this money included generator owners, participants that engaged in virtual and external transactions, and load-serving entities, among others.

4.2.4 FTR Market Concentration

The concentration of FTR ownership among market participants in 2021 was similar to prior years. The average amount of FTRs held per hour by the top four participants with the most MWs each year is shown in Figure 4-6 below.[280] 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 4-6: Average FTR MWs Held per Hour by Top Four FTR Holders by Year and Period



Note: 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.

On average, the top four participants held 61% of on-peak FTR MWs and 64% of off-peak FTR MWs in 2021. The concentration ratio of the top four FTR holders has stayed stable over the reporting period, ranging between 58%-70%. However, the percentage of FTRs held by the largest FTR holder has trended downward over the reporting period. The largest FTR holder held 35% of on-peak FTR MWs and 36% of off-peak MWs on average in 2017, but held only 24% of on-peak FTR MWs and 25% of off-peak MWs on average in 2021.

The total number of unique FTR holders fell to its lowest level of the reporting period in 2021 with only 35 unique participants in both the on-peak and off-peak periods. This is down modestly from the range of 38-45 different participants in the previous four years.

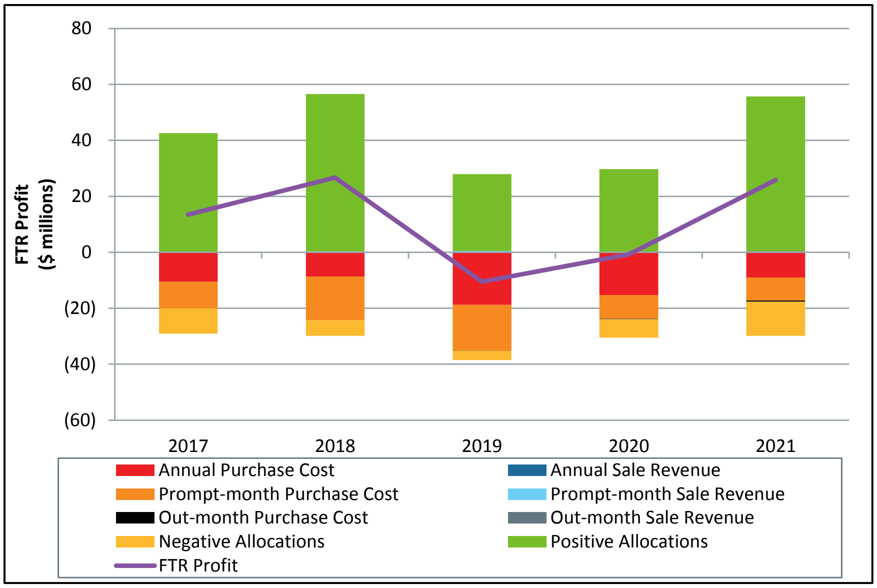
4.2.5 FTR Profitability

As a group, FTR holders were profitable in 2021. Profit in this case 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. Each of these components as well as total profit (purple line) can be seen in Figure 4-7 below. 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

[280] These percentages are often referred to as "C4" values because they summarize the concentration of ownership for the four participants with the largest FTR portfolios.

allocations are shown as negative values (as they reduce FTR profitability). Further, this figure classifies the purchase costs and sales revenues by auction type (i.e., annual, prompt-month, or out-month).

Figure 4-7: FTR Costs, Revenues, and Profits by Year



In 2021, the total profit from FTRs was $25.9 million (purple line). This represents a substantial increase from 2020 when total FTR profit was -$0.8 million, and an even larger increase from 2019 when total FTR profit was -$10.5 million. Two primary factors led to the year-over-year increase in FTR profitability in 2021:

1. Positive target allocations increased. Payments to FTR holders with positive target allocations increased by $25.7 million in 2021 ($55.2 million) relative to 2020 ($29.5 million). Positive target allocations in 2021 were very close to the high from the reporting period, which occurred in 2018 when they reached $56.2 million.
2. FTR purchase costs decreased. Participants spent $6.3 million less to procure FTRs in 2021 than they did in 2020. The decrease in purchase costs was almost entirely the result of a large decrease in expenditures in the annual auctions. Participants spent $6.3 million less to purchase FTRs in the 2021 annual auctions ($9.0 million) than they did to purchase FTRs in the 2020 annual auctions ($15.3 million).

Most Profitable FTR Paths

Table 4-4 below provides information about the 10 most profitable FTR paths in 2021. Each row in this table provides the names of the source and sink locations that define the FTR path. The purchase amount field indicates the total amount that participants spent in FTR auctions in 2021 to purchase FTRs on this path. The sale amount indicates the total amount that participants earned in 2021 from sales of this path in FTR auctions. The positive and negative target allocation fields are the 2021 totals of these values for the specific path. The profit field indicates the total profit for the specific FTR path in 2021.[281] Lastly, the table also includes a count of the number of different participants that owned FTRs for the path during 2021.

Table 4-4: Top 10 Most Profitable FTR Paths in 2021

Source Location	Sink Location	Purchase Amount ($k)	Sale Amount ($k)	Positive Target Allocations ($k)	Negative Target Allocations ($k)	Profit ($k)	# of Participants
.I.ROSETON 345 1	.H.INTERNAL_HUB	$(7,652)	$214	$17,018	$(1)	$9,579	14
UN.POWERSVL115 GNRT	.H.INTERNAL_HUB	$(1,060)	$-	$4,225	$(86)	$3,079	3
.H.INTERNAL_HUB	.Z.NEMASSBOST	$(776)	$25	$2,167	$(45)	$1,372	14
LD.KEENE_RD46	UN.ENFLD_ME115 IND5	$(353)	$-	$974	$(0)	$621	5
UN.BERLN_NH13.8BURG	LD.BERLN_NH34.5	$(78)	$-	$680	$-	$603	4
UN.OAKFIELD34.5OAKW	UN.PASADMKG34.5PASW	$(17)	$-	$488	$(15)	$456	3
.H.INTERNAL_HUB	.Z.SEMASS	$(433)	$-	$900	$(22)	$445	15
UN.RISE 18.0RISE	.H.INTERNAL_HUB	$(294)	$-	$1,010	$(294)	$422	5
.H.INTERNAL_HUB	.Z.RHODEISLAND	$(149)	$-	$532	$(22)	$361	9
UN.TOWANTIC18.0TO1A	.H.INTERNAL_HUB	$(125)	$-	$487	$(2)	$360	2

Several of the most profitable FTR paths in 2021 involved locations in frequently export-constrained areas that tended to experience negative congestion pricing. Participants can hedge this type of congestion by procuring FTRs that source from within the area experiencing the negative congestion pricing and that sink in a location outside that constrained area (the Hub is frequently used by participants). A path of this type tends to produce positive target allocations because the source location is likely to have a smaller congestion component than the sink location. Two examples of this are the two most profitable paths listed in Table 4-4: 1) .I.ROSETON 345 1 to .H.INTERNAL_HUB and 2) UN.POWERSVL115 GNRT to .H.INTERNAL_HUB.[282] Both of these paths had a source location whose average day-ahead congestion component was negative in 2021.

However, several locations shown in Table 4-4 are in areas that are frequently import-constrained. These locations tend to experience positive congestion pricing. Participants can hedge this type of congestion by procuring FTRs that sink inside the area experiencing the positive congestion pricing and that source from outside that constrained area (again, the Hub is often used by participants). A path of this type often produces positive target allocations because the sink location is likely to have a larger congestion component than the source location. Examples of this include: 1) .H.INTERNAL_HUB to .Z.NEMASSBOST, 2) .H.INTERNAL_HUB to .Z.SEMASS, and 3)

[281] Similarly to how it was defined earlier, profit here is defined as ∑[purchase amount + sale amount + positive target allocations + negative target allocations].

[282] As mentioned earlier. .I.ROSETON 345 1 is ISO-NE's external node for trading across the NYNE interface. In 2021, .I.ROSETON 345 1 primarily experienced negative congestion as a result of the NYNE interface. Meanwhile, UN.POWERSVIL115 GNRT is a node for a generator located in Maine. This location primarily experienced negative congestion as a result of the Keene Road Export (KR-EXP) interface constraint. A list of the most frequently binding interface constraints in the day-ahead energy market in 2021 is provided in Section 3.4.10.

.H.INTERNAL_HUB to .Z.RHODEISLAND.[283] All three of these paths had sink locations whose average day-ahead congestion component was positive in 2021.

All 10 of the most profitable FTR paths in 2021 are examples of prevailing flow FTR paths. This means that these paths are defined in the direction that congestion was expected to occur based on FTR auction clearing prices, which can be seen by the negative value in the purchase amount column in Table 4-4. The fact that these FTR paths were profitable to their holders suggests that more congestion occurred along these paths in the day-ahead market than participants had expected (based on the clearing prices from the FTR auctions). While not shown in Table 4-4, the least profitable FTR path in 2021 (.H.INTERNAL_HUB to .Z.CONNECTICUT) was an example of a counterflow path.[284] Collectively, participants were paid $0.6 million to hold FTRs on this path. However, these FTRs incurred $2.4 million of negative target allocations. With very little positive target allocations or revenue from FTR sales, FTRs for this path finished the year with a loss of $1.8 million.

Congestion on the New York – New England Interface (.I.ROSETON345 1)

As detailed in Section 3.4.10, one of the most frequently binding transmission constraints in the day-ahead market in 2021 was the NYNE interface. Participants may purchase FTRs that involve .I.ROSETON 345 1, ISO-NE's external node for trading across the NYNE interface, as a way to hedge their external transactions at this interface. Typically, participants purchase FTRs that source from .I.ROSETON 345 1 and sink somewhere within the ISO-NE system because .I.ROSETON 345 1 tends to experience negative congestion pricing in the day-ahead market.

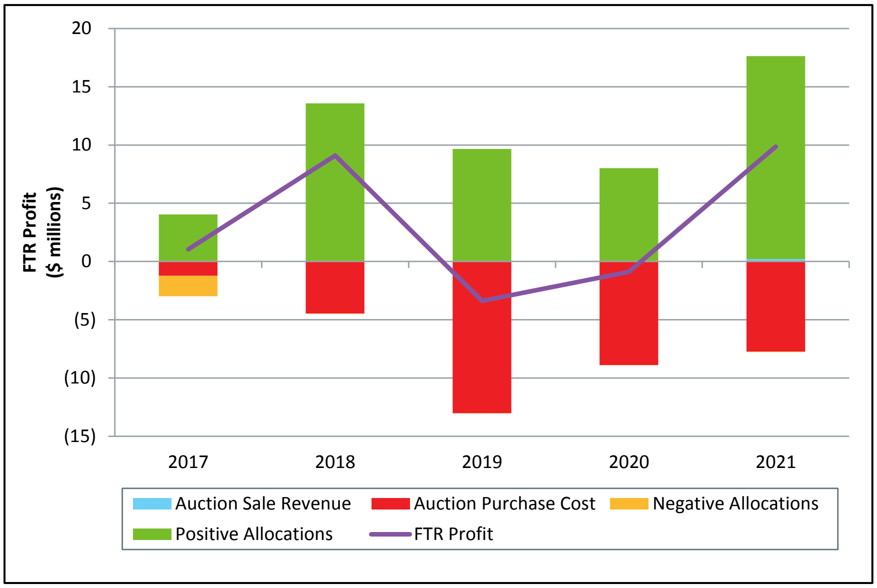
Because of the large MW-volume of FTRs sourcing from .I.ROSETON 345 1 and the frequency that the NYNE interface is constrained, market outcomes for these FTRs can contribute significantly to overall FTR outcomes. To provide some perspective, the purchase costs for FTRs sourcing from .I.ROSETON 345 1 represented 44% of all the FTR auction purchase costs in 2021, the positive target allocations for these FTRs represented 32% of all positive target allocations in 2021, and the profit for these FTRs represented 38% of all FTR profit in 2021.

Figure 4-8 shows the total profit (purple line), purchase costs, sale revenues, and positive and negative target allocations for all FTRs that sourced from .I.ROSETON 345 1 by year over the last five years.

[283] .Z.NEMASSBOST is the node for the Northeast Massachusetts and Boston load zone, .Z.SEMASS is the node for the Southeast Massachusetts load zone, and .Z.RHODEISLAND is the node for the Rhode Island load zone. In 2021, these three locations primarily experienced positive congestion related to the New England West-East (NE_WE) interface. Again, see Section 3.4.10 for more information about the most frequently binding constraints in 2021.

[284] .Z.CONNECTICUT is the node for the Connecticut load zone.

Figure 4-8: FTR Profits and Costs for FTRs Sourcing from .I.ROSETON 345 1 by Year



The profitability of FTRs sourcing from .I.ROSETON 345 1 increased by $10.7 million between 2020 (-$0.9 million) and 2021 ($9.8 million). This increase was largely the result of a sizeable jump in positive target allocations associated with this group of FTRs. The holders of these FTR paths received $9.5 million more in positive target allocations in 2021 ($17.4 million) than they did in 2020 ($8.0 million). At the same time, participants paid slightly less to acquire FTRs sourcing from .I.ROSETON 345 1 in 2021 ($7.7 million) than they did in 2020 ($8.9 million).

Section 5
External Transactions

This section examines trends in external transactions in the day-ahead and real-time energy markets. It provides a detailed breakdown of total flows across the external interfaces with New York and Canada, a review of bidding behavior and an analysis of the performance of Coordinated Transaction Scheduling (CTS) with New York. In 2021, New England remained a net importer of power with net real-time imports averaging 2,145 MW each hour, meeting about 16% of New England demand.

Key Takeaways

The majority of import transactions continue to flow into the New England (NE) market regardless of price, particularly over the Canadian interfaces. This has applied downward pressure on energy prices, particularly around the areas of interconnection with the New England system. The average day-ahead prices at the Phase II (which connects New England and the Hydro-Québec control area) and New York North (NYN) interfaces (the two largest ties) were 1% and 8% lower than the New England Hub price, respectively. Similarly, the other two Canadian interfaces, New Brunswick and Highgate's average day-ahead prices were 5% and 9% lower than the Hub, respectively.

Over the primary New York (NY) interface, New York North, net interchange fell in 2021. In the day-ahead market an increase in congestion over New York's Central-East interface, caused by the retirement of the Indian Point 3 nuclear plant, led to higher prices on the New York side of the interface. This, in turn, led to an increase in cleared exports.

The performance of Coordinated Transaction Scheduling (CTS) was broadly similar to prior years. Introduced in 2015, CTS improved the optimization of real-time power flow between New York and New England across the New York North interface. It did this by unifying the bid submission and clearing processes, reducing latency between clearing and actual flow (delivery) and eliminating transaction fees. While there are considerable economic and reliability benefits of the CTS rules, we find that there is room for improvement, specifically in the related areas of price forecasting and participant bidding.

ISO forecast error resulted in frequent uneconomic scheduling of price-sensitive CTS transactions at New York North. Many participants clear bids in the day-ahead market and go on to offer price insensitive bids in real-time. Though this is a reasonable strategy to mitigate forecast error risk, this bidding strategy inhibits CTS from adjusting to changes in price between New York and New England.

In addition to participant bidding behavior, price differences between the control areas are an important factor in determining CTS flows. Average real-time New England prices at the New York North interface were about \$2/MWh higher than in New York, consistent with the 2020 price spread.[285] Power flowed from New York into New England 69% of the time in 2021. However, when examining the flow of energy at the 15-minute interval level we find the net flow was to the higher-priced area just 56% of the time. Conversely, net flows are to the lower-priced market 44% of the

[285] Congestion pricing due to NYN constraints binding is removed from these external prices to ensure better-capturing of 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.

time. This indicates that CTS is not effectively adjusting flows to real-time price differences, i.e., net imports are too high relative to the real-time price differences.[286] Further, when the price difference between regions was high, on average CTS did not fully utilize the transfer capability or ramp constraint allowances to converge prices. For example, even in scenarios where price differences were between $50 and $100 per MWh, there was 150 MW of average unused interface capacity.

Price convergence between New York and New England did not improve materially. Setting aside directionality, the average absolute price difference between New England and New York at the CTS interface in 2021 was $10.78/MWh, 70% higher than in 2020. However, overall New England LMPs at NYN were 92% higher in 2021 (rising from $22.45/MWh to $43.03/MWh) while NY LMPs doubled in 2021, from $20.46 in 2020 to $41.07 in 2021. So as a percentage of average LMPs, the absolute price difference in 2021 was similar to 2020 (30% in 2021 vs. 31% in 2020).

Forecast error introduces risk of clearing CTS transactions out-of-merit; for example an import spread bid of $1/MWh will clear when the forecasted LMPs are $10 and $12/MWh in NY and NE, respectively. However if the actual LMPs turn out to be $12 and $10/MWh (the spread flipped), the scheduled import is out-of-merit and must pay $2/MWh to import power. One strategy to avoid this risk is to hedge real-time CTS transactions by taking on positions in the day-ahead market. Many participants acquire day-ahead schedules and offer price insensitive transactions in the real-time to match their day-ahead positions. This minimizes risk of clearing out-of-merit in real-time, but inhibits CTS from being flexible in response to real-time price difference. For example, if an import spread bid is backed by a day-ahead position and insulated from real-time prices, it could be priced at -$999/MWh. A -$999/MWh bid will clear whether New York prices are $500/MWh higher, $500/MWh lower, or the same as New England prices. By pricing at such an extremely price-insensitive level, the participant has eliminated the risk of forecast-error-driven losses.

Because 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.

5.1 External Transactions with New York and Canada

There are six external interfaces that interconnect the New England system with its neighboring control areas. The three interconnections with New York are:

1. **New York North**; comprised of seven alternating current lines that carry power between New York and western New England. This is the only interface that utilizes Coordinated Transaction Scheduling (CTS).
2. **Cross Sound Cable**; a direct current line running between Connecticut and Long Island, New York.
3. **Northport-Norwalk Cable**; an alternating current line running between Connecticut and Long Island, New York.

The three interconnections with Canada are:

1. **Phase II**; a direct current line running between New England and the Hydro-Québec control area.

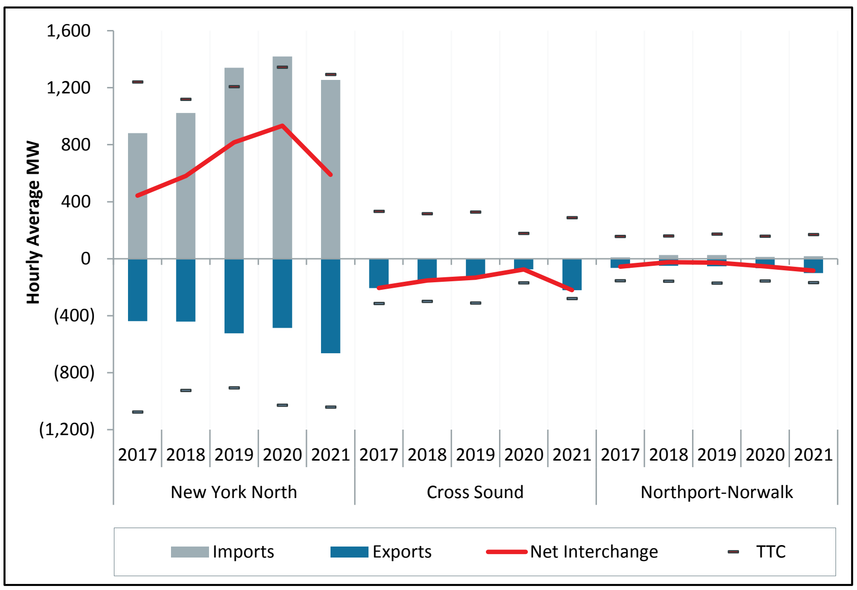
[286] Fixed wheeling transactions were excluded for this calculation.

2. **Highgate**; a direct current line running between New England and the Hydro-Québec control area.
3. **New Brunswick**; comprised of two high-voltage alternating current lines running between New England and the New Brunswick control area.

New York Interfaces

While New England continues to be a net importer of power overall, there are also substantial volumes of power exported from New England, primarily at the New York interfaces. The annual hourly average real-time net interchange volumes as well as the gross import and export volumes at each New York interconnection for 2017 through 2021 are shown in Figure 5-1 below. The average hourly real-time total transfer capability (TTC) ratings for each interface in the import and export directions are also plotted using black dashed lines.[287] Note that the annual observations are grouped by interface.

Figure 5-1: 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 285 MW per hour of net imports from New York in 2021.

For the first time in the reporting period the average hourly real-time imports at the **New York North** interface decreased, falling by 12% in 2021 relative to 2020 (down 165 MW, from 1,420 MW to 1,255 MW per hour). Average hourly real-time exports at the New York North interface increased by 37% (up 178 MW, from 487 MW to 665 MW per hour). The combined effect was that average hourly net interchange decreased by 37% (down 343 MW, from 933 MW to 590 MW per hour). A primary driver of this decrease in net interchange was the retirement of Indian Point 3, an

[287] 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.

820 MW nuclear power plant in New York, in April 2021.[288] This caused the New York Central-East interface to bind much more frequently throughout the year, limiting flows to the east and resulting in higher prices.[289] Additionally, an outage of one of the transmission lines that comprises the Central East interface in September 2021 contributed to higher congestion prices in New York. The aforementioned increase in exports at the New York North interface cleared in response to higher prices. For more in-depth analysis of CTS see Section 5.4.

Average hourly real-time exports at the **Cross-Sound Cable** interface increased to the highest level recorded over the reporting period, almost tripling from 75 MW per hour in 2020 to 221 MW per hour in 2021. During November 2021, the interface's transfer capability was set to zero due to annual maintenance. Unlike last year, this was the only major outage over the interface. With less planned transmission work, real-time export levels increased to be more in line with 2017-2019 values. Additionally, higher prices in New York resulted in higher export levels. The average real-time New York premium rose from $7.25/MWh in 2020 to $11.01/MWh in 2021.

Average hourly net interchange at the **Northport-Norwalk** interface increased by 56% in 2021 from 2020 levels. Net interchange averaged 84 MW per hour in 2021 versus 54 MW per hour in 2020 due to an increase in exports and relatively constant imports. Average hourly real-time imports increased by only 5 MW per hour, rising from 12 MW per hour in 2020 to 17 MW per hour in 2021. Whereas average hourly real-time exports increased by 52%, increasing from 66 MW per hour in 2020 to 101 MW per hour in 2021.

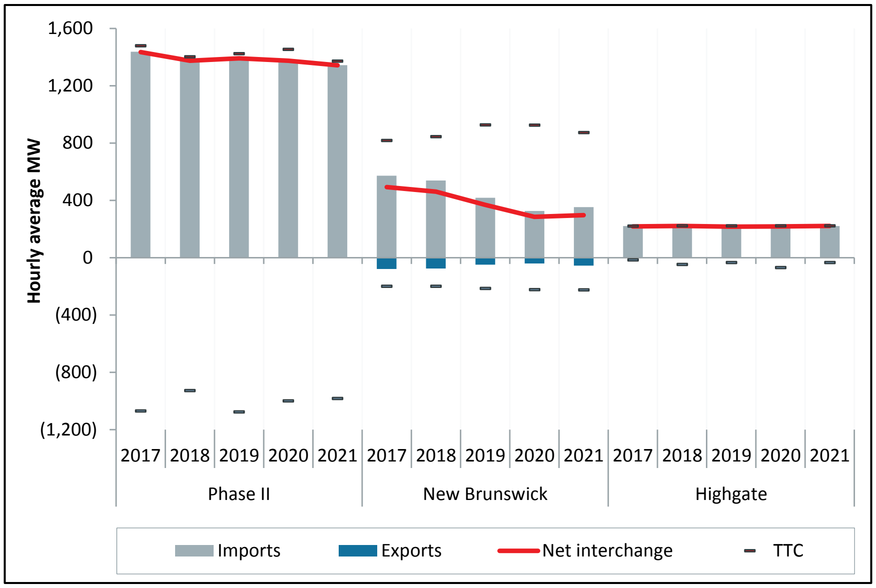
Canadian Interfaces

Annual hourly average real-time net interchange volumes and the gross import and export volumes at each Canadian interface are graphed for each year between 2017 and 2021 in Figure 5-2 below. The average hourly real-time total transfer capability (TTC) ratings for each interface in the import and export directions are also plotted using the black dashed lines.

[288] 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

[289] The New York Central-East interface limits power flows from the NY Central Zone to Eastern NY. It runs between NY's zones E and F and NY's zone D and Vermont. See https://www.nyiso.com/documents/20142/3692388/Total_East_S-16_Report_08102017_Final.pdf/7e867322-cab7-7174-ed54-c34fdf827ca2

Figure 5-2: Real-Time Net Interchange at Canadian Interfaces



New England continues to import significantly more power from Canada than it does from New York. Across all three Canadian interfaces, real-time net interchange averaged 1,860 MW per hour in 2021, a modest 1% decrease (16 MW) relative to 2020. New England predominately imports power from Canada, with a small amount of exports to New Brunswick.

5.2 Bidding and Scheduling

Import and export transactions may be submitted as either priced or fixed in both the day-ahead and real-time markets at a single external node.[290] A priced transaction is evaluated for clearing based on its offer price relative to the nodal LMP. A fixed transaction is akin to a self-scheduled generator offer; that is, there is no price evaluation and the transaction will be accepted unless there is a transfer constraint.

Day-Ahead Market

In the day-ahead market, external transactions establish financial obligations to buy or sell energy at external nodes. There is no coordination with other control areas when clearing day-ahead transactions. Participants can also submit up-to congestion (UTC) transactions. These transactions create simultaneous load and generation obligations where one of those obligations has to occur at an external node. These transactions clear based on the congestion and loss differences between the LMPs of the two nodes. UTC volumes have historically been very low, accounting for around 1% of cleared external transactions. All external transactions in the day-ahead market are cleared for whole-hour periods based on economics while respecting interface transfer limits.

[290] Virtual transactions, including up-to-congestion transactions, can also be submitted at external nodes. However, the volumes are very small compared to export and import volumes.

Real-Time Market

Unlike the day-ahead market, scheduled real-time transactions define the physical flow of energy that will occur between control areas. In addition to import and export transactions, participants may also wheel energy through New England, flowing between two external nodes. Wheel-through transactions are evaluated as fixed transactions and flow unless there is a transfer constraint. The ISO-NE operators coordinate real-time tie flows with the neighboring balancing authorities based on joint acknowledgement that the transactions have been scheduled in each area and can be accommodated under operational criteria. At external interfaces other than New York North, transactions are scheduled 45 minutes ahead for a one-hour schedule.

At the New York North interface, where CTS is enabled, real-time transactions are submitted as interface bids instead of set bid prices. Interface bids indicate the direction of trade and the minimum price spread between the New York and New England prices the participant is willing to accept in order to clear. Additionally, interface bids are cleared 20 minutes ahead for 15-minute schedules (unlike the hourly schedules at the other external interfaces).[291]

External transactions clear in the day-ahead and real-time markets independently, although a single transaction can have day-ahead and real-time offers associated with it. A cleared day-ahead transaction does not automatically carry over to real-time; the participant must elect to also submit the transaction in real-time. Alternatively, the participant may choose to offer the transaction only in real-time. When a participant does submit a transaction with both day-ahead and real-time offers, there is some scheduling priority afforded during real-time. In particular, the day-ahead MW-amount cleared is scheduled as if it were offered as a fixed transaction in real-time unless the participant alters the offer price or withdraws the transaction in real-time.[292]

New York Interfaces

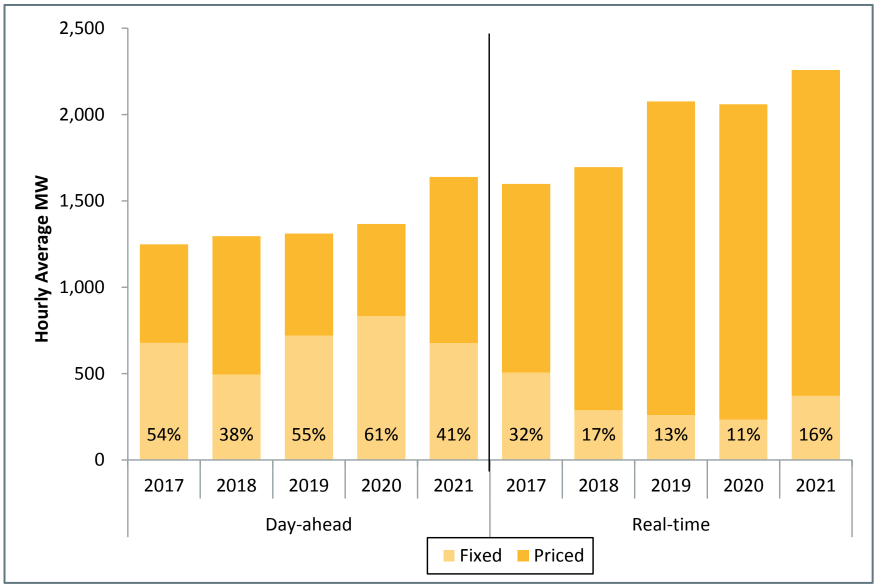
The composition of day-ahead and real-time cleared transactions (both imports and exports) at all the New York interfaces is charted in Figure 5-3 below for each year between 2017 and 2021.[293] The lighter orange series illustrates the total volume of cleared fixed transactions; the percentage is the share of overall cleared transactions that were fixed. The darker orange series illustrates the volume of cleared priced transactions. The volumes presented represent the annual average MW volumes per hour for each year.

[291] The clearing process *begins* 45 minutes before the 15-minute interval and ends 20 minutes before.

[292] This scheduling priority is not applicable to real-time interface bids at CTS locations.

[293] Refer to Section 2.4 for details of the external nodes associated with the New York, Québec, and New Brunswick.

Figure 5-3: Cleared Transactions by Market and Type at New York Interfaces



The share of total priced day-ahead external transactions at the New York interfaces increased noticeably in 2021, from about 40% in 2020 to 60% in 2021. Most of the increase was due to an increase in the volume of priced exports, which more than doubled compared to the prior year, reaching their highest level over the reporting period in 2021. One driving factor behind this increase is the higher prices at the NYN interface, particularly due to constraints associated with the retirement of Indian Point 3 and congestion at Central-East interface as discussed in the preceding subsection.

In the real-time market, the split between priced and fixed transactions in 2021 was similar to 2020 with 84% of transactions being priced. Since the implementation of CTS in December 2015, all real-time transactions at the New York North interface are evaluated based on price, although participants may offer prices as low as -$1,000/ MWh, which effectively schedules the transaction as fixed.

The breakout of fixed and priced transactions by directional flow (import/export), at the New York interfaces is shown in Table 5-1 below. The values presented are cleared average MW per hour.

Table 5-1: Transaction Types by Market and Direction at New York Interfaces (Average Cleared MW per hour)

Market	Direction	Type	2017	2018	2019	2020	2021
Day-ahead	Import	Priced (MW)	195	447	323	308	382
		Fixed (MW)	577	441	699	815	639
		Priced (%)	25%	50%	32%	27%	37%
		Fixed (%)	75%	50%	68%	73%	63%
	Export	Priced (MW)	375	354	268	227	580
		Fixed (MW)	101	54	21	17	38
		Priced (%)	79%	87%	93%	93%	94%

Market	Direction	Type	2017	2018	2019	2020	2021
		Fixed (%)	21%	13%	7%	7%	6%
Real-time	Import	Priced (MW)	657	967	1,281	1,265	996
		Fixed (MW)	234	82	86	168	276
		Priced (%)	74%	92%	94%	88%	78%
		Fixed (%)	26%	8%	6%	12%	22%
	Export	Priced (MW)	436	442	536	563	892
		Fixed (MW)	272	205	175	65	95
		Priced (%)	62%	68%	75%	90%	90%
		Fixed (%)	38%	32%	25%	10%	10%

The average volume of cleared day-ahead transactions was 20% higher in 2021 compared to 2020 (1,367 MW in 2020 compared to 1,640 MW in 2021) driven by an increase in exports. Total cleared exports more than doubled in 2021, increasing by 154% in 2021. This increase was offset by a 9% decrease in imports. Imports accounted for 62% of cleared volumes in the day-ahead market. This is lower than in 2020, when 82% of hourly average cleared MW were imports.

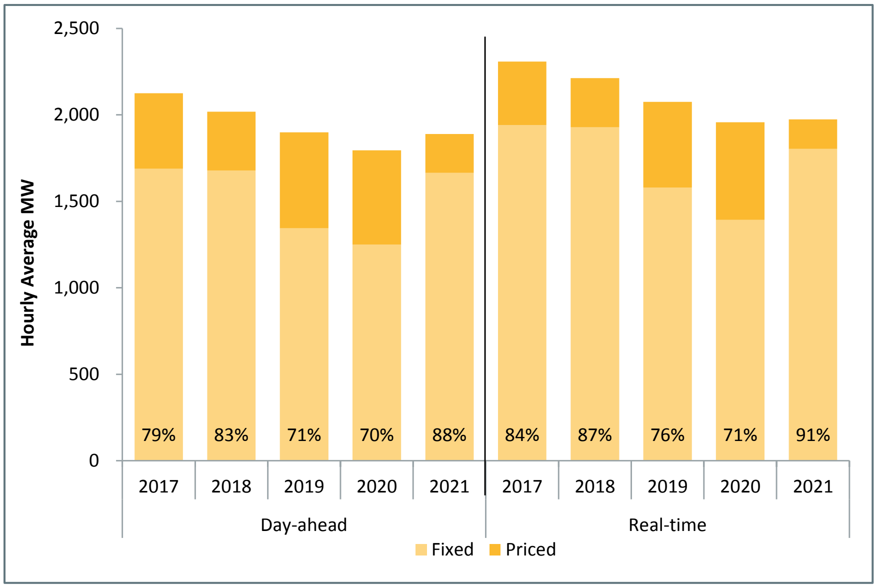
This increase in total cleared exports was attributed to activity at New York North due to higher New York prices. Most day-ahead cleared import transactions at the New York interfaces are fixed, while most exports are priced. In 2021, 37% of the average hourly cleared day-ahead import transactions at the New York interfaces were priced. This represents a 10% increase on 2020. Conversely, the majority of day-ahead export transactions at the New York interfaces continued to be priced.

In the real-time market, the majority of external transaction volumes continued to be priced transactions, on average. Table 5-1 shows a trend of increases in priced imports and exports over the entire reporting period. However, the average volume of real-time priced imports decreased for the first time over the reporting period in 2021, falling from 1,265 MW in 2020 to 996 MW in 2021. The average volume, and percentage share, of real-time fixed imports increased slightly in 2021, indicating that participants are less price sensitive in real-time and will flow power over the interface regardless of price differences.

Canadian Interfaces

The composition of transactions that cleared in the day-ahead and real-time markets at interfaces with the Canadian provinces is charted for 2017-2021 in Figure 5-4 below. The lighter orange series is the total volume of cleared fixed transactions and the percentage value is the share of overall cleared transactions that were fixed. The darker orange series is the volume of cleared priced transactions. The volumes presented are the average MW per hour values each year.

Figure 5-4: Cleared Transactions by Market and Type at Canadian Interfaces



There were lower volumes of priced transactions over the Canadian interfaces in both the day-ahead and real-time markets in 2021 than in 2020. In 2021, fixed transactions accounted for about 90% of volumes in both the day-ahead and real-time markets. This is consistent with 2017-2018 and higher than 2019-2020. As New England prices increase, participants transacting at Phase II might be less price sensitive and be willing to shift their bidding behavior toward fixed imports.

The breakout of fixed and priced transactions by directional flow at the Canadian interfaces is shown in Table 5-2 below. Here again, the values presented are average cleared MW per hour.

Table 5-2: Transaction Types by Market and Direction at Canadian Interfaces (Average MW per hour)

Market	Direction	Type	2017	2018	2019	2020	2021
Day-ahead	Import	Priced (MW)	418	327	544	529	184
		Fixed (MW)	1,677	1,667	1,336	1,242	1,664
		Priced (%)	20%	16%	29%	30%	10%
		Fixed (%)	80%	84%	71%	70%	90%
	Export	Priced (MW)	18	12	10	16	41
		Fixed (MW)	11	12	8	8	0
		Priced (%)	61%	50%	56%	69%	99%
		Fixed (%)	39%	50%	44%	31%	1%
Real-time	Import	Priced (MW)	354	275	487	559	150
		Fixed (MW)	1,871	1,859	1,539	1,358	1,767
		Priced (%)	16%	13%	24%	29%	8%
		Fixed (%)	84%	87%	76%	71%	92%
	Export	Priced (MW)	13	10	8	6	20
		Fixed (MW)	69	69	41	34	37
		Priced (%)	16%	12%	16%	16%	35%
		Fixed (%)	84%	88%	84%	84%	65%

Imports at the Canadian interfaces continue to be predominantly fixed. Years with the highest levels of fixed imports correspond to higher New England energy prices (2017, 2018, 2021). On the exports side, volumes are very small and have shifted more towards priced transactions.

5.3 External Transaction Uplift (Net Commitment Period Compensation) Credits

The ISO lacks sufficient information to calculate day-ahead or real-time congestion prices at non-CTS external nodes (i.e., the marginal cost of power on the other side of the interface).[294] In the day-ahead market the cost of relieving congestion is reflected in a transfer of uplift payments between those causing the congestion and those relieving the congestion.

Day-ahead uplift payments accrue when fixed import or export transactions exceed the TTC of the interface and offsetting interchange transactions (withdrawals or injections over the interface) are cleared to create counter-flow for the fixed transactions to clear. The participant with the offsetting transaction that provided the counter-flow *receives* the uplift and the participant with the fixed transaction that was allowed to clear is *charged* the uplift.

Absent congestion pricing, the day-ahead market applies a nodal constraint that limits the net injections at an external node to the transfer capability of each external interface. Offsetting injections (import transactions and virtual supply) and withdrawals (export transactions and

[294] Prior to CTS, this was the case at all external nodes. However, congestion pricing has been implemented for the New York North external node in both the day-ahead and real-time markets since December 2015, coincident with CTS implementation.

virtual demand) will be cleared so long as the interface limit is not exceeded. This means, for example, that a total volume of import transactions or virtual supply offers that exceed the import transfer capability can be cleared so long as offsetting export transactions or virtual demand bids are available. The clearing of these offsetting transactions does not affect the nodal LMP. The cleared offsetting export transaction or virtual demand bid is made whole up to its offer price.

Similar to generator out-of-merit credits, real-time uplift credits at external nodes are paid to priced transactions that prove to be out-of-merit for the hour. In the real-time energy market, external transactions are scheduled based on a comparison of the transaction price to the ISO-NE forecasted price for the external node.[295] If the actual real-time LMP for an external node is *less* than the offer price of a cleared *import* transaction at that node, the participant will receive uplift payments to be made whole to its offered price. Conversely, if the actual real-time LMP for an external node is *more* than the bid price of a cleared *export* transaction at that node, the participant will receive uplift payments to be made whole to its bid price. Real-time uplift payments to external transactions are only paid to priced transactions – fixed transactions are willing to clear at any price, and therefore cannot clear out-of-merit.

The annual uplift credit totals at all external nodes in both the day-ahead and real-time markets for each year from 2017 through 2021 are presented in Table 5-3 below.

Table 5-3: NCPC Credits at External Nodes

Year	Day-ahead credits ($ million)	Real-time credits ($ million)
2017	$0.56	$1.92
2018	$0.30	$2.73
2019	$0.02	$1.02
2020	$0.00	$1.39
2021	$1.04	$0.53

The total amount of uplift credits paid at external nodes is very small compared with other types of uplift (see Section 3.5). In the day-ahead market, we typically see these payments occur when there is a large decrease in an interface TTC until participants adjust their fixed bidding behavior.

Day-ahead uplift credits at external nodes increased from just over $1,000 in 2020 to $1.04 million in 2021. As noted above, day-ahead payments often coincide with transmission outages that lower the transfer capability of the interface. With a lower transfer capability, counter-flow transactions are cleared in order to bring the total cleared net power flow over the interface, when it exceeds the transfer limit, down to the constrained capacity. In 2021, outages constrained the Phase II and New Brunswick interfaces in January, June, October and December. About 80% of total day-ahead uplift at external nodes accrued during these months.

Total real-time external transaction uplift credits during 2021 were significantly lower than in 2020. This was due to two factors: 1) fewer transactions scheduled out-of-merit based on bid versus actual prices at non-CTS nodes and 2) a higher LMP that decreased any revenue shortfalls

[295] This is for non-CTS interfaces. For New York North (the only CTS interface) real-time interface bids are cleared based on forecasted price *differences* between NYISO and ISO-NE and are not eligible for uplift payments

created by out-of-merit scheduling. Almost all of the decrease in 2021 external uplift was due to decreased payments at all three of the Canadian interfaces. In 2021, the frequency of payments (the number of transactions that received uplift) as well as the amount of MWs associated with those transactions decreased significantly. In 2020, a total of approximately 345 thousand MWs, scheduled between 2,940 transactions, flowed out-of-merit and received a make-whole payment. In 2021, the out-of-merit power flow dropped to 35,000 MWs scheduled across 361 transactions. In addition to the volume of out-of-merit transactions, the decrease in payments is a function of higher LMPs rather than price forecast accuracy improvement. In fact, the price forecast appears to be worse in 2021 than in 2020; the average forecast error across the three interfaces increased from less than $1.00/MWh in 2020 to over $4.00/MWh in 2021. However, the average actual price across the three interfaces increased from $21.85/MWh in 2020 to $42.14/MWh in 2021. Since uplift is paid based on a revenue shortfall between *actual LMP revenue* and *bid price*, even with a less accurate price forecast, a higher nodal price would decrease any revenue shortfall.

5.4 Coordinated Transaction Scheduling

In December 2015, ISO-NE and the New York Independent System Operator (NYISO) implemented coordinated transaction scheduling (CTS) at the New York North interface.

The ISOs designed CTS to better optimize real-time power flow between New England and New York; more specifically, to facilitate the flow of more power from the lower- to higher-cost region and better converge prices between the control areas. To accomplish these goals, the ISOs made changes to interface bid and offer scheduling and settlement.[296]

Table 5-4, below, summarizes CTS design features. The header of the table shows the purpose of each feature.

Table 5-4: CTS design features[297]

CTS features that reduce inefficient schedules	CTS features that increase efficient bidding opportunities	No longer needed under CTS
Unified New York and New England's bid submission and clearing processes	Reduced schedule duration from one hour to 15-minutes	Discontinued real-time NCPC credits for out-of-merit schedules driven by ISO forecast error[298]
Reduced schedule duration from one hour to 15-minutes	Eliminated transaction fees, including NCPC charges	
Decreased time between bid clearing and power flow		

Since CTS is a coordinated process between ISO-NE and NYISO, CTS transactions are not scheduled with the real-time market software that generates desired dispatch points (DDPs) and LMPs.

[296] External bids and offers are "scheduled" to flow based on forecasted prices over a pre-specified time period (under CTS schedules are set in 15-minute blocks).

[297] The design basis documents, FERC filing materials, and implementation documentation describing the CTS design in detail can be found on the ISO-NE key project webpage: http://www.iso-ne.com/committees/key-projects/implemented/coordinated-transaction-scheduling/

[298] Pre-CTS the NYN interface, along with the other New England interfaces, paid NCPC credits to scheduled external offers when price forecast error led to uneconomic scheduled transactions. In other words, when transactions forecasted to be in-the-money flowed despite being out-of-the-money when prices materialized.

Rather, CTS scheduling is based on price forecasts from each ISO. As a consequence, CTS schedules are not always economic after energy prices are determined. When forecast error causes uneconomic CTS schedules, participants are not compensated for losses. Uneconomic schedules, driven by ISO forecast error, dampen the positive impacts of CTS by working against the functions of CTS design. In other words, forecast error *increases* inefficient scheduling and *decreases* efficient bidding opportunities. 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.

This section is broken into three subsections: the first measures CTS performance against its high-level primary goals. The second addresses CTS impacts on inefficient scheduling. The third subsection addresses CTS impacts on efficient bidding opportunities.

5.4.1 CTS performance against high-level goals

The high-level goal of CTS is to improve the efficiency of interface flows between New England and New York. 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 between 2017 and 2021 is shown in Table 5-5 below. The percentage of time power flowed into each control area is shown in the *Net Flow* columns.[299] The percentage of time the flow was directionally correct (i.e., power flowed from lower- to high-cost region, based on the forecasted or actual prices) is shown in the *Correct Flow* columns. The prices used in this subsection are proxy prices that represent the marginal cost of energy on each side of the NYN interface.[300]

Table 5-5: 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
2017	61%	39%	67%	61%
2018	77%	13%	61%	63%
2019	91%	9%	49%	58%
2020	95%	5%	40%	55%
2021	69%	31%	52%	56%

Power flowed into New England from New York 69% of the time, much lower than the 95% of hours in 2020. Although ISO-NE exported over the NYN interface more often in 2021, the impact on *correct* flows was modest. In 2021, power flowed in the correct (economic) direction, based on the

[299] 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 2021 there were 277 MW of fixed-wheeling transactions importing over the NYN interface in each interval.

[300] 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.

actual price spread between New York and New England 56% of the time – a similar percentage of time to 2020 (55%).

CTS's ability to adjust interface flows is limited by two constraints: the total transfer capability (TTC) and the ramp limit of the New York North interface. The normal TTC of the New York North interface is between 1,400 and 1,600 MW when importing and 1,200 MW when exporting to New York. The ramp limit restricts the net interface flow from changing by more than 300 MW in each 15-minute interval.

Ideally, power would flow from the control area with lower energy prices to the control area with higher prices until either:

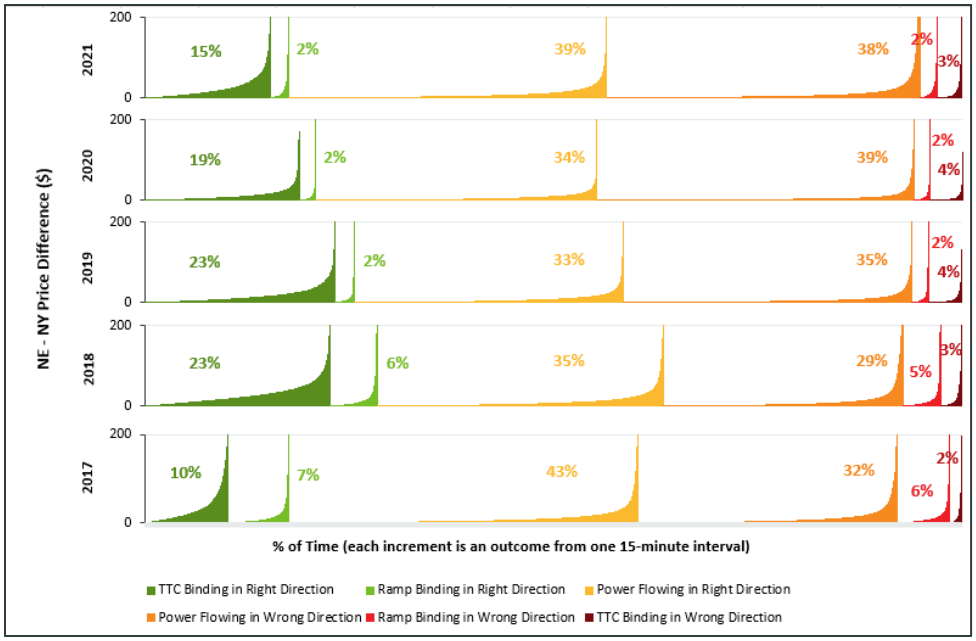
- the prices converge,
- the TTC binds, or
- the ramp limit of the interface binds.

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 5-5 below.

- The green areas on the chart represent CTS's 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 least attractive CTS 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.

The overall price difference between control areas is shown by the height of the area, in descending order of price difference.

Figure 5-5: 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 2020 (55%) and 2021 (56%). However, in 2021, CTS worked as efficiently as possible by flowing up to the TTC or ramping at the limit in the correct direction (the green areas) only 17% of the time, 4% less often than in 2020.

As a primary consideration for the implementation of CTS, it is important to evaluate CTS's impact on price convergence. The height of each bar in Figure 5-5 above, represents the absolute price difference in each interval. Less area under each curve represents better price convergence. In 2021, the average absolute price difference (the average of the lines in each year) between NE and NY was $12.76, 86% higher than in 2020. However, overall NE LMPs were 92% higher in 2021 (not shown). So as a percentage of average LMPs, the absolute price difference in 2021 was similar to 2020, 30% in 2021 vs. 31% in 2020.

Price differences between regions exist for many reasons and cannot be completely eliminated by CTS. CTS's ability to converge prices is limited by the price levels and elasticity in each control area and the TTC and ramp constraints of the interface. However, when prices differ between control areas and neither the TTC or ramp constraint is binding, CTS is not converging prices optimally.

Figure 5-6 below shows the available unused capacity up to the nearest TTC or ramp constraint that could be used to converge prices at different degrees of regional price separation in 2021. 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. 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 would result in a larger price difference. However, this scenario is less likely as the price difference gets larger.

Figure 5-6: CTS unused capacity[301]

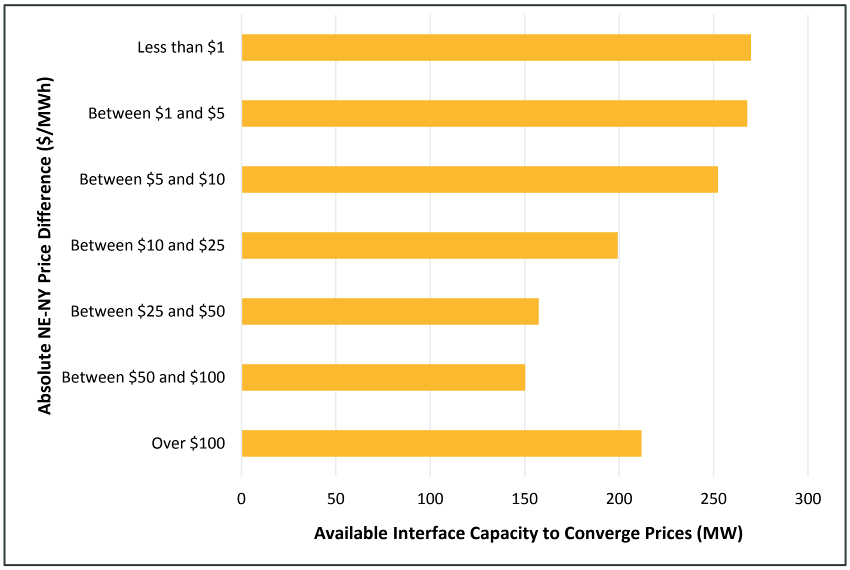


Figure 5-6 highlights that in 2021, even when the price difference between regions is high, on average CTS did not fully utilize the TTC or ramp constraint allowances to converge prices. Even in scenarios where price differences were between $50 and $100 per MWh, there was 150 MW of average unused interface capacity. Since implementation, CTS has consistently left NYN interface capacity underutilized. Although it is difficult to attribute price differences in New England and New York to CTS, Figure 5-6 indicates that CTS is not effectively utilizing all available capacity to improve price convergence.

5.4.2 CTS impacts on inefficient ISO scheduling

As discussed above, one of the primary functions of CTS is to improve the efficiency of ISO scheduling of external transactions.

Price forecasting is core to CTS's scheduling efficiency. Price forecasts are calculated for each 15-minute interval and used to determine the price differences between the regions. These forecasted price differences then determine which participant bids are scheduled. ISO-NE creates its CTS price forecast using current offers and system conditions 45 minutes ahead of the scheduling interval. The NYISO forecasts its internal price at about 30 minutes ahead of the scheduling interval.

The ISOs eliminated NCPC for schedules clearing uneconomically when CTS was implemented. CTS participants are not compensated when energy-price incentives are misaligned with CTS transaction schedules. The resulting risk reduces efficient bidding opportunities and impacts rational bidding behavior.

A summary of forecast versus actual prices, as well as the average and absolute forecasting errors, is provided in Table 5-6 below. Similar to above analyses, unless otherwise noted (i.e., in the *Spread, with Cong.* column), NYN proxy prices net congestion are shown to better capture the marginal cost

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[301] 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.

of energy on each side of the interface.[302] Some column titles are colored to facilitate tying table values to the text below.

Table 5-6: 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
2017	$33.62	$30.76	$2.87	($0.36)	$34.97	$29.66	$5.30	$1.34	($1.09)	$2.44	$8.17	$6.84	$12.31
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

Price forecasting continues to be a challenge for the ISOs. The *Average Absolute Forecast Error* columns ignore directionality and show the amount that the forecast differed from the actual prices. The average absolute forecast error indicates that between 2020 and 2021 CTS forecasts became less accurate on an absolute basis, increasing from $6.34 to $10.78/MWh between 2020 and 2021.

The *Average Forecast Error* columns take direction into account. Since 2018, ISO-NE prices have been higher than the forecast, while NYISO prices have on average been lower than the forecast. Because these errors are in opposite directions, they are additive - the forecast error in the spread is larger than each ISO's individual forecast error.

The *Actual LMP - Spread* column shows that ISO-NE energy prices have been consistently higher than NYISO energy prices in the reporting period. However, due to congestion over the interface, New York settled prices are *higher* than New England settled prices, shown in the *Actual LMP – Spread, with Cong.* column. Interface constraints, coupled with bid and offer behavior from CTS participants drive a sub-optimal outcome where, on average, bids and offers converging prices (i.e., moving energy from the lower- to higher-cost region) are loss-generating. This occurs when participants make bids and offers that are less than zero (i.e., willing to clear at a loss).[303]

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 hedge the real-time position in the day-ahead market and submit low-priced real-time transactions to minimize the chance of deviating from the day-ahead schedule.

[302] 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.

[303] 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).

Table 5-7 shows the average bid prices of 2021 bids and offers submitted in each price bin, along with forecasted and settled LMPs.[304] 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 2021.

Table 5-7: Profit Scenarios

Bid Price Bin ($/MWh)	Average Bid Price ($/MWh)	Forecasted LMP Difference ($/MWh)	Settled LMP Difference ($/MWh)
Less than -$25	($674.23)	($2.54)	($1.43)
-$25 and -$5	($14.88)	($0.91)	($0.95)
-$5 and $0	($2.35)	$3.02	$0.83
$0 and $5	$2.48	$5.84	$1.61
$5 and $25	$8.14	$13.56	$6.55
Greater than $25	$48.90	$65.14	$4.99

Table 5-7 above shows how forecast error has impacted CTS participants in each bid and offer price bin. Due to price forecast error, positively-priced bids were, on average, loss generating (i.e., scheduled transactions with positive costs were uneconomic once prices materialized). Additionally, settled LMP differences were negative for bids priced at less than -$5/MWh, indicating that, although the bids are economic based on the offer price, too much power is moving counter-intuitively, from the higher- to lower-cost region. However, as discussed above in the forecast error analysis, this is driven by the negatively-priced bids setting price when the interface is congested. CTS price forecast error exposes participants to risk when bids are positively priced, and risk of setting price at a loss for negatively priced bids. 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. As a consequence, the NYN interface lacks the level of price sensitive bids and offers needed to adjust to regional price differences.

5.4.3 CTS impacts on participants' efficient bidding opportunities

Inefficient scheduling due to forecast error reduces efficient bidding opportunities. In this subsection, we examine actual participant bidding behavior.

Average CTS transaction curves, by year, are shown in Figure 5-7 below. Import offers for 2021 are shown in the first graph (gold curves) followed by 2021 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

[304] To better compare LMPs with bid prices, forecasted and settled LMPs in this table are weighted by scheduled MWs, reflect external congestion, and price differences are shown 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.

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.

The x-axis shows the spread of New England and New York prices – positive numbers indicate higher New England prices. When New England prices are higher (i.e., the price spread is positive), the expectation is that more imports and fewer exports are willing to clear.

The y-axis shows the volume of energy that would clear, on average, at each price spread. For example, in 2021, at a price spread of $0/MWh (i.e., NE price is equal to the NY price), about 1,000 MW of imports would have cleared, 500 MW of exports would have cleared, and the net flow of CTS transactions would have been 500 MW, on average. The typical import TTCs, less the average number of wheeling transactions, are shown in dotted lines as well.[305] The net imports cannot clear above these lines, and when the price difference is forecasted to be greater than the intersection (about $11/MWh New England – New York when the TTC is 1,200MW) a CTS bid will set the congestion prices at NYN.[306]

Figure 5-7: Price Sensitivity of Offered CTS Transactions

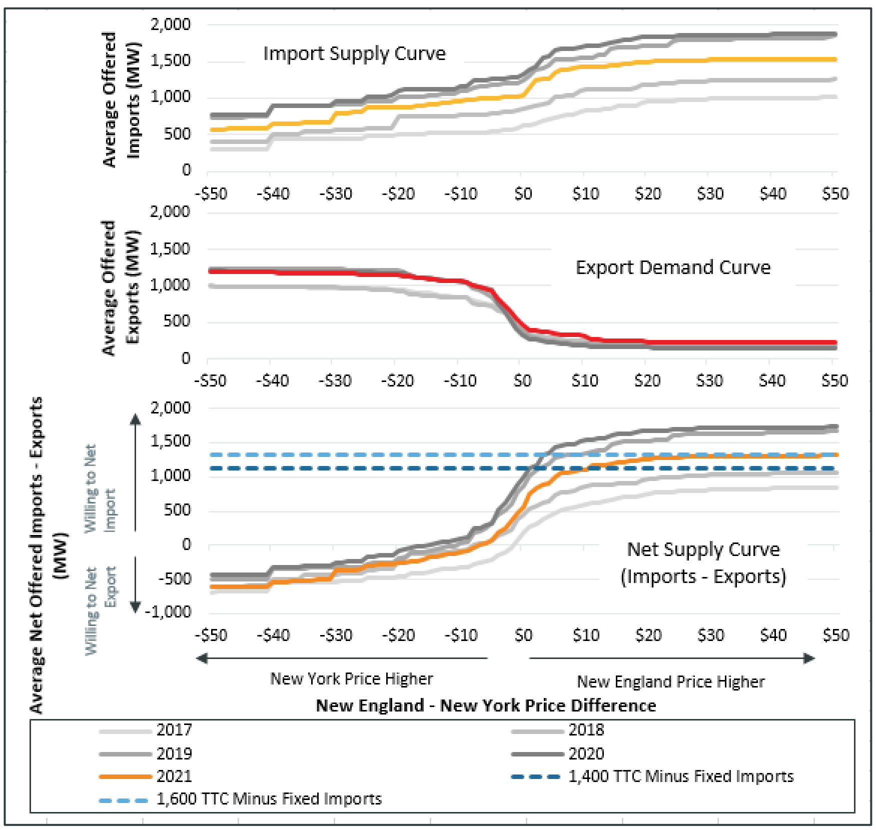

Figure 5-7 highlights a few key takeaways about participant bidding behavior. First, on average, there are many price-insensitive imports willing to clear in each interval; about 576 MW of imports are willing to clear in each hour at a greater than $50/MWh loss. Because of the large number of

[305] The export TTC (plus wheeling transactions) is not shown because the average net imports curve does not cross the limit.

[306] 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.

price-insensitive imports, CTS participants, as a whole, are net importers even when prices are up to $7/MWh lower in New England. Additionally, a relatively small New England price premium – about $11/MWh – is enough to bind the TTC when the TTC is 1,400 MW. Between 2020 and 2021, there was a 430 MW decrease in net imports at a price difference of $0/MWh, on average.

The large quantity of price insensitive bids reflect price-insensitive participants with day-ahead positions. 47% of exports and 72% of imports scheduled in real-time were hedged with a day-ahead position. When bids and offers that are not backed by a day-ahead position are removed, the supply and demand curves appear to be much more price sensitive (i.e., less willing to flow power from the higher- to lower-cost region).

Price forecast error makes price-sensitive bidding at CTS risky. Many participants clear bids in the day-ahead market and go on to offer price insensitive bids in real-time. Though this is a reasonable strategy to mitigate forecast error risk, this bidding strategy prohibits CTS from adjusting to changes in price between New York and New England.[307] Because 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.

[307] This section highlights CTS mechanics that muddy participant incentives. In reality, market participants may offer in ways that appear uneconomic for many reasons, including capturing environmental credits or long-term contracts.

Section 6
Forward Capacity Market

This section reviews the performance of the Forward Capacity Market (FCM), including key trends in resource participation, auction prices and auction competitiveness.

Overall, the FCM has achieved its design objectives of attracting new efficient resources, maintaining existing resources and sending price signals for the exit or retirement of less efficient resources. Capacity prices resulting from the Forward Capacity Auctions (FCAs) have fluctuated in line with how the region's surplus capacity has changed.

Summary of FCA Trends Covered in this Section

The first seven FCAs, for the commitment periods between June of 2010 and May of 2017, experienced relatively stable capacity prices resulting from surplus capacity and administrative price-setting rules. In contrast, in FCA 8 the retirement of over 2,700 MW of older nuclear, coal- and oil-fired generators reduced the region's capacity surplus and produced higher capacity prices. Payments for capacity commitment period (CCP) 8 reached $3 billion, a 162% increase in payments from the prior commitment period ($1.2 billion).

The trend of minimal surplus and increased capacity payments continued into 2018-19. As capacity prices increased, new suppliers entered the market in FCAs 9 and 10 and increased the amount of system capacity, leading to a decline in prices. This pattern of increasing prices followed by decreasing prices is what one would expect in a market that is gaining new and losing older generators as it oscillates around an equilibrium. Further, planned transmission improvements, coupled with an increase in the number of resources competing in the auctions, increased the capacity market's overall competitiveness. FCAs 11-14 saw continuous decreases of clearing prices even absent of significant new entry. FCA 15 saw the first clearing price increase since FCA 8, accompanied with significant price separation between the Rest-of-Pool, export-constrained Northern New England, and import-constrained Southeastern New England capacity zones.

The clearing price in the most recent auction, FCA 16, was $2.59/kW-month in the Rest-of-Pool capacity zone, $2.64/kW-month in the Southeastern New England capacity zone, and $2.53/kW-month in the Northern New England capacity zone. The price separation in these zones reflects the export- and import-constrained nature of certain areas in the New England grid. Payments are expected to reach $1.0 billion for FCA 16, $0.3 billion less than the expected payments for FCA 15. A total of 1,863 MW de-listed from the auction, with 256 MW (13%) coming from resource retirements and the remainder for a period of one year. New cleared capacity cleared 576 MW, with the largest portion of new capacity comprising solar projects (208 MW).

This section is structured as follows:

- Section 6.1 provides a high-level overview of the market design, summarizing resource qualification, auctions mechanics and performance incentives.
- Section 6.2 summarizes overall payments made to capacity resources, including adjustments such as peak energy rent, shortage event penalties, and pay-for-performance.

- Section 6.3 summarizes the inputs and outcomes of the most recent forward capacity auction, FCA 16.[308]
- Section 6.4 reviews key trends in primary (FCA) and secondary capacity trading.
- Section 6.5 focuses on trends in the resource mix and the major new entry and exit of resources that have shaped those trends.
- Sections 0 and 6.7 present metrics on the structural competiveness of the FCAs. They also describe mitigation measures in place to address the potential exercise of market power, and provide statistics on the extent to which uncompetitive offers were mitigated.

6.1 Forward Capacity Market Overview

The Forward Capacity Market (FCM) is designed to achieve several market and resource adequacy objectives. First, the FCM provides developers of new resources and owners of existing resources an additional revenue source. The FCM or "capacity" revenue is intended to offset the revenue shortfall or "missing money" that arises as a result of marginal-cost bidding and administrative offer caps in the energy market. Second, a developer or owner will know their capacity payment rate ($/kW-month) for the first year of commercial operation in advance of starting construction of a new resource, or making a significant capital investment in an existing resource. Third, the FCM provides all owners (of a new or existing resource) with financial incentives to operate and maintain their resource so it is available during system shortage conditions. Finally, the FCM's descending clock auction is designed to produce a market-based price for capacity by selecting the least-cost set of qualified supply resources that will satisfy the region's price-sensitive demand needs.

The FCM provides Additional Revenue to Capacity Developers and Owners

If New England's energy markets included sufficiently high scarcity pricing, resource owners would have the opportunity to earn infra-marginal rents (the difference between energy market prices and their resource's variable costs) to cover fixed costs, earn reasonable profits, and earn a return on capital investments in the long run. Marginal-cost bidding and energy market offer caps limit energy market prices and prevent investors from earning significant profits in the energy market that would cover their fixed costs. The gap between the revenue developers need to justify capital investments and the revenue available to fund those investments is often termed "missing money." This "missing money" is related to several specific terms used throughout this report, including Net Cost of New Entry (Net CONE), offer floor prices, net going-forward costs, and de-list bids.

The FCM's capacity prices and revenues are intended to facilitate efficient entry and exit decisions. That is, the market *should* attract new resources, maintain competitively-priced resources, and retire uncompetitive resources while meeting the region's resource adequacy standard in the most cost-effective manner. In FCA 13, this was not the case. Mystic 8 and 9 submitted retirement bids but were retained for fuel security within the Southeastern New England capacity zone, and entered into a cost-of-service agreement with the ISO.[309] The agreement suggests that the FCA could not facilitate an efficient *and* reliable solution as resource attributes (in this case fuel security) are not reflected in the CSO market product. In FCA 15, the cost-of-service agreement ended with the

[308] A more detailed review of FCA 16 is covered in the IMM Winter 2021/2022 Quarterly Markets Report, at https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor/

[309] For more information on the fuel security order see: https://www.iso-ne.com/static-assets/documents/2018/12/fuel_security_order.pdf

acceptance of transmission proposals and updated fuel security reviews, allowing Mystic 8 and 9 to retire effective June 1, 2024.[310]

The FCM provides Resource Owners with Reasonable Certainty about the Future

The FCM procures capacity through an auction mechanism 40 months in advance of when it must be delivered in the energy markets. The delivery period is known as the capacity commitment period (CCP). A resource that successfully sells its capacity in the auction assumes a capacity supply obligation (CSO) and is expected to deliver capacity at the start of the CCP.[311] The long lead-time between the auction and the CCP was chosen to provide developers and owners with sufficient time to design, finance, permit, and build new capacity resources. The FCM also provides opportunities for secondary CSO trading through reconfiguration auctions and bilateral trading between the primary auction and the CCP. The volumes transacted in the secondary auctions are typically a small fraction of those in the primary auction.

The FCM provides Financial Incentives to Operate and Maintain Resources

The FCM provides financial incentives to owners to offer their resources competitively in the energy markets and to ensure the resource's availability during times of system shortage conditions. First, the tariff requires the owner of a capacity resource to offer its CSO into the day-ahead and real-time energy markets every day, provided the resource is physically available.[312] Second, changes known as the "pay-for-performance" (PFP) rules were made to the FCM rules starting with FCA 9 to improve resource performance.[313] Up to that auction, a resource owner faced *de minimis* financial penalties if it was unable to perform during shortage conditions. The rule changes improve underlying market incentives by replicating performance incentives that would exist in a fully functioning and uncapped energy market.

Pay-for-performance rules achieve this goal by linking payments to performance during scarcity conditions. Without this linkage, participants would lack incentives to make investments that ensure the performance of their resource when needed most. Also, absent these incentives, participants that have not made investments to ensure their resource's reliability would be more likely to clear in future FCAs because they could offer at lower prices. This can create a structural bias in the FCM to clear less reliable resources, which, over time, will erode system reliability. Paying for actual performance during scarcity conditions incents resource owners to make

[310] For more information on the end of the Mystic 8 and 9 cost-of-service agreement, see: https://www.iso-ne.com/static-assets/documents/2020/08/a7_fca_15_transmission_security_reliability_review_for_mystic_8_9.pdf

[311] Resources are subject to penalties if their generation capacity does not meet their CSO at the start of the CCP. See Section 6.2.3, Delayed Commercial Operation Rules, for more information on these penalties.

[312] See Section III.13.6.1. of the tariff for more information.

[313] The PFP rules have been in effect since FCA 9, meaning that the settlement rules will be effective from the CCP beginning on June 1, 2018.

investments and perform routine maintenance to ensure that their resources will be ready and able to provide energy or operating reserves during these periods.[314]

The FCM produces Market-Based Capacity Prices

The ISO conducts a primary FCA every year, where supply of existing and new resources is procured to satisfy the system's resource adequacy needs. The FCA is conducted in two stages: a descending clock auction followed by an auction clearing process. The FCA results in the selection of resources that will receive a CSO for the future CCP, and capacity clearing prices ($/kW-month) for the period. The descending clock auction consists of multiple rounds. During the rounds, resource owners and developers submit offers expressing their willingness to keep specific MW quantities in the auction at different price levels. During one of the rounds, the capacity willing to remain in the auction at some price level will intersect the demand curve. At that point, the auction will stop and move on to the auction-clearing stage, which produces the capacity clearing prices and quantities with the objective of maximizing social welfare.

Inputs into the Forward Capacity Auction

The demand curve used in the auction is based on resource adequacy planning criteria that establish the installed capacity requirement (ICR).[315] Load-serving entities do not actively participate in the FCA. Instead, the willingness of demand to pay for capacity at certain levels of reliability (relative to ICR) is determined by an administrative demand curve. Over the 16 FCAs to date, the market has transitioned from vertical to sloped demand curves. A vertical demand curve, by definition, lacks price sensitivity and can therefore result in large changes in capacity prices at different quantity levels. Accounting for price elasticity through sloped curves reduces market price volatility; it allows the market to procure more or less than the ICR, and reduces the likelihood of activating any market protection mechanisms, such as price floors and caps.

The auction supply curve is based on offers from market participants seeking to enter new capacity into the FCM, and bids from market participants seeking to remove their existing capacity from the FCM. All other existing resources are price takers.

Market participants seeking to enter a new resource into the FCM must first go through a qualification process. At a high level, the process comprises two parts. First, the ISO determines the maximum capacity the resource can safely and reliably deliver to the system; this establishes the resource's "qualified capacity". Second, the new resource is subject to buyer-side market power mitigation rules, which are administered by the IMM. This is done through a cost-review process known as the Minimum Offer Price Rule (MOPR), which mitigates the potential for a new resource that receives out-of-market revenues to suppress capacity prices below competitive levels. A developer with a new resource wishing to remain in the auction below a benchmark minimum

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[314] PFP works as follows: a resource owner is compensated at the auction clearing price and is subject to adjustments based on its performance during shortage conditions. The PFP design replaced the shortage event rules in place through May 31, 2018. PFP is based on a two-settlement market built around the delivery of energy and operating reserves when they are needed most. If a resource fails to perform relative to expectation, it must buy the difference back at a performance payment rate. Under-performers will compensate over-performers, with no exceptions. Prior to PFP the consequences of poor performance were limited. Shortage events were rare, with only two occurring and each limiting penalties to a maximum of 5% of annual capacity revenues. Furthermore, the prior rules included numerous exemptions, which diluted performance incentives.

[315] The system planning criteria are based on the probability of disconnecting load no more than once in ten years due to a resource deficiency (also referred to as Loss of Load Expectation or "LOLE"

competitive offer price (known as an Offer Review Trigger Price) is required to provide cost justification for review and approval by the IMM.[316]

Once a new resource clears in a primary auction it becomes an existing resource and goes through a different qualification process. Similar to new resources, the high-level qualification process for existing resources, comprises two parts. First, a resource's qualified capacity for an auction is based on actual measured performance. Second, existing resources are subject to seller-side market power mitigation rules, which are also administered by the IMM. The cost-review process mitigates the potential for existing resources that have market power (as a pivotal supplier) to inflate capacity prices above competitive levels by withdrawing capacity from the market at an artificially high price. A participant submitting a request to remove an existing resource from the auction at a price above a competitive benchmark price (known as the dynamic de-list bid threshold) is required to provide cost justification for review and approval by the IMM.

6.2 Capacity Market Payments

This section provides an FCM payment overview, including trends in overall payments and pay-for-performance (PFP) outcomes in 2021. Payments in CCP 9 (2018/19) reached a record $4 billion. After the peak of CCP 9, projected payments declined by an average of $600 million each year through CCP 14. This was due to an increasing capacity surplus and lower clearing prices as new capacity entered the market. CCP 15 saw the first payment increase in six years, driven by an increase of clearing prices and a higher Net ICR. Immediately after, CCP 16 saw a decline in Net ICR[317], leading to lower clearing prices and decreasing projected payments close to the record low in CCP 14.

6.2.1 Payments by Commitment Period

Total payments for CCPs 9-16 and the Rest-of-Pool clearing price for existing resources are shown in Figure 6-1 below. The blue bars represent gross FCM payments by commitment period. Payments for CCPs 12-16 are projected payments based on FCA outcomes, as those periods have not yet been settled.[318] The green bar represents peak energy rent (PER) adjustments made in past commitment periods.[319] The red line series represents the existing resource clearing price in the Rest-of-Pool capacity zone.[320] Payments correspond to the left axis, while prices correspond to the right axis.

[316] The ISO has proposed to eliminate the MOPR and replace with a narrow form of buyer-side mitigation rules effective from FCA 19, following a 2-year transition period. See *Revisions to ISO New England Transmission, Markets and Services Tariff of Buyer Side Market Power Review and Mitigation Reforms*, Docket No. ER22- 1528-000, March 2022.

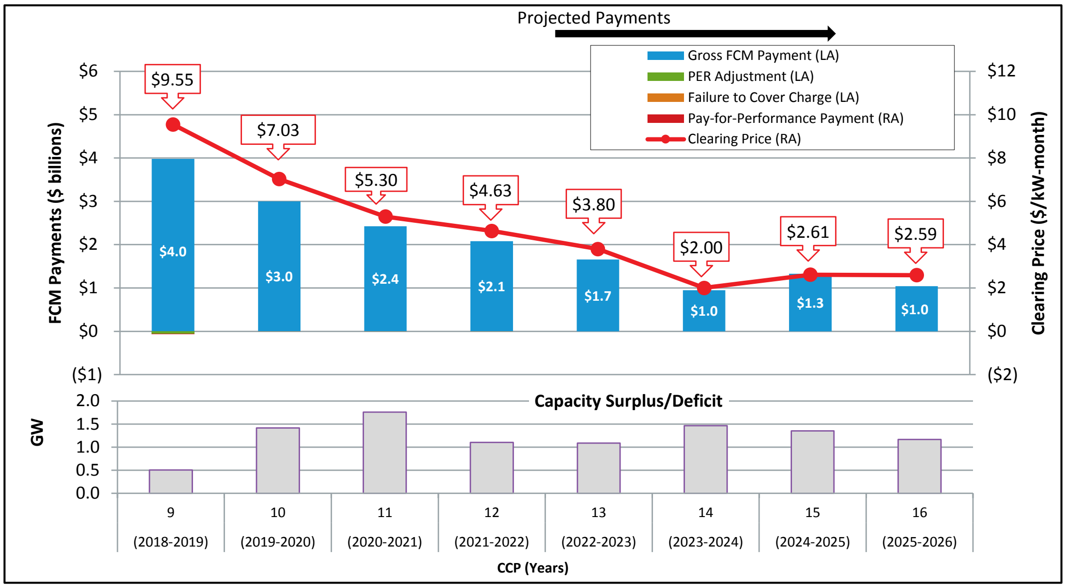
[317] The Net Installed Capacity Requirement (NICR) is the amount of capacity needed to meet the region's reliability requirements after accounting for tie benefits with Hydro-Quebec.

[318] Payments for incomplete periods, CCP 11 through CCP 15, have been estimated as: $FCA\ Clearing\ Price\ \times Cleared\ MW\ \times 12$ for each resource.

[319] The Peak Energy Rent (PER) adjustment decreased system-wide CSO payments when periods of abnormally high energy prices occurred. PER adjustments were eliminated for Capacity Commitment Periods from June 1, 2019 (CCP 10) onward.

[320] The Rest-of-Pool capacity zone is made up of all unconstrained import/export capacity zones.

Figure 6-1: FCM Payments by Commitment Period



High clearing prices for FCA 9 provided price signals to the market that new generation is needed. Over time, as more capacity cleared and Net ICR fell, clearing prices declined. System-wide clearing prices fell from $7.03/kW-month in FCA 10 to a low of $2.00/kW-month in FCA 14. With lower clearing prices, total payments are projected to decrease by 76% from CCP 9 to 14.

In FCA 15, capacity price rebounded slightly: an increase in Net ICR and removal of Mystic 8 and 9 in Southern New England resulted in a decreased capacity surplus and higher system-wide and zonal clearing prices. Higher clearing prices in FCA 15 increased projected payments to $1.3 billion. Finally, projected payments fell for FCA 16 along with clearing prices; total payments for CCP 16 are projected to be $1.0 billion, down $0.3 billion (21%) from projected payments for CCP 15, due to a decline in total capacity obligations (CSOs) and a lower price (or less price separation) in the import-constrained Southeastern New England (SENE) capacity zone.

6.2.2 Pay-for-Performance Outcomes

There were no Pay-for-Performance (PFP) events in 2021, and therefore no performance charges and credits. The absence of system events and scarcity pricing is discussed in more detail in Section 3.4.8. On September 3, 2018, three months after the implementation of the PFP rules, scarcity conditions were triggered over the course of about 2½ hours due to a combination of higher than anticipated loads and unplanned generator outages. Based on the performance scores of supply resources during the event, credits totaled $44.2 million and charges totaled $36.3 million, representing a small fraction of $4 billion in annual base payments for the corresponding CCP.[321]

[321] See Section 5 of the Summer 2018 QMR for more information on the September 2018 Pay-for-Performance event.

6.2.3 Delayed Commercial Operation Rules

On June 1, 2019, the ISO implemented rules to address resources holding capacity supply obligations (CSOs) with a delayed commercial operation date. The rules incent resources to cover their CSOs when they have not physically demonstrated the ability to offer capacity into the energy market. The failure-to-cover charge calculation penalizes resources for the difference of their maximum demonstrated output (MDO), or highest MW output from the previous six capacity periods, and their CSO. If the MDO is less than their CSO, the resource is charged the maximum clearing price from the FCA and associated annual reconfiguration auctions (ARAs) for all undemonstrated capacity.[322]

Since implementation in 2019, resources were charged roughly $1 million in CCP 10 (2019/20), $0.8 million in CCP 11 (2020/21), and $0.5 million over the first five months of CCP 12 (2021/22) for undemonstrated capacity.[323]

6.3 Review of the Sixteenth Forward Capacity Auction (FCA 16)

This section provides a closer review of FCA 16, the most recent primary auction held in February 2022. Further detail on the auction is contained in the IMM's Winter 2022 quarterly markets report.[324] This section is organized into two subsections. First, an overview of qualified and cleared capacity across a number of different dimensions is provided. Then the focus moves to auction results, with emphasis on the shift in the demand curve, auction competitiveness, and the results of the third substitution auction.

At the beginning of the auction, qualified capacity (37,630 MW) significantly exceeded the Net Installed Capacity Requirement (31,645 MW), by 5,985 MW. The Net Installed Capacity Requirement (NICR) decreased 1,625 MW from the prior year, driven by a decrease in the accompanying load forecast.[325] The auction closed in the fourth round for all capacity zones with a system surplus of 1,165 MW relative to NICR. As capacity exited the auction, prices fell below the dynamic de-list bid threshold (DDBT) price of $2.61/kW-month in the fourth round.

The Rest-of-Pool cleared just below the DDBT at $2.59/kW-month. In the Southern New England capacity zone, the import-constrained demand curve increased the clearing price to $2.64/kW-month for the zone while the export-constrained zones of Northern New England and Maine (nested) cleared slightly below the Rest-of-Pool at $2.53/kW-month.

Projected payments for FCA 16 ($1.0 billion) decreased 21% from the projected payments for FCA 15. A total of 1,540 MW of capacity dynamically de-listed (i.e., did not take on a CSO for one year) in round four, including 781 MW of oil-fired generation and 417 MW of gas-fired generation. New cleared capacity totaled 576 MW, with solar projects comprising the largest share at 208 MW. The

[322] After June 1, 2022, the Failure-to-Cover charge rate will be the clearing rate from a special run of the third ARA. The special run will include mandatory demand bids for all undemonstrated capacity.

[323] From June 2021 to November 2021, 15 generating and 4 demand response resources were charged $499,690 and $25,850, respectively, in failure-to-cover charges. A failure-to-cover charge data error in December 2021 has not been reconciled at the time of publishing this report. All charges in December 2021 have been omitted from this section's analysis.

[324] See https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor.

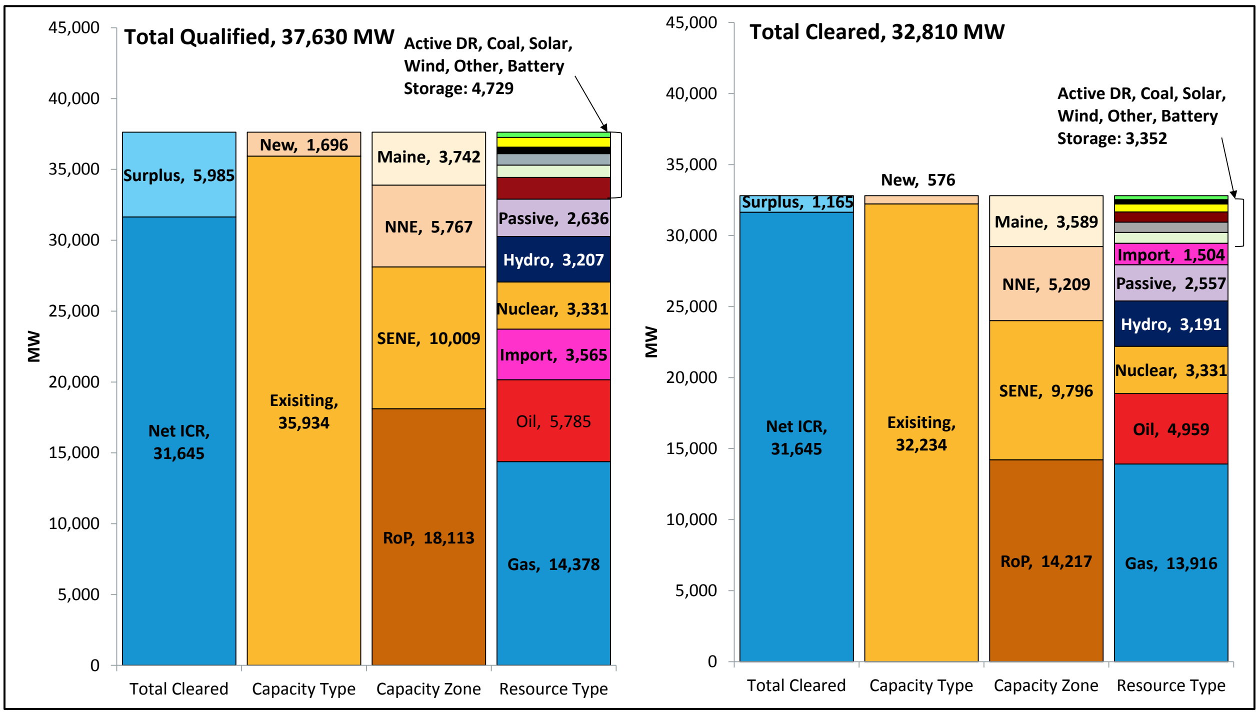
[325] For more information on the decrease in Net ICR, see Section 2.3.

substitution auction following FCA 16 did take place, but no resources cleared as all demand bids by existing resources were priced below all supply offers by sponsored policy resources.[326]

6.3.1 Qualified and Cleared Capacity

The amount of qualified and cleared capacity from new and existing resources compared to the capacity requirement provides an important indication of the level of potential competition in the auction. The qualified and cleared capacity in FCA 16 compared to Net ICR (blue bars) is illustrated in Figure 6-2 below. Qualified capacity is shown in the graph on the left and cleared capacity on the right.[327] The height of the stacked bars equals total capacity. Total qualified and cleared capacity are broken down across three dimensions: capacity type, capacity zone and resource type.

Figure 6-2: Qualified and Cleared Capacity in FCA 16



In FCA 16, qualified capacity exceeded Net ICR by 5,985 MW, or almost 19%. New qualified capacity totaled 1,696 MW, down by over 1,900 MW from the FCA 15 value (3,680 MW). New battery storage projects held the largest portion of new qualified capacity, totaling nearly 1,000 MW.

As excess supply declined during the auction rounds, the surplus fell from 5,985 MW of qualified capacity to 1,165 MW of cleared capacity in FCA 16. The capacity dropping out of the auction (4,820 MW) comprised both existing resources de-listing and new supply resources exiting the market at prices greater than the associated zonal clearing price. The first orange "Total Cleared" bar

[326] A sponsored policy resource is any resource that receives subsidies from the New England states to help cover investment costs. These resources typically comprise of renewable projects.

[327] The 632 MW of qualified capacity for Killingly Energy Center are excluded from the final qualified capacity amounts. Its capacity was terminated prior to the auction, and the termination decision was ultimately upheld by FERC after the auction.

(capacity type) in the figure on the right illustrates that existing capacity accounted for 98% of cleared capacity, leaving just 2% (576 MW) of capacity obligations held by new resources.

Three capacity zones were modelled in addition to Rest-of-Pool: the import-constrained zone of Southeastern New England (SENE), 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). The import- and export-constraints for SENE and NNE drove the price separation seen in FCA 16.

6.3.2 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 6-3 below.

On the *demand* side, the demand curve, Net CONE, and Net ICR are shown in black. FCA 16 was the third auction with a demand curve that relied solely on the Marginal Reliability Impact (MRI) methodology in the calculation of the sloped system and zonal demand curves. The MRI methodology estimates how an incremental change in capacity impacts system reliability at various capacity levels.[328] Net ICR and Net CONE are used as the scaling point for the MRI curve. Net CONE changed due to updated reference technologies in FCA 16.[329] The reference technology for FCA 16 reflects the break-even capacity payment ($7.47/kW-month) to cover the costs of a combustion turbine. The Net ICR value for FCA 16 was 31,645 MW, a significant reduction of 1,625 MW on the FCA 15 requirement. [330]

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 (dotted red line) and the demand curve, just below the dynamic de-list bid threshold (DDBT) price of $2.61/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.[331]

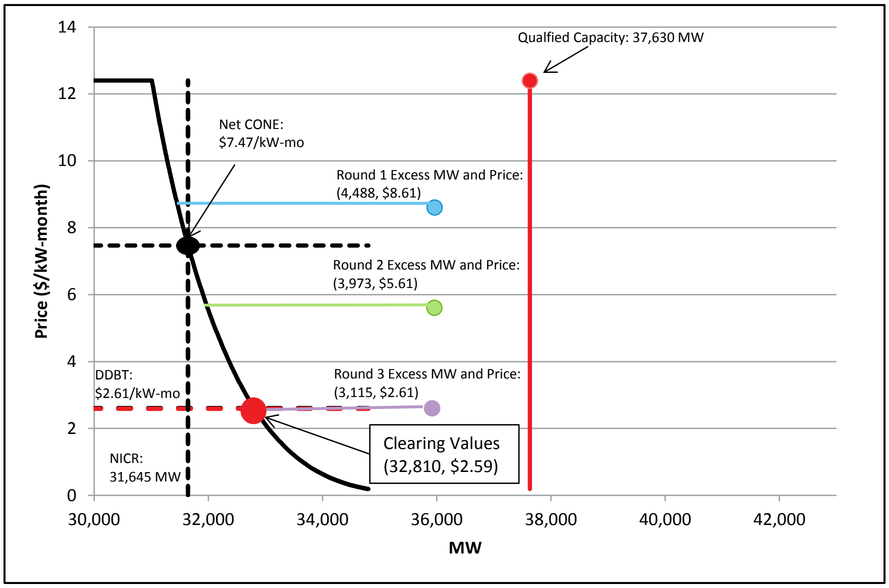
[328] Prior to FCA 14, a transitional approach was taken, with the demand curve reflecting a hybrid of the previous linear demand curve and the new convex-shaped MRI curve. The transition period began with FCA 11 and can last for up to three FCAs, unless certain conditions relating to Net ICR growth are met, pursuant to Section III.13.2.2.1 of the Tariff.

[329] The market rule requires the ISO to recalculate Net CONE with updated data at least every three years. See Market Rule 1, Sections III.13.2.4 and III.A.21.1.2(a). The study composed for the updated FCA 16 Net CONE calculation can be found here.

[330] See Section 2.3 for more information on changes to the Net ICR.

[331] The colored dots and lines move from cooler colors at higher prices and capacity, to warmer colors at lower prices and less capacity.

Figure 6-3: System-wide FCA 16 Demand Curve, Prices, and Quantities



The auction closed in the fourth round for all capacity zones and interfaces; however, differences in zonal capacity and supply led to price separation in Southeastern New England (SENE) and Northern New England (NNE). The fourth round opened with 3,115 MW of excess capacity at the system level (purple dot) and a price equal to the DDBT price, allowing existing resources to exit the market through dynamic de-list bids.[332] Given the surplus capacity conditions associated with prices below the dynamic de-list bid threshold, it is difficult for a participant to profitably exercise market power. Therefore, dynamic de-list bids are not subject to the IMM's cost review or mitigation.

In the Rest-of-Pool and SENE capacity zones, a fully-rationable dynamic de-list bid at $2.59/kW-month resulted in system-wide capacity precisely matching system-wide demand. Prior to analyzing the rationable bid, the clearing engine evaluated whether to clear (remove CSO) or not clear (award CSO) two dynamic de-list bids right below the $2.59/kW-month clearing price. The bids had a rationing minimum limit, meaning a minimum quantity had to be taken if the resources were selected. These de-list bids placed below the clearing price would typically receive a CSO, however, the clearing engine found awarding the minimum allowable amount of capacity to either resource would decrease social surplus. Therefore, the two de-list bids did not receive a CSO as they not result in an optimal solution given their lumpiness, even though their price was below the Rest-of-Pool clearing price.

Price separation occurred in the SENE capacity zone as zonal supply was less than zonal demand at the Rest-of-Pool clearing price of $2.59/kW-month. The clearing engine moved up the supply curve to see if the removal of the next available supply offer triggered the supply shortfall. The removal of this bid at $2.90/kW-month did not result in zonal supply falling short of zonal demand, so the clearing engine descended from $2.90/kW-month until zonal demand intersected zonal supply, which occurred at $2.64/kW-month.

[332] Excess system capacity only includes import capacity up to the capacity transfer limit.

Zonal demand exceeded zonal supply in the NNE capacity zone at the Rest-of-Pool clearing price of $2.59/kW-month. Descending down from $2.59/kW-month, the clearing engine found that fully clearing a fully-rationable dynamic de-list bid placed at $2.53/kW-month would have resulted in a shortage of zonal supply. The bid was then rationed to the MW amount that intersected zonal demand to zonal supply and the NNE clearing price was set at $2.53/kW-month.

Competitiveness

Prior to the auction, the IMM conducts a competitiveness assessment of bids and offers flagged by buyer-side (ORTPs) and seller-side (DDBT prices) market power thresholds for review. The detail and results of this review process are covered further in Section 6.7. After the auction, the IMM reviews participant behavior and whether any participants potentially exercised potential market power. However, the IMM does not assess every bid for consistency with costs. Dynamic de-list bids, which ultimately set the clearing price as described above, are not subject to an IMM cost review.[333] Ultimately, we found that since the supply curve in the fourth round was relatively flat (elastic), it is difficult for a market participant to profit from economic withholding given the small impact it would have on clearing prices (changes in quantity supplied have a small impact on price).

The pivotal supplier test, covered in detail in Section 0, is limited to pre-auction calculations and the application of mitigation to static de-list bids. However, capacity conditions change as the auction proceeds (new resources leave, existing capacity de-lists, the quantity demanded 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.[334]

Prior to the auction, the only capacity zone with a pivotal supplier prior was Southeastern New England (SENE) and there were no static-delist bids from any pivotal suppliers. During the auction, the zone entered the fourth round with approximately 856 MW of excess capacity. Of the suppliers with portfolios larger than the supply margin, none submitted dynamic de-list bids; the transaction which could, in theory, be employed to exercise seller-side market power in the unlikely event that this would be a profitable strategy. The rest of the system entered the fourth round with approximately 3,115 MW of excess capacity. No suppliers held portfolios larger than 3,115 MW, indicating no opportunities for exercising seller-side market power.

In summary, the IMM did not observe any bidding behavior of concern by pivotal suppliers during the auction. 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.

6.3.3 Results of the Substitution Auction (CASPR)

In FCA 13, the ISO introduced Competitive Auctions with Sponsored Policy Resources (CASPR). CASPR provides a market-based mechanism for state-sponsored resources to enter the FCM while maintaining competitive prices in the primary auction. The substitution auction is intended to

[333] Under the Tariff, as the DDBT is a proxy price intended to represent the net going forward costs of the likely marginal resource. See Docket No. ER18-620-000, Order Accepting Tariff Revisions, to update the DDBT price at https://www.iso-ne.com/static-assets/documents/2018/03/er18-620-000.pdf.

[334] 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 NICR or LSR, respectively).

accommodate new resources that secure out-of-market revenue through state-sponsored programs designed primarily to meet state environmental goals.

FCA 16 marked the fourth year with the substitution auction construct. In order to participate, resources submit demand bids and supply offers prior to the FCA; however, this does not guarantee inclusion in the substitution auction. Demand bids can consist of voluntary bids or retirement de-list bids from existing resources that received a CSO in the primary auction; supply bids come from new sponsored policy resources with minimum offer prices above the auction clearing rate. However, if the demand-bid resource de-lists their capacity or the supply-offer resource obtains a CSO, their respective bids will not enter the substitution auction.

Additionally, each resource with a demand bid is given a test price, an IMM-approved value that represents the competitive cost of obtaining a CSO. A demand bid is removed from the substitution auction if the primary auction clearing price falls below the resource's test price. Cleared supply offers obtain capacity from the FCA, while cleared demand bids shed capacity obtained in the FCA. Depending on whether the substitution auction-clearing price is positive, cleared supply offers are compensated, and cleared demand bids are charged, and *vice versa*.

In FCA 16, the substitution auction did proceed, but did not clear any capacity. Nearly 120 MW of supply offers entered the substitution auction at a weighted price of *negative* \$0.14/kW-month. Two demand resources submitted bids totaling 740 MW at a weighted price of *negative* \$3.26/kW-month. Despite offers from supply and the demand resources meeting all requirements to participate, the substitution auction cleared 0 MW as all demand bids were priced lower than the prices supply resources were willing to accept.

6.4 Forward Capacity Market Outcomes

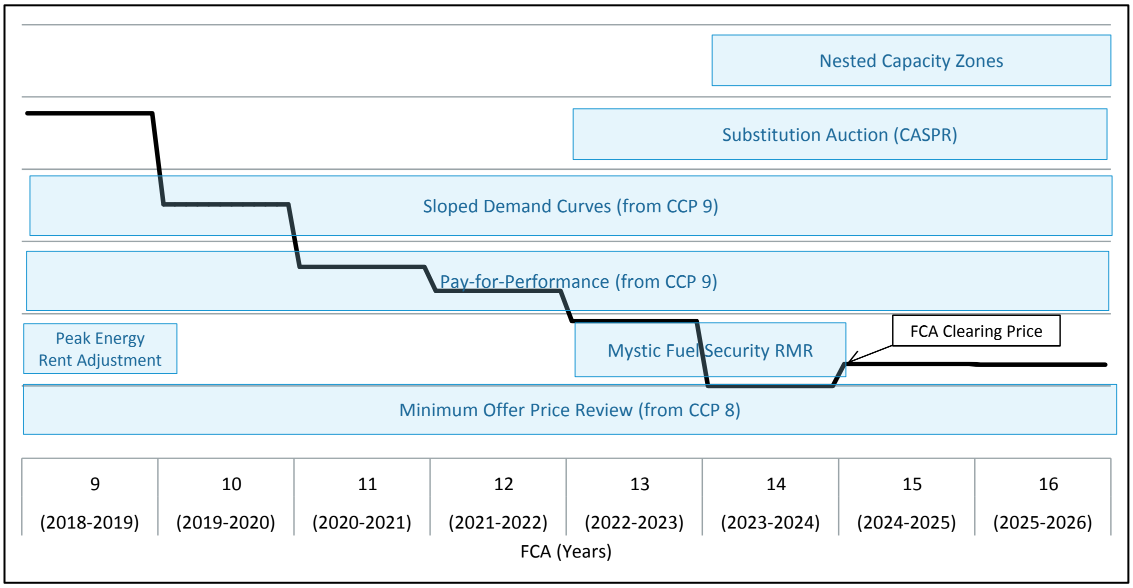
This section reviews the overall trends in prices and volumes in the FCM. It covers both the primary auction (FCA), as well as secondary trading of capacity in the substitution auction, reconfiguration auctions, and bilateral transactions.

6.4.1 Forward Capacity Market Outcomes

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.

It is also important to interpret pricing outcomes in the context of the market rules that were in effect at the time of an auction. This is particularly important, since the FCM has undergone a number of significant market rule changes in recent years. This is illustrated in Figure 6-4 below, which shows the trend in Rest-of-Pool FCA clearing prices against the backdrop of some of the major parts of the FCM rules that were in effect for some, but not for all, auctions.

Figure 6-4: FCA Clearing Prices in the Context of Market Rule Changes



FCA 9 introduced the sloped demand curve, improving price formation and reducing price volatility over the entire reporting period.[335] When the FCAs clear at a surplus, a sloped demand curve results in a price below Net CONE, as happened in all auctions in the reporting period. Following a 2-year transition period, as the system demand curve shifted to its ultimate non-linear form in FCA 11, the value of excess capacity diminished, and clearing prices continued to drop.

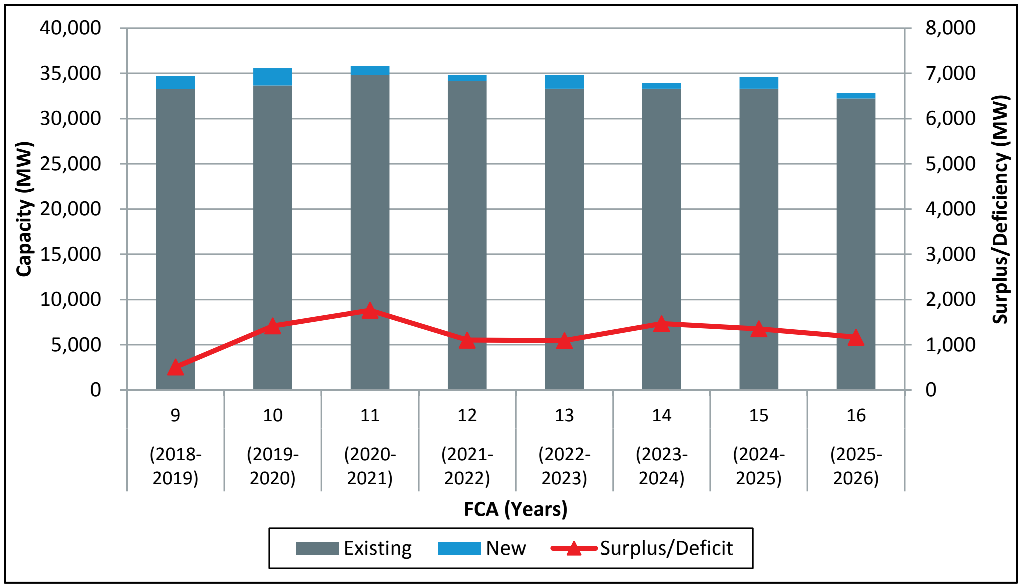
The minimum offer price rules (MOPR) were implemented in FCA 8; they are a form of buyer-side mitigation intended to ensure good price formation by mitigating the impact of below cost bidding (i.e., the ability to decrease prices below competitive levels). From FCA 9, the Pay-for-Performance (PFP) market rules replaced the shortage event penalty rules. The PFP rules placed a financial obligation on resources with capacity obligations to perform during capacity scarcity events. Combined, the MOPR and PFP rules encouraged a greater degree of active participation in the auctions, with more new and existing resources submitting offers in the auction.

In FCA 13, two rules were implemented with implications on price formation in the FCM. First, the ISO agreed to a cost-of-service agreement with Mystic 8 and 9, citing system-wide fuel security needs. The Mystic resources account for 1,413 MW of capacity (by CSO), and were treated as price-takers in the FCA. This had a downward impact on prices in FCA 13 and FCA 14 before the agreement ended in FCA 15. The second rule, CASPR, addresses the price-suppressing impact of state-sponsored resources in the FCA, along with the MOPR. These resources are often priced too high (after the application of MOPR) to clear in the FCA, but with CASPR they can potentially take on capacity obligations through participation in the substitution auction. This would help mitigate the impact of out-of-market revenues on the primary auction in the first year the new sponsored policy resources enters the market.

[335] 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.

The procured capacity relative to the Net ICR by auction is shown in Figure 6-5 below. The stacked bar chart shows the total cleared MWs in each auction, broken down between existing and new capacity resources. The red line (corresponding to the right axis) shows the surplus or deficit relative to Net ICR.

Figure 6-5: Cleared and Surplus Capacity, FCA 9 – FCA 16



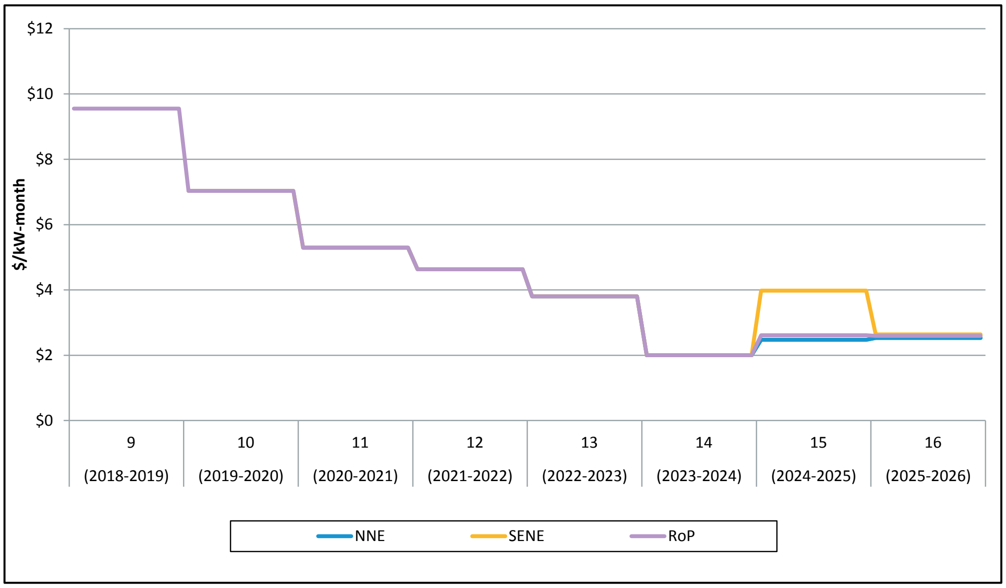
Since FCA 9, cleared capacity has exceeded net ICR, providing a net surplus of capacity on the system. The surplus has pushed clearing prices below Net CONE in all auctions, which signals the declining need for new entry and applies pressure on older and more-expensive generation to exit for single capacity periods or permanently.

After the capacity deficit and high prices in FCA 8 (not shown), the system rebounded to a surplus in FCAs 9 and 10 by attracting new entry, particularly from new combined-cycles. The capacity surplus reached its peak in FCA 11 (1,760 MW). The surplus declined in FCAs 12 and 13, primarily due to one-year dynamic de-lists. Once the auction price fell below the dynamic de-list bid threshold ($5.50/kW-month in FCA 12 and $4.30/kW-month in FCA 13), resources entered de-list bids to remove their capacity for the commitment period and the surplus fell to 1,100 MW in both auctions.

The surplus rose once again in FCA 14 to 1,500 MW, driven primarily by a decrease in the Net ICR of almost 1,300 MW. In FCA 15, cleared capacity rose by 665 MW over FCA 14, yet the Net ICR increased by 780 MW and contributed to a decrease in capacity surplus. FCA 15 saw over 900 MW of existing supply to dynamically de-list; new additions of battery storage (596 MW) and gas-fired generation (334 MW) drove a 1,121 MW influx of new supply. The surplus fell slightly in FCA 16, down to 1,165 MW. While the Net ICR decreased by 1,625 MW, cleared capacity decreased by a greater amount of 1,810 MW. Existing capacity delisted by 1,864 MW while only 567 MW of new supply was added to the system.

The changes in new and existing capacity clearing prices for each FCA are illustrated in Figure 6-6 below. The different colored lines represent the price paid to resources in each modeled capacity zone.

Figure 6-6: Forward Capacity Auction Clearing Prices



Prior to FCA 9, higher capacity prices sent a signal to market participants that load was willing to pay for more capacity that would improve system reliability. Clearing prices then fell steadily, beginning at $9.55/kW-month in FCA 9 and continued to drop in FCAs 10 and 11.[336]

In FCAs 12 through 16, the clearing prices dropped below the dynamic de-list bid threshold (DDBT) price. In each auction, the closing round started at the DDBT price. A dynamic de-list bid set the system-wide clearing price at $4.63/kW-month in FCA 12, at $3.80/kW-month in FCA 13, and at $2.00/kW-month in FCA 14.

In FCA 15, the Rest-of-Pool clearing price increased for the first time in six auctions, up to $2.61/kW-month. Significant decreases in capacity in the South Eastern New England (SENE) capacity zone, led by the retirement of Mystic 8 and 9, allowed the zone to clear one round earlier than the Rest-of-Pool (RoP), resulting in a higher $3.98/kW-month zonal clearing 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 fell to $2.48/kW-month, slightly below the RoP benchmark.

The Rest-of-Pool clearing price in FCA 16 was comparable to FCA 15, decreasing only two cents to $2.59/kW-month. Price separation also occurred in FCA 16, but at a much smaller scale than in previous auctions, allowing all zones to clear immediately after the dynamic de-list bid threshold was reached in the fourth round. The import-constrained SENE capacity zone cleared a few cents higher than RoP at $2.64/kW-month and the export-constrained zones of Northern New England and Maine (nested) cleared a few cents lower than RoP at $2.53/kW-month.

[336] Within SEMA/RI, the price separated in FCA 9 due to inadequate supply. The administratively-set prices were $17.73/kW-month for new resources and $11.08/kW-month for existing resources.

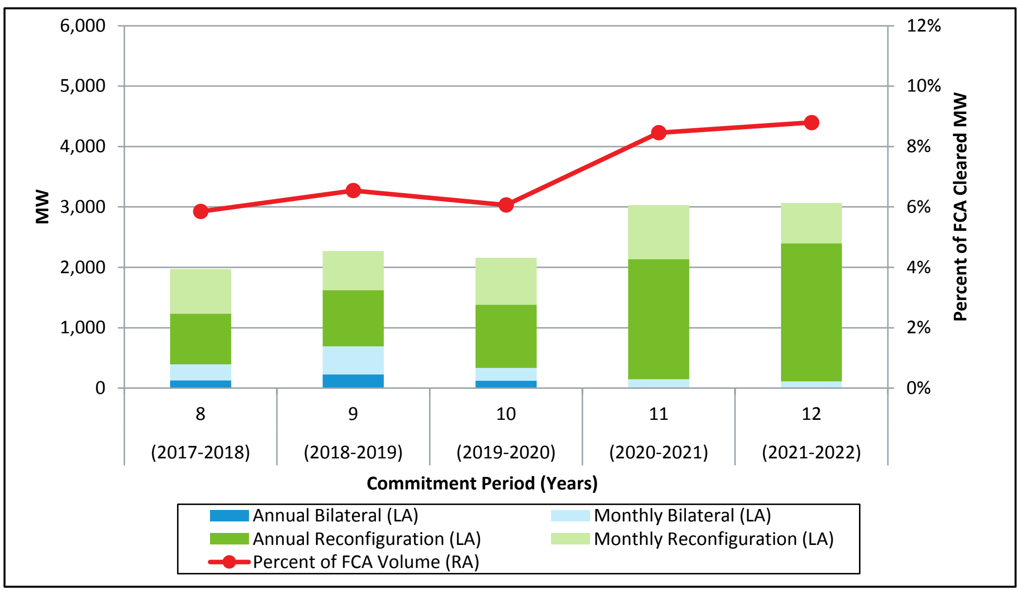
6.4.2 Secondary Forward Capacity Market Results

Reconfiguration auctions and bilateral transactions facilitate the secondary trading of CSOs. That is, they provide an avenue for participants to adjust their CSO positions after the primary FCA takes place.[337] Differences between the FCA and reconfiguration auction (RA) clearing prices can also present an opportunity for participants that obtained an obligation in the FCA to shed it at a lower price (i.e., they receive the FCA clearing price minus the RA clearing price).

Prices in the secondary markets are set through sealed-bid reconfiguration auctions or through bilateral agreements between parties. As the beginning of a capacity commitment period approaches, estimated system load is recalculated, which in practice has generally decreased the Net Installed Capacity Requirement (Net ICR) and diminished the value of surplus capacity.[338]

The average annual volume by secondary market products (stacked bars corresponding to the left axis) and volume as a percentage of cleared volume in the corresponding FCA (red line corresponding to the right axis) are shown in Figure 6-7 below.[339] Monthly and annual *reconfiguration auction* volumes are shown in green colors and monthly and annual *bilateral transaction* volumes in blue colors. Beginning in CCP 11, annual bilateral auctions (dark blue) were replaced by annual reconfiguration auctions with the introduction of annual reconfiguration transactions (ARTs).

Figure 6-7: Traded Volumes in FCA and Reconfigurations



[337] There are five opportunities for participants to adjust their obligations before the monthly commitment period. Immediately after the FCA occurs, the ISO holds a substitution auction. Before the commitment period, there are three annual reconfiguration auctions (ARAs) to acquire one-year commitments. There are twelve monthly reconfiguration auctions (MRAs) held starting two months before a capacity commitment period. Windows for submitting bilateral transactions are open around the reconfiguration auctions.

[338] See Section 5, Decreasing ARA Prices Under Increasing Surplus Supply Conditions, of the IMM's Summer 2020 Quarterly Markets Report, at https://www.iso-ne.com/static-assets/documents/2020/11/2020-summer-quarterly-markets-report.pdf

[339] 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.

Historically, the traded volume in the secondary markets has been much lower than in the primary auctions. Since CCP 8, the trade volumes as a percentage of FCA volumes has increased steadily, ranging from 6% in CCP 8 to 9% in CCP 12. The majority of secondary trading occurs during annual bilateral periods and reconfiguration auctions. The annual auctions utilize ISO-updated demand curves to reflect system needs; monthly auctions reallocate CSOs among resources without the influence of ISO demand curves. In CCP 12, the largest portion of secondary trading in ARAs (dark green) occurred, reaching almost 2,300 MW. The disappearance of dark blue (ABA trading) is driven by the conversion of annual bilateral changes to annual reconfiguration transactions. This change is further discussed below.

Annual Reconfiguration Transactions

Beginning in CCP 11, physical annual bilateral agreements were replaced with financial annual reconfiguration transactions (ARTs). ARTs serve the same purpose as their bilateral counterparts; they allow resources to secure a set capacity price when acquiring or shedding CSO MWs. While bilateral agreements instruct resources to transfer physical capacity between resources on a kW-to-kW basis, ARTs instead leverage one resource's available capacity to cover another resource's CSO without physically trading the capacity.[340]

If a resource wants to shed CSO MWs through an ART, they must designate the amount of departing CSO MW and the price they are willing to pay to clear the obligation. Their transaction counterpart must have enough available capacity to cover the CSO MW and a willingness to sell their available capacity at the price set by the shedding resource. When both sides reaching an agreement, the ART is complete without any payment or capacity changing hands. Instead, the ART price will serve as a binding benchmark with transaction payments dependent on the clearing price of the upcoming annual reconfiguration auction (ARA).

If the auction clears below the ART price, the market values capacity below the agreed-upon price, invoking the shedding resource to pay the value difference to the acquiring resource. If the auction clears above the ART price, the market values capacity above the agreed-upon price, requiring the acquiring resource to pay the value difference to the shedding resource. When paired with a cleared demand bid from the shedding resource and a cleared supply bid from the acquiring resource, the ART serves equivalently to a private transaction, or the annual bilateral transaction that was removed.

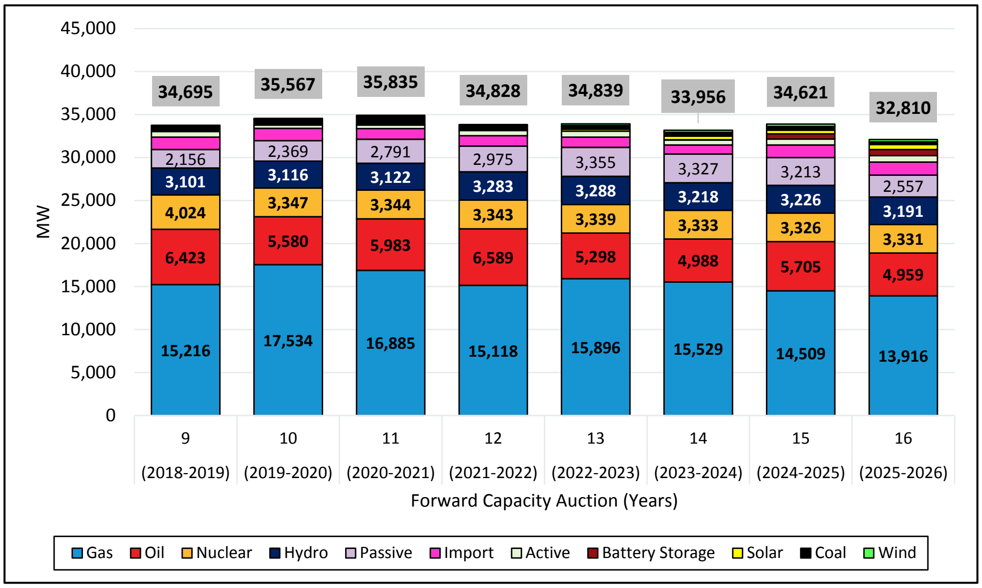
For CCP 12, ARA 1 had no associated ARTs and ARA 2 saw minimal ART activity; less than 7 MWs traded between resources. ARA 3 saw even fewer ARTs with only a pair of demand response resources transacting 1 MW with the mechanism.

6.5 Trends in Capacity Supply Obligations

This section discusses trends and major changes in capacity since FCA 9. Retirements and new additions drive major changes in capacity supply. There are three categories of capacity resources that can participate in the FCM: generation, demand response and import resources. Figure 6-8 below illustrates the relative share of these categories in the context of total capacity (gray box), with generation broken down by fuel type and demand response categorized as passive or active.

[340] See Section 8.1.3, Annual Reconfiguration Transactions (ARTs) for Annual FCM Auctions, of the IMM's 2019 Annual Markets Report https://www.iso-ne.com/static-assets/documents/2020/05/2019-annual-markets-report.pdf

Figure 6-8: Capacity Mix by Fuel Type, FCA 9 - FCA 16



Since FCA 10, gas capacity has trended downwards, driven by large retirements and terminations. Negative shocks in gas capacity shares correspond with the termination of Burrillville Energy Center (485 MW in FCA 12), retirement of Mystic 8 and 9 (1413 MW in FCA 15), and termination of Killingly Energy Center (632 MW in FCA 16).

Other notable movements over the past eight FCAs were made by passive demand response resources, solar generation, and battery storage projects. Between FCAs 9 and 13, capacity from passive demand sharply increased from 2,156 MW to 3,355 MW, in line with state policy goals to increase energy efficiency. Since FCA 13, however, passive demand response has decreased their share of CSO to 2,557 MW. Existing qualified capacity for passive demand response decreased by almost 700 MW in FCA 16 due to amortization of energy efficiency assets.[341] Solar capacity jumped from 20 MW in FCA 9 to 561 MW in FCA 16. More efficient solar technology has reduced project costs and the renewable technology resource exemption helped solar projects enter the capacity market during FCAs 10-14.[342] Even without the exemption in FCA 16, solar resources added 208 MW of new capacity. Battery storage projects are the newest entrant to New England's capacity market. FCA 15 saw over 500 MW of new battery storage projects; FCA 16 brought in an additional 100 MW. Since being introduced to the market in FCA 13, battery storage projects have increased their share of capacity from 5 MW to 713 MW. Total share of capacity for wind, solar, and battery storage resources reached 5% in FCA 16.

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[341] 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.

[342] 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.

6.5.1 Retirement of Capacity Resources

A participant can choose to retire its resource by submitting a retirement request to the ISO.[343] This is an irrevocable request to retire all or a portion of a resource.[344] Up to FCA 11, this request was not contingent on market clearing prices; it was known as a non-price retirement. Starting in FCA 11, non-price retirements were replaced by priced-retirements which go through an IMM cost-review process to establish if the bid may be an attempt to inflate clearing prices above competitive levels. A resource can still choose an unconditional retirement, choosing to retire regardless of the ISO's reliability determination.

Retired generating resources with capacity exceeding 50 MW from FCA 9 are shown in Table 6-1 below.

Table 6-1: Generating Resource Retirements over 50 MW, FCA 9 - FCA 16

FCA # (Commitment Period)	Resource Name	Fuel Type	Capacity Zone	FCA MW
FCA 9 (2018/19)	Mt. Tom.	Coal	WCMA	144
FCA 10 (2019/20)	Pilgrim Nudear	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

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 other energy polices have led to increased production 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 shifts toward more efficient gas technology and brings in large volumes of renewable projects.

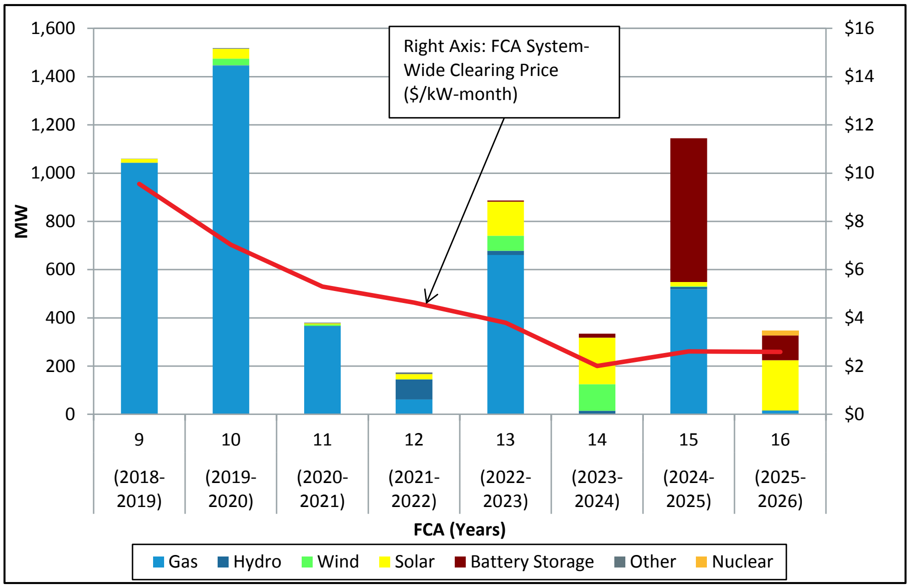
[343] The FCA retirement permanently sheds a CSO; however, a resource may effectively retire before the FCA retirement, if it sheds its obligation through secondary markets and the retirement does not trigger reliability concerns.

[344] Non-price retirement requests are subject to a review for reliability impacts. If the ISO notifies a resource owner of a reliability need for the resource, the resource owner has the option to retire the resource as requested or continue its operation until the reliability need has been met. Once the reliability need has been met, the resource must retire.

6.5.2 New Entry of Capacity Resources

This section provides an overview of major new resource additions to the FCM. New entry typically implies a resource entering the market for the first time. However, existing resources that require significant investment to repower or provide incremental capacity, and meet the relevant dollar per kilowatt thresholds in the tariff, can also qualify as new capacity resources.[345] Figure 6-9 presents new generation capacity by fuel type since FCA 9.

Figure 6-9: New Generation Capacity by Fuel Type, FCA 9 - FCA 16



The majority of new additions between FCA 9 and FCA 13 were natural gas-fired resources. In *FCA 9*, over 1,000 MW of gas-fired capacity was added; the largest addition was CPV Towantic, a 725 MW combined cycle resource in Connecticut. FCA 10 saw the largest amount of new generation entry in the reporting period, with an additional 1,400 MW of new natural gas-fired capacity. Three natural gas-fired resources accounted for 94% of this supply: Bridgeport Harbor 6 (484 MW), Canal 3 (333 MW), and Burrillville Energy Center (485 MW).[346] FCA 13 also saw the inclusion of another large gas-fired resource, Killingly Energy Center, for an additional 632 MW.[347] 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 from Ocean State Power. Battery storage projects also cleared a significant amount (596 MW) of new

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[345] See Market Rule 1, Section III.13.1

[346] 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.

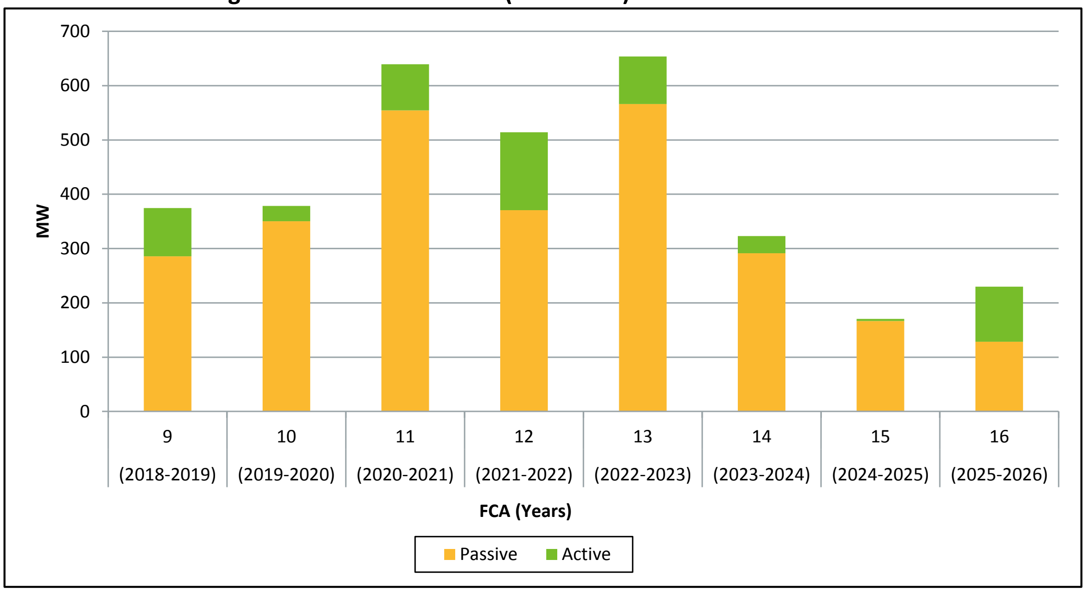
[347] In November 2021, ISO-NE filed to terminate the 632 MW CSO of Killingly Energy Center, which was accepted and upheld by the Commission. Per the filing, the project sponsor had not made sufficient progress to achieve Killingly Energy Center's critical path schedule milestones. With the insufficient 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.

capacity in the auction. Updated assumptions on battery storage project revenues reduced their minimum offer price, allowing these resources to offer below the low system clearing prices.

FCA 16 saw a smaller inclusion of new capacity, totaling only 567 MW. Battery storage projects entered at a decreased rate, reaching only 100 MW of new supply while the largest increase in the auction came from 208 MW of new solar projects.

Significant increases in new passive demand response resources have driven most new demand response capacity since FCA 9. Passive demand response is defined as on-peak and seasonal-peak resources, while active-demand capacity resources (ADCRs) act as dispatchable reduction of demand, typically dispatched during constrained system conditions due to their high energy market offer prices.[348] Figure 6-10 below shows cleared new active and passive resources since FCA 9.

Figure 6-10: New Demand (Reduction) Resources with a CSO



The annual additions of new demand resources in the FCM is primarily driven by state-sponsored energy efficiency programs that participate in the FCM as passive (on-peak or seasonal-peak) supply resources. FCA 13 saw the peak of new demand response capacity, with over 650 MW of new demand resources cleared. Since then, new demand response capacity has decreased, with only 230 MW clearing in FCA 16.

[348] On-peak resources are energy efficiency and load-reducing distributed generation projects that provide long term peak capacity reduction. Seasonal-peak resources are comprised of energy efficiency projects that also provide long term peak reductions. The difference is that seasonal-peak resources provide reductions at or near the system peak, meaning they have a broader definition of peak hours. Lastly, real-time demand response resources are dispatchable resources that provide reliability during demand response events.

6.6 Market Competitiveness

This section discusses the competitiveness of the Forward Capacity Market (FCM) using two key metrics:

- Residual Supply Index (RSI)
- Pivotal Supplier Test (PST)

The RSI measures the percent of capacity remaining in the market after removing capacity from the largest supplier. The PST determines whether the ISO needs a supplier's capacity to meet system and import-constrained zone requirements.[349] Both metrics respect system constraints and account for affiliations between suppliers to reflect all capacity under a supplier's control. These metrics consider only existing resources prior to the auction to avoid predicting intra-auction new supply behavior.[350]

The RSI measures the percentage of capacity requirements (system or zonal) that can be met without capacity from the largest supplier's portfolio of qualified capacity resources. It is measured on a continuous scale from zero to an uncapped upper limit. When the RSI is greater than 100%, suppliers other than the largest supplier have enough capacity to meet the relevant capacity requirement. This indicates that the largest supplier should have little opportunity to profitably increase the market-clearing price. Alternatively, if the RSI is less than 100%, the largest supplier is needed to meet demand. Consequently, the largest supplier could increase its offer prices above competitive levels to increase the market clearing price. Therefore, the lowest possible value of zero represents a pure monopoly scenario.

While the RSI uses a continuous measure and provides a sense of the largest supplier's ability to influence clearing prices, the PST is binary and asks whether each individual supplier is needed to meet the system and import-constrained zone requirements. The PST therefore provides the total number of suppliers who may be able to influence prices. The PST compares (1) the total existing capacity in a zone without a given supplier's portfolio of existing capacity to (2) the relevant capacity requirement for the zone.[351] If the former quantity is less than the latter quantity, the supplier is pivotal. As a result, any de-list bids submitted by a pivotal supplier at prices above the dynamic de-list bid threshold may be subject to mitigation.[352] 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.

Both metrics use the following inputs:

[349] Section III.A.23 of the Tariff.

[350] 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)."

[351] The relevant requirements are the Installed Capacity Requirement net of HQICCS (Net ICR) at the system level and the Local Sourcing Requirement (LSR) at the import-constrained zonal level.

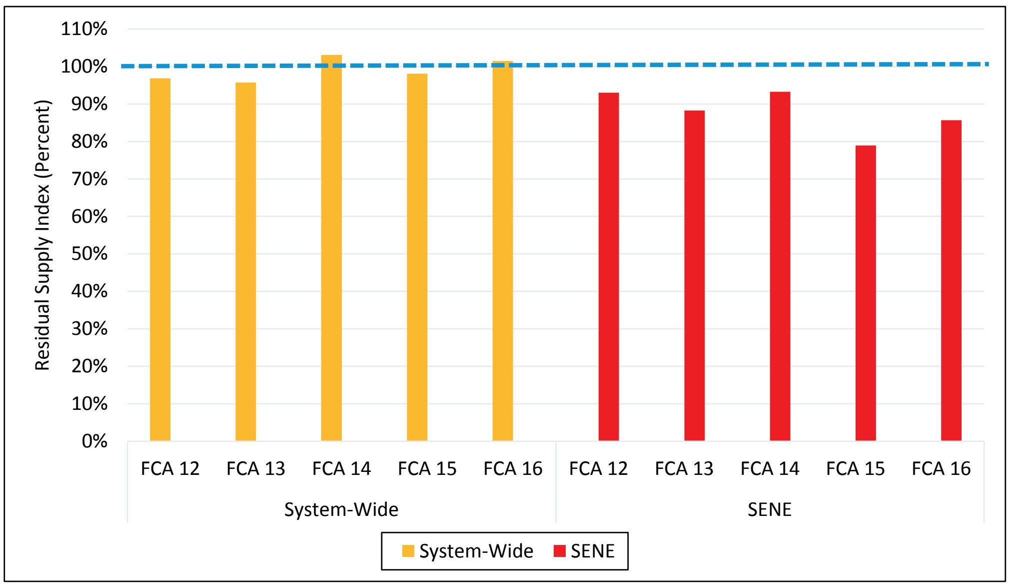
[352] Note that there are certain conditions under which capacity is treated as non-pivotal. These conditions are described in Section III.A.23.2 of the Tariff.

- *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.
- *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). Recently, there have been steady gains in large new and incremental generation (described in Section 6.5.2).
- *Supplier-specific portfolios of existing capacity* – values that can change year over year as a result of mergers, acquisitions, divestitures, affiliations, resource performance, etc.

Residual Supply Index Results

The RSIs for the system and for each import-constrained zone over the past five FCAs are illustrated in Figure 6-11 below.[353]

Figure 6-11: Capacity Market Residual Supply Index, by FCA and Zone



With the exception of FCA 14 and FCA 16 (system-wide only), the RSI was below 100% in every auction since FCA 12 at both the system and zonal levels. An RSI below 100% indicates the presence of at least one pivotal supplier. The system-wide RSI (yellow) increased from 96% in FCA 13 to a high of 103% in FCA 14, decreasing slightly to 101% in FCA 16. The changes can be attributed to a variety of factors including: changes to the largest supplier (i.e., retirements, acquisitions, sales, etc.), the steady procurement of new generation in recent FCAs, and reductions in Net ICR.

[353] The RSI measure in this section leverages the capacity counting rules outlined in the Tariff for the Pivotal Supplier Test. These are the most recent capacity counting rules for this purpose and were in effect beginning with FCA 10. They are used for prior auction periods for consistency.

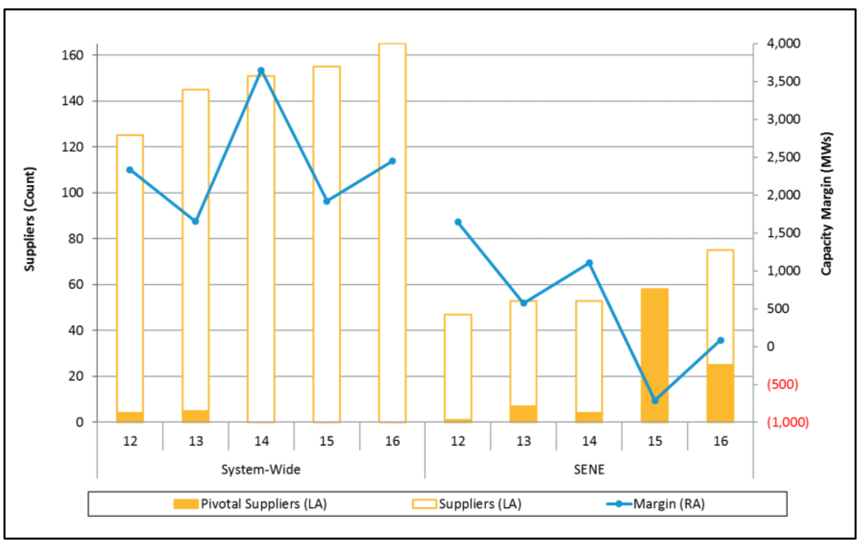
The zonal RSI (red) decreased from a high of 93% in FCAs 12 and 14 to a low of 79% in FCA 15, before rebounding to 86% in FCA 16. The decreases in FCA 13 and FCA 15 were due to higher LSR values and retirements within the capacity zone.

Pivotal Supplier Test Results

The number of suppliers and pivotal suppliers within each zone over the past five FCAs are presented in Figure 6-12 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 LSR, resulting in a capacity margin of approximately 1,105 MW right axis – blue marker). Consequently, only suppliers with a portfolio of 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.

Now consider the SENE capacity zone in FCA 15. The amount of capacity was less than the LSR, resulting in a capacity margin of approximately -711 MWs. The negative capacity margin means that, given the existing quantity of supply in SENE, there was not enough supply to meet the LSR prior to FCA 15. Consequently, every supplier located in SENE of every portfolio size was pivotal; even with presence of every supplier's existing capacity, the zone still fell short of the LSR. Note that the FCA 15 system-wide margin was approximately 1,922 MW with no pivotal suppliers. The FCA 16 SENE capacity margin was 87 MWs, resulting in 25 pivotal suppliers whose portfolio size exceeded the margin.

Figure 6-12: Overview of Suppliers, Pivotal Supplier, and Capacity Margin, by Zone



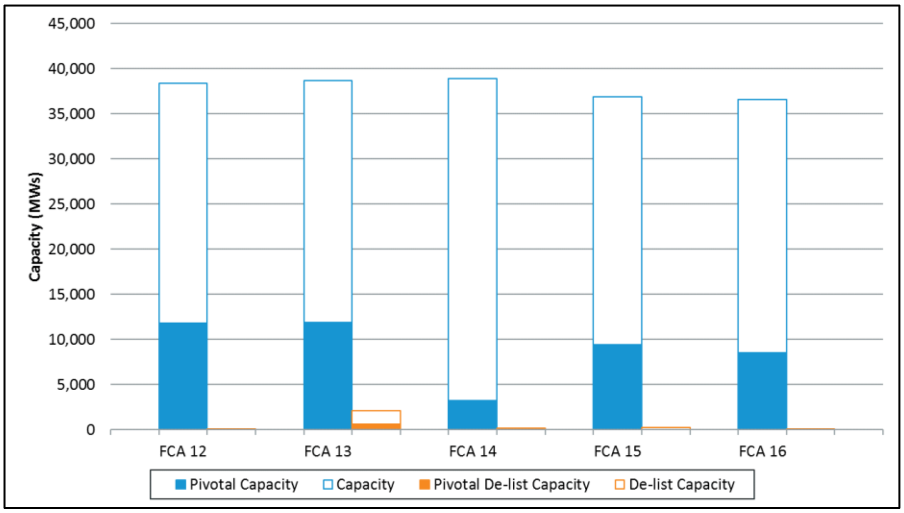
At the system level, the capacity margin has remained high over the past five FCAs. In FCA 16, the capacity margin increased even further to approximately 2,453 MWs. The increase in the system capacity margin between FCA 15 and FCA 16 was driven largely by a significant decrease in net ICR, down 1,625 MWs from FCA 15 (33,270 MW) to FCA 16 (31,645). As a result of sustained high capacity margins, due to a decreasing net ICR and few retirements, there have been few pivotal suppliers at the system level since FCA 12.

The SENE capacity zone margin rose to 87 MW in FCA 16, primarily due to a significant drop in the LSR from the prior year, after falling to -711 MW in FCA 15 due to a combination of an increase in the LSR and a decrease in supply in the zone. The relatively low FCA 16 capacity margin led to 25 suppliers in SENE being pivotal, down from 58 pivotal suppliers in FCA 15.

Pivotal Suppliers submitting de-list bids

While a pivotal designation may indicate the ability to influence clearing prices, a de-list bid is necessary to exercise it. An overview of the total capacity, pivotal capacity (i.e., capacity associated with a pivotal supplier), de-list capacity, and pivotal capacity with de-list bids, for the last five FCAs, across all capacity zones is presented in Figure 6-13 below.[354]

Figure 6-13: Overview of Capacity, Pivotal Capacity, De-list Capacity, and Pivotal De-list Capacity



Over the past five years, there have been relatively few active de-list bids, and even fewer that have had a pivotal status. FCA 13 was the only year to have de-list capacity with a pivotal status. In FCAs 12 and FCAs 14-16, there were no active de-lists from pivotal suppliers. As a result, no mitigation was applied to existing resources in these auctions. In FCA 13, several pivotal resources submitted 628 MW of de-lists bids. These accounted for 30% of the total of de-list capacity. Ultimately, mitigation did not apply to any de-list capacity in FCA 13, since the resources either withdrew their bid or lowered their price below the IMM-mitigated price. In FCA 14 there were a handful of pivotal suppliers at the zonal level, but none submitted de-list bids. In FCA 16, 25 suppliers in the SENE zone were pivotal, but none submitted de-list bids. There were no active de-lists bids from resources associated with a pivotal supplier in FCA 15 or FCA 16.

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[354] 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 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.

The results of these two complementary measures (the residual supply index and the pivotal supplier test) indicate that, historically, the New England capacity market has been structurally uncompetitive at the zonal level, but competitive at the system level. The capacity market was the most competitive headed into FCA 14 and FCA 16, with an RSI of over 100% and no pivotal suppliers. When suppliers do have market power, buyer- and supplier-side mitigation rules are in place to prevent the potential exercise of market power. This is discussed in the next section.

6.7 Capacity Market Mitigation

In this section, we provide an overview of the IMM's FCM-employed mitigation measures, as well as summary statistics on the number and impact of these mitigations. This section presents summary information for FCA 12 through FCA 16.

Two forms of mitigation apply to FCA bids and offers: supplier-side mitigation for existing resources and buyer-side mitigation, namely the Minimum Offer Price Rules (MOPR) for new resources.

6.7.1 Supplier-Side Market Power

A market participant attempting to exercise supplier-side market power will try to economically withhold capacity during the FCA – for a single year or permanently - in an effort to *increase* the clearing price above a competitive level. An inflated clearing price can benefit the remaining resources in the market participant's portfolio, as well as the portfolios of other suppliers. A market participant would only attempt this if they believed (1) their actions would inflate the clearing price and (2) the revenue gain from their remaining portfolio would more than offset the revenue loss from the withheld capacity.

De-list bids are the mechanism that allow capacity resources to remove some or all of their capacity from the market for one or more commitment periods.[355] De-list bids specify the lowest price that a resource would be willing to accept in order to take on a capacity supply obligation (CSO). To restrict resources from leaving the market at a price greater than their competitive offers, the IMM reviews de-list bids above a proxy competitive offer threshold called the dynamic de-list threshold (DDBT) price.[356] A competitive de-list bid is consistent with the market participant's net going forward costs, expected capacity performance payments, risk premium, and opportunity costs.

All existing capacity resources, as well as certain types of new import capacity resources (described below), are subject to the pivotal supplier test, which was described in more detail in the last section. If the IMM determines that a de-list bid is uncompetitive and the supplier fails the pivotal supplier test, the IMM mitigates the de-list bid to a competitive price.

[355] Dynamic and static de-list bids are both mechanisms to remove the capacity from an existing resources from the FCA for a period of one year. The essential difference between the two is that static-delist bids are at or above a certain price level that requires an IMM cost review.

[356] De-list bids priced below the DDBT are presumed to be competitive and are not subject to the IMM's cost review or mitigation; consequently, they are not discussed in this section. Market participants can dynamically de-list resources if the auction price falls below the DDBT price. The DDBT has undergone a number of revisions since the start of the FCM. The DDBT price was $5.50/kW-month in FCA 12, $4.30/kW-month in FCAs 13 through 15, and $2.61/kW-month for FCA 16.

Retirement and permanent de-list bids

Between FCA 12 and FCA 16, the IMM received about 3,100 MWs of retirement and permanent de-list bids. The IMM reviewed 3,000 MWs (above the 20 MW threshold) and mitigated 2,200 MWs, roughly 72% of all retiring capacity. In FCA 12, Bridgeport Harbor 3 submitted a 383 MW retirement de-list bid, and Enerwise Global Technologies, Inc. submitted retirement de-list bids for over 100 MWs of capacity. In FCA 13, over 1,400 MW of retirement de-list bids came from Mystic 8 and 9. While their bids were mitigated, they were denied for reliability and treated as existing capacity in FCAs 13 and 14. In FCA 15, the Mystic generators were no longer retained. Two more significant retirements occurred (CDECCA and West Springfield 3), combining for a total of 1,560 MW. In FCA 16, Potter 2 retired 72 MW and West Springfield GT-1, GT-2 and 10 removed a total of 95 MW.

Static de-list bids

As previously stated, the IMM reviews de-list bid submissions to determine if they are consistent with the participant's net going forward costs, expected capacity performance payments, risk premium, and opportunity costs. This process has led to approximately 40% of the general static de-list bids (93% of de-list MW capacity) being denied by the IMM from FCA 12 to FCA 16.[357]

For FCA 12 through FCA 16, the IMM reviewed 63 general static de-list bids from 13 different lead participants, totaling roughly 7,800 MW of capacity (an average of 1,600 MW per auction).[358] Generation resources accounted for 7,700 MW of the total capacity and 57 of the 63 general static de-list bid submissions. Two import resources made up just 1 MW of total capacity and 4 demand response resources made up the remaining 80 MW of the total capacity; the latter resource types consistently have smaller-sized projects than generating resources. Separate from the above statistics, the IMM reviewed supply offers from import capacity resources without transmission investments, totaling approximately 1,700 MW.[359]

Summary statistics for static de-list bids from FCA 12 through FCA 16 as well as the path the bids took from the time of initial submittal to the auction are provided in Figure 6-14 below. Note that all de-list bid prices are megawatt-weighted averages.[360]

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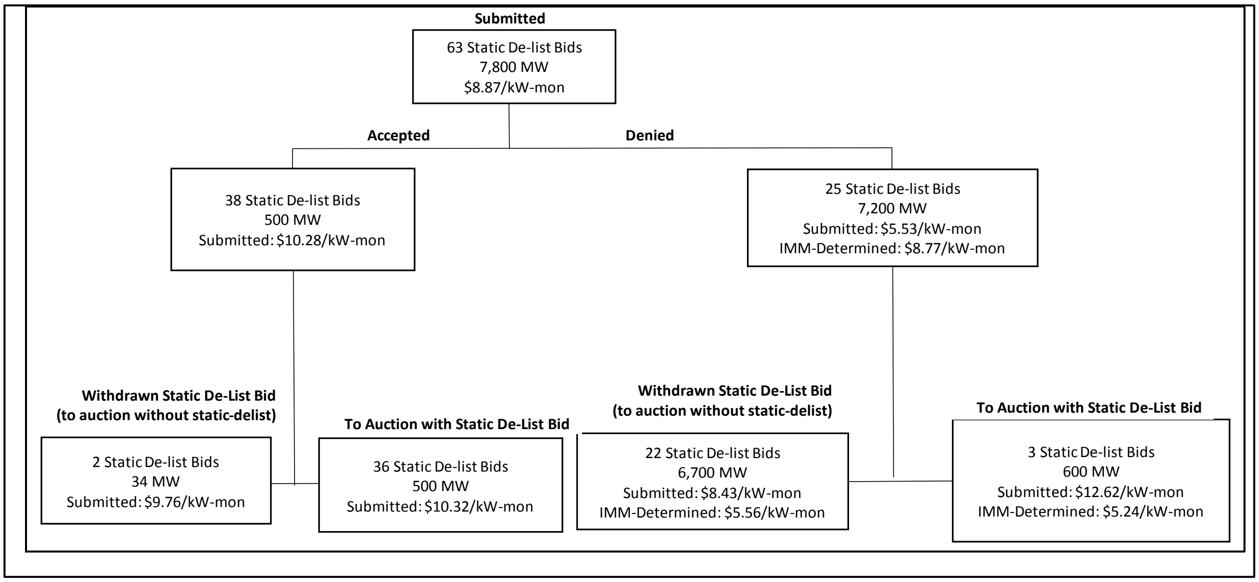
[357] If a supplier is pivotal, the IMM-determined value is entered into the auction; if not, the participant-submitted bid is entered. The mitigation only takes effect if the supplier is deemed pivotal, an evaluation that is done some months after the cost review process in completed.

[358] 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.

[359] For market power mitigation purposes, import resources without transmission investment are evaluated for seller-side market power. New imports resources with associated transmission investment are evaluated under the MOPR.

[360] 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 6-14: General Static De-list Bid Summary Statistics, by Key Milestone Action (FCAs 12 – 16) [361]



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 $7.38/kW-month less ($5.24 vs. $12.62) than the market participant's originally submitted price.

As discussed above, only de-list bids belonging to pivotal suppliers are subject to mitigation. Only FCA 13 had active de-list bids from pivotal suppliers; the four other auctions did not have any de-list bids from pivotal suppliers. In FCA 13, the de-list bids for three resources (628 MW) were denied and subsequently mitigated in the auction. There were no pivotal suppliers mitigated in FCA 16.

6.7.2 Test Price Review

The test price mitigation rule was introduced in FCA 14, and applies to resources (above 3 MW) seeking to retire through the substitution auction. The rule is designed to protect the primary FCA from price suppression, by mitigating behavior commonly referred to as "bid shading".

Bid shading occurs when an existing resource may have an incentive to include the value of a severance payment in its primary auction bid price. This behavior would increase the likelihood of retaining its CSO, and subsequently trading out of it for a severance payment in the substitution auction. This could have a price-suppressing impact in the FCA. The test price is an IMM-calculated value, based on a cost submission from the resource owner, which represents the competitive cost of obtaining a CSO, excluding any expected severance payment from the substitution auction.

The test price serves as a screen to determine whether a resource's demand bid will be entered into the substitution auction based on the clearing price of the primary auction. If the resource's test

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

price is below the primary auction clearing price, the resource is allowed to enter the substitution auction. If the test price is greater than the primary auction clearing price, the resource is not permitted to enter a demand bid into the substitution auction.

In FCA 16, fifteen existing resources with a combined capacity of 994 MW elected to participate in the substitution auction. The IMM reviewed 12 resources (above the three MW threshold) and denied five. The reviewed resources had a combined capacity of 993 MW. The weighted-average submitted test price of the reviewed resources was $4.35/kW-mo. The weighted-average IMM-determined test price of the reviewed resources was $4.10/kW-mo. All 737 MWs that obtained a CSO in the primary auction were eligible to participate in the substitution auction. However, the substitution auction did not clear any capacity obligations because its demand and supply curves did not intersect; i.e., demand bid prices were less than supply offer prices. Therefore, the mitigation of submitted test prices did not have an impact on demand side participation in the FCA 16 substitution auction.

6.7.3 Minimum Offer Price Rule

A market participant attempting to exercise buyer-side market power will try to offer capacity below cost in an effort to *decrease* the clearing price to benefit the capacity buyer. In practice, the risk of price suppression in the ISO-NE market is largely due to out-of-market revenue streams inherently designed to incent new build of renewable generation to meet the states' environmental goals, as opposed to the exercise of market power. To guard against price suppression, the IMM evaluates requests to offer capacity below pre-determined competitive threshold prices, or Offer Review Trigger Prices (ORTPs). Market participants that want to offer below the relevant ORTP must submit detailed financial information to the IMM about their proposed project. The financial information is reviewed for out-of-market revenues or other payments that would allow the market participant to offer capacity below cost.[362] The out-of-market revenues are either replaced with market-based revenues or removed entirely and the offer is recalculated to a higher, competitive price (i.e., the offer is mitigated).

For FCAs 12 through 16, the IMM reviewed 461 new supply offers[363] from participants requesting to offer below the ORTP.[364] These offers came from 64 different lead participants and totaled 20,800 MWs of qualified capacity, of which about 12,000 MW (~58%) entered the auction.[365] Generation resources accounted for the majority of new capacity reviewed, with 83% of the total (17,200 MW). Non-emitting resources inclusive of Battery Storage, Solar and Wind made up 66% of 17,200 MWs. Demand response resources accounted for 6% (1,200 MW) of total capacity reviewed and import resources accounted for 11% (2,400 MW).

[362] Out-of-market revenues are defined in Section III.A.21.2 of the tariff.

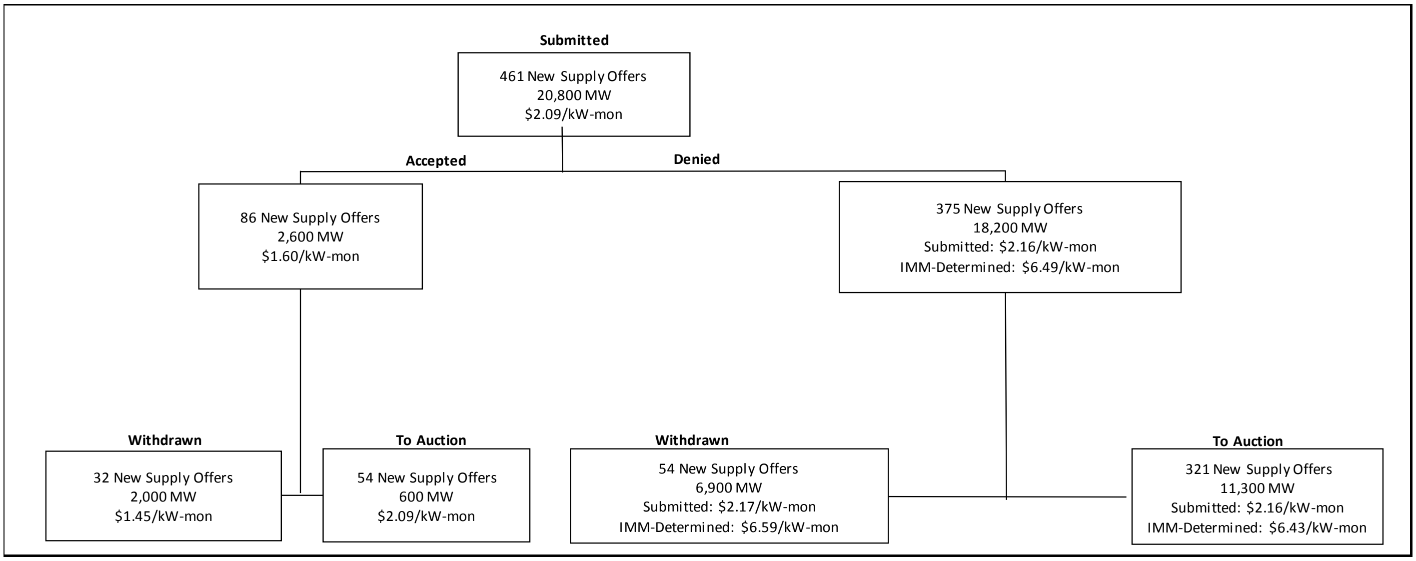
[363] Note that the count does not capture all unique resources. If a resource was mitigated in FCA 11 and did not clear, it could return in FCA 12 and would be captured twice in the count.

[364] 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.

[365] 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.

Summary statistics for resources requesting to offer below their respective ORTP in FCAs 12 through 16 are provided in Figure 6-15 below. Note that all offer prices are megawatt-weighted averages.

Figure 6-15: Reviewable Offer Request Summary Statistics, by Key Milestone Action (FCAs 12 – 16)[366]



The IMM mitigated approximately 82% (375) of new supply offers it reviewed, or approximately 88% (18,200 MW) of new supply capacity.[367] 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 $4.33/kW-month (from a submitted price of $2.16/kW-month to an IMM-determined price of $6.49/kW-month).

366 All MW values are rounded to the nearest hundred.

367 Note that the value does not capture all unique capacity. In other words, if a 100 MW PV resource was mitigated in FCA 11 and did not clear, it could return in FCA 12 and would be captured as 200 MW.

Section 7
Ancillary Services

This section reviews the performance of ancillary services in ISO New England's forward and real-time markets. There are six main types of ancillary service products:

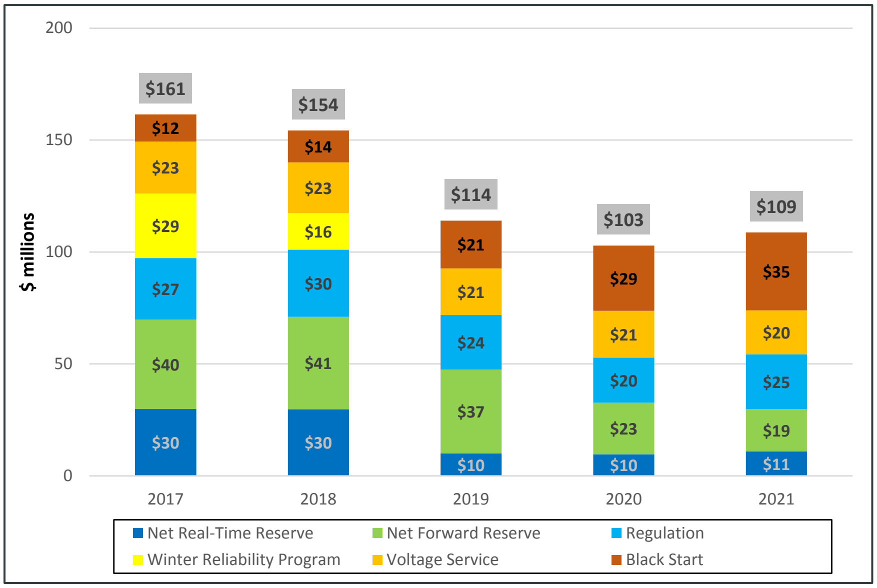
- *Real-time operating reserves* represent additional generating capacity that is available to respond to unexpected contingencies (such as the unexpected loss of a generator or transmission line) during operation of the real-time energy market.
- *Forward reserves* represent the procurement of fast-response reserve capability from generators in advance of the delivery period; that is, the ability to start and ramp quickly in the event of system contingencies.
- *Regulation service* is provided by generators that alter their energy output over very short time intervals (minute-to-minute) to balance supply and demand in the real-time energy market.
- *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, when it is more challenging to procure natural gas. The program ended after Winter 2018, coinciding with the start of the pay-for-performance rules in the capacity market in June 2018.[368]
- *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.[369]
- *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.

[368] 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.

[369] 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

Figure 7-1: Ancillary Service Costs by Product (in $ millions)[370]



Overall, ancillary costs increased to $109 million in 2021 from $103 million in 2020, and represented the second lowest total over the five-year reporting period. Blackstart costs rose by $5.6 million in 2021. The increase was due to blackstart fleet composition changes, coupled with the annual rate adjustment for inflation of approximately 5.7%. Voltage service costs and net real-time reserve costs were similar to 2020 costs. There were no Winter Reliability Program payments in 2020 or 2019 because the program expired in March 2018. Net forward reserve costs decreased by $4.1 million in 2021 compared to 2020, and regulation costs rose by $4.3 million. The subsections below discuss reserve and regulation costs.

7.1 Real-Time Operating Reserves

Bulk power systems need reserve capacity to be able to respond to contingencies, such as the unexpected loss of a large generator or transmission line. To ensure that adequate reserves are available, the ISO procures several different reserve products through the locational Forward Reserve Market (FRM) and the real-time co-optimized energy and reserves market. The following section reviews real-time operating reserve products and analyzes real-time reserve outcomes in 2021. Higher fuel prices and energy costs led to increased reserve prices. The impact of higher average reserve prices on total reserve payments was partially offset by less frequent reserve pricing.

7.1.1 Real-Time Operating Reserve and Pricing Mechanics

Generators, dispatchable asset related demand (ARDs), and demand response resources provide reserves for four products:

- **Ten-minute spinning reserve (TMSR):** TMSR is the highest-quality reserve product. It is provided by online resources that can convert reserves to energy within 10 minutes. In other words, a synchronized generator that can increase its output within 10 minutes can

[370] The Voltage Service category includes payments for capacity costs, lost opportunity costs, costs of energy consumed, and costs of energy produced.

provide TMSR. This gives the system a high degree of certainty that it can recover from a significant system contingency quickly.

- **Ten-minute non-spinning reserve (TMNSR):** TMNSR is the second-highest quality reserve product. It is provided by offline resources that require a successful startup (e.g., a generator that can electrically synchronize to the grid and increase output within 10 minutes).[371]
- **Thirty-minute operating reserve (TMOR):** TMOR is a lower quality reserve product provided by less-flexible resources (e.g., an on-line resource that can increase output within 30 minutes or off-line resource that can electrically synchronize to the system and increase output within 30 minutes).
- **Local Thirty-minute operating reserve (Local TMOR)**: Local TMOR is thirty-minute operating reserve provided for a local reserve zone in order to meet the local second contingency in import-constrained areas. Local TMOR requirements are set for each of the local reserve zones: Connecticut (CT), Southwest Connecticut (SWCT), and NEMA/Boston.

The ISO dispatch software determines real-time reserve levels and the pricing software determines real-time prices for each of the above reserve products. The software co-optimizes energy and reserves. That is, it solves for the least-cost dispatch for the whole system, while meeting energy demand and satisfying the reserve requirements (see Section 7 for information on reserve requirements). The solution produces energy and reserve prices. A reserve price above zero occurs when the pricing software must re-dispatch resources that would otherwise provide energy to satisfy the reserve requirement, which imposes additional costs to the system. Generally, when this happens, the re-dispatch cost (or opportunity cost) of the next available MW of reserves sets the reserve price, but is capped by the Reserve Constraint Penalty Factor (RCPF).[372]

RCPFs represent the maximum value provided by operating reserves to maintain system reliability. The software will not re-dispatch resources to meet reserves at any price; when the re-dispatch costs exceed the RCPF for a product, the price cap (RCPF) takes effect. At this point, the market software stops re-dispatching resources to meet reserves. The intention is to limit re-dispatch costs the system incurs to satisfy reserve requirements.[373] These RCPFs are then added to the energy price due to the interdependence in procurement.[374] The RCPFs also serve as a pricing mechanism that signals reserve scarcity in real-time through high reserve prices, and the RCPFs for non-spinning reserve products trigger capacity scarcity conditions under the Pay for Performance rules. Each reserve product has a corresponding RCPF, as shown in Table 7-1 below.

[371] Higher quality online spinning reserves (TMSR) count towards the total 10-minute reserve requirement as well. In general, higher quality available reserves count towards lower quality reserve requirements.

[372] The re-dispatch cost, or opportunity cost of providing reserves, is the forgone profit the resource could have made in the energy market.

[373] When an RCPF is reached and the real-time energy market's optimization software stops re-dispatching resources to satisfy the reserve requirement, the ISO will manually re-dispatch and commit resources to obtain the needed reserves, if possible.

[374] Reserve prices are not added to the energy price when the system is ramp constrained. This is extremely rare.

Table 7-1: Reserve Constraint Penalty Factors

Requirement	Requirement Sub-Category	RCPF ($/MWh)
System TMSR (10-min spinning)		50
System TMNSR (10-min non-spinning)[375]		1,500
System TMOR (30-min)	Minimum TMOR	1,000
System TMOR (30-min)	Replacement Reserves[376]	250
Local TMOR		250

Although the TMSR is the highest-quality reserve product, it has the lowest RCPF ($50/MWh). By design, RCPFs reflect the upper range of the re-dispatch costs rather than the quality or value of the product. To ensure that the incentives for providing the individual reserve products are correct, the market's reserve prices maintain an ordinal ranking. This ranking is consistent with the quality of the reserves provided as follows:

10-minute spin (TMSR) ≥ 10-minute non-spin (TMNSR) ≥ 30-minute (TMOR)

The price of higher-quality reserve products must be at least as high as the price of lower-quality reserve products. For example, if the ISO alters the dispatch to provide TMOR at a cost of $40/MWh, the prices for TMSR and TMNSR both must be equal to or greater than $40/MWh. The ordinal ranking of reserve prices is also maintained when the ISO needs to re-dispatch the system to create multiple reserve products. For example, if the ISO re-dispatches the system to create TMSR, the reserve price is capped at $50/MWh, the TMSR RCPF. However, if the ISO re-dispatches the system to create TMSR *and* TMNSR, the reserve price is capped at $1,500/MWh for TMNSR resources and the higher-valued TMSR resources are paid $1,550/MWh. This preserves the ordinal ranking of the reserve product prices.

Non-spinning system and local (TMNSR and TMOR) reserve requirements are also procured in the Forward Reserve Market (FRM) for winter and summer seasons. Participants selling the products in the FRM are then expected to designate resources to satisfy their forward obligation in the co-optimized real-time energy and reserve markets. The FRM is discussed in detail in section 0.

7.1.2 Real-Time Operating Reserve Payments

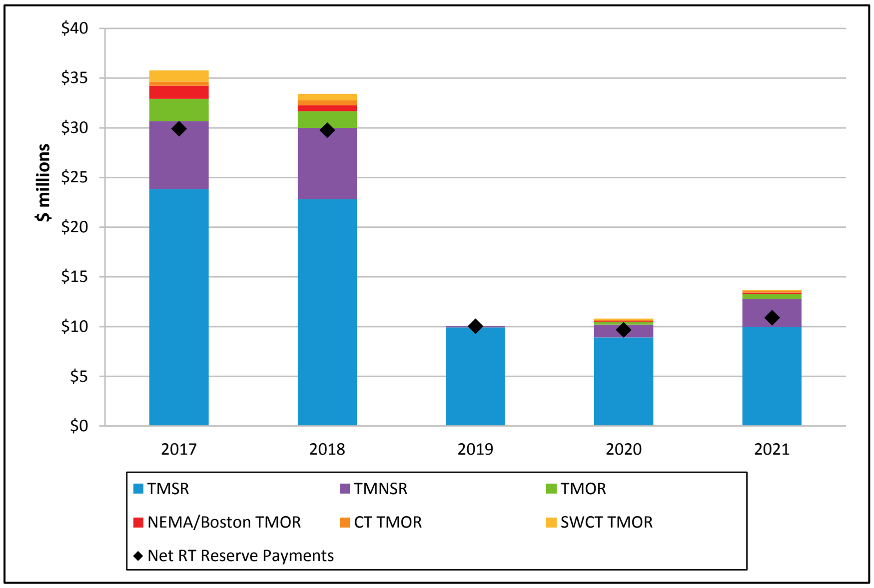
The payments presented in Figure 7-2 below are a measure of the value of real-time reserves between 2017 and 2021. The height of each bar represents the payments by system and local reserve products. Each bar (total payments) comprises the product of aggregated resource real-time reserve levels and the reserve market clearing prices. The black diamond displays total net real-time reserve credits. The diamond will be lower than the height of the bars when real-time

[375] The energy market offer hard cap is $2,000/MWh. If we reach the TMOR and TMNSR RCPF, reserve prices alone will be $2,500/MWh, and will exceed the offer cap. This means the energy price can exceed the energy market offer cap.

[376] Section 2.3 discusses the replacement TMOR requirement in detail.

payments are "clawed back" 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



Real-time operating reserve payment totals can change significantly on a percentage basis from year to year as a result of changes in operating reserve requirements, fuel prices costs, and system conditions. However, total payments are relatively small compared to overall energy market and capacity market payments. Total gross real-time reserve payments were approximately 0.1% of the total wholesale market costs in New England in 2021.

As gas prices increased in 2021, so did real-time energy prices. This meant the opportunity cost, or cost of re-dispatch in the co-optimization process, discussed above, increased as well. This caused higher reserve prices in 2021, which led to a $2.9 million increase in gross reserve payments, up to $13.7 million in 2021 from $10.8 million in 2020. Due to increased reserve prices, TMSR payments increased $1.1 million, or 12%, up to $10.0 million in 2021 compared to $8.9 million in 2020. Payments increased despite 28% fewer hours of TMSR pricing.[377]

Payments for non-spinning reserve products remained very small due to a lack of tight system conditions; TMNSR ($2.8 million) and TMOR ($0.9 million) payments increased because the re-dispatch costs increased from 2020 to 2021. Due to the "claw back" of forward reserve obligation charges, net reserve payments were $10.9 million, or 13% higher than in 2020. This is reflected in the difference between the top of the orange bar and the diamond.[378]

Impact of Fast-Start Pricing on Operating Reserve Payments[379]

Fast-start pricing (FSP), which was discussed in detail in the Summer 2017 Quarterly Markets Report, was implemented in March 2017 to improve price formation and performance incentives in

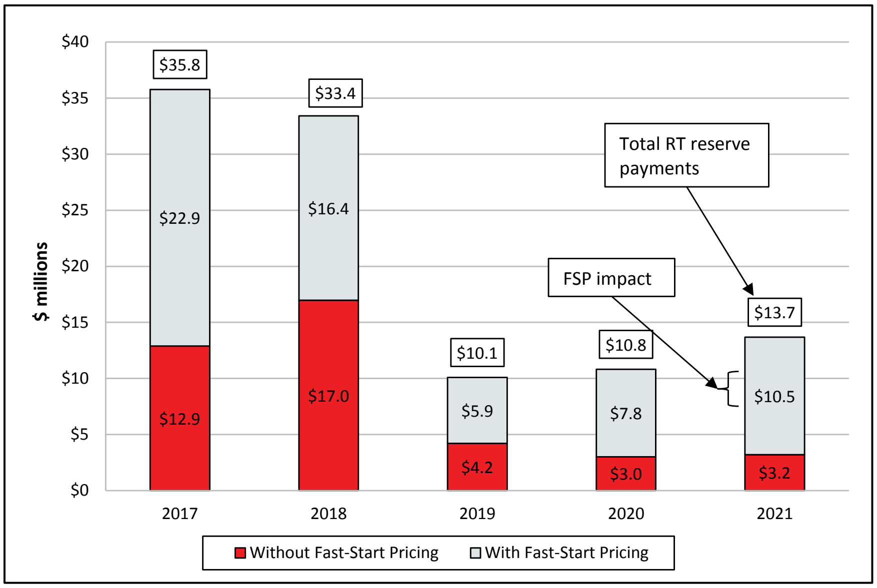
[377] Section 7.1.3 explains the decline in TMSR pricing frequency.

[378] Section 7.3.2 discusses FRM payments. For reference, net FRM payments in 2021 were roughly $18.9 million.

[379] The impact of fast-starting pricing on real-time energy prices is discussed in Section 3.3.4.

the real-time energy market.[380] Fast-start pricing intends to better reflect short-term operating cost of fast-start generators. On average, FSP has increased the price of energy. Consequently, the opportunity costs to provide reserves produced by the pricing software increased as well, which has resulted 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.

Figure 7-3: Impact of Fast-Start on Reserve Payments[381]



Without fast-start pricing, real-time reserve payments would have been approximately $3.2 million in 2021, compared to the actual amount of $13.7 million. Since its implementation in 2017, fast-start pricing has had a significant impact on real-time reserve payments, increasing payments by over $63 million. That accounts for 61% of the $104 million in total payments since 2017. A detailed assessment of the impact of fast-start pricing in provided in Section 3.3.4 of this report.

7.1.3 Real-Time Operating Reserve Prices: Frequency and Magnitude

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 illustrates both the frequency (left panel) and magnitude (right panel) of non-zero reserve prices by reserve product over time.

[380] 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

[381] 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.

Figure 7-4: Frequency of Non-Zero Pricing and Average of Non-Zero Reserve Prices

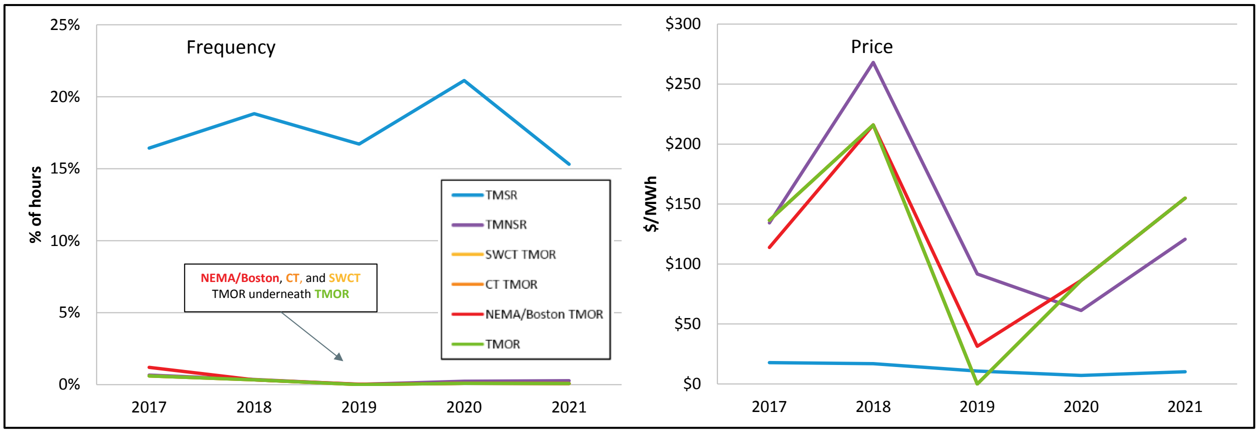
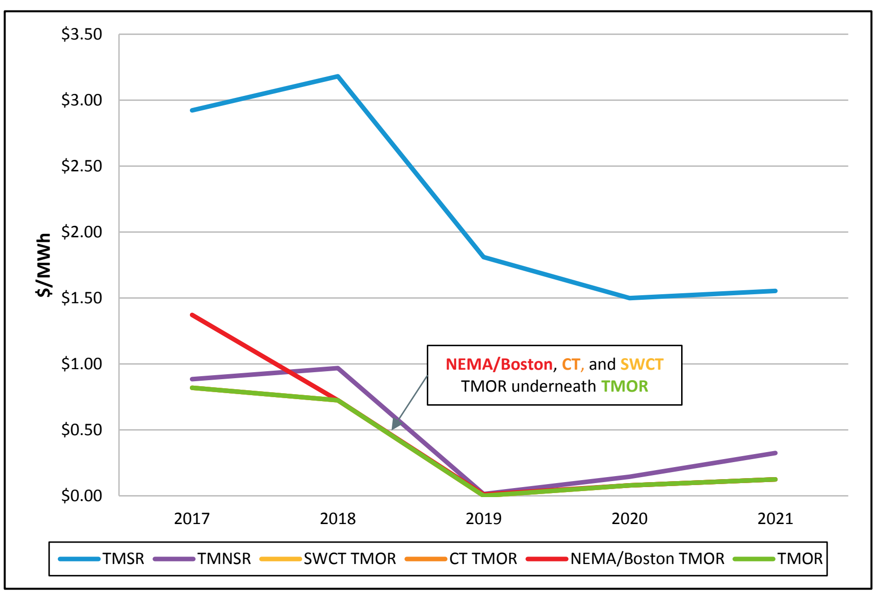


Figure 7-4 shows that TMSR pricing was non-zero for 15% of all hours in 2021, down from 21% in 2020 (left-panel). From 2020 to 2021, the average TMSR margin increased more than the requirement, due to additional online gas-fired and battery storage generators, which is discussed further in Section 3.4.7. TMSR prices averaged $10.15/MWh in non-zero pricing intervals, an increase from $7.09/MWh in 2020 (right panel). The high non-zero TMSR price was driven by fuel and energy prices in 2021.

The frequency of TMNSR and TMOR pricing was below 0.3% in all hours for 2020 and 2021. There were only 24 hours of TMNSR and 7 hours of TMOR in 2021, compared to 21 and 7 hours, respectively in 2020. Similar to average TMSR prices, average TMNSR and TMOR prices increased year-over-year. The increases are more noticeable on a $/MWh basis, since the re-dispatch costs for non-spinning reserves are more expensive. In 2021, there was no price separation among TMOR products, which indicates no local TMOR pricing. We can evaluate the impact of both *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

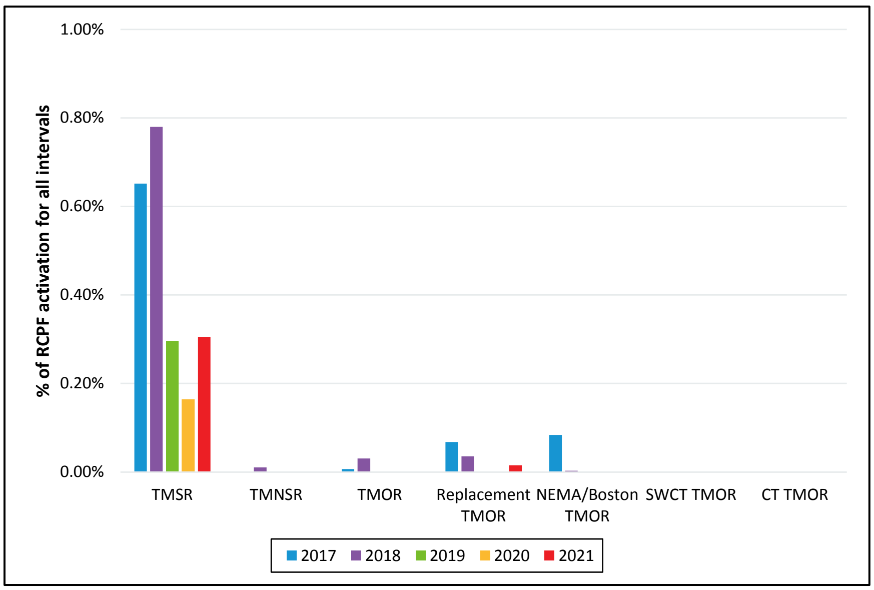


Average TMSR prices during all pricing intervals (i.e., zero- and non-zero pricing intervals) increased by 4%, from $1.50/MWh in 2020 to $1.55/MWh in 2021. The 2020 to 2021 increase in the magnitude of non-zero prices (43%) outweighed the decrease in the frequency of non-zero pricing (28%). That is why average prices in all hours increased by 4% and payments increased by 12% year-over-year.

Reserve Constraint Penalty Factors

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



In 2021, the RCPF for TMSR bound in 321 five-minute intervals (roughly 27 hours or 0.3% of total intervals). The TMSR RCPF had the highest frequency of activations due to the higher frequency of non-zero TMSR pricing and a relatively low RCPF value ($50/MWh) compared to the other products. The replacement TMOR RCPF, which has a lower penalty factor than TMOR ($250/MWh vs $1,000/MWh) bound in 16 five-minute intervals (0.02% of total intervals).

The low level of reserve scarcity, as reflected in the low frequency of penalty factors binding, is consistent with the average healthy reserve margin on the system and few periods of system stress over recent years.

7.2 Forward Reserves

The Forward Reserve Market (FRM) was designed to attract investments in, and provide compensation for, the type of resources capable of satisfying off-line (non-spinning) reserve requirements. Any resource that can provide 10- or 30-minute reserves, from an on-line or off-line status, can participate in the FRM.

The ISO conducts two FRM auctions each year, one each for the summer and winter reserve periods (June through September and October through May, respectively). The auctions award obligations for participants to provide pre-specified quantities of each reserve product. Forward reserve obligations are not resource specific. In order to fulfill these obligations, participants must assign the obligation to one or more resources during the reserve delivery period. This is discussed in more detail below.

Forward reserve auction clearing prices are calculated for each reserve product in each reserve zone. When enough supply is offered to meet the requirement for a product in a particular zone, the auction clearing price for that product is set equal to the price of the marginal supply offer. When supply offers are inadequate to meet a reserve requirement, the clearing price is set to the $9,000/MW-month price cap.[382]

The FRM requires participants to convert their participant-level obligations to resource-level obligations by assigning forward reserve to their forward-reserve resources. Participants are not expected to assign forward reserve to resources that are normally in-merit because they would forego the infra-marginal revenue from selling energy. Conversely, assigning forward reserve to high-incremental-cost peaking resources creates a lower opportunity cost because such resources are in-merit less frequently.

To maintain resources that are normally expected to provide reserves instead of energy, the FRM requires resources to offer energy at or above the FRM threshold price. Participants must submit energy offers for the weekday, on-peak delivery period equal to or greater than the threshold price for these resources to satisfy their FRM obligations. The intent of the market design is to set threshold prices to approximate the marginal cost of a peaking resource with an expected capacity factor of 2% to 3%. Therefore, if the threshold price is set appropriately, LMPs should exceed the threshold price only 2% to 3% of the time. A resource that offers at exactly the threshold will be dispatched only when the LMP exceeds the threshold price.

Bilateral transactions, as well as any reserve-capable resource in a participant's portfolio, can meet the reserve obligations obtained in an auction. Bilateral trading of forward reserve obligations allows suppliers facing unexpected outages to substitute alternative resources. This feature is useful to suppliers if the cost of expected penalties for non-delivery exceeds the cost of acquiring substitute resources through bilateral transactions. A failure-to-reserve penalty will result when a participant fails either to assign the obligation to a resource they control or to transfer the obligation to another participant.

Allocation of the costs for paying resources to provide reserves is based on real-time load obligations in load zones. These obligations are allocated both at the system level and to specific reserve zones that have local forward reserve requirements.

[382] This occurred on several occasions in NEMA/Boston for delivery periods during 2015 to 2018.

Over the review period, the most significant FRM trends have been:

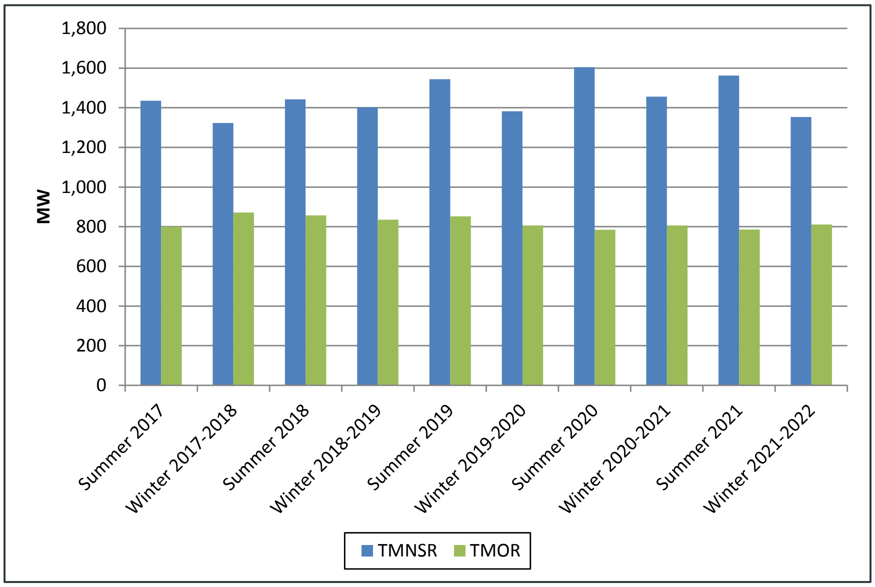
- Market requirements for the quantity of procured forward reserve capacity at the system level have relied on a stable set of first and second contingencies, leading to reasonably stable requirements over the review period.
- Local reserve zone requirements have fluctuated to a more significant degree; these fluctuations have reflected the availability of transmission capacity to provide external reserve support (ERS) to the local reserve zones. However, in the six most recent auctions (summer 2019 through winter 2021/22), external reserve support has been sufficient to eliminate the need for a local requirement in all local reserve zones.
- FRM auction prices generally have been below $2,000/MW-month, and in some auctions have been below $1,000/MW-month. The prices above $2,000/MW-month have occurred in NEMA/Boston, when local reserve constraints were binding.
- FRM payments have declined significantly during the review period; in 2021, lower auction clearing prices compared to earlier periods resulted in a continuing reduction in payments.
- The FRM auctions have required the offered capacity of the largest supplier to meet certain systemwide and local reserve requirements over the past ten auctions. At the system level, three auctions (Summer 2019, 2020, and 2021) revealed modest structural market power. In those instances, the residual supply index estimates indicated that the single largest FRM supplier in those auctions would need to provide at least 10% to 16% of cleared supply to satisfy the TMNSR requirement and at least 3% to satisfy the TMOR requirement.
- Despite structural market power, there is no form of offer price mitigation in this market. There has also been a wide range in supply offers levels across participants, likely reflecting varying expectation of future reserve pricing events, penalties and foregone energy rents associated with the holding the FRM obligation. However, clearing prices and payments have been comparatively low over the past two years (than the prior three years) and stable during auctions with and without structural market power. Prices for the higher quality product, TMNSR, have averaged about $1,200 per MW-month over the prior two summers.

7.2.1 Market Requirements

The FRM auction is intended to ensure adequate reserves to meet 10- and 30-minute non-spinning reserve requirements. The FRM requirements for the New England control area are based on the forecast of the first and second largest contingency supply losses for the next forward reserve procurement period. The ten-minute non-spinning reserve (TMNSR) requirement for the control area is based on the forecasted first contingency, while the thirty-minute operating reserve (TMOR) requirement for the control area is based on the forecasted second contingency.

The system-wide forward reserve requirements from summer 2017 through winter 2021-22 are shown in Figure 7-7 below.

Figure 7-7: Forward Reserve Market System-wide Requirements



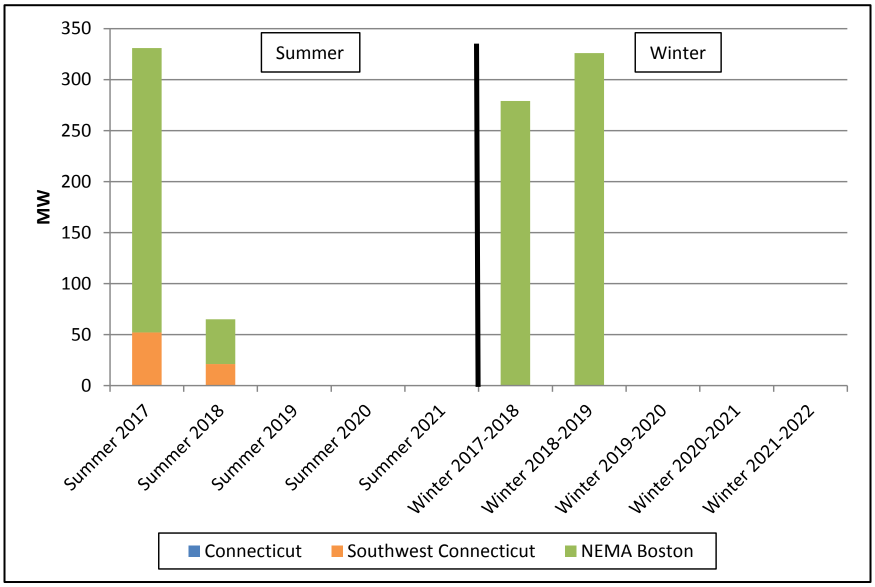
Over the past ten auctions, the TMNSR purchase amount has represented the expected single contingency of the HQ Phase II Interconnection. The TMOR purchase amount has represented the expected single second contingency of either Mystic 8/9 or Seabrook.[383] Therefore, the requirements have been relatively 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 can therefore have different clearing prices. As a result, instead of having a single reserve requirement for each reserve product for all of New England, 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 requirement is a 30-minute operating reserve requirement, which can be met through 10- or 30-minute reserve supply offers in each local reserve zone.

[383] 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



Local forward reserve requirements for the reserve zones, which account for both local second contingency and external reserve support (ERS) MWs, reflect the need for a 30-minute contingency response to provide support in import-constrained areas.[384] Resources within a local region as well as operating reserves available in other locations, through ERS, can satisfy second contingency reserve requirements.

At the local level, the summer and winter procurement periods have experienced a significant reduction in aggregate local FRM requirements, as illustrated in Figure 7-8. This results from a considerable increase in ERS for Connecticut/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 three 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.

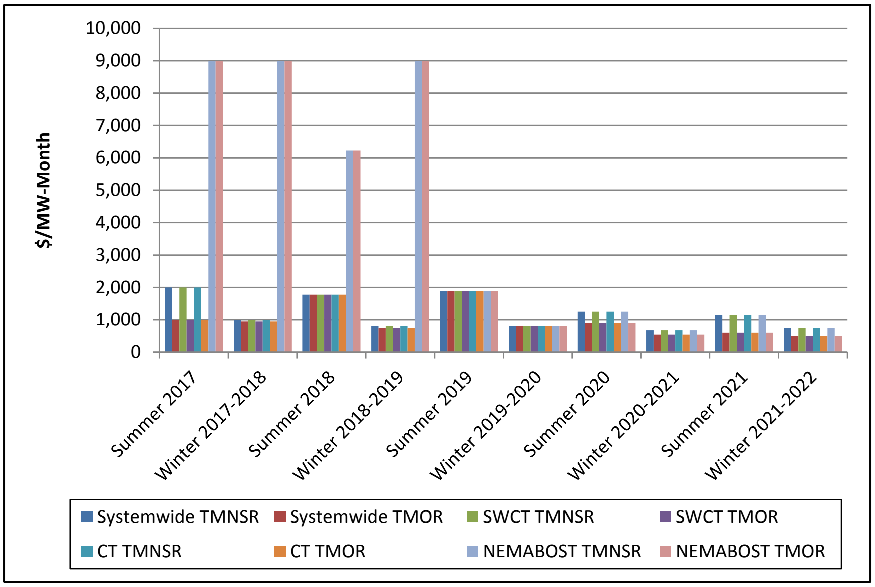
7.2.2 Auction Results

This section covers FRM auction pricing outcomes from the summer 2017 auction through the Winter 2021-22 auction. The TMNSR and TMOR clearing prices by reserve zone for each auction are shown in Figure 7-9 below.[385]

[384] The ISO establishes the locational reserve requirements based on a rolling, two-year historical analysis of the daily peak hour operational requirements for each reserve zone for like forward reserve procurement periods (winter to winter and summer to summer). The daily peak hour requirements are aggregated into daily peak hour frequency distribution curves and the MW value at the 95th percentile of the frequency distribution curve for each reserve zone establishes the locational requirement. For more information about how the ISO establishes zonal forward reserve requirements, see ISO Manual M-36, Forward Reserve and Real-Time Reserve, Sections 2.2.3-2.2.5.

[385] 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.

Figure 7-9: Forward Reserve Prices by FRM Procurement Period



With the exception of the summer periods for 2018 and 2019 and local reserve prices for NEMA/Boston, auction prices for reserve products have generally declined by product and delivery season over the review period. This decline is consistent with lower auction offer prices by participants over the period, perhaps reflecting expected low natural gas prices and energy market LMPs (i.e., reduced energy market opportunity costs for participating in the FRM) and a low frequency and magnitude of reserve pricing. In general, a number of factors can affect TMNSR and TMOR clearing prices, including: offer prices for TMNSR and TMOR, 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 cleared high-priced TMOR supply needed for local requirements that reduces the amount of TMOR supply needed to meet the rest-of-system requirement.

In NEMA/Boston, forward reserve supply shortfalls frequently resulted in very high auction clearing prices from the summer 2017 auction through the winter 2018/19 auction, including clearing prices at the offer cap (discussed below). However, a local reserve requirement for NEMA/Boston was not needed for the six most recent auctions (occurring in 2019 to 2021), as external reserve support supplanted that need.

The uniform clearing prices for TMOR and TMNSR in three auctions (summers 2018 and 2019 and winter 2019-2020) indicate that some TMNSR offers were cleared to meet the system-wide TMOR requirement. The auction clearing software treats the system-wide TMOR requirement as an upper limit on the amount of TMOR that can clear the auction and will select the higher-quality TMNSR reserve product to meet the TMOR requirement when it is economical to do so.[386]

When the auction has sufficient reserves to meet the total system-wide reserve requirement (TMNSR plus TMOR), but clears less TMOR than the system-wide TMOR requirement, the prices for TMNSR and TMOR will be identical. It is only when the auction reaches the upper limit for TMOR, represented by the system-wide TMOR requirement, that there will be price separation between the TMOR and TMNSR reserve products. The result is that TMNSR cannot have a price that is less

[386] See Market Rule 1, Section III.9.4, Forward Reserve Auction Clearing and Forward Reserve Clearing Prices; and, Manual M-36, Forward Reserve and Real-Time Reserve, Section 2.6, Forward Reserve Auction Clearing.

than TMOR. In seven instances during the review period, TMNSR cleared the auction at higher prices than TMOR.

7.2.3 FRM Payments

Participants obtain FRM payments by participating in forward reserve auctions or by obtaining an obligation from another participant that has an auction-based obligation.[387] Auction obligations are specific to participants and are not specific to resources. Participants must convert their obligations into the physical delivery of operating reserve capacity by assigning obligations to resources for the real-time energy market. Assignments must be equal to or greater than the auction-based obligations controlled by the participant (whether obtained directly from an auction or through an internal bilateral transaction). FRM payments are provided during the FRM delivery period based on auction obligations, auction clearing prices, and the actual delivery of the obligation in the real-time energy market.

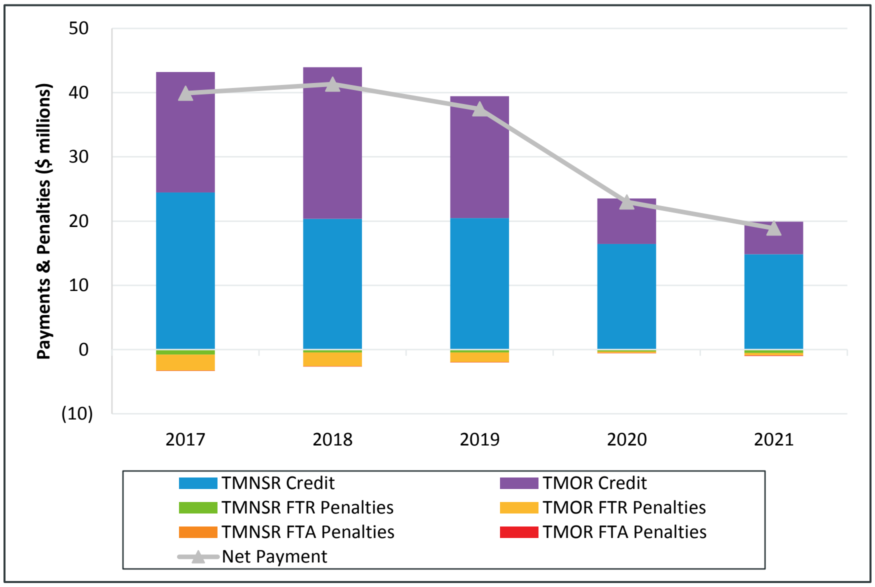
In the real-time energy market, participants are subject to two types of FRM delivery penalties: failure-to-reserve and failure-to-activate penalties. Failure-to-reserve penalties occur when a participant's assignments to resources are less than the participant's obligation. In this case, the participant forfeits auction revenue for any unassigned megawatts and is assessed additional penalties. The failure-to-activate penalties occur when a resource that has been assigned an FRM obligation fails to provide energy (when called upon by the ISO). The failure-to-activate penalties are separate from the failure-to-reserve penalties assessed to a participant.

Annual FRM payment and penalty data by year 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.[388]

[387] 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.

[388] "FTR" refers to failure-to-reserve and "FTA" refers to failure-to-activate.

Figure 7-10: FRM Payments and Penalties by Year



As indicated in the figure, net reserve payments were relatively stable from 2017 through 2019; however, payments declined considerably in 2020 (by 39% compared to 2019). This decline reflects the reduction in auction clearing prices in 2020 relative to earlier years; TMOR prices in particular fell by 53% (or $999/MW-month) between summer 2019 and summer 2020, and the winter auction prices for TMOR declined by 32% from winter 2019-20 to winter 2020-21. In 2021, net payments declined by an additional 18%, primarily reflecting a 33% decline in summer auction TMOR prices.

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, total penalties have declined as auction prices have declined over time.

7.2.4 Structural Competitiveness

The competitiveness of the FRM can be measured by the Residual Supply Index (RSI). RSI measures the extent to which an individual participant has market power and controls enough supply to be able to increase price above a competitive level. In other words, the RSI measures the percentage of the forward reserve requirement that can be met without the largest supplier's FRM portfolio offer. If the requirement cannot be met without the largest supplier, then that supplier is pivotal. The RSI is calculated based on FRM offer quantities.

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.

The heat map provided in Table 7-2 below shows the offer RSI for TMNSR at a system level and for TMOR at a zonal level.[389] 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. An RSI value less than 100 (shown in red) indicates the presence of at least one pivotal supplier, which means the auction was not structurally competitive. Pivotal suppliers may be able to strategically offer reserves at uncompetitive prices.

Table 7-2: Offer RSI in the FRM for TMNSR (system-wide) and TMOR (zones)

Procurement Period	Offer RSI TMNSR (System-wide)	Offer RSI TMOR (ROS)	Offer RSI TMOR (SWCT)	Offer RSI TMOR (CT)	Offer RSI TMOR (NEMA)
Summer 2017	110	114	183	N/A	21
Winter 2017-18	127	124	N/A	N/A	24
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

Table 7-2 shows that, at the system level, three (out of the ten) auctions had RSI values below the structurally-competitive level for TMNSR, TMOR or both. All three auctions were for recent summer periods (2019, 2020 and 2021). TMNSR RSI values were below structurally-competitive levels in the three most recent 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.

System-wide total thirty RSI values were inconsistent with a structurally-competitive level for the summer 2019 and 2020 auctions. In those two 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).

[389] Starting with this report, the reported total thirty (TMOR) RSI values are being revised based on an updated methodology. Previously, the total thirty/TMOR RSI system-wide calculation included both TMNSR and TMOR supply, and compared that supply to the incremental TMOR requirement (e.g., 786 MW in summer 2021), rather than comparing that supply to the total thirty-minute requirement (2,348 in summer 2021). The previous formulation of the RSI calculation overstated the potential competitiveness of TMOR supply offers, by understating the actual thirty-minute requirement. The revised system-wide total thirty RSI is now calculated by comparing all supply offers in the auction (TMNSR and TMOR) to the total thirty-minute requirement.

Considering the TMOR RSI at the zonal level, only the NEMA/Boston zone had an RSI at less than the structurally-competitive level. For the summer 2017 to the winter 2018-19 auctions, every participant that offered forward reserve supply in NEMA/Boston was needed to meet the local requirement, and those supply offers were insufficient to meet that requirement; in these auctions, every supplier for that zone had market power.

7.3 Regulation

This section examines the participation, outcomes, and competitiveness of the regulation market in 2021. Overall, the available supply of regulation service in 2021 far exceeded the regulation requirements, resulting in a competitive market.

The regulation market is the mechanism for selecting and paying generators needed to balance supply levels with second-to-second variations in electric power demand and to assist in maintaining the frequency of the entire Eastern Interconnection.[390] The objective of the regulation market is to acquire adequate resources such that the ISO meets NERC's *Real Power Balancing Control Performance Standard* (BAL-001-2).[391] NERC establishes technical standards for evaluating Area Control Error (ACE, unscheduled power flows) between balancing authority areas (e.g., between New England and New York). A new performance standard was implemented in 2016 for measuring the control of ACE; this metric, referred to as Balancing Area ACE Limits (BAAL), measures performance relative to violations (exceedances) of ACE.[392]

Regulation market performance in 2021 may be summarized as:

- Regulation clearing prices for capacity increased from $16.12/MWh in 2020 to $19.23/MWh in 2021 (a 19% change), reflecting a rise in regulation capacity offer prices.
- Regulation service prices were stable at $0.21/mile in both 2020 and 2021.
- Regulation payments increased in by 20% in 2021, primarily reflecting the increase in capacity prices; 2020 payments were $21.1 million compared to $25.3 million in 2021.
- Regulation requirements in 2021 were steady compared to 2020 requirements, needing 90.0 MW per hour, on average, in 2020 and 90.7 MW per hour, on average, in 2021 (an increase of 0.8%).
- The regulation market was structurally competitive in 2021. The residual supply index indicates that, on average, residual available supply exceeded regulation needs by at least a factor of 10.

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390 The *Eastern Interconnection* consists of the interconnected transmission and distribution infrastructure that synchronously operates east of the Rocky Mountains, excluding the portion of the system located in the Electric Reliability Council of Texas, Newfoundland, Labrador, and Québec.

391 This NERC standard can be accessed at http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf.

392 The primary measure for evaluating control performance is as follows: "Each Balancing Authority shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes, calculated in accordance with Attachment 2, for the applicable Interconnection in which the Balancing Authority operates." This measure replaces CPS2. See NERC BAL-001-2.

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.”

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,[393] (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.

Regulation clearing prices for the past five years are shown in Table 7-3 below.[394]

Table 7-3: Regulation Prices

Year	Regulation Service Clearing Price ($/Mile)			Regulation Capacity Clearing Price ($/MW per Hour)		
	Min	Avg	Max	Min	Avg	Max
2017	0.00	0.34	10.00	0.00	29.23	1,010.16
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

In 2021, regulation service prices were unchanged compared to the prior year. In 2020 and 2021, the average service price was $0.21/mile. Mileage payments represent a small share of overall regulation payments (17% or $4.3 million in 2021).

Regulation capacity prices increased by 19% in 2021, 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 to the ISO. The increase in opportunity costs is consistent with a significant increase in real-time energy market LMPs, which almost doubled in 2021 compared to 2020. The increase in incremental cost savings is affected by other regulation offer

[393] Opportunity costs represent the expected value to the regulation resource of foregone energy market opportunities, when providing regulation. The ISO adjusts capacity offer prices for these estimated opportunity costs. Additionally, the ISO also adjusts capacity offer prices to include “incremental cost savings.” Incremental cost savings represent the reduction in total system cost provided by a specific regulation offer, when compared to the next most expensive offer.

[394] The prices in the table are simple average prices for each year.

components, and reflects the cost difference between the marginal offer and the next most expensive offer.

In 2020, regulation capacity prices decreased by 27% compared to 2019; this reflected a large decline in the "opportunity cost" component of regulation capacity pricing, which was consistent with a significant decline in real-time energy market LMPs (by 24%). Similarly, the large decrease in regulation capacity prices in 2019, compared to 2018, resulted from a large decline in the "opportunity cost" component of regulation capacity pricing.

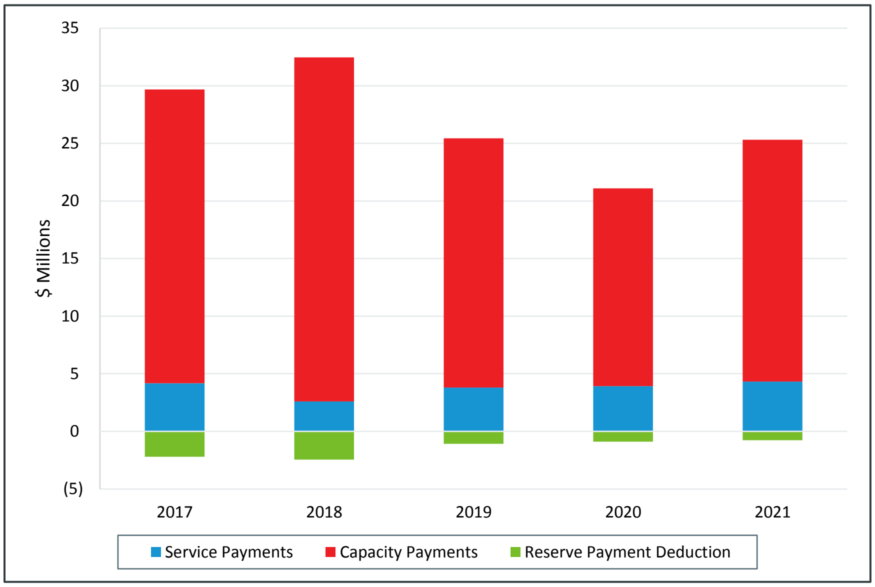
7.3.2 Regulation Payments

Compensation to generators providing regulation includes a regulation capacity payment, a service payment, and a make-whole payment. Starting in March 2017 with the sub-hourly settlement of several market activities (including real-time operating reserves), a deduction was added to regulation payments. This deduction represents the over-compensation of regulation resources for providing operating reserves. 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 settlement of regulation resources includes the deduction for the over-compensation of providing operating reserves.[395]

Annual regulation payments over the past five years are shown in Figure 7-11 below. 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.

[395] The reserve payment deduction represents the MW quantity overlap of the regulating range and operating reserve range, multiplied by the operating reserve price.

Figure 7-11: Regulation Payments[396]



Payments to regulation resources totaled $25.3 million in 2021, 20% more than the $21.1 million in 2020 (these totals exclude the reserve payment adjustment). The increase in 2021 payments resulted from a 22% increase in capacity payments; this increase in capacity payments is consistent with the above-noted increase in capacity prices (19%) and a small increase in committed regulation capacity (3%) in 2021.

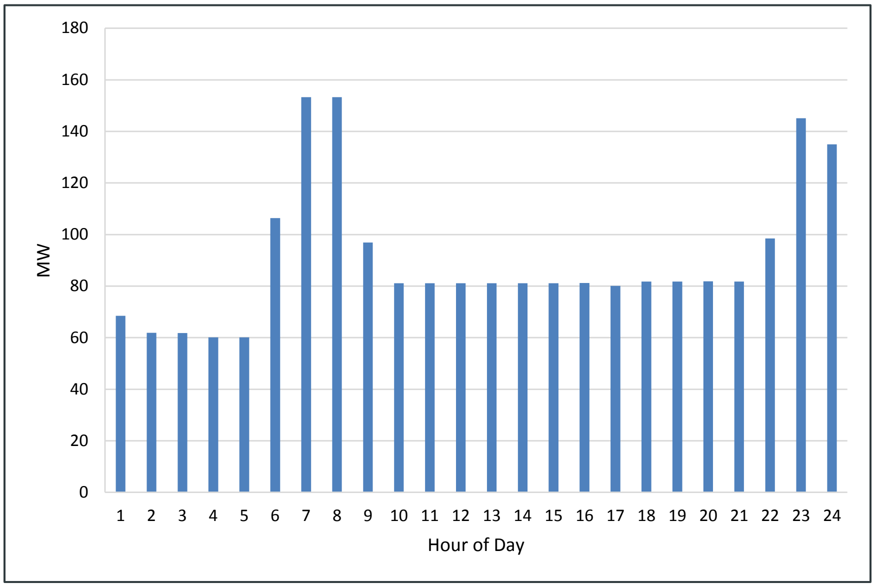
The lower payments in 2020 resulted primarily from a significant decline in capacity prices in that year. The capacity component of regulation payments accounted for 81% of total regulation compensation in 2020. The decline in payments from 2018 to 2019 also resulted from a decline in energy market opportunity costs and reduced capacity prices. Regulation payments totaled $32.5 million in 2018, a 9% increase from the $29.7 million in 2017. In 2018, the average regulation requirement increased by 12%, which led to a commensurate increase in regulation capacity utilization. A 3% decrease in average regulation capacity prices helped to moderate the increase in overall regulation payments.

7.3.3 Requirements 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 2021 is shown in Figure 7-12 below.

[396] In the chart, 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.

Figure 7-12: Average Hourly Regulation Requirement, 2021



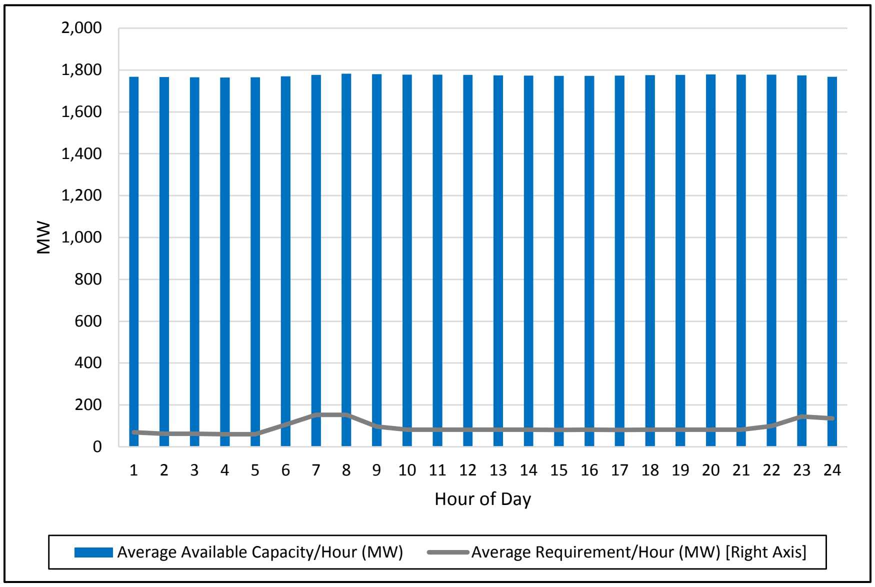
The average hourly regulation requirement of 90.7 MW in 2021 was slightly higher than the 89.9 MW requirement in 2020. This 0.8 MW (0.8%) increase represents a negligible change in the requirement.

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 2021, there were no BAAL violations.

7.3.4 Regulation Market Structural Competitiveness

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 2021. For these reasons, we believe that the regulation market was competitive in 2021. Figure 7-13 below indicates the regulation requirement relative to available supply.

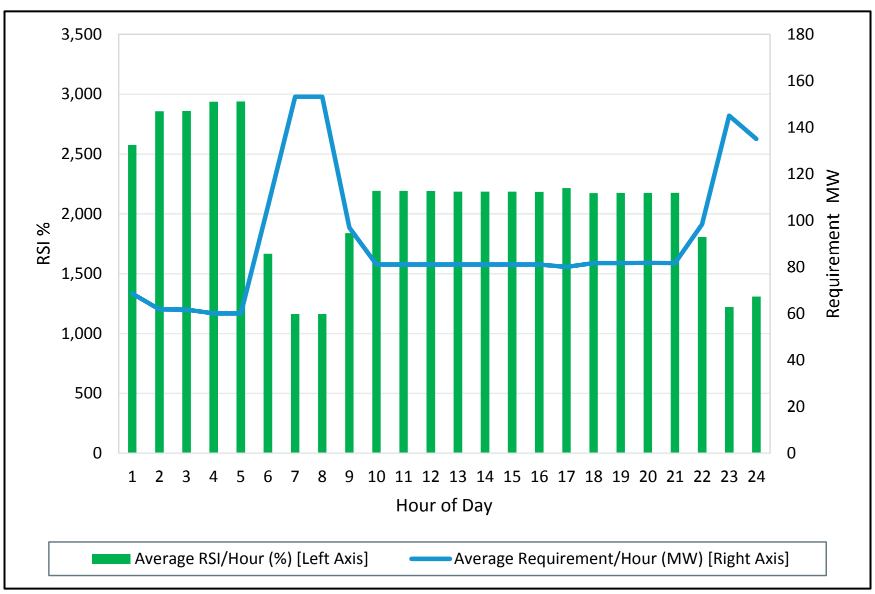
Figure 7-13: Average Regulation Market Requirement and Available Capacity, 2021



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. It measures how much of the regulation requirement can be met without any regulation supply from the largest supplier. An RSI below 100 indicates the presence of a pivotal suppler (i.e., supply from the largest regulation supplier is needed to fulfill the regulation requirement). As shown in Figure 7-14, the regulation requirement (right axis) and RSI (left axis) are inversely correlated (the lower the requirement the higher the RSI).

Figure 7-14: Average Regulation Requirement and Residual Supply Index



In 2021, 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 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.[397]

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
FCA Parameters Review	Interim Compensation Treatment
Removal of Appendix B from Tariff	FERC Order 2222, Distributed Energy Resources
Transmission Cost Allocation to Network Customers with Behind-the-Meter Generation	Competitive Capacity Markets without a Minimum Offer Price Rule (MOPR)
Competitive Transmission Solicitation Enhancements	New England's Future Grid Initiative
Extended-Term Transmission Planning Tariff Changes	Resource Capacity Accreditation (RCA) in the Forward Capacity Market

8.1 Major Design Changes Recently Implemented

The following subsections provide an overview of changes recently implemented.

8.1.1 FCA Parameters Review

FERC issued orders on updated FCA parameters

In 2020 and 2021, as part of its triannual review process, the ISO submitted to FERC updated values for several FCA parameters: the dynamic de-list bid threshold (DDBT), cost of new entry (CONE), Net CONE, performance payment rate (PPR), and offer review trigger prices (ORTPs).

Dynamic De-list Bid Threshold (DDBT)

On March 1, 2021, FERC accepted the ISO's proposed new methodology for calculating the DDBT.[398] The DDBT determines which FCA de-list bids are reviewed for supply-side market power. Previously the tariff did not specify a calculation method and the value was updated every three years. Under the new "recalibration method", the DDBT will be updated every FCA based in part on the auction's expected demand curve and the prior FCA's supply conditions.[399] This approach aims to balance the objectives of preventing supply-side market power, limiting unnecessary

[397] An overview of key ISO projects is also available on the ISO website at https://www.iso-ne.com/committees/key-projects

[398] FERC, *Order Accepting Tariff Revisions,* Docket No. ER21-782-000 (March 1, 2021), https://www.iso-ne.com/static-assets/documents/2021/03/er21-782-000.PDF

[399] ISO New England Inc. and New England Power Pool, *Market Rule 1 Change to Implement New Methodology for Calculating Forward Capacity Market Dynamic De-List Bid Threshold*, FERC filing, Docket No. ER21-782-000 (December 31, 2020), https://www.iso-ne.com/static-assets/documents/2020/12/ddbt_filing.pdf

interference in the capacity market, and using a transparent and robust approach. In its submitted comments, the IMM generally supported the recalibration method.[400]

Cost of New Entry (CONE), Net CONE, and Performance Payment Rate (PPR)

On December 31, 2020, as amended on March 30, 2021, the ISO filed proposed updated values for CONE, Net CONE and the PPR. FERC found the ISO's calculations to be consistent with the tariff and its assumptions just and reasonable with one exception: the Commission determined that the ISO should include gas compression equipment cost when modeling the hypothetical reference unit used to calculate Net CONE.[401] The ISO subsequently submitted a compliance filing, which FERC accepted, resulting in CONE, Net CONE, and PPR values for FCA 16 of $12.40/kW-mo, $7.468/kW-mo, and $9,337/MWh, respectively.[402]

Offer Review Trigger Prices (ORTPs)

On April 7, 2021, the ISO and NEPOOL submitted a "jump ball" filing to FERC with alternative proposals for updating the ORTPs.[403] The primary differences between the ISO and NEPOOL proposals were the ORTPs for off-shore wind (FCA Starting Price versus $0.00/kW-month), photovoltaic solar ($1.381 versus $0.00/kW-mo), and lithium-ion battery storage ($2.912 versus $2.601/kW-mo). FERC accepted most of the ISO proposed FCA 16 values, but preferred NEPOOL's proposed ORTP for batteries (as well as its ORTP adjustment for solar for FCAs 17 and 18.)[404]

Table 8-2 below compares the FCA 15 parameter values to the FCA 16 values proposed by the ISO and the parameters ultimately accepted by FERC.

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[400] IMM, *Comments of the Internal Market Monitor on the Recalculation of the Dynamic De-List Bid* Threshold, Docket No. ER21-782-000 (January 21, 2021), https://www.iso-ne.com/static-assets/documents/2021/01/imm_comments_ddbt.pdf

[401] FERC, *Order Accepting, in Part, Tariff Revisions, Subject to Condition and Directing Compliance Filing,* Docket No. ER-21-787-001 (May 28, 2021), https://www.iso-ne.com/static-assets/documents/2021/05/er21-787-000_05-29-2021_order_cone.pdf

[402] ISO New England Inc., *Compliance Filing (Updates to CONE, Net CONE, and Capacity Performance Payment Rate)*, FERC filing, Docket No. ER21-787-001 (June 11, 2021), https://www.iso-ne.com/static-assets/documents/2021/06/cone_net_cone_compliance_filing.pdf

[403] ISO New England Inc. and New England Power Pool, *Joint Filing of ISO New England Inc. and New England Power Pool Regarding Offer Review Trigger Prices*, FERC filing, Docket No. ER21-1637-000 (April 7, 2021), https://www.iso-ne.com/static-assets/documents/2021/04/offer_review_trigger_prices_filing.pdf

[404] FERC, *Order Accepting in Part and Rejecting in Part Proposed Tariff Revisions and Directing Compliance,* FERC filing, Docket No. ER-21-1637-000 (June 7, 2021), https://www.iso-ne.com/static-assets/documents/2021/06/er21-1637-000_ortp_jumpball_order_6-7-2021.pdf

Table 8-2: FCM Parameter Values (in $/kW-mo unless otherwise stated)

Parameter	FCA 15 Value	ISO Proposed Value for FCA 16	FERC Accepted Value for FCA 16
CONE	$11.951	$11.978	$12.400
Net CONE	$8.707	$7.114	$7.468
PPR	$5,455/MWh	$8,894/MWh	$9,337/MWh
ORTP: Gas CT	$7.161	$5.355	$5.355
ORTP: Gas CC	$8.967	$9.811	$9.811
ORTP: Onshore Wind	$0.000	$0.000	$0.000
ORTP: Offshore Wind	FCA Starting Price	FCA Starting Price	FCA Starting Price
ORTP: Li-ion Battery	N/A	$2.912	$2.601
ORTP: Photovoltaic Solar	N/A	$1.381	$1.381
ORTP: Load Management	$1.008	$0.750	$0.750
ORTP: DR- On-Peak Solar	N/A	$5.414	$5.414
ORTP: Energy Efficiency	$0.000	$0.000	$0.000

Note: The ISO's proposed CONE, Net CONE, and PPR values are from its March 30, 2021 filing. [405]

8.1.2 Removal of Appendix B from Tariff

FERC accepted proposal to eliminate Appendix B

In August 2021, FERC accepted the joint filing by the ISO and NEPOOL to eliminate Appendix B of Market Rule 1.[406] The appendix was a procedure for sanctioning market participants for noncompliance or wrongdoing. The ISO and IMM had determined that Appendix B was unnecessary, unused, and inconsistent with recent FERC rulings, and brought a proposal to remove it through the complete stakeholder process. The NEPOOL Participants Committee voted to support the proposal (60.12% in favor), and in June 2021, the ISO and NEPOOL made a joint filing to FERC.

As explained in the filing letter, all potential violations of the Tariff, FERC Orders, or regulations are already subject to referral by the IMM under Appendix A and FERC regulation.[407] Appendix B was part of the tariff before the ISO added a referral protocol to Appendix A (see Tariff Section III.A.19) in response to FERC Order No. 719 issued in 2008. When the ISO adopted the new protocol, it left Appendix B in place. However, Appendix B proved to be an unused sanctioning procedure with various unnecessary provisions.

8.1.3 Transmission Cost Allocation to Network Customers with Behind-the-Meter Generation

FERC accepted Participating Transmission Owners (PTO) proposal in February 2022

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[405] ISO New England Inc., *Response to Commission Deficiency Notice and Revised CONE, Net CONE, and Capacity Performance Payment Rate Values*, FERC filing, Docket No. ER21-787-000 (March 30, 2021), https://www.iso-ne.com/static-assets/documents/2021/03/er21-787-001_iso_deficiency_response.pdf

[406] FERC, Letter Order Accepting ISO New England Inc.'s et al June 28, 2021 Filing of Revisions to its Transmission, Markets and Services Tariff to Remove Appendix B, Titled "Imposition of Sanctions by the ISO", Docket No. ER-21-2220-000 (August 13, 2021), https://www.iso-ne.com/static-assets/documents/2021/08/er21-2220-000.pdf

[407] ISO New England Inc., Tariff Revisions to Remove Appendix B Titled "Imposition of Sanctions by the ISO" And All References Thereto from Market Rule 1 of the Tariff, FERC filing, Docket No. ER-21-2220-000 (June 28, 2021), https://www.iso-ne.com/static-assets/documents/2021/06/appendix_b_removal.pdf

In our Spring 2020 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.[408] 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.[409] On July 1, 2021, the Participating Transmission Owners Administrative Committee (PTO AC), joined by the ISO,[410] filed a proposal to modify the monthly Regional Network Load (RNL) calculation to exclude BTM generation. In its filed comments, the IMM described why the PTO proposal was deficient and should be rejected.[411] In February 2022, FERC issued an order accepting the PTO's proposal effective September 1, 2021.[412]

8.1.4 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.[413] 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

[408] 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

[409] 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

[410] 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 at 1 n.4 ("the ISO does not take a position on the proposed revisions").

[411] 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

[412] 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

[413] 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/

the competitive transmission planning process.[414] In February 2022, FERC issued an order accepting the ISO's filing.[415]

8.1.5 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 state mandates and policies as a routine planning practice."[416] In February 2022, FERC accepted the proposed tariff changes.[417]

In 2022, the ISO will begin the project's next phase, which will potentially allow states to consider options for addressing issues identified in transmission analyses and cost allocation.

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 future years.

8.2.1 Interim Compensation Treatment

Planned implementation for winters 2023/24 and 2024/25

In February 2019, the ISO filed proposed market rule changes to implement an interim solution to compensate and incent inventoried energy during winter months. The program is known as Interim Compensation Treatment (ICT).[418] The ICT is also intended to reduce the likelihood that an otherwise economic resource might seek to retire from the wholesale energy and capacity markets because of inadequate compensation for its winter energy security attributes.

Using a standard two-settlement structure, ICT allows resources to sell up to 72 hours (3-days) of inventoried energy to be held during trigger conditions[419] either at a forward settlement rate of $82.49 per MWh for the winter season or a spot settlement rate of $8.25 per MWh for inventoried energy maintained during each trigger condition. Eligible resources that choose to participate in the program must submit certain information, including the quantity of inventoried energy it elects to sell forward, no later than October 1st preceding the winter season. If a resource sells inventoried

[414] 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

[415] 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

[416] NESCOE, *Report to the Governors* (June 2021), https://nescoe.com/wp-content/uploads/2021/06/Advancing_Vision_Report_6-29-21.pdf

[417] 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

[418] ISO New England Inc., *Inventoried Energy Program,* Docket No. ER19-1428-000 (March 25, 2019), https://www.iso-ne.com/static-assets/documents/2019/03/inventoried_energy_program.pdf

[419] A trigger condition occurs when the average of the daily high and low temperature is 17°F or lower.

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. The spot settlement rate represents the rate that resources are paid (or charged) for deviations between the quantity of inventoried energy sold forward and the quantity of inventoried energy maintained during trigger conditions.

By administratively setting these forward and spot settlement rates several years in advance, the ISO's intention is to provide greater revenue certainty to generators with inventoried energy, which in turn allowed generators to reflect such revenue streams in their bidding strategies for FCAs 14 and 15.

8.2.2 FERC Order 2222, Distributed Energy Resources

Compliance proposal filed in February 2022

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).[420] 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[421], 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.[422] 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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[420] 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

[421] A "participant 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.

[422] 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

8.2.3 Competitive Capacity Markets without a Minimum Offer Price Rule (MOPR)

MOPR elimination filing submitted in March 2022

In March 2022, the ISO and NEPOOL jointly filed proposed tariff changes to transition New England away from the MOPR. The proposal would eliminate the core components of the MOPR (i.e., offer review trigger prices) as well as the substitution auction effective FCA 19 (capacity commitment period June 2028–May 2029). There would be 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 would be reinstated, which would allow a greater number of sponsored policy resources to enter the market.[423]

In June 2021, the ISO began a stakeholder process to eliminate MOPR effective for FCA 17 (i.e., with no transition period).[424] The ISO, however, acknowledged at the start of the project that there were risks associated with MOPR's elimination.[425] During the process, the IMM expressed concerns with the proposal; the IMM stated that although the MOPR creates potential barriers to states achieving their decarbonization goals and can result in an "over-procurement" problem, there are market performance risks posed by MOPR's removal.[426]

Ultimately, a stakeholder sponsored proposal to eliminate MOPR with a two-year transition period gained ISO support. Additionally, in light of the ISO's preference for the transition, five of the six states did not oppose it (although they supported a more immediate MOPR reform). At its February 2022 meeting, the NEPOOL Participants Committee supported the transition proposal with a 69.56% vote in favor. Eliminating the MOPR with a transition period creates a definitive MOPR end date (FCA 19), allows more sponsored policy resources to enter the market in the interim (FCAs 17 and 18), and gives the ISO time to develop ongoing market design initiatives that will help mitigate risks posed by MOPR's elimination.

8.2.4 New England's Future Grid Initiative

Reports published in 2022

In 2021, the ISO undertook major analyses 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

[423] The RTR exemption would be 300 MW in FCA 17 and 400 MWs in FCA 18 (less CASPR MWs in FCA 17). During the transition period, the substitution auction test price would also be eliminated.

[424] ISO New England Inc., Revisions to ISO New England Transmission, Markets and Services Tariff of Buyer-Side Market Power Review and Mitigation Reforms, FERC filing, Docket No. ER22-1528-000 (March 31, 2022), https://www.iso-ne.com/static-assets/documents/2022/03/mopr_removal_filing.pdf

[425] See ISO memo to NECPUC, NESCOE, NEPOOL dated May 17, 2021 https://www.iso-ne.com/static-assets/documents/2021/05/a0_memo_on_elimination_of_mopr.pdf

[426] See IMM Presentation to NEPOOL Market Committee on December 7, 2021 https://www.iso-ne.com/static-assets/documents/2021/12/a02c_mc_2021_12_07_09_imm_presentation_mopr.pptx

The IMM also provided considerable feedback on the ISO's proposed buyer-side mitigation rules; see IMM memo to NEPOOL Markets Committee dated October 12, 2021 https://www.iso-ne.com/static-assets/documents/2021/10/a03b_mc_2021_10_13_14_iso_ne_memo_preliminary_views_post_mopr_self_certification_proposal.pdf grid.[427] 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 "to assess and discuss the future state of the regional power system in light of current state energy and environmental laws."[428] 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 2021, following NEPOOL's request, the ISO began work on Phase 1 of the FGRS using stakeholder-defined scenarios and performing engineering and economic analyses to identify potential grid reliability challenges in 2040. The ISO plans to issue a draft executive report for Phase 1 in June 2022. Phase 2 of the FGRS is expected to involve a gap analysis to identify any potential market deficiencies based on the results of Phase 1.

Pathways to the Future Grid

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 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 results and findings of this work were released in the Pathways Study report.

8.2.5 Resource Capacity Accreditation (RCA) in the Forward Capacity Market (FCM)

Stakeholder process to begin in Q2 2022

The ISO's resource capacity accreditation project aims to assess and implement methodologies of accrediting resources in the FCM that will better reflect their contributions to resource adequacy.

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[427] See p. 12 of the *NEPOOL 2021 Annual Report* https://nepool.com/wp-content/uploads/2021/12/Annual_Report_2021.pdf

[428] 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

During 2021, the ISO held technical sessions with stakeholders to discuss approaches to resource accreditation, such as Effective Load Carrying Capability (ELCC). In recent years, other ISOs/RTOs have proposed or implemented ELCC-based accreditation reforms. ELCC and related approaches are often viewed as more accurate at measuring a resource's contribution to overall resource adequacy (as compared to the heuristic type methods currently employed) and seen as increasingly important to adopt as the resource mix evolves.

The ISO plans to initiate a stakeholder process for this project in mid-2022 with the goal of submitting a filing to FERC in 2023 and having tariff changes effective for FCA 19.